

Westcoast Energy Inc.

Annual Report 1998



Focus & Execution

Westcoast Energy Inc.

Focus & Execution

We will focus and execute to become one of the few big North American energy companies by providing superior energy services value to our customers.

Natural gas is the clean-burning, economical and plentiful energy source that fuels Westcoast Energy's network of gathering, processing, transportation, storage, distribution and power generation operations.

The managed growth of these core businesses has positioned Westcoast Energy as a leading energy company with assets of \$11 billion, and as a partner of choice for new major pipeline projects across North America.

Through the development of competitive businesses in energy marketing and retail, information and financial services, the Company continues to progress towards its goal of becoming a provider of superior energy services value to its customers.

Westcoast Energy will rely on the talents and dedication of its 6,000 employees as it builds on the foundation of its asset-based businesses, establishes new energy-related services initiatives, increases its involvement in the electric power industry, finds growth opportunities in areas of existing market presence, and aims for above-average financial returns.

Annual Meeting

The Annual Meeting of Shareholders of Westcoast Energy Inc. will be held in the Pacific Ballroom of the Hotel Vancouver in Vancouver, British Columbia, on Thursday, April 29, 1999, 11:00 a.m. (Local time).

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Financial Summary

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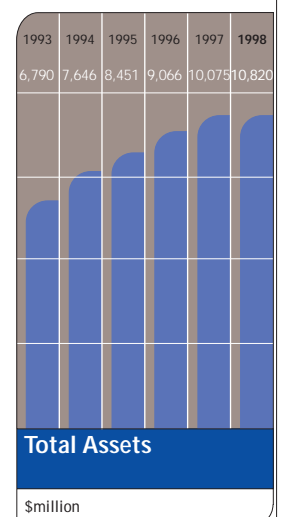
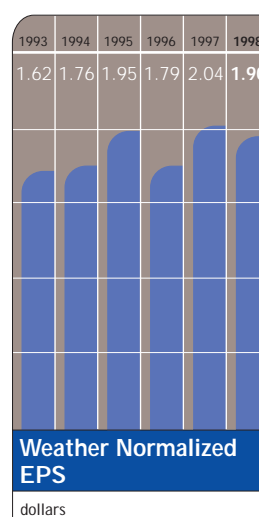
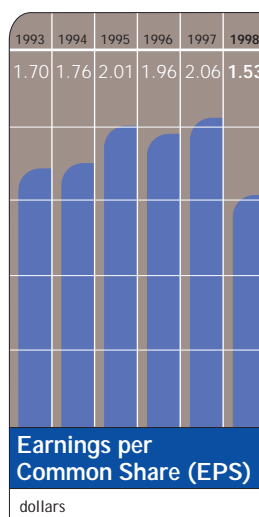
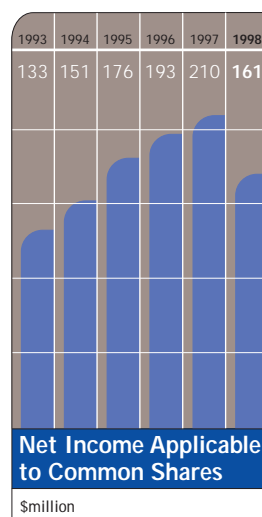
Westcoast Energy Inc.

- Net income applicable to common shares was \$161 million in 1998, \$49 million lower than in 1997. This performance was influenced by warm weather conditions in the Company's Ontario and Manitoba natural gas distribution markets, and by a number of unusual items.
- In 1998, capital expenditures and investments exceeded \$1 billion, a 28% increase from 1997. These expenditures provide a foundation for the Company's future earnings growth.
- In the second quarter of 1998, the Company raised its quarterly common share dividend from \$0.31 to \$0.32, an increase of 3.2% and the sixth dividend increase in five years. This increase reflects the solid underlying fundamentals of the Company and the positive long-term outlook for natural gas and electricity related businesses.
- During 1998, Westcoast Energy's common share price declined from \$33.00 to \$30.50 (TSE). This decline in the Company's common share price, combined with an annual common share dividend of \$1.26, resulted in a total 1998 common shareholder return of -3.8%. This return is slightly higher than The Toronto Stock Exchange Pipelines Sub-Index, the Company's industry peer group, which recorded a total return of -4.8%. The Toronto Stock Exchange 300 Index, a broad measure of Canadian equity market performance, recorded a total return of -1.6%.
- In 1998, the Company completed public offerings of 7,315,000 common shares and 6,000,000 preferred shares. The proceeds from these share issues, totalling approximately \$372 million, strengthen the Company's financial position in support of its 1999 capital expenditure program.

For the years ended December 31 (\$million)

FINANCIAL

	1998	1997	1996
Operating revenues	7,376	7,312	4,875
Net income	198	238	212
Net income applicable to common shares	161	210	193
Operating cash flow	448	522	543
Total assets	10,820	10,075	9,066
Per common share (dollars)			
– Earnings	1.53	2.06	1.96
– Dividends	1.26	1.20	1.05



Chairman's Letter

Annual Report 1998

Westcoast Energy Inc.



Michael E.J. Phelps
CHAIRMAN AND CHIEF EXECUTIVE OFFICER

In 1998, Westcoast Energy took several major steps to position itself for continued growth in the coming years. In this letter, I want to address these developments and outline what we intend to do to strengthen our earnings and our businesses in the months and years ahead.

Following three years of record earnings, our 1998 results were as follows:

- Net income applicable to common shares was \$161 million in 1998, compared with \$210 million in 1997, \$193 million in 1996 and \$176 million in 1995.

- Earnings per common share were \$1.53 in 1998, compared with \$2.06 in 1997, \$1.96 in 1996 and \$2.01 in 1995.

I would note that our growth in the last decade has been substantial. Our revenues have grown tenfold, from \$729 million in 1988 to \$7.3 billion in 1998. Our assets have grown fivefold, from \$2.2 billion in 1988 to \$10.8 billion in 1998. Our net income applicable to common shares, on a weather normalized basis, has grown fourfold, from \$52 million in 1988 to \$201 million in 1998.

A number of factors contributed to the lower level of earnings in 1998. The most significant was the weather – in Canada we experienced the warmest year on record. These warmer temperatures eroded demand for energy and, when compared with 1997, reduced Westcoast Energy's 1998 earnings by 39 cents per common share.

If we exclude the impact of weather, and before any adjustments for unusual items, earnings per common share were \$1.90 in 1998 compared with \$2.04 in 1997.

Weather is weather – we can, and are, mitigating the effects of unusually warm temperatures on our bottom line through a continued focus on operational performance. These efforts will help offset the negative effects of warmer weather on our financial results.

In 1998, we absorbed losses from a number of unusual items, including Centra Gas Manitoba's disallowed natural gas price management activities and third-party defaults at Engage Energy. Earnings were also reduced due to start-up costs for our new retail energy services business and costs relating to our Year 2000 program.

While no one can be content with a drop in earnings, I would point out that during 1998 we also experienced positive results in many of our business operations. We began new pipeline projects, opened new markets and created new businesses. Our British Columbia Pipeline and Field Services divisions had another exceptional year and again made a strong contribution to earnings. We achieved continued customer and rate base growth in our natural-gas distribution businesses, as well as higher service and rental revenues. All of these factors helped significantly, but in total only partially mitigated the impact of warmer weather.

Canada's resource-based economy has felt the substantial impact of global economic turmoil, particularly the retrenchment in the Asian economies. This has affected investor confidence, stock market values, and the availability and cost of capital. Uncertainty and volatility worldwide have changed investor appetites for risk and forced companies, including Westcoast Energy, to review their business strategies.



JANUARY

January 22

Westcoast Energy formed an alliance to offer natural gas services to Atlantic Canadians through the pursuit of natural gas distribution rights in Nova Scotia and New Brunswick.

FEBRUARY

February 25

Westcoast Energy launched its information services subsidiary Enlogix with a \$25-million contract to manage 325,000 residential and commercial utility customer accounts for The City of Calgary.

MARCH

March 31

Westcoast Energy agreed to sell its wholly owned natural gas distribution subsidiary Centra Gas Alberta for \$61 million.

As a company, we remain confident with our broad direction and our goal. This confidence is evident in our capital investment plans. Your Board of Directors has approved capital spending of \$1.6 billion for 1999, the largest expenditure budget in Westcoast Energy's history.

In my view, the key to success as we manage these investments - and as we enter the new century - can be summed up in two words: **focus and execution**. We have chosen these words as the theme of this year's report to shareholders because they will guide our activities in the years ahead.

Focusing is a matter of setting rigorous criteria around how we invest and enhance the assets entrusted to us. We will, for example, ensure that our core businesses have sufficient resources available to them to continue their profitability and to ensure that they remain a solid foundation for new ventures. Focusing also means that we will evaluate new projects against tough minimum risk and return criteria. This will likely result in taking on fewer, but potentially more profitable, opportunities. Those areas that do not meet our intended goals will be sold or discontinued.

Execution is critical to the success of a business such as ours. Without efficient execution, even the best projects will not generate the intended results. Where we believe it is wise, we will also seek new partners to increase the probability of successful execution.

This takes us, again, to the issue of corporate risk. In an uncertain and volatile global economic climate, lower-risk investments have the advantage. As we re-focus our deployment of assets on a narrower set of opportunities, apply tougher criteria to new and existing ventures and execute our activities well, we are **in reality** reducing the risk profile of the Corporation.

I believe that the strategies we have in place, combined with a more focused effort and the expertise and dedication of our people, will allow the Company to thrive and prosper in the years ahead. But a sharp focus and solid execution in all of our activities is crucial.

Where are we headed and how do we get there?

It is in the context of 'focus and execution' that I wish to expand on our strategies for achieving our goal and reaching our earnings target of \$3.00 per share by 2001.

As a company, Westcoast Energy strives to provide superior energy services value to its customers and, in the process, to become one of the few big successful North American companies in an industry that is rapidly converging and consolidating. Continued growth in the continental energy sector has widened our industry's playing field. But it has also shortened the list of participants as companies are acquired, merged and realigned. We intend

to be one of the big companies on that larger playing field. And we plan to be in the winner's circle.

To achieve that goal we have committed ourselves to the following core strategies:

- To build on the foundation of our core asset-based businesses;
- To establish new, energy-related services businesses;
- To increase the density of our activities in geographic areas where we already have significant assets and market presence;
- To increase our presence and involvement in the electric power industry;
- To tap the energies and talents of our employees; and
- To achieve above-average financial returns.

Although external factors may challenge our commitment to these strategies, I firmly believe that if we remain focused and execute our strategies with care and precision, we will be successful - and we will move ahead of the competition.

Building on the foundation of our core asset-based businesses

New pipelines

More than 40 years ago, Westcoast Energy was created to build a pipeline and processing plants to connect natural gas supplies in

APRIL	MAY	JUNE
<p>April 30 Westcoast Energy announced the conversion of a heavy fuel oil generating station in New Brunswick to a 250-megawatt cogeneration unit that will produce electricity and steam from natural gas. The \$160-million Bayside Power Project is expected to be in service in early 2001.</p>		<p>June 1 Westcoast Energy received regulatory approval for the January 1, 1999, transfer of existing merchandise-related programs, including energy appliance sales, rentals and services assets valued at approximately \$500 million, from wholly owned natural gas distribution subsidiary Union Gas to wholly owned unregulated retail businesses Union Energy and Westcoast Capital.</p>
		<p>June 19 Westcoast Energy's Centra Gas Manitoba subsidiary was disallowed the recovery of approximately \$27 million of natural gas costs related to price management activities. This resulted in a one-time loss, after recoveries, of \$12 million.</p>
		<p>June 25 Westcoast Energy received NEB approval of the framework for light handed regulation, agreed to by the Company and its customers, of the Field Services Division's natural gas gathering and processing services. Transmission services will continue to operate under the multi-year incentive-based toll settlement approved by the NEB in August 1997.</p>

northeast British Columbia to markets in the B.C. Lower Mainland and the United States. We began as pipeliners and our pipeline infrastructure remains one of the two largest contributors to our net income and to our future growth prospects.

The business environment for new North American pipeline projects is positive. This is clear from the expeditious regulatory approval of a number of major pipeline projects and from the market acceptance and affirmation of the economic viability of these ventures. Further affirmation comes from the strong support shown by shippers, by financial institutions and – last but not least – from the continued market growth for natural gas.

Westcoast Energy has a long history of excellence in pipeline operations and we intend to continue investing substantial capital into these businesses. Today, we are a major partner in many of the largest and most advanced pipeline projects in North America. And, in this regard, for Westcoast Energy and our partners, 1998 was a banner year.

- Following approvals by both the National Energy Board (NEB) in Canada and the Federal Energy Regulatory Commission (FERC) in the United States, construction of the **Maritimes & Northeast Pipeline** is underway in both Canada and the U.S. The pipeline will be fully operational and generating revenue by the end of 1999. Westcoast Energy is

project manager of the Canadian portion of the pipeline and 37.5 percent owner of the entire pipeline project. We have also applied to the NEB to build about \$200 million of new laterals in Nova Scotia and New Brunswick.

- Westcoast Energy has a major interest in the **Alliance Pipeline Project** to move natural gas from northeast B.C. to markets in the U.S. Midwest, notably Chicago. This is the largest pipeline construction project in North America this decade – a \$4.5-billion, 3,100-kilometre pipeline capable of shipping up to 1.6 billion cubic feet of natural gas per day. During 1998, Westcoast Energy increased its ownership position from an initial 10.5 percent interest to 23.6 percent.
- Westcoast Energy has a one-third interest in the \$600-million **TriState Pipeline Project** that will link western Canadian natural gas to markets in the U.S. Northeast. The TriState Pipeline Project will move natural gas from Chicago to our Union Gas hub at Dawn, Ontario, where it will be available to feed the proposed **Millennium West Pipeline** and **Millennium Pipeline** projects. The Millennium pipeline projects will move natural gas east to growing markets in New York State.

In a few short years, Westcoast Energy will have developed a key stake in a system to

move natural gas from western Canada to the U.S. East Coast – a new west-to-east energy corridor.

These projects show the execution of our strategy. We are focusing on activities at which we excel, in this instance pipelines, in clearly defined geographical areas.

Transforming Pipeline and Field Services

Our B.C. Pipeline and Field Services divisions remain a core business for us. Their contribution to our bottom line this year, a record \$104 million, shows yet again that this business provides a superior return on the equity committed. In 1998, we focused on transforming this business to meet new market challenges. And we have already seen positive financial results.

In June, the NEB gave final approval to a light handed regulatory framework, developed directly with our customers. This new regulatory framework applies to natural gas gathering and processing services and, in conjunction with multi-year incentive-based toll settlements for transmission services, creates a partnership-based relationship with our customers in B.C.

While current industry conditions have led to a reduction in budgets for exploration and development in oil, natural gas development expenditures are less affected. Natural gas remains a growth sector in a period of low international oil prices. Natural gas is the right industry, we are on

JULY

July 10

Westcoast Energy announced that its 50-50 joint venture energy trading company Engage Energy had incurred a loss due to customer defaults on electricity trading. The Company's share of the one-time loss was \$14 million.

AUGUST

August 27

Westcoast Energy announced its 45% interest in an international consortium contracted to construct and operate a 250 million cubic feet per day offshore gas compression and liquids recovery facility in Mexico. The \$420-million Campeche Natural Gas Compression Services Project, scheduled for service in early 2000, will increase natural gas recovery from the Cantarell oil field for delivery into Mexico's expanding national pipeline system.

SEPTEMBER

the right track. The success of this core business is proof of that.

Developing on our core businesses in distribution

The second cornerstone of our core business is natural gas distribution. Since the 1992 acquisition of Union Gas to supplement our Centra Gas assets in B.C., Manitoba and Ontario and our Pacific Northern Gas subsidiary in B.C., distribution has been a major contributor to our earnings.

Despite the severe impact of warmer weather on revenues last year, our distribution business contributed some \$122 million to our net income. Markets for all of our distribution companies continue to grow, with Union Gas exhibiting a 3 percent growth in customer base in 1998.

In Ontario, we took two important steps to strengthen our distribution business. First, Union Gas completed the integration of Centra Gas Ontario in 1998. Then, on January 1, 1999, we completed the transfer of \$500 million of assets from Union Gas to Union Energy.

In March 1998, we sold our small Centra Gas Alberta business to provide funds to strengthen our core distribution businesses where they are geographically stronger.

We expect a continuation of solid growth opportunities in natural gas distribution. We intend to benefit by continuing to offer superior value to our customers and by aligning these businesses for more flexible, performance-

based regulation, bringing us closer to our customers.

Establishing new, energy-related services businesses

We see growth opportunities in certain new, energy-related service businesses where we have a competitive advantage by reason of our assets and core competencies. This has led to the creation of Union Energy, Enlogix, Engage Energy and Westcoast Capital.

- **Union Energy** was formed to take advantage of unregulated market opportunities in the retail energy services market, including appliance sales, service and installation, equipment financing and energy management. Union Energy has developed a base of established dealers in B.C., Manitoba and Ontario, and now has more than one million customers.
- **Enlogix** was created to bring together our information technology and customer information systems management businesses in an emerging unregulated market. Enlogix has secured a major contract with The City of Calgary to manage the information services and billing requirements for its 325,000 utility customers. It also provides systems for other Westcoast Energy companies, and is a significant component of our Year 2000 program.

- **Engage Energy**, a 50-50 joint venture with The Coastal Corporation, was formed in 1997 to enter the natural gas and electricity trading market in North America. Engage Energy is actively involved in natural gas and electricity trading in both Canada and the U.S. While the Engage Energy joint venture has presented some start-up challenges, ultimately its marketing and trading activities represent risk mitigation potential as we are exposed to some further degree of competition.
- **Westcoast Capital** was created as a financial services arm to develop financing solutions for customers, including the Westcoast Energy group of companies. Westcoast Capital has already been instrumental in the asset transfer from Union Gas to Union Energy. It will become a more significant part of our energy services business as it builds its financial portfolio.

We have real opportunities and real challenges in these new ventures – we must ensure that we are offering superior energy services value to customers, and we must ensure that the right people are delivering the goods. These start-up enterprises require our full and active corporate support, and an intensive system of corporate oversight to minimize business risks.

In their unregulated markets, these new ventures have higher profit potential commensurate with a higher level of risk.



OCTOBER

October 19

Westcoast Energy acquired the remaining 60% interest in the Island Cogeneration Project to become sole owner of the \$235-million, 250-megawatt natural gas fired cogeneration facility to be constructed at a pulp and paper mill near Campbell River, B.C.

NOVEMBER

November 3

Westcoast Energy began clearing the 568-kilometre right-of-way for the Canadian portion of the Maritimes & Northeast Pipeline. The Company is responsible for the \$830-million Canadian portion of the \$1.7-billion pipeline which will deliver more than 500 million cubic feet of natural gas per day to markets in Nova Scotia, New Brunswick and New England. The Canadian and U.S. portions of the 1,051-kilometre main pipeline are scheduled for service in November 1999.

November 10

Westcoast Energy announced the development of a 500-megawatt natural gas fired electrical generation plant in Pennsylvania. The Liberty Power Project, expected to cost about \$450 million to develop, will supply energy to the Pennsylvania-New Jersey-Maryland interconnected power pool, a major crossroads of the growing transmission grid where electricity is bought and sold for large markets in the mid-Atlantic U.S.

November 26

Westcoast Energy announced a 1999 capital spending program of \$1.6 billion, the largest in its history.

Increasing our presence in the electric power industry

The convergence of natural gas and electricity as complementary, and often interchangeable, sources of energy provides us with growth prospects. We have for, some years, been active in electric power generation. As a significant Canadian independent power producer, this is a business we know well. We will continue to pursue alliances and acquisitions in electric power, and we will continue to allocate resources to support the growth of this business. In North America, we are currently developing power projects in New Brunswick, on Vancouver Island in B.C. and in Pennsylvania. The total generation capacity of these three projects alone amounts to some 1,000 megawatts.

Re-focusing our International Activities

One of our corporate strategies was to increase Westcoast Energy's international presence. Given today's increased emerging market volatility, and a lower investor tolerance for risk, we have chosen to focus our international activities in the near term in Mexico and in two other countries where power projects are already either well advanced or in full operation.

We have a 32.5 percent interest in a 50-megawatt power project under construction in Shanghai, and have increased our investment in our Irian Jaya power project in Indonesia. The Irian Jaya

power facility has been expanded, and in late 1997 we increased our interest in it to 43 percent. In 1998, it contributed \$8.0 million to our earnings.

We have a 20 percent interest in the \$1.5-billion Cantarell Nitrogen Project and a 45 percent interest in the \$420-million Campeche Natural Gas Compression Services Project. In both of these we partnered with a group of experienced international companies to provide services under contractual arrangements with subsidiaries of PEMEX, Mexico's national oil company. This is a considerable capital commitment year for both projects. Construction at Cantarell is about 60 percent complete with operations to start in April 2000. The Campeche project is expected to be in service in early 2000.

As Mexico becomes increasingly integrated into a North American economy, we believe that our activities there represent relatively secure investments with manageable risk. These projects will also broaden our investment in a growing continental energy market. They will be on-stream in 2000, providing revenues and contributing to our earnings.

Seeking above-average financial returns

We intend to manage our assets to achieve above-average financial returns and future growth, while minimizing risk.

This year we divested several non-strategic assets at attractive prices. We sold Centra Gas Alberta for \$61 million; in December we sold our 50 percent interest in the Eastern Gas Pipeline Project in Australia for \$27 million. These sales allow us to redirect funds into ventures with the potential for greater financial returns.

In November, the Board authorized the issuance of 7,315,000 common shares, at a price of \$30.30 per share, for total proceeds of \$222 million. The proceeds will be used to finance our portfolio of investments while maintaining a prudent balance of debt and equity.

Our target remains to reach earnings of \$3.00 per share by 2001. This is a stretch target. To achieve this goal we need to execute on all of our planned projects. We need to ensure that our TriState, Millennium West and Millennium pipeline projects to move natural gas east from Chicago are developed quickly and effectively. Finally, we need to ensure that our services businesses contribute positively to earnings over the next three years.

The Year Ahead

We believe that we are on track with our strategy and we intend to stay the course. The natural gas business is a growth business. Demand for natural gas, and for the services we provide, is growing for direct

DECEMBER

December 17

Westcoast Energy acquired an additional interest in the \$4.5-billion Alliance Pipeline Project, designed to transport up to 1.6 billion cubic feet of natural gas per day from Western Canada to the Chicago area. The Company has a 23.6% interest in the 3,100-kilometre pipeline project scheduled for service in October 2000. Westcoast Energy and its partners have received the necessary Canadian and U.S. regulatory approvals required for construction.

December 17

Westcoast Energy filed a NEB application for construction of the \$165-million Millennium West Pipeline Project, a 75-kilometre pipeline from the Union Gas storage facilities at Dawn, Ontario, to Lake Erie. The pipeline, designed to transport 700 million cubic feet of natural gas per day, would connect to the proposed Millennium Pipeline Project, a 611-kilometre pipeline extension from eastern Canada to New York. Westcoast Energy has a 21% interest in the \$950-million Millennium Pipeline Project, expected to be in service in late 2000.



December 22

Westcoast Energy announced the sale of its 50% interest in the Eastern Gas Pipeline Project for \$27 million. The 800-kilometre Australian pipeline, to extend from Melbourne, Victoria, to Sydney, New South Wales, was at the construction-ready stage of development.

consumption by industry, commerce and individual customers, for use by power generators, and for replacement as a preferred fuel by energy consumers throughout North America. Prices should remain healthy.

We are in the right business. Our corporate goal - providing superior energy services value - and our efforts to provide equally superior financial results will continue to direct our activities.

We will, however, be adjusting some key business strategies to narrow the focus, and the geographic areas, of our activities to ensure the execution of key projects and initiatives.

We will build on the foundation of our core business activities of transportation and distribution and ensure that they remain strong.

We will improve upon the specific competitive advantages of our various core businesses, particularly distribution, and strengthen our ties with customers all along the value chain. The world is becoming more competitive; our focus on our customers reflects their importance to us.

We will accelerate the completion of our west-to-east pipeline transportation route, including the TriState, Millennium West and Millennium pipeline projects. We will develop a real North American footprint in the marketplace.

We will continue to position our energy services business activities for

profitability, first to support their assets, second for future growth. We will monitor their progress closely.

We will continue to increase our presence and involvement in power generation opportunities, particularly in geographic areas where we already have core businesses.

We will monitor and measure performance more closely across all of our businesses.

And we will continue our efforts to encourage and bring out the best in our people.

We anticipate that 1999 will be a year of many challenges. We believe that our focus on North America is the prudent one. We also believe that we have chosen the appropriate combination of investments that, when executed successfully, will achieve above-average returns for our shareholders.

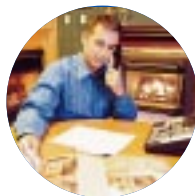
We recognize that we face new and different types and levels of risk. We have established a business risk management team and are developing reporting and monitoring systems to help us manage these business risks.

We are in the middle of an aggressive capital expenditure program. By any standard, our 1999 \$1.6-billion investment program is large. Above all, this is a manifestation of our confidence in our strategic direction and our faith in our capacity to deliver on our strategic goal.

1999 will demand focus, diligence and exceptional execution on the part of all of us at Westcoast Energy.

The support of our Board of Directors and the contribution of all of our employees to this year's achievements has been outstanding. We all share a common commitment to achieving the goals we have set for 1999 and beyond.

"signed Michael E. J. Phelps"
 "Chairman and Chief Executive Officer"
 March 1, 1999



JANUARY

January 18
 Westcoast Energy's Union Energy subsidiary purchased an additional three heating, ventilation and air conditioning (HVAC) businesses, bringing Union Energy's total HVAC investments in B.C., Manitoba and Ontario to 18 businesses with annual revenues of approximately \$66 million.



FEBRUARY

January 21
 Westcoast Energy announced the filing of a NEB application for the proposed TriState Pipeline Project, designed to deliver between 450 million and one billion cubic feet of natural gas per day from Chicago, through Michigan, to the existing Union Gas hub at Dawn, Ontario. The Company has a 33.3% interest in the project which, based on a capacity of 450 million cubic feet per day, is expected to cost approximately \$600 million. An application for the project, scheduled to begin service in November 2000, was also filed with the U.S. FERC in November 1998.

Corporate Profile

Annual Report 1998

Westcoast Energy Inc.

<p>TRANSMISSION & FIELD SERVICES</p> <p>Westcoast Energy's transmission and field services businesses operate natural gas gathering and processing facilities and transport natural gas, through strategic pipeline connections, on the North American pipeline grid.</p> <p>Operating Revenues \$672 million</p>	<p>British Columbia Pipeline and Field Services Divisions (100% OWNED)</p> <p>Westcoast Gas Services (100% OWNED)</p> <p>St. Clair Pipelines (1996) (100% OWNED)</p> <p>Empire State Pipeline (50% OWNED)</p> <p>Foothills Pipe Lines (50% OWNED)</p>	<p>Maritimes & Northeast Pipeline (37.5% OWNED)</p> <p>NrG Information Services (50% INTEREST)</p> <p>Sulphur Products (50% INTEREST)</p> <p>Alliance Pipeline (23.6% OWNED)</p>
<p>GAS DISTRIBUTION</p> <p>Westcoast Energy's gas distribution businesses serve 1.4 million Canadian customers with safe, reliable and cost-effective natural gas delivery, storage and transmission.</p> <p>Operating Revenues \$2,070 million</p>	<p>Union Gas (100% OWNED)</p> <p>Centra Gas Manitoba (100% OWNED)</p> <p>Centra Gas British Columbia (100% OWNED)</p>	<p>Pacific Northern Gas (41% OWNED, 100% OF VOTING SHARES)</p> <p>Trillium Energy Canada Trillium USA (100% OWNED)</p>
<p>POWER GENERATION</p> <p>Westcoast Energy's power generation businesses build and operate facilities to generate thermal and electrical energy from natural gas.</p> <p>Operating Revenues \$95 million</p>	<p>Westcoast Power (100% OWNED)</p> <p>Island Cogeneration Project (100% OWNED)</p>	
<p>INTERNATIONAL</p> <p>Westcoast Energy's international operations apply the Company's technical and commercial skills to the development of energy infrastructure projects in select geographies.</p> <p>Operating Revenues \$48 million</p>	<p>Westcoast Energy International (100% OWNED)</p> <p>Campeche Natural Gas Compression Services Project (45% INTEREST)</p>	<p>P.T. Puncakjaya Power (43% OWNED)</p> <p>Shanghai Power Project (32.5% INTEREST)</p> <p>Cantarell Nitrogen Project (20% OWNED)</p>
<p>SERVICES</p> <p>Westcoast Energy's services businesses offer retail energy equipment and service, customer information management, financing, energy management, and natural gas and electric power marketing services.</p> <p>Operating Revenues \$4,486 million</p>	<p>Union Energy (100% OWNED)</p> <p>Enlogix (100% OWNED)</p> <p>Westcoast Capital (100% OWNED)</p>	<p>NGX Canada (100% OWNED)</p> <p>Engage Energy (50% OWNED)</p>
<p>OTHER ACTIVITIES</p> <p>Westcoast Energy's other activities include energy projects, currently under development, corporate expenses and income tax benefits.</p> <p>Operating Revenues \$5 million</p>	<p>PROPOSED</p> <p>Millennium West Pipeline Project (100% OWNED)</p> <p>Bayside Power Project (100% OWNED)</p> <p>McNab Liquefied Natural Gas (LNG) Project (100% INTEREST)</p>	<p>Liberty Power Project (50% INTEREST)</p> <p>TriState Pipeline Project (33.3% INTEREST)</p> <p>Millennium Pipeline Project (21% INTEREST)</p>

Strategic Corporate Goal

Annual Report 1998

Westcoast Energy Inc.

It is Westcoast Energy's corporate goal to become one of the few big North American energy companies by providing superior energy services value to its customers.

We will focus and execute to achieve this goal using six key strategies:

To build on the foundation of our core asset-based businesses.

"Our British Columbia Pipeline and Field Services divisions continue to record success in the new light handed regulatory environment. Our incentive-based settlement gives us an opportunity to tailor services to individual customers on competitive terms."

Arthur Willms, President and Chief Operating Officer

To establish new, energy-related services businesses in energy marketing, retail, information and financial services.

"With the transfer of assets from Union Gas, and the acquisition of 18 heating, ventilation and air conditioning businesses in British Columbia, Manitoba and Ontario, Union Energy has established itself as a leader in the Canadian retail energy services sector."

Michael Phelps, Chairman and Chief Executive Officer

To increase the density of our activities in geographic areas where Westcoast Energy already has significant assets and market presence.

"Development of the proposed TriState, Millennium and Millennium West pipeline projects will increase use of the existing Union Gas hub at Dawn, Ontario, and create a key destination and delivery point for growing markets in the northeast United States."

Jim Anderson, Senior Vice President, Strategic Development

To increase our presence and involvement in the electric power industry.

"Westcoast Energy is a significant independent electric power producer. We will continue to look for greenfield opportunities and acquisitions in electric power services to capture the potential provided by the convergence of natural gas and electricity as interchangeable energy options."

Michael Stewart, Executive Vice President, Business Development

To tap the energies and talents of our employees.

"Our reputation for providing employment and growth opportunities for people based on their ability to do the job, regardless of gender, ethnic origin or disability, will ensure that we remain an employer of choice."

Bohdan Bodnar, Vice President, Human Resources and Administration

To achieve above-average financial returns.

"We have narrowed the focus of our North American and international investments. We intend to develop projects where we can capitalize on our long-standing industry experience and achieve above-average returns over the long term."

Graham Wilson, Executive Vice President
and Chief Financial Officer

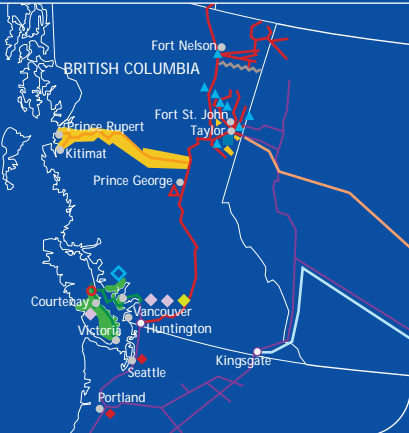
Systems & Strategic Pipeline Connections

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Westcoast Energy Inc.

British Columbia Operations

Canada



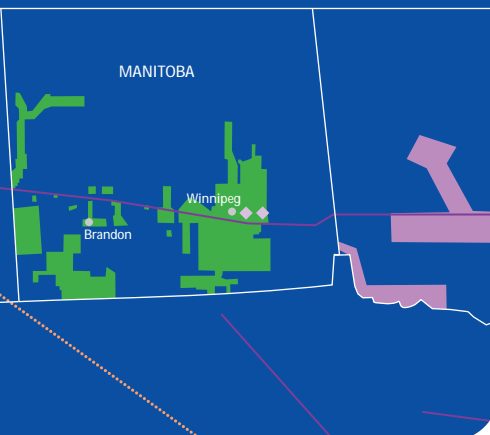
Alberta Operations

Canada



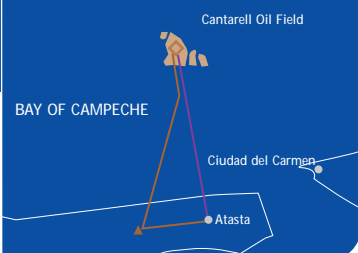
Manitoba Operations

Canada



Cantarell Oil Field

Mexico



Ontario

Canada

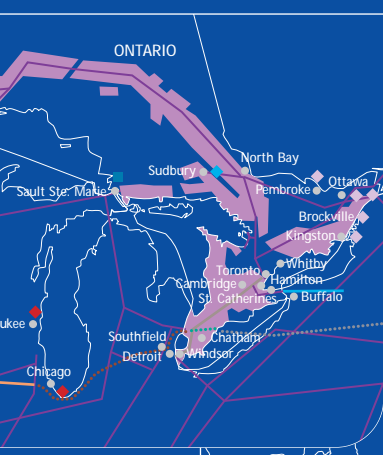


Maritime

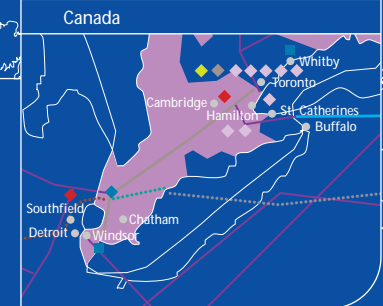
Canada



Operations



Southern Ontario Operations



Shanghai Power Project

China

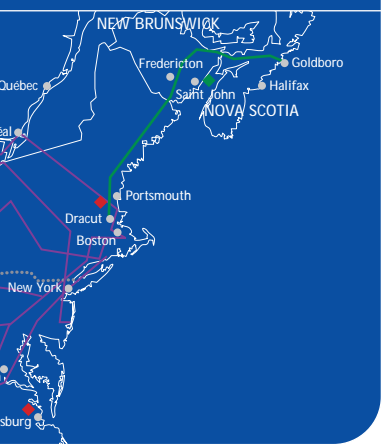


P. T. Puncakjaya Power

Indonesia



Operations



LEGEND

- British Columbia Pipeline and Field Services Divisions
- Pacific Northern Gas Pipeline
- Pacific Northern Gas Service Area
- Foothills Pipe Lines
- Centra Gas British Columbia Transmission Pipeline
- Centra Gas Service Area
- Union Gas Transmission Pipeline
- Union Gas Service Area
- Empire State Pipeline
- Maritimes & Northeast Pipeline
- Alliance Pipeline
- Cantarell Nitrogen Project Pipeline
- Connecting Pipelines
- Dawn Hub
- Cantarell Nitrogen Project
- Campeche Natural Gas Compression Services Project
- Engage Energy
- Natural Gas Exchange
- Island Cogeneration Project
- Shanghai Power Project
- Union Energy
- Enlogix
- Westcoast Capital
- NrG Information Services
- Gas Processing Plant
- Power Generation
- Liquefied Natural Gas Storage Facility
- Sulphur Products Plant
- Export Meter Station
- Fort Nelson Powerline
- Gas Flow
- Future Gas Flow

PROPOSED PROJECTS

- McNab Liquefied Natural Gas Project
- Liberty Power Project
- Bayside Power Project
- TriState Pipeline Project
- Millennium West Pipeline Project
- Millennium Pipeline Project

SUSTAINABLE DEVELOPMENT

Westcoast Energy's corporate goal is to provide its customers with superior energy services value. As industry competition intensifies, Westcoast Energy intends to distinguish itself by providing this energy services value, and by building and maintaining the trust of its customers, partners, shareholders and employees.

To build and maintain stakeholder trust, Westcoast Energy is committed to providing superior financial results. This annual report covers, in depth, the scope of Westcoast Energy's activities and its financial results. However, building and maintaining stakeholder trust also requires that the Company protect the environment and employee and public health, offer equal access to employment and promotions and contribute to the success of the communities in which it operates.

CLIMATE CHANGE

Westcoast Energy is working towards a balance between the continued economic growth of the Company's businesses and a reduction in the environmental impact of its activities. The ingenuity and resources aimed at financial and operational success will also be applied to the search for climate change solutions.

While the Kyoto Protocol sets a target for Canadian greenhouse gas emissions reductions, the mechanisms and compliance measures to reach these targets have not yet been set. Westcoast Energy has chosen to take a proactive approach to meeting the challenges of greenhouse gas emissions reduction targets. This approach is focused on the benefits of increased use of natural gas, including:

- Implementing process improvements to reduce greenhouse gas emissions. In its 1998 Voluntary Challenge and Registry Action Plan, the Company reported an 18% decline in greenhouse gas emissions on a per unit of throughput basis between 1990 and 1997.

- Encouraging customers to increase energy efficiency and conserve energy. Westcoast Energy educates its customers to reduce energy usage, to increase use of energy efficient equipment and to shift energy use from peak to non-peak periods. The Company's Union Energy subsidiary is also working with partners and suppliers to develop more efficient natural gas fireplaces and appliances that integrate space heating, water heating and ventilation.
- Encouraging energy users to switch to natural gas. Unlike other fossil fuels, natural gas burns cleaner and results in lower greenhouse gas emissions per unit of energy used. Switching energy users to natural gas can lower residential carbon dioxide emissions by 30%. In 1998, Westcoast Energy's Centra Gas British Columbia subsidiary converted more than 4,200 residential and commercial customers to natural gas.

Westcoast Energy will continue to work in partnership with industry, scientists, governments, corporations and communities to find lasting solutions to climate change.

COMMUNITY INVOLVEMENT


Westcoast Energy listens to, and learns from, the communities in which it operates. In particular, the Company is committed to building long-term relationships with Aboriginal communities based upon mutual respect and economic opportunity.

During the past eight years, Westcoast Energy's Centra Gas British Columbia subsidiary has worked to develop successful business relationships with the Aboriginal communities within its service area. Its work with the Cowichan Band has led to the development of Khowutzun Mustimuhw Contractors Ltd., an Aboriginal-owned contracting firm that employs 65 people and provides more than 30% of Centra Gas British Columbia's distribution installations.

Westcoast Energy's Maritimes & Northeast Pipeline has also identified meaningful business opportunities for Aboriginal communities in Atlantic Canada. In 1998, route-clearing contracts were awarded to two Aboriginal firms in Nova Scotia and New Brunswick, HEF Industries and R. MacLean Forestry. As the project progresses towards its November 1999 in-service date, Aboriginal businesses may also provide construction services and long-term pipeline maintenance.

Building relationships and developing business opportunities is mutually beneficial for Westcoast Energy and Aboriginal communities. It gives the Company an opportunity to contribute education and support for the development of Aboriginal businesses, and gives Aboriginal businesses the ability to provide competitive, quality services to Westcoast Energy.

Our customers, partners, shareholders and employees will play an important role in Westcoast Energy's future – their support will determine the Company's ongoing success. The Company will continue to offer maximum value for our customers' energy dollar. In addition, the Company will build and maintain stakeholder trust through a continued focus on environmental protection and employee and public health and safety, and the execution of its Aboriginal relations, employment equity and corporate contributions programs.



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Management's Discussion & Analysis

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Westcoast Energy Inc.

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 accounting principles generally accepted in Canada and are presented in Canadian dollars. The effects on net income arising from the variances between accounting principles generally accepted in Canada and the United States are described in note 20 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.

CONSOLIDATED OPERATIONS

Net income applicable to common shares was \$161 million in 1998 compared with \$210 million in 1997 and \$193 million in 1996. Earnings per common share were \$1.53 in 1998 compared with \$2.06 in 1997 and \$1.96 in 1996. Excluding the impact of weather and before any adjustment for unusual items, earnings per common share were \$1.90 in 1998 compared with \$2.04 in 1997 and \$1.79 in 1996.

Higher earnings were realized in 1998 compared with 1997 from a number of the Company's operations, including the British Columbia Pipeline and Field Services divisions, new pipeline projects, continued growth in the number of natural gas distribution customers and rate bases, higher service and rental revenues, international operations and the higher utilization of previous years' unrecorded tax losses.

These factors were more than offset by unusually warm weather experienced in the Company's gas distribution franchise areas in 1998 compared with 1997 and 1996. The earnings contribution applicable to the Gas Distribution businesses is subject to weather variances which reduced earnings per common share in 1998 by 39 cents and 54 cents when compared with 1997 and 1996, respectively.

Unusual items that impacted 1998 earnings include the Manitoba Public Utilities Board's (MPUB) disallowance of certain natural gas costs incurred by Centra Gas Manitoba Inc. (Centra Gas Manitoba) related to price management activities, Engage Energy's loss arising from customer defaults, and the write-off of a small non-National Energy Board (NEB) regulated natural gas processing plant. These factors were partially offset by the gains realized on the sale of Centra Gas Alberta Inc. (Centra Gas Alberta) and the sale of the Company's interest in the Australian Eastern Gas Pipeline Project. Together, these unusual items reduced 1998 net income applicable to common shares by 11 cents.

1998 earnings were also reduced by start-up costs related to the Company's retail energy services business, lower allowed rates of return on common equity applicable to the majority of the Company's regulated

businesses, operating losses incurred by the Energy Marketing business, costs related to the Year 2000 program, higher interest expenses and higher financing costs as a result of having significant capital invested in projects under development that are not yet earning income.

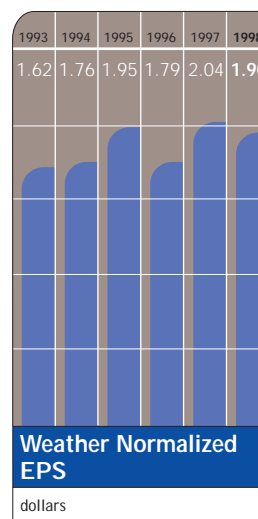
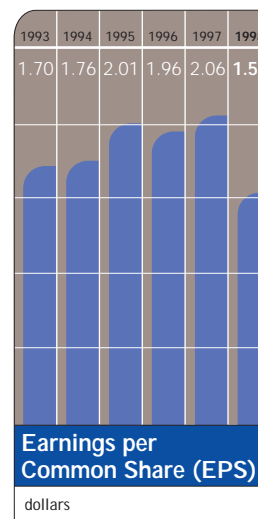
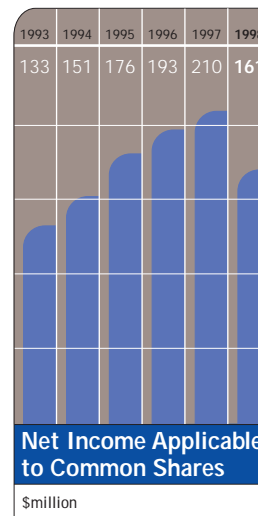
With respect to the previous year's results, there was an increase in net income applicable to common shares in 1997 over 1996 as a result of higher earnings from the Gas Distribution businesses, primarily due to continued growth in the number of customers, customer usage of natural gas, service and rental revenues, as well as an increase in Union Gas Limited's (Union Gas) common equity component of rate base from 29% to 34%. Net income in 1997 was also higher than 1996 due to the utilization of previous years' unrecorded tax losses. In addition, 1996 earnings included a one-time charge of 15 cents per common share for restructuring costs relating to a reorganization of the British Columbia Pipeline and Field Services divisions.

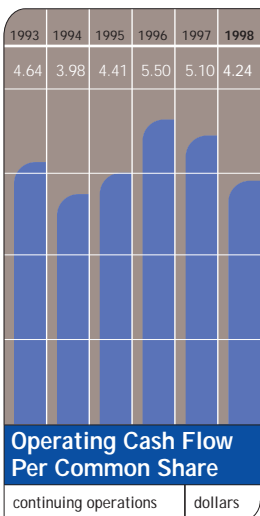
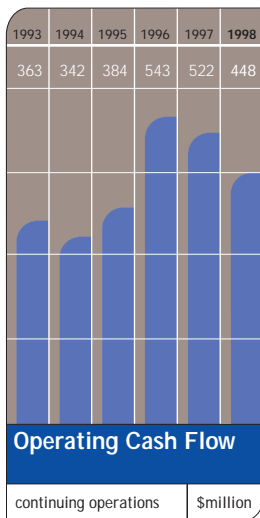
These factors were partially offset by weather that was warmer in 1997 as compared to 1996, a higher loss attributable to the Energy Marketing business, development costs related to the Company's non-regulated retail energy services business, higher preferred share dividends, and lower approved rates of return on common equity applicable to the majority of the Company's regulated businesses.

The increase in operating revenues in 1998 over 1997 primarily reflects increased revenues generated from higher natural gas and electric power volumes traded by Engage Energy, revenues generated from the new heating, ventilating and air conditioning (HVAC) operations acquired by the Company's retail energy services business in 1998 and higher revenues from the Company's Irian Jaya power joint venture, resulting from the acquisition of an additional interest in the power facilities in late 1997, together with an expansion of the facilities. These increases were partially offset by lower revenues from the Gas Distribution businesses due to warmer weather in 1998 compared with 1997.

The increase in cost of sales in 1998 over 1997 reflects increased costs due to higher natural gas and electric power volumes traded by Engage Energy, costs associated with the new HVAC operations acquired in 1998, Engage Energy's loss arising from customer defaults and the MPUB's disallowance of certain natural gas costs incurred by Centra Gas Manitoba related to price management activities.

Operating revenues and cost of sales increased in 1997 over 1996 primarily due to higher volumes of natural gas sales and new electric power trading from Engage Energy. Revenues also increased due to tolls which reflected higher rate bases, higher volumes applicable to the British Columbia Pipeline and Field Services divisions, and higher service and rental revenues





applicable to certain of the Gas Distribution businesses. These increases were partially offset by warmer weather and lower approved rates of return on common equity applicable to the majority of the Company's regulated businesses.

The increase in operation and maintenance expense in 1998 over 1997 and 1996 reflects higher levels of activity in the majority of the operating businesses, the introduction of new businesses, the write-off of a small non-NEB regulated natural gas processing plant and costs relating to the Company's Year 2000 program.

The increase in depreciation expense in 1998 over 1997 and 1996 was primarily the result of higher depreciable capital asset balances in the majority of the operating businesses.

The increase in allowance for funds used during construction in 1998 over 1997 and 1996 primarily reflects the increased investment in the Maritimes & Northeast Pipeline Project.

The increase in investment and other income in 1998 over 1997 and 1996 reflects the gains realized on the sale of Centra Gas Alberta and the sale of the Company's interest in the Australian Eastern Gas Pipeline Project, as well as income recorded from the Company's equity investment in the Alliance Pipeline Projects. Included in investment and other income for 1998 are equity earnings from the Alliance Pipeline Projects, which relate to allowance for funds used during construction recorded by the Alliance Pipeline Projects.

The interest expense increase in 1998 over 1997 and 1996 was primarily due to higher short term interest rates and increased borrowings as a result of investments in projects under development.

The high level of other non-operating expenses in 1996 compared with 1998 and 1997 was primarily due to the costs relating to the reorganization of the British Columbia Pipeline and Field Services divisions.

The income tax provision decrease in 1998 relative to 1997 and 1996 was primarily due to the utilization of previous years' unrecorded tax losses. The effective consolidated income tax rate for 1998 was 19.0% compared with 33.4% in 1997 and 34.2% in 1996. Details of the consolidated income tax provisions are provided in note 3 to the consolidated financial statements and a discussion of other taxes is noted below under Taxation.

The increase in the provision for dividends on preferred shares in 1998 over 1997 reflects preferred shares issued in September 1998 and December 1997. The increase in the provision for dividends on preferred shares in 1997 over 1996 reflects preferred shares issued in December 1997 and 1996 as detailed in note 17 to the consolidated financial statements.

RESULTS BY BUSINESS SEGMENT

Effective for years ending after January 1, 1998, accounting principles generally accepted in Canada require the disclosure of segmented information based on the Company's internal reporting system. As a result, the Company's disclosure now includes results specifically relating to the International and

Services business segments. Further changes in segmented information include:

- discontinuing the practice of allocating certain corporate financing costs to business segments. These costs are now included in the Other business segment; and
- the inclusion of business development expenditures and costs related to projects under development in the Other business segment. Once a project has received all the required approvals to proceed, it will be included in the applicable business segment.

Segmented information for prior years has been restated to reflect the changes noted above.

The results 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 and information technology and financial services;
- Other – other activities, including corporate expenses, business development expenditures, corporate financing expenses and utilization of previous years' unrecorded tax losses.

The contribution to net income applicable to common shares by these business segments, after allocation of acquisition costs, was:

Years ended December 31 (\$million)	1998	1997	1996
NET INCOME (LOSS) APPLICABLE TO COMMON SHARES			
Transmission & Field Services	128	114	92
Gas Distribution	122	161	150
Power Generation	6	11	11
International	16	5	4
Services	(46)	(15)	(5)
Other	(65)	(66)	(59)
	161	210	193

The contribution to consolidated operating cash flow after non-cash working capital changes by these business segments, after allocation of acquisition costs, was:

Years ended December 31 (\$million)	1998	1997	1996
CASH FLOW FROM OPERATING ACTIVITIES			
Transmission & Field Services	234	195	202
Gas Distribution	283	328	351
Power Generation	25	31	34
International	30	2	(2)
Services	(65)	3	1
Other	(59)	(37)	(43)
Operating cash flow	448	522	543
Non-cash working capital changes	(19)	(16)	(45)
	429	506	498

The decrease in consolidated operating cash flow before non-cash working capital changes for 1998 over 1997 and 1996 was primarily due to lower earnings in 1998.

Additional segmented information is provided in note 19 to the consolidated financial statements.

TRANSMISSION & FIELD SERVICES

The operating businesses included in this segment consist of the British Columbia Pipeline and Field Services divisions, the non-NEB regulated Field Services Division, Foothills Pipe Lines Ltd. (Foothills), Empire State Pipeline, the Maritimes & Northeast Pipeline Project, the Alliance Pipeline Projects, St. Clair Pipelines (1996) Ltd. (St. Clair), NrG Information Services Inc. (NrG) and a sulphur products facility.

The contribution to net income applicable to common shares for Transmission & Field Services was:

Years ended December 31 (\$million)	1998	1997	1996
NET INCOME (LOSS) CONTRIBUTION			
British Columbia Pipeline and Field Services divisions	104	94	73
Non-NEB regulated Field Services Division	(7)	1	1
Foothills	9	9	10
Empire State Pipeline	10	8	8
Maritimes & Northeast Pipeline	9	4	-
Alliance Pipeline	4	-	-
Other	(1)	(2)	-
	128	114	92

The increase in the contribution to net income applicable to common shares for Transmission & Field Services in 1998 over 1997 is primarily due to higher earnings realized by the Company's British Columbia Pipeline and Field Services divisions under the multi-year incentive-based toll settlement which was approved by the NEB in 1997. Under the multi-year incentive-based toll settlement, which was implemented effective January 1, 1997, gathering and processing tolls are partially indexed to natural gas prices in representative market areas served by gas transported through the system. These gas prices were higher in 1998 than in 1997 resulting in higher revenues. In addition, 1998 interruptible toll revenues from the British Columbia Pipeline and Field Services divisions exceeded 1997 levels.

The amount of allowance for funds used during construction recorded by the Maritimes & Northeast Pipeline and Alliance Pipeline projects increased in 1998 as compared to 1997 and 1996 as a result of the higher level of investment in the projects in 1998. These increases, together with higher earnings from the Empire State Pipeline due to a stronger U.S. dollar and the payment received on the cancellation of a transportation contract by one shipper, were partially offset by the write-off of a small non-NEB regulated natural gas processing plant as a result of the low level of development and the decline in natural gas production in the area served by the plant.

The increase in the contribution to net income applicable to common shares for Transmission & Field Services in 1997 over 1996 was primarily due to a one-time charge in 1996 of \$26 million (\$15 million after-tax) relating to a reorganization of the British Columbia Pipeline and Field Services divisions. Additional earnings were realized in 1997 from allowance for funds used during construction recorded by the Maritimes & Northeast Pipeline Project.

British Columbia Pipeline and Field Services Divisions

The Company's integrated natural gas gathering, processing and transmission system in British Columbia, Alberta, and the Yukon and Northwest Territories consists of approximately 5,700 kilometres of natural gas transmission pipelines and five gas processing plants which include three sulphur recovery plants. These facilities are regulated by the NEB.

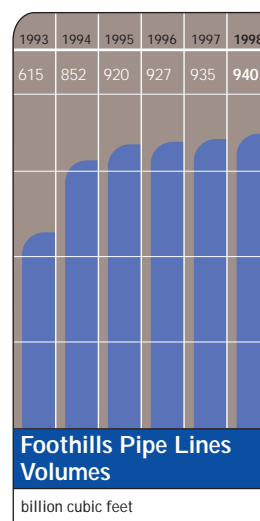
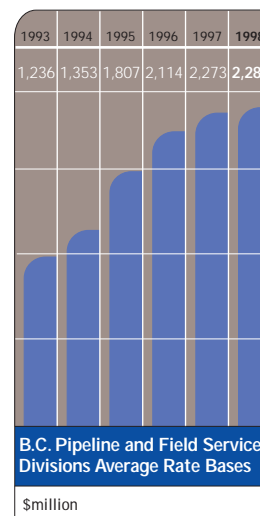
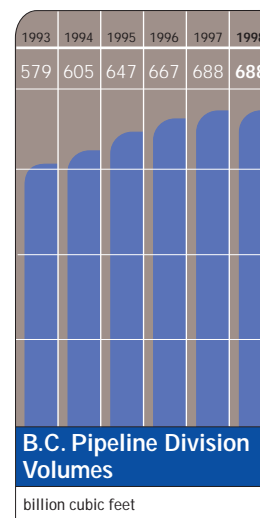
Natural gas is delivered to markets in British Columbia, other parts of Canada and the western United States. Total throughput on the transmission mainline in 1998 was 688 billion cubic feet (Bcf), the same as the record levels achieved in 1997 and higher than the 667 Bcf transported in 1996.

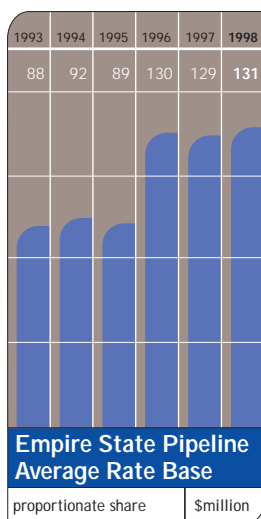
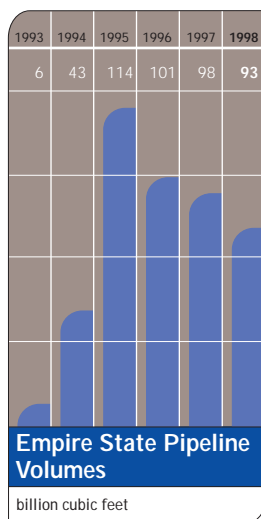
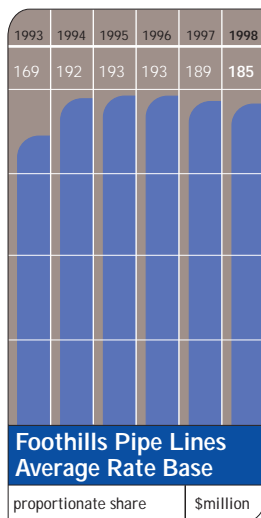
Incentive-Based Regulation

The continuation of the multi-year incentive-based toll settlement beyond December 31, 1997 was subject to agreement by the Company and its customers and other stakeholders on the principles of light-handed regulation and its applicability to the gathering and processing services provided by the Company. In January 1998, the Company and its stakeholders agreed to a framework for light-handed regulation. This framework became effective immediately upon approval by the NEB in June 1998.

The framework amends the multi-year incentive-based toll settlement applicable to the Company's gathering and processing services. The framework defines the principles under which the Company negotiates individual service contracts with shippers, including the tolls applicable to gathering and processing services. Consistent with these principles, the Company is responsible for the utilization of its gathering and processing assets and, accordingly, tolls for service are no longer based on the cost of service method of regulation.

The multi-year incentive-based toll settlement provided gathering and processing shippers the one-time option of contracting for fixed base tolls for 1, 3, or 5-year service. The base tolls reflect a 500 basis point reduction from the NEB prescribed rate of return on common equity for 1997 of 10.67% and are subject to a monthly surcharge based on an index of monthly gas prices. The gas price sensitive monthly surcharge allows the Company the opportunity to earn additional revenue when gas prices rise. Under the framework for light-handed regulation, the Company and its customers negotiate replacement contracts as the business need arises or as the 1, 3, or 5-year contracts expire.





Natural gas prices in 1998 were sufficiently high to allow the recovery of the revenues associated with the 500 basis point reduction and allow a return on equity that exceeded the NEB prescribed rate.

Transmission services continue to operate under the multi-year incentive-based toll settlement which is effective from 1997 to 2001. The settlement provided transmission customers a one-time option of contracting for fixed tolls for a contract term of 5 years, or tolls that are adjusted annually in accordance with a prescribed incentive-based methodology. Fixed tolls for 5-year service were based on a 10.67% return on common equity. Approximately 70% of the customers contracting for firm transmission service elected the 5-year fixed toll option.

Contractual Developments

In April 1998, the Company invited shippers to submit expressions of interest for an expansion of the mainline transmission system. In May 1998, the Company received expressions of interest for additional service effective November 1999, but insufficient contracts were signed to warrant an expansion.

In May 1998, gas gathering volumes of 280 million cubic feet (MMcf) per day, or 14% of total volumes under firm service contracts, were not renewed effective November 1998. Since then, more than 139 MMcf per day of firm service has been recontracted.

Similarly in May 1998, gas processing volumes of 190 MMcf per day, or 11% of total volumes under firm service contracts, were not renewed effective November 1998. Since then, more than 151 MMcf per day of firm service has been recontracted.

Additional service continues to be provided on an interruptible basis. Under light-handed regulation, the Company advertises the available capacity and negotiations regarding contracting of additional volumes are ongoing.

Other

The Company's capital expenditures for the British Columbia Pipeline and Field Services divisions amounted to \$90 million in 1998 and are projected to be \$124 million in 1999. The average rate bases of the British Columbia Pipeline and Field Services divisions were \$2,287 million in 1998, and are projected to be \$2,319 million in 1999.

Non-NEB Regulated Field Services

Westcoast Gas Services Inc. owns interests in four provincially regulated natural gas processing plants.

In 1998, the Company wrote-off its investment in the Buckingham natural gas processing plant due to low drilling activity and production in the area served by the plant.

The Company's capital expenditures for the non-NEB regulated Field Services Division amounted to \$3 million in 1998 and are projected to be \$1 million in 1999.

Foothills

The Company has a 50% interest in Foothills, which currently transports Canadian natural gas to markets in the United States through portions of the Canadian segment of the Alaska Natural Gas Transportation System which were prebuilt (Phase I).

In 1998, a major expansion of the Foothills Eastern Leg was constructed and placed into service. The \$178-million project increased firm export capacity at Monchy, Saskatchewan, by approximately 45% to 2.2 Bcf per day for delivery primarily to U.S. Midwest markets. Foothills now delivers approximately 3.3 Bcf of natural gas per day on its total system, representing more than one-third of Canadian exports to the U.S.

Throughput reached a record volume of 940 Bcf in 1998 compared with 935 Bcf in 1997 and 927 Bcf in 1996.

The rate of return on common equity for Foothills, as prescribed by the NEB, is 9.58% for 1999, compared with 10.21% in 1998. The common equity component of rate base remains at 30%.

Foothills' total capital expenditures amounted to \$169 million in 1998 and are projected to be \$9 million in 1999. The Company has a 27% interest in the average rate base of Foothills' Phase I pipeline system, which was \$685 million in 1998, and is projected to be \$833 million in 1999.

Empire State Pipeline

The Company has a 50% interest in the Empire State Pipeline, located in upper New York State, which indirectly connects the natural gas transportation and storage facilities of Union Gas in Ontario with markets in upper New York State. Total throughput for 1998 was 93 Bcf, compared with 98 Bcf in 1997 and 101 Bcf in 1996. The reduction in 1998 volumes reflects the termination of a transportation contract by an industrial customer and warmer weather in 1998.

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 seven-year average rate base of \$214 million. Empire State Pipeline maintained this rate of return and common equity component for 1998 and 1999.

Pipeline Projects

Maritimes & Northeast Pipeline

The Company has a 37.5% interest in the Maritimes & Northeast Pipeline Project (M&NP), which will transport in excess of 500 MMcf 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 1,051-kilometre main pipeline and associated lateral pipelines are expected to cost approximately \$1.7 billion to construct. The main pipeline is expected to be in service by November 1999.

The Company is responsible for the development of the 568-kilometre main pipeline and associated lateral pipelines in Canada that are estimated to cost approximately \$830 million. Canadian regulatory approvals have been received for the main pipeline and in November 1998, M&NP commenced the clearing of the Canadian portion of the pipeline right-of-way through Nova Scotia and New Brunswick. Clearing work is scheduled for completion in March 1999, with construction to commence thereafter.

In 1998, M&NP filed applications with the NEB for proposed lateral pipeline projects to Point Tupper and Halifax, Nova Scotia and Saint John, New Brunswick. In December 1998, the NEB approved construction of the 59-kilometre, \$21-million Point Tupper lateral pipeline project and construction is proceeding to meet the anticipated in-service date of November 1999. The applications for the \$74-million Halifax and \$90-million Saint John laterals have not yet been heard by the NEB and, as a result, in-service dates for these laterals may be delayed to 2000.

U.S. regulatory approvals have been received for the portion of the pipeline in the United States. Construction of Phase I of the U.S. portion of the main pipeline commenced in mid-1998. Construction of Phase II will commence in the spring of 1999 with an in-service date of November 1999. An application was made to the Federal Energy Regulatory Commission (FERC) in January 1999 to amend the certificate in order to recognize that the initial firm contracts on the U.S. pipeline will be less than originally planned. Levelized rates are now being proposed for the first four years of service for the U.S. pipeline.

Alliance Pipeline

The proposed Alliance Pipeline is designed to deliver up to 1.6 Bcf per day of natural gas from western Canada to the Chicago area. The pipeline is 96% subscribed by shippers with 15-year contracts. Direct capital costs (excluding allowance for funds used during construction) for the 3,100-kilometre pipeline are currently estimated at \$4.5 billion and the Chicago area liquids recovery facilities associated with the pipeline are expected to cost an additional \$525 million.

In December 1998, the Company acquired an additional 9.1% ownership interest in the Alliance Pipeline Projects, increasing the Company's interest in the projects from 14.5% to 23.6%. The Company entered the projects in late 1997 with a 10.5% interest, and has twice purchased additional interests in the projects from existing partners. The Company's total equity commitment to the projects is approximately \$450 million.

Canadian and U.S. regulatory approvals have been received and construction will commence in the second quarter of 1999. The Alliance Pipeline Projects are expected to be in operation in October 2000.

Other

St. Clair

The pipeline facilities of St. Clair connect Union Gas' natural gas transportation and storage facilities to

pipeline and storage facilities in the United States. These connecting pipelines provide increased natural gas supply, storage and transportation options for customers in Canada and the United States. St. Clair also provides management services associated with the construction of the Canadian portion of the Maritimes & Northeast Pipeline Project and the development of the Millennium West Pipeline Project.

NrG

The Company has a one-third interest in NrG, a joint venture project with TransCanada PipeLines Ltd.

NrG has developed a computerized transaction and information service called the NrG Highway. The NrG Highway provides the interface which facilitates electronic commerce between pipelines and their shippers. At year end, NrG was serving over 850 customers and was electronically processing over 90% of the nominations for three pipelines.

Sulphur Products

In February 1999, the Company's participation in the operations of a sulphur products facility at Prince George, British Columbia increased from 32% to 50% pursuant to the original agreement with the other partner in the facility. The facility, which is operated by the Company, produces sulphuric acid, sulphur dioxide and alum for the pulp and paper and fertilizer industries in western Canada and the United States.

GAS DISTRIBUTION

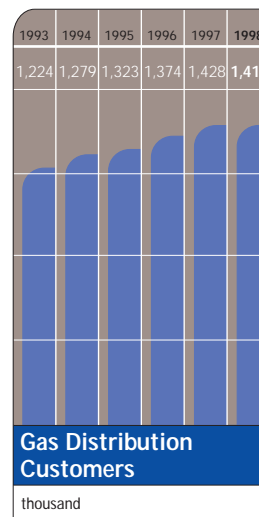
The operating businesses included in this segment primarily consist of the natural gas distribution and transmission and storage businesses of Union Gas, Centra Gas Manitoba, Centra Gas British Columbia Inc. (Centra Gas BC), Pacific Northern Gas Ltd. (PNG) and a business related to natural gas-fuelled vehicles.

These companies distribute natural gas to more than 1.4 million residential, commercial and industrial customers in Ontario, Manitoba and British Columbia.

The allowed rates of return on common equity are decided in each province by the respective provincial regulatory authority. The rates of return on common equity and the common equity components of the respective rate bases of the regulated businesses for 1996 to 1998 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.

The Gas Distribution businesses are also 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.



The contribution to net income applicable to common shares for Gas Distribution was:

Years ended December 31 (\$million)	1998	1997	1996
NET INCOME (LOSS) CONTRIBUTION			
Union Gas ⁽¹⁾	97	128	112
Centra Gas Manitoba	(4)	14	19
Centra Gas BC	12	12	11
PNG	3	3	3
Other ⁽²⁾	14	4	5
	<u>122</u>	<u>161</u>	<u>150</u>

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

(2) includes the gain on the sale of Centra Gas Alberta which was sold in March 1998

The decrease in the contribution to net income applicable to common shares for Gas Distribution in 1998 over 1997 primarily reflects the unusually warm temperatures in most of the Company's gas distribution franchise areas which reduced earnings in 1998 compared with 1997 by \$41 million or 39 cents per common share. In 1998, earnings were reduced by 37 cents due to warmer than normal weather whereas in 1997 and 1996, earnings were higher by 2 cents and 17 cents, respectively, due to colder than normal weather.

The reduction in 1998 earnings also reflects lower allowed rates of return on common equity applicable to most of the Gas Distribution businesses and the MPUB's disallowance of certain natural gas costs incurred by Centra Gas Manitoba related to price management activities. The reduction was partially offset by continued growth in the number of natural gas distribution customers and rate bases, higher service and rental revenues, management of operating and maintenance expenses and the gain realized on the sale of Centra Gas Alberta.

The increase in the contribution to net income applicable to common shares for Gas Distribution in 1997 over 1996 primarily reflects continued growth in number of customers, customer usage of natural gas and service and rental revenues, as well as an increase in the common equity component of the Union Gas rate base from 29% to 34%. The increase in the Union Gas equity component did not apply to the rate base of Centra Gas Ontario Inc., which already had a 36% common equity component.

These positive factors were partially offset by warmer weather in 1997 compared with 1996 in all of the Company's distribution franchise areas, together with lower approved rates of return on common equity applicable to most of the Gas Distribution businesses.

Natural gas volumes delivered by the Gas Distribution businesses were:

Years ended December 31 (Bcf)	1998	1997	1996
VOLUMES			
Union Gas ⁽¹⁾	1,127	1,193	1,137
Centra Gas Manitoba	63	67	72
Centra Gas BC	23	24	24
PNG	36	39	39
Other	11	15	15
	<u>1,260</u>	<u>1,338</u>	<u>1,287</u>
Centra Gas Alberta	6	18	19
	<u>1,266</u>	<u>1,356</u>	<u>1,306</u>

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

The number of customers for the Gas Distribution businesses was:

As at December 31 (thousand)	1998	1997	1996
NUMBER OF CUSTOMERS			
Union Gas ⁽¹⁾	1,075	1,041	1,002
Centra Gas Manitoba	242	239	235
Centra Gas BC	61	55	48
PNG	39	38	36
Other	2	1	1
	<u>1,419</u>	<u>1,374</u>	<u>1,322</u>
Centra Gas Alberta	—	54	52
	<u>1,419</u>	<u>1,428</u>	<u>1,374</u>

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

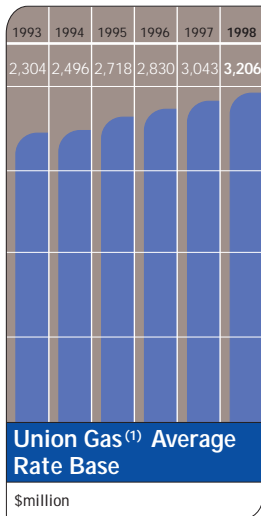
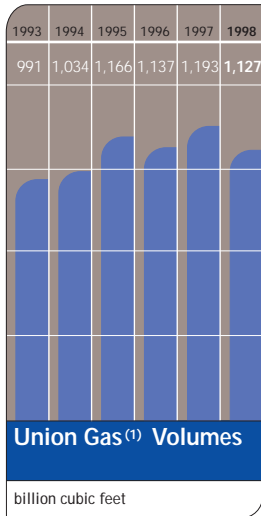
Union Gas

In January 1998, Union Gas Limited and Centra Gas Ontario Inc. were amalgamated. The companies, which were both wholly owned subsidiaries of the Company, had operated under a shared services arrangement since 1994. The amalgamated company continues to carry on the Ontario distribution operations as Union Gas Limited (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 131 Bcf and are the largest in Canada.

Following the approval of the Ontario Energy Board (OEB) in May 1998, Union Gas transferred the operating responsibilities of its retail merchandise and service programs to Union Energy Inc. (Union Energy), an affiliated, non-regulated retail energy services business. This transfer occurred on January 1, 1999 when approximately \$500 million of net assets were acquired by Westcoast Capital Corporation (Westcoast Capital) and Union Energy.

The transferred retail merchandise and service programs include appliance sales and rentals, appliance service work and merchandise financing. Union Energy and Westcoast Capital, as non-regulated businesses, have more flexibility than the regulated utilities to



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

design and package energy products and services to meet customer needs. Union Gas will concentrate on developing and operating new services that emphasize cost effectiveness and reliability in the delivery of natural gas to customers.

In January 1999, the OEB approved 1999 rates for Union Gas based on a rate of return on common equity of 9.61% and a common equity component of 35% on a rate base of approximately \$2.7 billion.

Other Gas Distribution Businesses

Centra Gas Manitoba, Centra Gas BC and PNG transport and distribute natural gas in Manitoba and British Columbia and comprise the Company's Other Gas Distribution operations. Centra Gas Alberta was sold in March 1998.

Centra Gas Manitoba

In June 1998, the MPUB approved the recovery of \$19 million and disallowed the recovery of \$27 million of approximately \$46 million of natural gas costs related to price management activities. Of the \$27 million of disallowed natural gas costs, \$9 million have been recovered from brokers serving the direct purchase market.

The impact of the disallowance, net of recoveries, related items and income taxes is a net reduction to earnings of approximately \$12 million or 12 cents per common share.

The dynamic hedging practices used by Centra Gas Manitoba in its price management program have been discontinued and are not in use at the other Gas Distribution businesses.

In December 1998, Centra Gas Manitoba and the MPUB agreed to a general rate application for 2000 with a review of 1999 interim rates. The application will be filed in June 1999.

Centra Gas BC

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.

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, resulting in a rate of return on common equity of approximately 8.02% for 1999 as compared with 8.59% in 1998.

PNG

The rate of return on common equity for PNG, as determined by the formula approved by the British Columbia Utilities Commission (BCUC), is 10.00% for 1999 compared with 10.75% for 1998, on a common equity component of rate base of 36%.

Centra Gas Alberta

In June 1998, the Company completed the sale of Centra Gas Alberta to AltaGas Services Inc. for \$61 million, resulting in an after-tax contribution to net income of \$14 million or 14 cents per common share. This gain is included in the \$14 million contribution to net income shown as Other in the Gas Distribution business segment.

Gas Distribution Statistics

The average rate bases and capital expenditures for the Gas Distribution businesses for 1998 and projected for 1999 are:

Years ending December 31 (\$million)	1999	1998
RATE BASE		
Union Gas ⁽¹⁾	2,705	3,206
Centra Gas Manitoba	297	287
Centra Gas BC	408	375
PNG	175	168
Other	22	21
	<u>3,607</u>	<u>4,057</u>

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

Years ending December 31 (\$million)	1999	1998
CAPITAL EXPENDITURES		
Union Gas	260	264
Centra Gas Manitoba	21	23
Centra Gas BC	44	37
PNG	11	11
Other	7	4
	<u>343</u>	<u>339</u>

POWER GENERATION

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

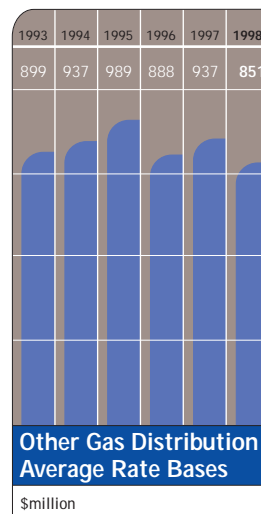
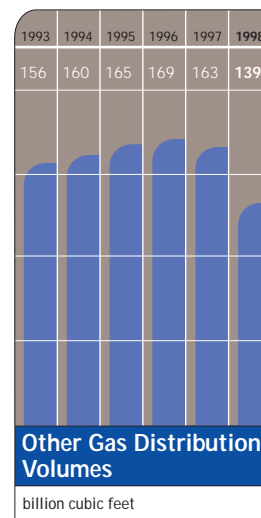
The contribution to net income applicable to common shares for Power Generation was:

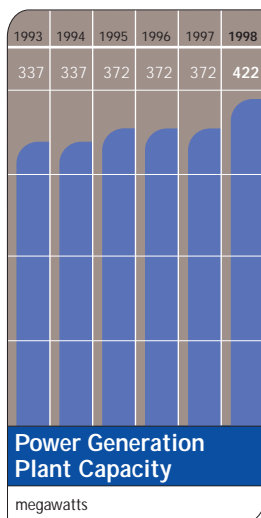
Years ended December 31 (\$million)	1998	1997	1996
NET INCOME CONTRIBUTION	6	11	11

The decrease in the contribution to net income applicable to common shares for Power Generation in 1998 over 1997 and 1996 is primarily due to the shut down of the Fort Frances Cogeneration Plant due to a labour strike at Abitibi-Consolidated Inc., the steam host facility.

Fort Frances Cogeneration

The operations at the Fort Frances Cogeneration Plant were shut down from June to late November 1998 as a result of a labour strike at the adjacent operations of Abitibi-Consolidated Inc., the steam host for the cogeneration plant. As a result, the Fort Frances facility incurred a net loss applicable to common shares of \$2 million in 1998 compared to net income of \$2 million in 1997.





Whitby Cogeneration Plant

The Company is a joint venture partner with Atlantic Packaging Products Ltd. in a 50-megawatt cogeneration plant. The plant, which began commercial operations in September 1998, provides electricity to the provincial power grid and steam to the Atlantic Packaging Products Ltd. paper mill at Whitby, Ontario.

Island Cogeneration Project

In October 1998, the Company acquired Fletcher Challenge Energy Inc.'s 60% interest in the \$235-million Island Cogeneration project (ICP). The Company now has sole ownership of the 250-megawatt cogeneration plant which is under construction at Fletcher Challenge Canada Limited's pulp and paper mill near Campbell River on Vancouver Island, British Columbia.

In late 1998, ICP and BC Hydro signed a 20-year Electricity Purchase Agreement. With the signing of this agreement, all major contracts have been completed and ground breaking was initiated in January 1999. The proposed in-service date for the project is late 2000.

INTERNATIONAL

The operating business included in this business segment is a power generation facility located in Irian Jaya, Indonesia. In addition, this business segment includes two projects under development in Mexico and one project under development in China.

The contribution to net income applicable to common shares for International was:

Years ended December 31 (\$million)	1998	1997	1996
NET INCOME CONTRIBUTION	16	5	4

The increase in the contribution to net income applicable to common shares for International in 1998 over 1997 and 1996 reflects the \$8 million gain on the sale of the Company's interest in the Australian Eastern Gas Pipeline Project and higher earnings applicable to the Company's Irian Jaya power investment in Indonesia. The higher earnings from the Irian Jaya power investment result from an increase in the Company's ownership in the plant from 20% to 43% in December 1997, together with an expansion of the power facilities.

Indonesia – Irian Jaya Power Plant

The Company has a 43% interest in P.T. Puncakjaya Power (PJP) which owns and operates an integrated power generation plant, a related transmission line and associated facilities at the Grasberg mine in Irian Jaya, Indonesia.

The approximately \$800-million PJP power facilities provide electrical power to the Grasberg mine under a long-term contract payable in U.S. funds in the United States. The total generating capacity of the PJP facilities is approximately 388 megawatts.

Mexico - Cantarell Nitrogen Project

The Company has a 20% interest in the Cantarell Nitrogen Project. The project facilities, which are expected to cost approximately \$1.5 billion, will produce 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.

Construction work is underway and the project is approximately 60% complete. The project, scheduled to commence operations during the third quarter of 2000, includes the largest nitrogen processing facilities ever built, a 95-kilometre pipeline system, mainly offshore, and a 200-megawatt natural gas fired power plant. Project financing, on a limited recourse basis, is being arranged.

Mexico - Campeche Natural Gas Compression Services Project

In August 1998, an international consortium in which the Company has a 45% interest, was awarded a five-year take or pay contract by PEP to provide 250 MMcf per day of offshore gas compression and liquids recovery services on a platform in the Cantarell oil field in the Bay of Campeche, Gulf of Mexico. The consortium will construct, own and operate the platform which has an estimated cost of \$420 million.

As a result of the recent deterioration in the international financial markets, limited recourse financing is more difficult and expensive to secure. Pursuant to a provision in the contract, the consortium is claiming price relief from PEP based on the changed financing environment. Under the terms of the contract, the effect of the claim was to suspend the project commencing November 23, 1998, while negotiations between the consortium and PEP proceed. The contract with PEP contains a provision for cost recovery should the project not proceed as a result of these negotiations.

The facility is expected to be in service in early 2000 subject to the satisfactory conclusion of these negotiations.

China - Shanghai Power Project

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

All key commercial agreements, including power purchase and fuel supply contracts, have been executed. A turnkey contract for the engineering, procurement and construction of the power plant has been awarded and construction commenced in September 1998. The plant is scheduled to commence commercial operations in late 1999.

Australia - Eastern Gas Pipeline Project

In December 1998, the Company sold its 50% interest in the Eastern Gas Pipeline Project to a subsidiary of Duke Energy for approximately \$27 million. The disposition resulted in a contribution to net income applicable to common shares of \$8 million or 8 cents per common share.

SERVICES

Included in this business segment are businesses that provide energy services, energy marketing, retail energy, information technology and financial services. These services are provided by Engage Energy Canada, L.P. and Engage Energy U.S., L.P. (collectively Engage Energy), Union Energy, NGX Canada Inc. (NGX), Enlogix Inc. (Enlogix) and Westcoast Capital.

The contribution to net income applicable to common shares for Services was:

Years ended December 31 (\$million)	1998	1997	1996
NET INCOME (LOSS) CONTRIBUTION			
Energy Marketing	(34)	(9)	(3)
Union Energy	(12)	(5)	—
NGX	1	(1)	(2)
Enlogix	(1)	—	—
Westcoast Capital	—	—	—
	(46)	(15)	(5)

The decrease in the contribution to net income applicable to common shares for Services in 1998 over 1997 reflects an unusual loss incurred by Engage Energy, combined with operating losses incurred by Engage Energy and higher start-up costs related to Union Energy.

The decrease in the contribution to net income applicable to common shares for Services in 1997 over 1996 primarily reflects higher operating losses incurred by Engage Energy resulting from intense competition and related margin contraction and start-up costs related to Union Energy.

Energy Marketing

In 1997, the Company and The Coastal Corporation (Coastal) merged their natural gas and electricity marketing businesses under Engage Energy Canada, L.P. in Canada and Engage Energy U.S., L.P. in the United States. The resulting joint venture businesses, in which the Company and Coastal each own 50%, operate as Engage Energy.

Engage Energy is a major marketer of natural gas and electricity and provides risk management and energy management services in North America through its major offices and trading centres in Calgary, Alberta, and Houston, Texas, and its 12 marketing offices across North America.

In 1998, Engage Energy marketed 2,555 Bcf of natural gas and 36 million megawatt hours of electricity, compared with 2,525 Bcf of natural gas and 31 million megawatt hours of electricity in 1997. Prior to the formation of Engage Energy, the Company marketed

1,097 Bcf of natural gas in 1996.

In late June 1998, unusual and prolonged hot weather, combined with forced electrical outages, led to electricity price spikes that resulted in two of Engage Energy's customers defaulting on their obligations to deliver electricity. To meet its own sales commitments, Engage Energy was required to purchase replacement electricity in the market at substantially higher prices resulting in an unusual loss, of which the Company's proportionate after-tax share was \$14 million, or 14 cents per common share. Engage Energy has proceeded with legal action; however the amount of recovery, if any, is uncertain.

Engage Energy has completed a review of its policies and procedures. The review concluded that the policies and procedures in place are appropriate; however, changes have been implemented in the execution of these policies resulting in a tightening of credit and operating practices.

A significant component of the deterioration in 1998 operating results from Engage Energy over 1997 has been the impact of substantially warmer than normal weather. Lower winter prices, reduced price volatility and very competitive market conditions have resulted in compressed margins for Engage Energy's natural gas trading activities in the United States.

Engage Energy's Canadian operations and individually structured natural gas and electricity trading arrangements for customers in the United States have been successful and continue to grow. Engage Energy's strategy is to increase focus on these higher-value services.

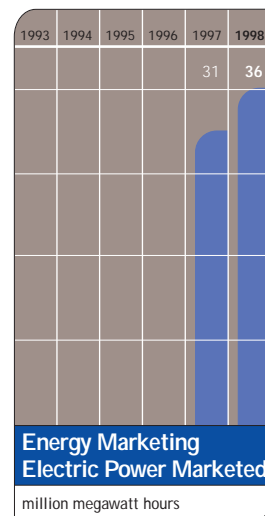
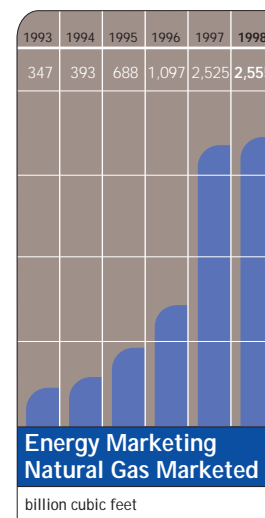
Union Energy

Union Energy, formed in 1997, provides energy equipment sales, rentals, installations and maintenance, as well as financing and energy management, procurement and sales to residential, commercial and industrial customers.

During 1998, Union Energy continued to pursue its non-regulated retail energy services business. The operation is pursuing growth through the acquisition of HVAC operations. To date, a total of 18 HVAC operations with annual revenues of approximately \$66 million have been acquired in Ontario, Manitoba and British Columbia. These purchases are part of an aggressive program of assembling leading HVAC operations in major markets to take a leadership role in providing non-regulated energy services.

In 1998, Union Energy formed strategic alliances with Carrier Canada Limited, the world's leading manufacturer and marketer of HVAC products, and CFM Majestic Inc., a major manufacturer of fireplaces and other energy products, to carry their products in Canada.

On January 1, 1999, Union Energy assumed the operating responsibilities for Union Gas' retail merchandise and service programs with net assets amounting to approximately \$500 million. The net assets relate to appliance sales and rental programs, appliance service work and merchandise financing.



NGX

NGX provides electronic natural gas trading services at the Alberta and Empress market centres in Western Canada.

NGX currently serves over 120 customers who electronically traded 1,308 Bcf of natural gas in 1998. This represents a 46% increase over the 895 Bcf traded in 1997 and reflects an acceptance of electronic commerce by gas traders.

Enlogix

In February 1998, the Company announced the launch of Enlogix, a new business entity created to capitalize on the demand for improved information services which will become vital to a deregulating energy marketplace for utilities, municipalities and energy service providers. Initial service offerings through Enlogix CIS include customer information services, billing and remittance processing and through IntraLynx, advanced metering equipment and services. Future offerings are anticipated to include electronic bill presentment, meter data management and network services.

In February 1998, Enlogix CIS was awarded a multi-year contract to provide services to The City of Calgary for the management of its 325,000 residential and commercial utility customer accounts.

In October 1998, Enlogix CIS began operating its new Customer Information System and providing customer billing services to approximately one quarter of Union Gas' one million customers. In January 1999, Enlogix CIS continued the implementation of the system at Union Energy with the addition of 900,000 new customer accounts.

In 1999, the Company plans to implement the Enlogix CIS system at five contracted clients including the remaining Gas Distribution businesses of the Company and The City of Calgary.

Demand for services is expected to increase particularly in Ontario and Alberta where deregulation of energy markets is most advanced.

Westcoast Capital

Westcoast Capital was established in April 1997 to provide selected financial services to complement the Company's other product offerings. Westcoast Capital's business is focused on energy-related investments and is divided into two distinct sectors, Retail Finance and Commercial and Industrial Finance. The Retail Finance business includes the financing and rental of household appliances to individual homeowners while the Commercial and Industrial Finance business includes the financing of capital equipment for businesses.

The total value of Westcoast Capital's portfolio of financial assets exceeded \$67 million at December 31, 1998, up from less than \$1 million at December 31, 1997. The portfolio of financial assets includes both a modest retail portfolio and a number of commercial and industrial transactions. On January 1, 1999, Westcoast Capital acquired the majority of the net assets of Union

Gas' retail merchandise and service programs with net assets amounting to approximately \$500 million.

OTHER

This business segment includes corporate expenses, business development expenditures, corporate financing expenses and utilization of previous years' unrecorded tax losses.

The contribution to net income applicable to common shares for Other was:

Years ended December 31 (\$million)	1998	1997	1996
NET INCOME (LOSS) CONTRIBUTION			
Corporate financing	(57)	(51)	(50)
Business development	(15)	(14)	(10)
Other	7	(1)	1
	(65)	(66)	(59)

Corporate financing costs increased in 1998 over 1997 and 1996 primarily due to higher interest rates, higher financing costs as a result of having significant capital invested in projects under development and higher borrowings to fund increased capital expenditures.

Business Development

TriState Pipeline Project

The Company has a one-third interest in the proposed TriState Pipeline Project which is designed with an initial capacity of 450 MMcf of natural gas per day and can be expanded to 1 Bcf of natural gas per day. The pipeline would connect with the Alliance Pipeline Project near Joliet, Illinois, where it will also connect with several other pipelines and proceed to the Union Gas system at Dawn, Ontario. From Dawn, deliveries can be made to markets in eastern Canada and the United States through connecting pipelines. The project as currently designed is expected to cost \$600 million and to be in service by November 2000.

In December 1998, the Company filed an application with the NEB for construction of the Canadian portion of the project and a decision is anticipated to be received in late 1999.

The Company's partner in TriState, CMS Energy Corporation, holds the remaining interest in the project. In November 1998, CMS Energy Corporation made an application to the FERC for project approval and a Preliminary Determination with respect to the U.S. portion of the TriState Pipeline Project is anticipated to be received in the third quarter of 1999.

Millennium Pipeline Projects

The Company has a 21% interest in the proposed Millennium Pipeline Project which is designed to deliver 700 MMcf of natural gas per day from southwest Ontario to New York City and other markets in the eastern United States. The 611-kilometre pipeline is expected to cost approximately \$950 million.

The Millennium West Pipeline Project, in which the Company has a 100% interest, is a \$165-million,

75-kilometre pipeline from Union Gas' existing pipeline system and storage facilities at Dawn, Ontario to the shore of Lake Erie northwest of Patrick Point, Ontario. The Millennium West Pipeline Project is intended to interconnect with another proposed pipeline that would cross Lake Erie to connect to the proposed Millennium Pipeline Project. The Millennium and Millennium West Pipeline projects are scheduled to be in service in November 2000.

Millennium Pipeline has made an application to the FERC for project approval and a Preliminary Determination with respect to the U.S. portion of the Millennium Pipeline is anticipated to be received during the second quarter of 1999.

In December 1998, St. Clair Pipelines (1996) Ltd., filed an application with the NEB for construction of the Millennium West Pipeline Project and a decision is anticipated to be received in late 1999.

McNab Liquefied Natural Gas (LNG) Storage Facility

In 1997, Westcoast Gas Services Inc. proposed the development of a LNG storage facility near McNab Creek, British Columbia. Through an interconnection with Centra Gas BC's existing pipeline in the region, the 3-Bcf storage facility would deliver a maximum of 300 MMcf per day of natural gas to meet peak-day requirements of markets in British Columbia and the U.S. Pacific Northwest.

The McNab LNG storage facility is one of four LNG projects and three pipeline projects that were proposed to the BCUC as alternatives to the Southern Crossing Pipeline Project proposed by BC Gas Utility Ltd., a customer of the Company. The Southern Crossing Pipeline Project is a proposal to build a major transportation pipeline in southern British Columbia. In April 1998, the BCUC recommended LNG storage as a low-cost solution to meet peak natural gas demand requirements and denied the BC Gas Utility Ltd. Southern Crossing Pipeline Project application. In December 1998, BC Gas Utility Ltd. filed a second application requesting immediate approval of the proposed pipeline. The BCUC has ordered a public hearing to review certain aspects of the Southern Crossing Pipeline Project. The hearing is scheduled to commence on March 29, 1999.

Maritimes NRG

In January 1998, the Company and Irving Oil Limited of Saint John, New Brunswick, announced that they had formed an alliance to pursue natural gas distribution rights in Nova Scotia and New Brunswick. The natural gas distribution system would offer natural gas service to residential, commercial and industrial customers.

In January 1999, Maritimes NRG filed an application with the Nova Scotia Utility and Review Board for a natural gas distribution franchise, in response to the Nova Scotia Government's call for proposals made in November 1998.

Bayside Power Project

In April 1998, Westcoast Power signed an agreement with New Brunswick Power Corporation (New Brunswick Power) of New Brunswick to proceed with development efforts to convert a 250-megawatt heavy fuel oil-fired generating plant located in Saint John, New Brunswick, to a natural gas fired combined cycle plant.

Under the agreement, the Company will provide the required equity and arrange project financing for the \$160-million conversion. New Brunswick Power will lease certain site assets and infrastructure to the project and contract to purchase the electric power output in the winter months. The Company will have the opportunity to export the electric power to the United States during the balance of the year.

The Company continues to advance the necessary agreements required for the Bayside Power Project which has an anticipated in-service date of late 2000.

In 1998, binding term sheets were executed with Irving Paper for the sale of process steam and with New Brunswick Power to sell firm winter electricity and optional summer power for 15 years.

Liberty Power Project

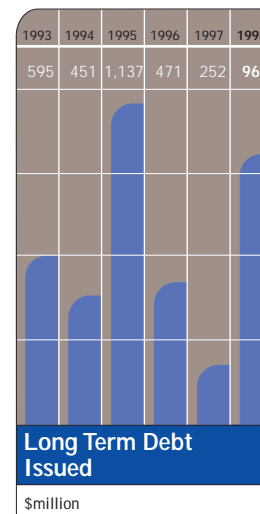
In November 1998, the Company and a subsidiary of Columbia Energy Group began preliminary development of a 500-megawatt natural gas fired electric generation plant near Philadelphia, Pennsylvania. The proposed Liberty Power Project is expected to cost about \$450 million to develop and would consume 80 MMcf of natural gas per day. Electricity would be supplied to the Pennsylvania-New Jersey-Maryland interconnected power pool, the growing electric transmission grid over which utilities and other companies buy and sell electricity for the heavily populated and growing U.S. Mid-Atlantic region. The proposed in-service date of the Liberty Power Project is mid-2001.

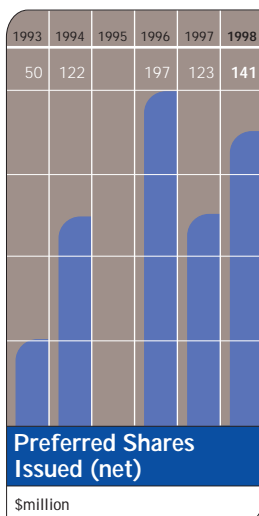
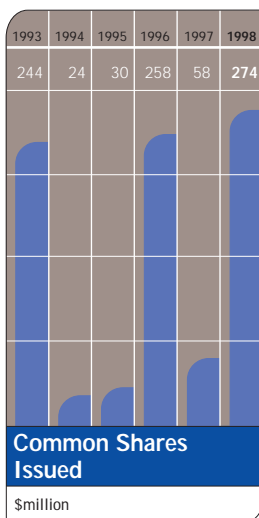
LIQUIDITY AND CAPITAL RESOURCES

The Company, its subsidiaries and joint ventures meet their cash requirements through funds generated from operations together with proceeds from the issuance of common and preferred shares, and short and long term debt.

Capital expenditures amounted to \$887 million in 1998 compared with \$676 million in 1997 and \$634 million in 1996. The increase in 1998 capital expenditures is primarily due to higher activity with respect to projects under development such as the Maritimes & Northeast Pipeline Project, the Cantarell Nitrogen Project, the Campeche Natural Gas Compression Services Project and the Shanghai Power Project.

The Company's planned capital spending for 1999 is currently projected to total \$1.6 billion; however, future expenditures are dependent on conditions in the energy industry. These expenditures are primarily for the completion of projects currently under development and for operational necessities. The Company, its subsidiaries and joint ventures have sufficient funds flow





from operations and anticipate no difficulty in accessing capital markets to finance these capital expenditures.

The Company, its subsidiaries and joint ventures also have the ability to draw down on operating lines of credit in excess of \$1,400 million with Canadian chartered 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. In December 1997, \$600 million of short term operating lines of credit were converted to a five-year term operating line of credit.

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.

The Company, its subsidiaries and joint ventures raised \$965 million through the issuance of long term debt in 1998 compared with \$252 million in 1997 and \$471 million in 1996. The details of long term debt are provided in note 14 to the consolidated financial statements.

In November 1998, the Company issued 7,315,000 common shares for cash under a public offering at a price of \$30.30 per share, thereby increasing common stock by approximately \$222 million. The net proceeds were used to retire commercial paper previously issued by the Company, finance capital expenditures, finance development projects and other capital purposes.

In February 1996, the Company issued 10,500,000 common shares for cash under a public offering at a price of \$21.25 per share, thereby increasing common stock by approximately \$223 million. The net proceeds were used to retire commercial paper previously issued by the Company. Approximately 20% of the common shares were issued in the United States under the multijurisdictional disclosure system.

The Company also issues common shares through its Dividend Reinvestment and Share Purchase Plan. Common shares issued under the plan increased common stock by \$51 million in 1998 compared with \$52 million in 1997 and \$43 million in 1996.

In July 1997, in light of the continuing strength of the Company's core businesses and the promise of new projects, the Board of Directors raised the quarterly common share dividend to 31 cents, an increase of 2 cents per quarter. The quarterly common share dividend was further increased by 1 cent per quarter to 32 cents in the third quarter of 1998. This raises the indicated annual dividend per common share to \$1.28.

Details of common share issues are provided in note 18 to the consolidated financial statements.

In November 1998, Union Gas raised \$100 million from the issue of the 4.88% Class B, Series 10 Preference Shares.

In September 1998, the Company raised \$150 million from the issue of the 5.50% Cumulative First Preferred Shares, Series 7.

In December 1997, the Company raised \$125 million from the issue of the 4.72% Cumulative Redeemable First Preferred Shares, Series 6.

In December 1996, the Company raised \$200 million from the issue of the 4.90% Cumulative Redeemable First Preferred Shares, Series 5.

Details of preferred share issues are provided in note 17 to the consolidated financial statements.

TAXATION

In addition to federal and provincial income taxes, the Company's operations are subject to significant indirect taxation. The amount of taxes paid by the Company and its subsidiaries in 1998 was \$340 million or 73% of income before income taxes, indirect taxes and non-controlling interest.

The types of taxes paid are:

Years ended December 31 (\$million)	1998	1997	1996
TAXATION			
Federal, provincial and state income taxes	107	144	117
Large corporation tax	18	14	14
Current income taxes	125	158	131
Property taxes	126	117	111
Provincial, state, capital and sales taxes	44	41	46
Payroll related taxes	24	23	22
Natural gas taxes	17	17	15
Other taxes and permits	4	6	7
	<u>340</u>	<u>362</u>	<u>332</u>

YEAR 2000 REVIEW

The Year 2000 issue refers to the business implications resulting from a failure of computer software when dealing with dates in the next century. These implications arise because many computerized systems use two digits rather than four to identify a year. Date-sensitive systems may recognize the year 2000 as 1900 or some other date, resulting in errors when information using 2000 dates is processed. The impact of the Year 2000 issue on an entity's operations and financial reporting may range from minor errors to significant systems failure which could affect an entity's ability to conduct normal business operations.

The Company formalized its Year 2000 program in 1997, when it undertook to identify and address Year 2000 issues and established project offices at each of its major operating companies and a Corporate Year 2000 Project Office at the Company's headquarters in Vancouver. The Company has underway an extensive program of assessment and remediation of computer systems and embedded logic systems in use throughout the Company in an effort to avoid Year 2000 problems which could cause material disruption to the Company's business. The assessment phase of the Year 2000 program was completed in 1998 and the Company is carrying out

the remediation, testing and implementation phase. The Company's goal is to correct, replace and test all critical systems well before December 31, 1999. The Company's progress to date, and plans for 1999, indicate that the Company is well-positioned to be Year 2000 ready in advance of December 31, 1999.

The effect of the Year 2000 issue on the Company also depends on the Year 2000 readiness of external parties. The Company is in communication with its customers, vital suppliers and other third parties to assess their level of Year 2000 readiness.

It is not possible for the Company to be certain that all aspects of the Year 2000 issue affecting the Company, including those related to efforts of external parties, if needed, will be fully resolved. The Company, therefore, is developing contingency plans to allow it to continue to carry on business in an orderly manner into the year 2000.

The Company projects the cost of its Year 2000 project to be approximately \$50 million, including internal costs, based on current estimates of remediation measures. Approximately 40% of the costs have been incurred to date. Year 2000 costs, net of recoveries and income taxes, reduced 1998 earnings applicable to common shares by \$6 million. The impact of Year 2000 program and contingency costs on 1999 earnings applicable to common shares is expected to be in the range of \$9 million to \$11 million.

Progress against plan is reviewed monthly by senior executives of the Company. The status of the Year 2000 program is also reported to the Audit Committee of the Board of Directors at their regular quarterly meetings.

MARKET OUTLOOK

Natural gas continues to evolve as the fuel of choice for energy needs as it is a cost-efficient and environmentally superior alternative to other fossil fuels and nuclear energy.

Demand forecasts for natural gas in North America are optimistic, indicating continued growth in demand, both in Canada and the United States. Growth in demand for natural gas is forecast to be generated by continued economic expansion in existing markets, access to new markets which have not been served by natural gas in the past and from additional demand for natural gas to fuel the generation of electrical power.

Natural gas reserves in North America are felt to be sufficient to meet the forecast demand growth over the longer term. Improvements in exploration and production technology have reduced the risks associated with the development of additional reserves.

To support the growing demand for natural gas, additional transportation infrastructure is needed to facilitate the delivery of natural gas to growing markets. As a result, the Company is proceeding with its largest ever capital expenditure program in 1999 in order to construct additional infrastructure that is needed to support this growing demand for natural gas.

The regulatory environment in which the majority of the Company's assets operate continues to evolve from the traditional cost recovery model to a less regulated and competitive environment. Regulatory changes are

occurring in the gathering, processing and transmission and gas distribution businesses. Changes to the regulatory environment are increasing the risk of the business somewhat as more responsibility is placed on the Company to optimize its revenues and costs. To compensate for this increased level of risk, the Company is developing opportunities to increase the potential returns from its regulated businesses.

The Company has been successful in implementing a new light-handed regulatory regime in British Columbia for its gathering and processing operations. Under this new regulatory model, the Company has been able to generate premium returns while providing improved reliability of service for its customers. Currently, Union Gas, the Company's largest distribution business is proceeding with the development of a new performance-based regulatory model for its operations in Ontario, to be in place in 2000.

Market opportunities are also developing to provide energy services in addition to the traditional transmission and distribution of natural gas. These opportunities include merchandizing, service and finance opportunities for end-use retail energy customers as well as risk and supply management services to wholesale customers such as other utilities or large industrial customers. Demand for information-based services is also developing in all of these markets.

New energy services businesses, established outside of the regulatory framework are being developed. Engage Energy, Union Energy, Westcoast Capital and Enlogix are new and developing businesses that are planned to fill customer service needs in the wholesale and retail energy services and information services areas.

Demand for electric power continues to grow in North America. The growth in demand is very strong in certain market areas in, or near, markets currently served by the Company's natural gas operations. The Company will continue to take advantage of these market opportunities to build its electric power business which is planned to be an area of significant future growth for the Company.

Given the considerable opportunities available to the Company in North America and the increase in risk associated with international markets over the recent past, the Company has focused its international development activities on the Mexican energy market. Given its North American Free Trade Agreement (NAFTA) status, and as its energy market is a contiguous part of the North American energy market, Mexico is seen as an acceptable risk market and an important component in developing a broad North American presence in the energy industry.

Underpinned by a cost-effective, environmentally acceptable and plentiful fuel, the North American natural gas industry is characterized by growing demand and developing markets. The Company's core businesses continue to prosper in this positive market environment. In addition, the Company is responding to these growing market opportunities by expanding its operations in its traditional businesses and by developing new businesses to meet the total needs of energy users.

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 accounting principles generally accepted in Canada 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 solely 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.

Ernst & Young LLP, Chartered Accountants, 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 has 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.

February 11, 1999

M.E.J. Phelps
Chairman and Chief Executive Officer

G.M. Wilson
Executive Vice President and Chief Financial Officer

Auditors' Report

To the Shareholders of Westcoast Energy Inc.

We have audited the consolidated balance sheets of Westcoast Energy Inc. as at December 31, 1998 and 1997 and the consolidated statements of operations, retained earnings and cash flow for each of the years in the three year period ended December 31, 1998. 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 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, 1998 and 1997 and the results of its operations and the changes in its financial position for each of the years in the three year period ended December 31, 1998 in accordance with accounting principles generally accepted in Canada.

"signed Ernst & Young LLP"
"Chartered Accountants"
Vancouver, Canada
February 11, 1999

Consolidated Statements of Operations

For the years ended December 31

\$million, except for share data

	1998	1997	1996
OPERATING REVENUES	7,376	7,312	4,875
OPERATING EXPENSES			
Cost of sales	5,473	5,379	3,001
Operation and maintenance	731	663	644
Depreciation	364	329	298
Taxes — other than income taxes	158	148	145
	6,726	6,519	4,088
OPERATING INCOME	650	793	787
OTHER INCOME			
Allowance for funds used during construction	19	12	12
Investment and other income	80	23	18
	749	828	817
OTHER EXPENSES			
Interest (Note 14)	488	454	448
Other (Note 4)	9	6	33
	497	460	481
INCOME BEFORE UNDERNOTED ITEMS	252	368	336
INCOME TAXES (Note 3)			
Current	125	158	131
Deferred	(77)	(35)	(16)
	48	123	115
	204	245	221
NON-CONTROLLING INTEREST	6	7	9
NET INCOME	198	238	212
PROVISION FOR DIVIDENDS ON PREFERRED SHARES	37	28	19
NET INCOME APPLICABLE TO COMMON SHARES	161	210	193
COMMON SHARES — WEIGHTED AVERAGE (million)	105	102	99
EARNINGS PER COMMON SHARE — BASIC (Note 2)	\$1.53	\$2.06	\$1.96
DIVIDENDS PER COMMON SHARE	\$1.26	\$1.20	\$1.05

See accompanying notes

Consolidated Statements of Cash Flow

For the years ended December 31 \$million, except for share data

	1998	1997	1996
OPERATING ACTIVITIES			
Net income	198	238	212
Add (deduct) items to reconcile to net cash			
Non-controlling interest	6	7	9
Deferred income taxes	(77)	(35)	(16)
Depreciation and amortization	370	339	305
Equity earnings	(4)	—	—
Other	(45)	(27)	33
Operating cash flow	448	522	543
Non-cash working capital changes (Note 6)	(19)	(16)	(45)
	429	506	498
INVESTING ACTIVITIES			
Additions to fixed assets	(887)	(676)	(634)
Acquisitions (Notes 13 and 15)	(137)	(122)	(19)
Dispositions (Notes 10 and 16)	88	—	—
Investments and other	(85)	(63)	86
Net cash used by investing activities	(1,021)	(861)	(567)
FINANCING ACTIVITIES			
Long term debt additions	965	252	471
Long term debt repayments	(586)	(208)	(385)
Common shares issued (Note 18)	274	58	258
Preferred shares issued (net) (Note 17)	141	123	197
Non-controlling interest preferred shares issued (redeemed)	100	(44)	(10)
Dividends paid	(175)	(155)	(131)
Net cash provided by financing activities	719	26	400
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS DURING THE YEAR			
	127	(329)	331
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR			
	(697)	(368)	(699)
CASH AND CASH EQUIVALENTS, END OF YEAR			
	(570)	(697)	(368)
OPERATING CASH FLOW PER COMMON SHARE (Note 2)			
	\$4.24	\$5.10	\$5.50

Cash and cash equivalents consist of cash and short term investments net of bank indebtedness.

See accompanying notes

Consolidated Balance Sheets

December 31

\$million

	1998	1997
ASSETS		
CURRENT ASSETS		
Cash and short term investments	107	60
Accounts receivable		
Trade	928	1,036
Other	132	57
Inventory (Note 7)	400	394
Prepayments	29	27
	<u>1,596</u>	<u>1,574</u>
INVESTMENTS (Note 8)	374	195
FIXED ASSETS (Note 9)		
Plant, property and equipment	11,475	10,665
Less accumulated depreciation	2,906	2,640
	<u>8,569</u>	<u>8,025</u>
DEFERRED CHARGES AND OTHER ASSETS (Note 10)	281	281
	<u>10,820</u>	<u>10,075</u>

On behalf of the Board:

"signed M.E.J. Phelps"
Director

"signed A.H. Willms"
Director

	1998	1997
LIABILITIES		
CURRENT LIABILITIES		
Bank indebtedness (Note 11)	677	757
Accounts payable and accrued liabilities		
Trade	656	584
Other	247	322
Income and other taxes payable	31	82
Interest on debt	96	95
Long term debt due within one year (Note 14)	228	205
	1,935	2,045
LONG TERM DEBT (Note 14)	5,297	4,941
DEFERRED INCOME TAXES (Note 3)	340	400
NON-CONTROLLING INTEREST		
Preferred	129	29
Common	35	34
	164	63
PREFERRED SHAREHOLDERS' EQUITY		
PREFERRED STOCK (Note 17)	716	570
COMMON SHAREHOLDERS' EQUITY		
COMMON STOCK (Note 18)	1,695	1,412
CUMULATIVE TRANSLATION ADJUSTMENT	30	21
RETAINED EARNINGS	643	623
	2,368	2,056
	10,820	10,075
CONTINGENCIES (Note 21)		

See accompanying notes

Consolidated Statements of Retained Earnings

For the years ended December 31

\$million

	1998	1997	1996
RETAINED EARNINGS, BEGINNING OF YEAR	623	536	456
NET INCOME	198	238	212
Share issue costs (Notes 17 and 18)	(8)	(1)	(8)
	813	773	660
DIVIDENDS			
Common shares	133	122	105
Preferred shares	37	28	19
	170	150	124
RETAINED EARNINGS, END OF YEAR	643	623	536

See accompanying notes

1. ACCOUNTING POLICIES**Accounting Principles**

The Company is incorporated under the laws of Canada and prepares its financial statements in accordance with accounting principles generally accepted in Canada which, as applied in these financial statements except as described in note 20, conform in all material respects with accounting principles generally accepted in the United States. 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

Westcoast Gas Holdings Inc. – 100% owned
Westcoast Gas Inc. – 100% owned
UEI Holdings Inc. – 100% owned
Westcoast Gas Services Inc. – 100% owned
St. Clair Pipelines (1996) Ltd. – 100% owned
Centra Gas Holdings Inc. – 100% owned
Centra Gas Utilities Inc. – 100% owned
Union Gas Limited – 100% owned
Centra Gas Manitoba Inc. – 100% owned
Centra Gas British Columbia Inc. – 100% owned
Pacific Northern Gas Ltd. – 41% owned,
including 100% of the voting shares
Westcoast Power Holdings Inc. – 100% owned
Westcoast Power Inc. – 100% owned
Westcoast Transmission Company (Alberta) Ltd.
–100% owned
Westcoast Energy International Inc. – 100% owned
Westcoast Capital Corporation – 100% owned
Westcoast Energy Risk Inc. – 100% owned
NGX Canada Inc. – 100% owned
Enlogix Inc. – 100% owned

Major Joint Ventures

Foothills Pipe Lines Ltd. – 50% owned
Empire State Pipeline – 50% owned
Maritimes & Northeast Pipeline Limited
Partnership – 37.5% owned
Maritimes & Northeast Pipeline, L.L.C.
– 37.5% owned
Engage Energy Canada, L.P. – 50% owned (Note 13)
Engage Energy US, L.P. – 50% owned (Note 13)
McMahon Cogeneration Plant – 50% owned
Lake Superior Power Limited Partnership
– 50% owned
Whitby Cogeneration Limited Partnership
– 50% owned
P.T. Puncakjaya Power – 43% owned (Note 13)
Cantarell Nitrogen Project – 20% owned (Note 13)
Campeche Natural Gas Compression Project
– 45% owned (Note 13)

Investments

Investments in which the Company exercises significant influence, but not control, are accounted for by the equity method. The Company's 23.6% (1997 – 10.5%) interest in the Alliance Pipeline Projects is accounted for as an equity investment (Note 15). 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.

Gas Distribution Revenue Recognition

Operating revenues include gas sales applicable to the Gas Distribution businesses which 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.

Income Taxes

The Company and its subsidiaries provide for income taxes relating to utility businesses using the income taxes currently payable method as directed by the regulators. 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.

The income tax allocation method is used for non-utility businesses of the Company, its subsidiaries and certain utility items as directed by regulators. Under this method, provision is made for income taxes deferred principally as a result of claiming capital cost allowance for income tax purposes in excess of depreciation provided in the accounts.

In 1997, following regulatory approval, the Company's subsidiary, Union Gas Limited, changed its accounting for income taxes relating to its utility business from the income tax allocation method to the income taxes currently payable method. This change was applied prospectively since the basis for determining Union Gas' rates and revenues for its utility business were previously established taking into account the provision for income taxes based on the income tax allocation method.

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		
	1998	1997	1996	1998	1997	1996
Westcoast Energy Inc.						
– Pipeline and Field Services	35	35	35	(a)	(a)	11.25
Foothills Pipe Lines Ltd.	30	30	30	10.21	10.67	11.25
Empire State Pipeline	40	40	25	12.50	12.50	14.58
Union Gas Limited	34	34	29	10.53	11.00	11.75
Centra Gas Ontario Inc.	(b)	36	36	(b)	11.25	12.13
Centra Gas Manitoba Inc.	40	40	40	9.91	10.58	11.28
Centra Gas British Columbia Inc.	35	35	35	8.59	9.32	10.05
Pacific Northern Gas Ltd.	36	35	35	10.75	11.00	11.75
Maritimes & Northeast Pipeline	25	–	–	13-14	–	–
Alliance Pipeline Projects	30	–	–	11.20	–	–

(a) In 1998, the Company and its major customers agreed to a framework for light-handed regulation of the gathering and processing facilities which are regulated by the National Energy Board (NEB). The framework became effective immediately upon approval by the NEB in June 1998.

The framework amends the multi-year incentive-based toll settlement applicable to the Company's gathering and processing services that was approved by the NEB in August 1997. 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 and, accordingly, tolls for service are no longer based on the cost of service method of regulation.

The multi-year incentive-based toll settlement approved in August 1997 provided gathering and processing shippers the option of contracting for fixed base tolls for 1, 3, or 5-year service for which the tolls reflect a 500 basis point reduction from the agreed upon rate of return on common equity and are subject to a monthly surcharge based on an index of monthly gas prices. The gas price sensitive monthly surcharge allows the Company the opportunity to recover the revenues associated with the 500 basis point reduction in return on common equity and the opportunity to earn additional revenues. As the 1, 3, or 5-year contracts expire, customers and the Company will negotiate replacement contracts under the framework for light-handed regulation.

Transmission services continue to operate under the multi-year incentive-based toll settlement (effective from 1997 to 2001) approved by the NEB in August 1997. The settlement provided transmission customers the option of contracting for fixed tolls for 5-year service or tolls that are adjusted annually in accordance with a prescribed incentive-based methodology. Fixed tolls for 5-year service were based on a 10.67% return on common equity.

(b) Effective January 1, 1998, Union Gas Limited and Centra Gas Ontario Inc. were amalgamated, continuing operations as Union Gas Limited.

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 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 foreign currency risks.

Cash and Short Term Investments

Short term investments are considered to be cash equivalents and are recorded at cost, which approximates current market value.

Price Risk Management

Certain of the Company's operations enter into forward, future, swap and option contracts to manage their exposure to changes in the market prices of natural gas and electric power. The Company defers the impact of changes in the market value of these contracts until such time as the associated transaction is completed.

The Company issues and trades energy option based products and services directly with customers for its own risk management purposes. The level of risk exposure from these options is managed by daily portfolio structuring and hedging against movements in energy prices. Gains and losses arising from these energy option based products and services are recognized on the delivery of natural gas and electric power or settlement of the financial contract.

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 3.3% for the year ended December 31, 1998 (for the year ended December 31, 1997 – 3.2%, for the year ended December 31, 1996 – 3.0%).

For some of the Gas Distribution businesses, the regulators have authorized the recovery over time of anticipated future removal and site restoration costs. For the other utility businesses, the regulators have not yet directed that future removal and site restoration costs be accrued. 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. For power generation facilities, provisions for major maintenance and gas turbine overhauls are normalized and accrued annually.

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.

Pension and Other Post Retirement Benefits

Pension costs and obligations are determined annually by independent actuaries using management's best estimates. Pension assets are valued by using current market values or average market related values over a 3 year period. Pension expense consists of current service costs and adjustments arising from plan amendments, changes in assumptions, and experience gains or losses which are amortized on a straight-line basis over the expected average remaining service life of the relevant employee group. The costs of health care and life insurance benefits for retirees are expensed as incurred.

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 incurred for development projects relate to projects which are in progress. The costs of projects that do not develop into viable operations are expensed. Costs related to long term debt are deferred and amortized on a straight-line basis over the life of the respective debt issues. Share issue costs of the Company are charged to retained earnings.

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.

Comparative Figures

Certain comparative figures have been reclassified to conform to the 1998 presentation.

2. EARNINGS AND CASH FLOW PER COMMON SHARE

Basic earnings per common share are calculated using the weighted average number of common shares outstanding during the year.

For the years ended December 31	1998	1997	1996
Net income applicable to common shares (\$million)	161	210	193
Number of shares (million)			
Shares outstanding, beginning of year	103	101	88
Changes due to common shares issued, options exercised and shares issued under the Dividend Reinvestment and Share Purchase Plan	2	1	11
Weighted average shares for the year	105	102	99
Earnings per common share – basic	\$1.53	\$2.06	\$1.96

Fully 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 (Notes 17 and 18). An imputed after-tax return of 2.8% has been used in these calculations.

For the year ended December 31	1998
Adjusted net income applicable to common shares (\$million)	180
Adjusted weighted average shares for the year (million)	121
Earnings per common share – fully diluted	\$1.49

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.

For the years ended December 31	1998	1997	1996
Operating cash flow before non-cash working capital changes (\$million)	448	522	543
Weighted average shares for the year (million)	105	102	99
Operating cash flow per common share	\$4.24	\$5.10	\$5.50

3. INCOME TAXES

A reconciliation between the statutory and the effective rate of income taxes is provided as follows:

For the years ended December 31 (\$million)	1998	1997	1996
Income before income taxes and non-controlling interest	252	368	336
Combined Canadian federal and provincial statutory income tax rates, including surtaxes (percent)	45.0	44.9	44.9
Statutory income tax rates applied to accounting income	113	165	151
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	(48)	(60)	(27)
– Other items recognized for income tax purposes subsequent to (in advance of) accounting income recognition	(18)	5	(25)
	(66)	(55)	(52)
– Foreign earnings subject to different tax rates	(4)	(2)	(2)
– Utilization of prior years' losses which have not been previously recognized	(17)	(9)	(5)
– Current year's losses for which tax benefits have not been recognized	4	6	5
– Large corporation tax in excess of surtax	17	14	14
– Other	1	4	4
	(65)	(42)	(36)
Provision for income taxes	48	123	115
Effective rate of income taxes (percent)	19.0	33.4	34.2

Income taxes by geographic location were:

For the years ended December 31 (\$million)	1998	1997	1996
Income before income taxes and non-controlling interest			
Canada	249	364	320
Foreign	3	4	16
	252	368	336
Current income taxes			
Canada	121	156	130
Foreign	4	2	1
	125	158	131
Deferred income taxes			
Canada	(67)	(31)	(20)
Foreign	(10)	(4)	4
	(77)	(35)	(16)
Provision for income taxes	48	123	115

With respect to the computation of deferred income taxes, the sources of timing differences and the income tax effects of each were:

For the years ended December 31 (\$million)	1998	1997	1996
Depreciation and amortization in excess of capital cost allowance claimed for income tax purposes	(35)	(20)	(21)
Net regulated deferrals deductible (included) for tax purposes	(21)	(18)	24
Net utilization (benefit) of tax losses recognized for accounting purposes	(11)	12	(2)
Other items deducted for accounting purposes in advance of income tax purposes	(10)	(9)	(17)
Deferred income taxes	(77)	(35)	(16)

If all the companies had used the income tax allocation basis for regulated utility operations, the additional provisions for the years ended December 31 and the additional accumulated provisions would be:

For the years ended December 31 (\$million)	1998	1997	1996
Unrecorded taxes, beginning of year	666	611	559
Increase in unrecorded taxes	60	55	52
Unrecorded taxes, end of year	726	666	611

Prior to 1997, the Company's subsidiary, Union Gas Limited, used the income tax allocation method for its utility business as directed by its regulator, accumulating deferred taxes of approximately \$383 million.

Certain of the Company's utility businesses, including Union Gas Limited, 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.

4. OTHER EXPENSES

During 1996, the Company's Pipeline and Field Services divisions initiated a major reorganization, including a reduction in the workforce, resulting in a charge to income of \$26 million.

5. FINANCIAL INSTRUMENTS

Energy Marketing

The Company's joint ventures, Engage Energy Canada, L.P. and Engage Energy US, L.P. (Engage Energy), market natural gas and electric power. Engage Energy's portfolio of natural gas and electric power contracts is comprised primarily of forward, 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. Engage Energy uses a variety of derivative instruments to manage these risks.

(a) Market risk is the risk that the value of the portfolio will change, either favourably or unfavourably, in response to changing market conditions. Market risks are monitored by an internal risk management group independent of Engage Energy's trading activities 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.

(b) Credit risk is the risk of loss from non-performance by suppliers, customers or financial counterparties to a contract. Engage Energy's operations are primarily concentrated in the natural gas and electric power industries and major customers' operations are also heavily concentrated in the same industries. Engage Energy maintains credit policies with respect to all its counterparties, 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 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 standards must provide secured credit terms.

In late June 1998, unusual and prolonged hot weather combined with forced electrical outages led to electricity price spikes that resulted in two of Engage Energy's customers defaulting in their obligations to deliver electricity. To meet its own sales commitments, Engage Energy was required to purchase replacement electricity in the market at substantially higher prices resulting in a pre-tax loss, of which the Company's proportionate share was \$21 million. Due to this default, Engage Energy completed a review of its policies and procedures. The review concluded that the policies and systems in place are appropriate, however, changes were required in the execution of these policies resulting in a tightening of credit and operating practices.

Natural Gas

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 payable position of these deferrals at December 31, 1998 was approximately \$3 million (December 31, 1997 – a net asset position of approximately \$57 million).

In 1998, the Manitoba Public Utilities Board approved the recovery of \$19 million and disallowed the recovery of \$27 million of a total of approximately \$46 million of natural gas costs related to price management activities which were deferred at December 31, 1997. Of the \$27 million of disallowed natural gas costs, \$9 million have been recovered from brokers serving the direct purchase market.

Approximately 36% of the forecast 1999 gas supply of the Gas Distribution businesses from January through December 1999 is indexed to variable pricing mechanisms. At December 31, 1998 the purchase price applicable to 16 billion cubic feet (Bcf) or 25% of this indexed supply has been effectively fixed through the use of natural gas swaps and other contracts.

The Company's Field Services Division enters into gas price derivative and shipper contracts to reduce its exposure to gas price sensitive tolls under the multi-year incentive-based toll settlement. At December 31, 1998, revenues associated with 52% of the forecast 1999 firm service volumes subject to gas price sensitive tolls have been fixed.

Notional Amounts of Derivative Instruments

The approximate notional amounts of derivative instruments at December 31, 1998 are:

	Within One Year	One to Three Years	Three to Five Years	More than Five Years	Total
FIXED PRICE RECEIVER					
Fixed and floating price swaps (Bcf)	295,603	98,840	7,945	13,425	415,813
Natural gas basis swaps (Bcf)	235,768	45,795	15,632	—	297,195
Natural gas futures contracts (Bcf)	106,700	500	—	—	107,200
Natural gas options (Bcf)	349	70	—	—	419
Foreign currency contracts (\$million)	133	54	5	—	192
FIXED PRICE PAYOR					
Fixed and floating price swaps (Bcf)	323,979	146,396	33,615	59,555	563,545
Natural gas basis swaps (Bcf)	267,735	82,742	10,284	—	360,761
Natural gas futures contracts (Bcf)	113,060	560	—	—	113,620
Natural gas options (Bcf)	410	55	—	—	465
Foreign currency contracts (\$million)	156	30	—	—	186

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.

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 would 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 are:

December 31 (\$million)	1998		1997	
	Carrying Value	Approx FMV	Carrying Value	Approx FMV
ASSETS				
Investments	374	375	195	208
Financial swaps (natural gas)	—	50	—	83
Futures contracts (natural gas)	—	107	—	12
Options (natural gas)	—	9	—	7
Foreign currency contracts	—	(1)	—	—
LIABILITIES				
Long term debt	5,297	6,066	4,941	5,705
Interest rate swaps	—	27	—	30
Financial swaps (natural gas)	—	174	—	140
Futures contracts (natural gas)	—	115	—	12
Options (natural gas)	—	16	—	12
Foreign currency contracts	—	(2)	—	1

6. NON-CASH WORKING CAPITAL CHANGES

For the years ended December 31 (\$million)	1998	1997	1996
Accounts receivable	84	(183)	(228)
Inventory and prepayments	(8)	(73)	(64)
Accounts payable and accrued liabilities	(42)	229	176
Interest and taxes payable	(53)	11	71
	(19)	(16)	(45)

7. INVENTORY

December 31 (\$million)	1998	1997
Gas in storage	288	278
Materials and supplies	112	116
	400	394

8. INVESTMENTS

December 31 (\$million)	1998	1997
Alliance Pipeline Projects (Note 15)	177	14
Finance contracts	124	104
Energy contracts (Note 13)	58	62
Other	15	15
	374	195

9. FIXED ASSETS

December 31 (\$million)	1998	1997
PLANT, PROPERTY AND EQUIPMENT		
Transmission & Field Services		
Natural gas pipeline systems	2,680	2,546
Processing plants	1,237	1,226
Other	208	172
Construction work in progress	218	73
	4,343	4,017
Gas Distribution		
Natural gas pipeline and distribution systems	4,578	4,395
Natural gas storage	527	493
Other	973	1,025
Construction work in progress	207	45
	6,285	5,958
Power Generation and Other		
Power generation plants	697	648
Other	84	27
Construction work in progress	66	15
	847	690
	11,475	10,665
ACCUMULATED DEPRECIATION		
Transmission & Field Services	1,181	1,078
Gas Distribution	1,612	1,479
Power Generation and Other	113	83
	2,906	2,640
	8,569	8,025

10. DEFERRED CHARGES AND OTHER ASSETS

December 31 (\$million)	1998	1997
Regulatory	153	152
Debt discount, premium and expense	32	33
Development projects (a)	30	56
Goodwill (Note 15)	17	—
Other	49	40
	281	281

(a) In December 1998, the Company sold its 50% interest in a joint venture to build a natural gas pipeline in Australia for cash of \$27 million, resulting in a pre-tax gain of \$8 million.

11. BANK INDEBTEDNESS

The Company, its subsidiaries and joint ventures have operating lines of credit in excess of \$1,400 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, 1998 was 5.3% (December 31, 1997 – 4.7%).

12. PENSION PLANS

The Company, its subsidiaries and joint ventures have defined benefit pension plans and retirement arrangements covering substantially all employees. Normal retirement benefits under these plans commence at age 65 and are related to employees' remuneration and years of service.

The pension expense for the year ended December 31, 1998 was \$15 million (for the year ended December 31, 1997 – \$17 million, for the year ended December 31, 1996 – \$17 million).

The pension fund assets at December 31, 1998 are \$546 million (December 31, 1997 – \$514 million) and the projected pension obligations at December 31, 1998 are \$538 million (December 31, 1997 – \$514 million). The projected pension obligations represent the discounted value of benefits expected to be paid to plan members, based on projected salaries, rates of return and years of service.

The assumed future rates of return on assets and discount rates used to determine the projected pension obligations of the plans range from 7% to 8% for 1998. The future long term salary and wage escalation rates, including merit increases, range from 3.25% to 6.5% for 1998.

13. 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:

For the years ended December 31 (\$million)	1998	1997	1996
Proportionate Statements of Joint Venture Operations			
Operating revenues	4,820	4,367	145
Operating expenses	(4,762)	(4,296)	(71)
Other income	11	6	—
Interest on debt	(47)	(26)	(28)
Income taxes	(4)	(3)	(2)
Net income	18	48	44

For the years ended December 31 (\$million)	1998	1997	1996
Proportionate Statements of Joint Venture Cash Flow			
Operating activities	91	9	88
Investing activities	(363)	(166)	(100)
Financing activities	311	145	14
Increase (decrease) in cash and cash equivalents during the year	39	(12)	2

December 31 (\$million)	1998	1997
Proportionate Joint Venture Balance Sheets		
Current assets	496	534
Investments	2	39
Fixed assets	1,290	900
Deferred charges and other assets	66	65
	1,854	1,538
Current liabilities	437	499
Long term debt	646	553
Deferred income taxes	43	46
Westcoast Energy's investment carrying value, including bridge financing	728	440
	1,854	1,538

(a) The Company has a 20% interest in a consortium which has entered into a contract with Pemex Exploración y Producción (PEP), the exploration and production arm of the national oil company of Mexico, to build, own and operate a large nitrogen supply and delivery complex. The nitrogen will be injected into the Cantarell oil field, located offshore in the Bay of Campeche in the Gulf of Mexico, to increase oil production.

The consortium has obtained financial commitments from a major international financing agency and from several commercial banks to provide senior debt financing for the project. Loan documentation is expected to be finalized with the intent of drawing down on the senior debt financing by the second quarter of 1999. The carrying value of the Company's interest in the project, including bridge financing for construction, at December 31, 1998 is approximately \$226 million.

(b) The Company has a 45% interest in a consortium which has entered into a contract with PEP to build, own and operate an offshore gas compression and liquids recovery facility in the Cantarell oil field. The facility will compress natural gas for PEP for processing and ultimate delivery into the Mexican national pipeline system.

Deterioration in the international financial markets during 1998 has resulted in limited recourse financing being more difficult to secure and, consequently, there is potential for a significant increase in the cost of capital for the project. Pursuant to a provision in the contract with PEP, the consortium is currently negotiating the revenues applicable to the project with PEP based on the changed financing environment. Under the terms of the contract, the contract has been suspended for the period of such negotiations. The contract with PEP contains a provision for cost recovery should the project not proceed as a result of these negotiations. The carrying value of the Company's interest in the project, including bridge financing for construction, at December 31, 1998 is approximately \$23 million.

(c) During 1997, the Company and The Coastal Corporation (Coastal) agreed to merge their natural gas and electric power marketing businesses. The joint venture businesses operate as Engage Energy Canada, L.P. in Canada and Engage Energy US, L.P. in the United States.

Each party contributed energy contracts and cash to the joint ventures with an aggregate fair value of approximately \$194 million each. In conjunction with this, the Company purchased approximately \$65 million of existing contracts from Coastal in order to equalize its ownership in each of the two joint ventures at 50%. This amount has been recorded as energy contracts and is being amortized on a straight-line basis over 10 years (Note 8).

(d) During 1997, the Company purchased additional interests in P.T. Puncakjaya Power, increasing its interest from 20% to 43%, and concurrently refinanced a major expansion of its power facilities. The acquisitions have been accounted for by the purchase method as follows:

December 31 (\$million)	<u>1997</u>
Fixed assets	256
Working capital	8
Long term debt	(214)
Deferred charges and other assets	<u>(3)</u>
Cash purchase price	<u>47</u>

14. LONG TERM DEBT

December 31 (\$million)	Due Date	1998	1997
WESTCOAST ENERGY INC.			
Unsecured Debentures			
8.3%–average fixed rate (8.8%–1997)	1999 – 2027	2,320	1,998
CENTRA GAS UTILITIES INC. AND SUBSIDIARIES			
Unsecured Senior Debentures			
9.4%–average fixed rate (9.8%–1997)	1999 – 2025	1,792	1,787
Preferred Stock			
5.3%–average fixed rate (6.6%–1997)		5	56
Term Bank Loans and Other			
8.0%–average fixed rate (7.9%–1997)	1999 – 2009	325	250
CENTRA GAS HOLDINGS INC. (1997 – held by Westcoast Gas Inc.)			
Term Bank Loans			
5.7%–average year end rate (4.6%–1997)	2003	350	350
FOOTHILLS PIPE LINES LTD.			
Term Bank Loans			
7.4%–average year end rate (7.4%–1997)	1999 – 2003	169	137
PACIFIC NORTHERN GAS LTD.			
Secured Debentures			
9.1%–average fixed rate (9.2%–1997)	1999 – 2027	92	95
EMPIRE STATE PIPELINE			
Term Bank Loans			
6.3%–average year end rate (6.7%–1997)	2009	73	76
WESTCOAST POWER HOLDINGS INC. AND SUBSIDIARIES			
Senior Secured Notes			
9.4%–average fixed rate (9.4%–1997)	2006	26	30
Term Bank Loans and Other			
6.7%–average year end rate (7.2%–1997)	2004 – 2012	373	367
		5,525	5,146
Deduct long term debt due within one year		228	205
		5,297	4,941

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

Due Date	\$million	Due Date	\$million
1999	228	2004–2008	1,462
2000	310	2009–2013	498
2001	176	2014–2018	855
2002	373	2019–2023	194
2003	819	2024–2028	610
	1,906		3,619

Consolidated interest on long term debt for the year ended December 31, 1998 was \$441 million (for the year ended December 31, 1997 – \$426 million, for the year ended December 31, 1996 – \$409 million). The Company uses interest rate swaps to manage the fixed and floating interest rate mix of the total debt portfolio.

The debt of joint ventures is non-recourse to the Company. The security provided by each joint venture is limited to the rights and assets of that joint venture and does not extend to the rights and assets of the Company, except to the extent of the Company's investment.

15. ACQUISITIONS

(a) Alliance Pipeline Projects

During 1998, the Company purchased additional interests in the Alliance Pipeline Projects (Alliance) from existing Alliance partners for cash of \$88 million (1997 – \$8 million). As a result of these transactions, the Company's equity interest in Alliance increased to 23.6% from 10.5%. The costs of acquiring the Company's interests in Alliance exceed the figure at which the equivalent proportion of the net assets is recorded in the books of Alliance by \$20 million. This excess will be amortized on a straight-line basis over 25 years upon commencement of operations.

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

During 1998, the Company purchased 100% of the outstanding shares in, or purchased certain assets of, 15 HVAC businesses. The acquisitions have been accounted for by the purchase method as follows:

December 31 (\$million)	1998
Fixed assets	4
Working capital	3
Goodwill	17
Assumption of long term debt	(1)
Cash purchase price	23

(c) Island Cogeneration Project

During 1998, the Company purchased an additional 60% in the Island Cogeneration Project (ICP) from its partner for cash of \$26 million. As a result of this transaction, the Company has a 100% interest in ICP. The costs of acquiring the Company's interest in ICP exceed the figure at which the equivalent proportion of the net assets is recorded in the books of ICP by \$21 million. This excess has been allocated to fixed assets and energy contracts.

16. SALE OF CENTRA GAS ALBERTA INC.

In 1998, the Company sold its wholly owned subsidiary Centra Gas Alberta Inc. for cash of \$61 million resulting in a pre-tax gain of \$20 million.

17. 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)	1998	1997
4,631,407 (1997- 4,800,000) - 8.08% Cumulative First Preferred Shares, Series 2 (a)(d)	116	120
5,000,000 - 6.90% Cumulative Redeemable First Preferred Shares, Series 4 (b)(d)	125	125
8,000,000 - 4.90% Cumulative Redeemable First Preferred Shares, Series 5 (b)(d)	200	200
5,000,000 - 4.72% Cumulative Redeemable First Preferred Shares, Series 6 (b)(d)	125	125
6,000,000 - 5.50% Cumulative First Preferred Shares, Series 7 (c)(d)	150	—
	716	570

(a) The Series 2 Preferred Shares are convertible into common shares of the Company at the option of the holder or the Company at the ratio determined by dividing \$25.00 by the greater of \$1.00 and 95% of a 20 day weighted average trading price of the Company's common shares. In 1998, preferred shareholders exercised their conversion privileges, resulting in the issuance of 138,334 common shares of the Company (Note 18).

(b) The Series 4, 5 and 6 Preferred Shares are convertible into common shares of the Company, at the option of the holder, on or after January 1, 2000, January 1, 2002 and April 15, 2003 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 4, 5 and 6 Preferred Shares on or after October 1, 1999, October 1, 2001 and January 15, 2003 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.

(c) 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.

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

18. 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, 1995	87,972,872	1,086
(a) Shares issued for cash under a public offering at a price of \$21.25 per share. The issue costs of these shares, amounting to \$10 million, less income taxes of \$4 million, have been charged to retained earnings.	10,500,000	223
(b) Shares issued for cash under the Dividend Reinvestment and Share Purchase Plan at prices ranging from \$19.07 to \$21.32 per share.	2,199,275	43
(c) Shares issued for cash on options exercised and shares issued under share appreciation rights, at option prices ranging from \$14.75 to \$23.93 per share.	75,106	2
■ Balance – December 31, 1996	100,747,253	1,354
(a) Shares issued for cash under the Dividend Reinvestment and Share Purchase Plan at prices ranging from \$21.32 to \$28.60 per share.	2,178,423	52
(b) Shares issued for cash on options exercised at option prices ranging from \$17.69 to \$24.02 per share.	320,200	6
■ Balance – December 31, 1997	103,245,876	1,412
(a) Shares issued for cash under a public offering at a price of \$30.30 per share. The issue costs of these shares, amounting to \$9 million, less income taxes of \$4 million, have been charged to retained earnings.	7,315,000	222
(b) Shares issued for cash under the Dividend Reinvestment and Share Purchase Plan at prices ranging from \$26.85 to \$33.65 per share.	1,701,448	51
(c) 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.	270,109	6
(d) Shares issued on the conversion of First Preferred Shares, Series 2 (Note 17)	138,334	4
■ Balance – December 31, 1998	112,670,767	1,695

In 1998, the Directors granted 1,080,900 options, at prices ranging from \$33.96 to \$34.45 per share based on a 10 day weighted average trading price of the Company's common shares on The Toronto Stock Exchange. At December 31, 1998, 3,630,460 common shares were under option at prices ranging from \$17.69 to \$34.45 per share, of which 1,479,100 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, 1998, 2,106,600 common shares were reserved for issuance upon the exercise of options.

At December 31, 1998, 3,599,180 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.

19. SEGMENTED INFORMATION

Effective January 1, 1998, accounting principles generally accepted in Canada require the disclosure of segmented information based on the Company's internal reporting system. The comparative balances in this note have been restated to reflect the required retroactive application of these new reporting requirements. 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 and information technology and financial services;

Other — other activities, including corporate expenses, business development expenditures, corporate financing expenses and utilization of previous years' unrecorded tax losses.

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	1998	1997	1996
Operating revenues, net of cost of sales	4%	3%	3%
Operating income	2%	2%	4%
Fixed assets and goodwill	13%	11%	

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

(\$million, except for share data)	Transmission & Field Services	Gas Distribution	Power Generation	International	Services	Other	Total
1998							
Total revenues	680	2,073	95	48	4,711	5	7,612
Inter company revenues	(8)	(3)	—	—	(225)	—	(236)
Operating revenues	672	2,070	95	48	4,486	5	7,376
Depreciation	(109)	(212)	(15)	(12)	(16)	—	(364)
Other operating expenses	(278)	(1,439)	(62)	(2)	(4,538)	(43)	(6,362)
Operating income (loss)	285	419	18	34	(68)	(38)	650
Interest income	—	4	1	2	5	7	19
Equity income	4	—	—	—	—	—	4
Interest expense	(157)	(227)	(7)	(24)	(6)	(67)	(488)
Other items	14	21	—	8	—	24	67
Income (loss) before undernoted items	146	217	12	20	(69)	(74)	252
Income taxes	(16)	(90)	(6)	(4)	23	45	(48)
Non-controlling interest	—	(5)	—	—	—	(1)	(6)
Net income (loss)	130	122	6	16	(46)	(30)	198
Provision for preferred dividends	(2)	—	—	—	—	(35)	(37)
Net income (loss) applicable to common shares	128	122	6	16	(46)	(65)	161
Per common share — basic	\$1.22	\$1.16	\$0.06	\$0.15	\$(0.44)	\$(0.62)	\$1.53
Operating cash flow	234	283	25	30	(65)	(59)	448
Operating cash flow per common share	\$2.22	\$2.68	\$0.24	\$0.28	\$(0.62)	\$(0.56)	\$4.24
Additions to fixed assets and goodwill	272	339	7	180	105	1	904
Total assets	3,555	5,464	278	402	792	329	10,820

(\$million, except for share data)							
1997	Transmission & Field Services	Gas Distribution	Power Generation	International	Services	Other	Total
Total revenues	639	2,405	113	12	4,228	4	7,401
Inter company revenues	—	(11)	(4)	—	(74)	—	(89)
Operating revenues	639	2,394	109	12	4,154	4	7,312
Depreciation	(97)	(202)	(18)	(1)	(11)	—	(329)
Other operating expenses	(254)	(1,679)	(68)	—	(4,165)	(24)	(6,190)
Operating income (loss)	288	513	23	11	(22)	(20)	793
Interest income	1	9	1	—	7	3	21
Interest expense	(159)	(236)	(8)	(4)	(5)	(42)	(454)
Other items	8	4	(1)	—	(2)	(1)	8
Income (loss) before undernoted items	138	290	15	7	(22)	(60)	368
Income taxes	(22)	(123)	(4)	(2)	7	21	(123)
Non-controlling interest	—	(6)	—	—	—	(1)	(7)
Net income (loss)	116	161	11	5	(15)	(40)	238
Provision for preferred dividends	(2)	—	—	—	—	(26)	(28)
Net income (loss) applicable to common shares	114	161	11	5	(15)	(66)	210
Per common share — basic	\$1.12	\$1.58	\$0.11	\$0.05	\$(0.15)	\$(0.65)	\$2.06
Operating cash flow	195	328	31	2	3	(37)	522
Operating cash flow per common share	\$1.90	\$3.21	\$0.30	\$0.02	\$0.03	\$(0.36)	\$5.10
Additions to fixed assets and goodwill	266	380	9	15	4	2	676
Total assets	3,041	5,494	253	400	844	43	10,075

(\$million, except for share data)							
1996	Transmission & Field Services	Gas Distribution	Power Generation	International	Services	Other	Total
Total revenues	677	2,323	110	9	1,841	4	4,964
Inter company revenues	(7)	(26)	(3)	—	(53)	—	(89)
Operating revenues	670	2,297	107	9	1,788	4	4,875
Depreciation	(80)	(195)	(16)	(1)	(5)	(1)	(298)
Other operating expenses	(328)	(1,584)	(65)	—	(1,792)	(21)	(3,790)
Operating income (loss)	262	518	26	8	(9)	(18)	787
Interest income	3	6	1	—	1	1	12
Interest expense	(159)	(243)	(4)	(3)	(1)	(38)	(448)
Other items	(22)	8	(2)	—	—	1	(15)
Income (loss) before undernoted items	84	289	21	5	(9)	(54)	336
Income taxes	8	(131)	(10)	(1)	4	15	(115)
Non-controlling interest	—	(8)	—	—	—	(1)	(9)
Net income (loss)	92	150	11	4	(5)	(40)	212
Provision for preferred dividends	—	—	—	—	—	(19)	(19)
Net income (loss) applicable to common shares	92	150	11	4	(5)	(59)	193
Per common share — basic	\$0.93	\$1.52	\$0.11	\$0.04	\$(0.05)	\$(0.59)	\$1.96
Operating cash flow	202	351	34	(2)	1	(43)	543
Operating cash flow per common share	\$2.05	\$3.55	\$0.34	\$(0.02)	\$0.01	\$(0.43)	\$5.50
Additions to fixed assets and goodwill	228	382	20	—	4	—	634

(a) The Statement of Financial Accounting Standards (SFAS) 106, Employers' Accounting for Post-Retirement Benefits Other Than Pensions, requires the accrual of liabilities applicable to post-retirement other than pension benefits. The consolidated accumulated post-retirement benefits at December 31, 1998 amount to \$65 million. The accrual related to the period prior to the introduction of SFAS 106 is being amortized on a straight-line basis over 20 years. Under Canadian GAAP, the costs of health care and life insurance benefits for retirees are expensed as incurred.

(b) SFAS 109, Accounting for Income Taxes, requires deferred income tax balances to be adjusted to reflect current legislated tax rates. For utility operations using the income taxes currently payable method, SFAS 109 requires the recording of deferred income taxes and the corresponding deferred charges which are to be collected from regulated customers in future years.

The variances in deferred income taxes are:

December 31 (\$million)	1998	1997
Deferred taxes under Canadian GAAP	340	400
SFAS 109 utility deferred income taxes	1,410	1,277
Other adjustments	(9)	(5)
Total future income tax liability under US GAAP	1,741	1,672

(c) SFAS 87, Employers' Accounting for Pensions, requires that pension fund assets be measured at current market values rather than at average market related values under Canadian GAAP and that the present value of the accrued pension plan obligations be discounted using current interest rates which may be different from management's long term assumptions for interest rates under Canadian GAAP. Using the requirements of SFAS 87, the consolidated pension fund assets at December 31, 1998 would be \$546 million and the consolidated pension obligations at December 31, 1998 would be \$598 million, and the pension expense would be \$21 million for the year ended December 31, 1998 (for the year ended December 31, 1997 – \$19 million, for the year ended December 31, 1996 – \$15 million).

(d) Effective January 1, 1996, the Company adopted 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.

(e) US GAAP require that changes in bank indebtedness be reported as a financing activity rather than as a change in cash and cash equivalents under Canadian GAAP.

(f) Canadian GAAP require the proportionate consolidation of the Company's investments in joint ventures. The Securities and Exchange Commission 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 13).

(g) Canadian GAAP require debt-like preferred shares and their dividends to be treated as long term debt and interest expense respectively. Under US GAAP, these shares are to be recorded as equity.

20. RECONCILIATION OF GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (continued)

(h) SFAS 133, Derivative Instruments and Hedging Activities, was issued in 1998. This statement, which is effective for the Company January 1, 2000, requires that all derivatives be recorded on the balance sheet at fair value. 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 for US GAAP purposes.

(i) The Statement of Position (SOP) 98-5, Reporting on the Costs of Start-Up Activities, was issued by the American Institute of Certified Public Accountants in 1998. This statement, which is effective for the Company January 1, 1999, requires that all costs of start-up activities be expensed as incurred rather than deferred and amortized to income over time as permitted under Canadian GAAP. A cumulative charge for any deferred amounts at December 31, 1998 will be recorded against 1999 net income under US GAAP to reflect this accounting change. 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 for US GAAP purposes.

21. CONTINGENCIES

(a) 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.

(b) The Year 2000 issue arises because many computerized systems use two digits rather than four to identify a year. Date-sensitive systems may recognize the year 2000 as 1900 or some other date, resulting in errors when information using 2000 dates is processed. In addition, similar problems may arise in some systems which use certain dates in 1999 to represent something other than a date. The effects of the Year 2000 issue may be experienced before, on, or after January 1, 2000, and, if not addressed, the impact on operations and financial reporting may range from minor errors to significant systems failure which could affect an entity's ability to conduct normal business operations.

The Company formalized its Year 2000 program in 1997 when it undertook to identify and address Year 2000 issues and established a Corporate Year 2000 Project Office at the Company's headquarters in Vancouver and project offices at each of its major operations. The Company has underway a program of assessment and remediation of computer systems and embedded logic systems in use throughout the Company in an effort to avoid Year 2000 problems which could cause material disruption to the Company's business. The assessment phase of the Year 2000 program has been completed and the Company is carrying out the remediation, testing and implementation phase. The Company is in ongoing communication with its customers, vital suppliers and other third parties to assess their level of Year 2000 readiness.

It is not possible for the Company to be certain that all aspects of the Year 2000 issue affecting the Company, including those related to efforts of customers, suppliers or other third parties, will be fully resolved. The Company, therefore, is developing business contingency plans to allow it to carry on business in an orderly manner into the year 2000.

Consolidated Quarterly Results

Unaudited Westcoast Energy Inc.

For the three months ended (\$million, except for share data)	March 31	June 30	Sept. 30	Dec. 31	Total
1998					
Operating revenues	2,002	1,664	1,843	1,867	7,376
Operating expenses	1,705	1,589	1,752	1,680	6,726
Operating income	297	75	91	187	650
Other net expenses	119	87	109	89	404
Income taxes	67	(22)	(21)	24	48
Net income	111	10	3	74	198
Provision for dividends on preferred shares	8	9	9	11	37
Net income (loss) applicable to common shares	103	1	(6)	63	161
Earnings per common share – basic	\$0.99	\$0.01	\$(0.06)	\$0.59	\$1.53

For the three months ended (\$million, except for share data)	March 31	June 30	Sept. 30	Dec. 31	Total
1997					
Operating revenues	2,235	1,563	1,485	2,029	7,312
Operating expenses	1,918	1,406	1,395	1,800	6,519
Operating income	317	157	90	229	793
Other net expenses	109	105	108	110	432
Income taxes	79	13	(8)	39	123
Net income (loss)	129	39	(10)	80	238
Provision for dividends on preferred shares	7	7	7	7	28
Net income (loss) applicable to common shares	122	32	(17)	73	210
Earnings per common share – basic	\$1.20	\$0.31	\$(0.17)	\$0.72	\$2.06

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 \$1.90 in 1998 compared with \$2.04 in 1997.

For the three months ended (dollar / share)	March 31	June 30	Sept. 30	Dec. 31	Total
1998					
Net income (loss) per common share	\$0.99	\$0.01	\$(0.06)	\$0.59	\$1.53
Weather impact – gas distribution	\$0.19	\$0.07	\$(0.01)	\$0.12	\$0.37
Weather normalized net income (loss) per common share	\$1.18	\$0.08	\$(0.07)	\$0.71	\$1.90

For the three months ended (dollar / share)	March 31	June 30	Sept. 30	Dec. 31	Total
1997					
Net income (loss) per common share	\$1.20	\$0.31	\$(0.17)	\$0.72	\$2.06
Weather impact – gas distribution	\$0.01	\$(0.07)	–	\$0.04	\$(0.02)
Weather normalized net income (loss) per common share	\$1.21	\$0.24	\$(0.17)	\$0.76	\$2.04

Ten-Year Review

Unaudited

Westcoast Energy Inc.

FINANCIAL

OPERATIONS (\$million)

Operating revenues	
Operating expenses	
Operating income	
Other net expenses	
Income taxes	
Net income from continuing operations	
Discontinued operations	
Net income (loss)	
Provision for dividends on preferred shares	
Net income (loss) applicable to common shares	
Dividends on common shares	
Operating cash flow	
– From continuing operations	
– After discontinued operations	

PER COMMON SHARE (dollars)

Net income (loss)—basic	
– From continuing operations	
– After discontinued operations	
Operating cash flow	
– From continuing operations	
– After discontinued operations	

Dividends

ASSETS (\$million)

Fixed assets	
Investments	
Current assets	
Deferred charges and other assets	
Total assets	

CAPITALIZATION (\$million)

Long term debt	
Preferred shareholders' equity	
Common shareholders' equity	
Deferred income taxes	
Current liabilities	
Non-controlling interest in subsidiary companies	
Total equity and liabilities	

1998	1997
7,376	7,312
6,726	6,519
650	793
404	432
48	123
198	238
—	—
198	238
37	28
161	210
133	122
448	522
448	522
\$1.53	\$2.06
\$1.53	\$2.06
\$4.24	\$5.10
\$4.24	\$5.10
\$1.26	\$1.20
8,569	8,025
374	195
1,596	1,574
281	281
10,820	10,075
5,297	4,941
716	570
2,368	2,056
340	400
1,935	2,045
164	63
10,820	10,075

1996	1995	1994	1993	1992	1991	1990	1989
4,875	4,184	3,827	3,674	1,818	1,501	1,494	741
4,088	3,445	3,208	3,107	1,473	1,236	1,240	589
787	739	619	567	345	265	254	152
460	436	360	353	224	177	170	83
115	109	95	68	36	15	22	16
212	194	164	146	85	73	62	53
—	—	—	—	(161)	10	21	13
212	194	164	146	(76)	83	83	66
19	18	13	13	11	6	6	6
193	176	151	133	(87)	77	77	60
105	81	76	65	49	45	44	39
543	384	342	363	233	189	161	96
543	384	342	385	292	249	239	167
\$1.96	\$2.01	\$1.76	\$1.70	\$1.23	\$1.18	\$1.03	\$0.97
\$1.96	\$2.01	\$1.76	\$1.70	\$(1.45)	\$1.36	\$1.41	\$1.24
\$5.50	\$4.41	\$3.98	\$4.64	\$3.88	\$3.33	\$2.93	\$1.97
\$5.50	\$4.41	\$3.98	\$4.91	\$4.87	\$4.39	\$4.35	\$3.43
\$1.05	\$0.93	\$0.89	\$0.82	\$0.80	\$0.80	\$0.80	\$0.80
7,304	7,056	6,390	5,674	5,678	3,535	3,129	1,972
184	162	100	32	87	23	111	143
1,328	994	974	939	844	364	376	140
250	239	182	145	118	102	103	41
9,066	8,451	7,646	6,790	6,727	4,024	3,719	2,296
4,743	4,715	3,647	3,383	3,396	1,780	1,701	856
445	245	245	120	195	75	75	75
1,890	1,542	1,417	1,320	1,005	896	850	678
366	396	399	391	593	368	352	327
1,517	1,441	1,828	1,465	1,400	827	663	309
105	112	110	111	138	78	78	51
9,066	8,451	7,646	6,790	6,727	4,024	3,719	2,296

Ten-Year Review

Unaudited

Westcoast Energy Inc.

STATISTICAL

VOLUMES (Bcf)

British Columbia Pipeline Division
Foothills Pipe Lines
Empire State Pipeline
Union Gas*
Other Gas Distribution

RATE BASE (\$million)

British Columbia Pipeline and Field Services Divisions
Foothills Pipe Lines (proportionate share – Phase I–27%)
Empire State Pipeline (proportionate share – 50%)
Union Gas*
Other Gas Distribution

NUMBER OF CUSTOMERS (thousand)

Union Gas*
Other Gas Distribution

COMMON SHARES

Shares outstanding at year-end
Toronto Stock Exchange price ranges
– high
– low
Number of common shareholders at year-end
Employees at year-end (consolidated–excluding joint ventures)

1998	1997
688	688
940	935
93	98
1,127	1,193
139	163
2,987	3,077
2,287	2,273
185	189
131	129
3,206	3,043
851	937
6,660	6,571
1,075	1,041
344	387
1,419	1,428
112,670,767	103,245,876
\$36.00	\$33.50
\$27.65	\$22.65
8,645	8,753
6,300	5,932

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

1996	1995	1994	1993	1992	1991	1990	1989
667	647	605	579	512	465	401	413
927	920	852	615	534	457	425	408
101	114	43	6	—	—	—	—
1,137	1,166	1,034	991	317	127	121	—
169	165	160	156	147	139	127	30
3,001	3,012	2,694	2,347	1,510	1,188	1,074	851
2,114	1,807	1,353	1,236	1,142	914	831	774
193	193	192	169	157	156	149	151
130	89	92	88	—	—	—	—
2,830	2,718	2,496	2,304	2,115	489	455	—
888	989	937	899	837	763	499	109
6,155	5,796	5,070	4,696	4,251	2,322	1,934	1,034
1,002	965	932	892	852	190	183	—
372	358	347	332	318	307	305	14
1,374	1,323	1,279	1,224	1,170	497	488	14
100,747,253	87,972,872	86,444,582	85,318,602	72,678,965	57,255,169	56,487,209	49,488,944
\$24.40	\$22.75	\$24.63	\$22.63	\$21.13	\$21.50	\$22.25	\$21.88
\$20.00	\$19.25	\$19.63	\$16.25	\$15.00	\$19.00	\$19.63	\$15.75
8,499	8,447	8,782	8,602	7,828	6,043	6,409	7,227
5,991	6,380	6,258	6,043	6,257	3,351	3,331	1,246

Directors

Annual Report 1998

Westcoast Energy Inc.

William C. Brown was formerly President and CEO of BC Sugar Refinery, Limited, and is a Director of Duke Seabridge Limited, TimberWest Forest Corp. and Harmac Pacific Inc. Mr. Brown was first elected to the Board in 1995 and is a member of the Audit and the Human Resources and Compensation Committees.

R. Donald Fullerton is a Director of the Canadian Imperial Bank of Commerce, George Weston Limited and Honeywell Inc. Mr. Fullerton was first elected to the Board in 1993 and is a member of the Audit Committee.

Wilbert H. Hopper was formerly Chairman and CEO of Petro-Canada, and served as Chairman of the Board of Westcoast Energy from 1983 to 1992. Mr. Hopper was first elected to the Board in 1979. He is Chair of the Audit Committee and is a member of the Executive Committee.

Lorna R. Marsden is President and Vice-Chancellor of York University, and is a Director of Manulife Financial and Gore Mutual Insurance Co. Dr. Marsden was first elected to the Board in 1995 and is a member of the Audit and the Human Resources and Compensation Committees.

George L. Mazanec is Advisor to the Chief Operating Officer of Duke Energy Corporation, and is a Director of National Fuel Gas Company, Aegis Insurance Services, Inc. and Northern Trust Bank of Texas. Mr. Mazanec was first elected to the Board in 1998 and is a member of the Audit Committee.

William H. Neville is Chairman of Hession, Neville & Associates. Mr. Neville was first elected to the Board in 1988. He is Chair of the Corporate Governance Committee and is a member of the Environment and Employees' Health and Safety Committee.

Marnie Paikin is a Director of Atomic Energy of Canada Limited and Union Gas Limited, and is a Governor of McMaster University and a Commissioner of the Ontario Human Rights Commission. Ms. Paikin was first elected to the Board in 1993. She is Chair of the Environment and Employees' Health and Safety Committee and is a member of the Corporate Governance Committee.

James S. Palmer Q.C. is Chairman of the law firm of Burnet, Duckworth & Palmer, and is a Director of the Bank of Canada and the Canadian Broadcasting Corporation. Mr. Palmer was first elected to the Board in 1990 and is a member of the Corporate Governance Committee.

Daniel U. Pekarsky is President of The Corporate Advisory Group Inc., and is a Director of Search Energy Corp. Mr. Pekarsky was first elected to the Board in 1993. He is Chair of the Executive Committee and is a member of the Corporate Governance and the Human Resources and Compensation Committees.

Michael E.J. Phelps is Chairman and CEO of Westcoast Energy. He is a Director of Canfor Corporation, the Canadian Imperial Bank of Commerce and Canadian Pacific Limited. He was appointed President and CEO in 1988, and became Chairman in 1992. Mr. Phelps was first elected to the Board in 1987 and is a member of the Executive Committee.

William G. Saywell is President and CEO of the Asia Pacific Foundation of Canada, and is a Director of Spar Aerospace Limited, the Bank of Tokyo-Mitsubishi (Canada) and Western Garnet International Ltd. Dr. Saywell was first elected to the Board in 1992 and is a member of the Corporate Governance and the Environment and Employees' Health and Safety Committees.

Arthur H. Willms is President and COO of Westcoast Energy. He is a Director of a number of Westcoast Energy companies, and is a Director of Crestar Energy Inc. Mr. Willms was first elected to the Board in 1983 and is a member of the Environment and Employees' Health and Safety and the Executive Committees.

W. Robert Wyman is Chairman and a Director of Suncor Energy Inc., and is a Director of Finning International Inc. and Fletcher Challenge Canada Limited. Mr. Wyman was first elected to the Board in 1993. He is Chair of the Human Resources and Compensation Committee and is a member of the Environment and Employees' Health and Safety and the Executive Committees.

Edwin C. Phillips is Director Emeritus of Westcoast Energy. Mr. Phillips, who was CEO of Westcoast Energy from 1975 to 1983, served as a Company Director from 1969 to 1989.

Senior Officer and Management Group

Annual Report 1998

Westcoast Energy Inc.

CORPORATE	HEAD OFFICE	GAS DISTRIBUTION	POWER GENERATION AND INTERNATIONAL
<p>Michael E.J. Phelps Chairman and Chief Executive Officer Westcoast Energy Inc.</p> <p>Arthur H. Willms President and Chief Operating Officer Westcoast Energy Inc.</p> <p>Graham M. Wilson Executive Vice President and Chief Financial Officer Westcoast Energy Inc.</p> <p>D. Michael G. Stewart Executive Vice President, Business Development Westcoast Energy Inc.</p> <p>Kenneth E. Rekrutiak Senior Vice President Westcoast Energy Inc.</p> <p>David G. Unruh Senior Vice President, Law and Corporate Secretary Westcoast Energy Inc.</p> <p>James R. Anderson Senior Vice President, Strategic Development Westcoast Energy Inc.</p> <p>Robert R. Foulkes Vice President, Corporate Communications Westcoast Energy Inc.</p> <p>Bohdan I. Bodnar Vice President, Human Resources and Administration Westcoast Energy Inc.</p>	<p>Westcoast Energy Inc. 1333 West Georgia Street Vancouver, British Columbia Canada V6E 3K9 (604) 488-8000</p> <p>TRANSMISSION & FIELD SERVICES</p> <p>Irvine J. Koop President Westcoast Energy Pipeline and Field Services Divisions Suite 2200 333 Seventh Avenue S.W. Calgary, Alberta Canada T2P 2Z1 (403) 297-1777</p> <p>Phillip R. Knoll President Westcoast Gas Services Inc. Suite 1600 300 Fifth Avenue S.W. Calgary, Alberta Canada T2P 3C4 (403) 216-1299</p>	<p>Robert T. Reid President and Chief Executive Officer Union Gas Limited 50 Keil Drive N. Chatham, Ontario Canada N7M 5M1 (519) 352-3100</p> <p>Otto E. Lang (Hon.) President and Chief Executive Officer Centra Gas Manitoba Inc. 444 St. Mary Avenue Winnipeg, Manitoba Canada R3C 3T7 (204) 925-0420</p> <p>Jac W. Kreut President and Chief Executive Officer Centra Gas British Columbia Inc. 1675 Douglas Street Victoria, British Columbia Canada V8W 3V3 (250) 480-4300</p> <p>Roy G. Dyce President and Chief Executive Officer Pacific Northern Gas Ltd. Suite 1400 1185 West Georgia Street Vancouver, British Columbia Canada V6E 4E6 (604) 691-5680</p>	<p>D. Michael G. Stewart President and Chief Executive Officer Westcoast Power Inc. and Westcoast Energy International Inc. 1333 West Georgia Street Vancouver, British Columbia Canada V6E 3K9 (604) 488-8000</p> <p>SERVICES</p> <p>Brian P. Gabel President Union Energy Inc. Suite 1200 2 Lansing Square Toronto, Ontario Canada M2J 4P8 (416) 499-7600</p> <p>Peter Krenkel President NGX Canada Inc. Suite 2330 140 Fourth Avenue S.W. Calgary, Alberta Canada T2P 3N3 (403) 974-1700</p>

Investor Information

Annual Report 1998

Westcoast Energy Inc.

Stock Market Price Ranges, Earnings, and Dividends per Common Share

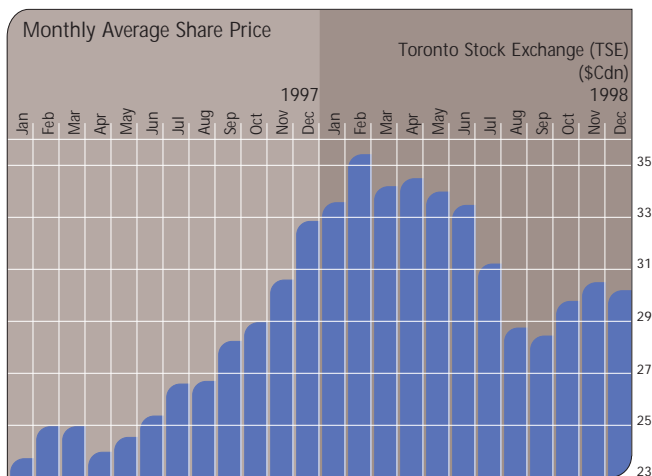
	Toronto (\$Cdn)		New York (\$US)		Earnings	Dividends
	Low	High	Low	High	(\$Cdn)	(\$Cdn)
1998						
January – March	31.60	36.35	22.63	25.25	0.99	0.31
April – June	32.55	35.70	22.31	24.94	0.01	0.31
July – September	27.25	33.60	17.56	22.63	(0.06)	0.32
October – December	27.75	31.50	18.00	20.06	0.59	0.32
					<u>1.53</u>	<u>1.26</u>

	Toronto (\$Cdn)		New York (\$US)		Earnings	Dividends
	Low	High	Low	High	(\$Cdn)	(\$Cdn)
1997						
January – March	22.65	25.85	16.50	18.88	1.20	0.29
April – June	23.45	25.70	16.75	18.50	0.31	0.29
July – September	25.25	28.90	18.13	20.88	(0.17)	0.31
October – December	27.35	33.50	19.75	23.50	0.72	0.31
					<u>2.06</u>	<u>1.20</u>

Key Dates

(tentative)

Quarters	Release of Financial Results	Common Share Dividend Payment Dates
1999		
1st Quarter	April 29, 1999	June 30, 1999
2nd Quarter	July 28, 1999	September 30, 1999
3rd Quarter	October 27, 1999	December 31, 1999
4th Quarter	February 16, 2000	March 31, 2000



Investor Information

Annual Report 1998

Westcoast Energy Inc.

Dividend Reinvestment and Share Purchase Plan

Westcoast Energy's Dividend Reinvestment and Share Purchase Plan provides registered holders of Westcoast Energy common shares and convertible preferred shares with two convenient and economic ways to increase their holdings in the Company.

Registered shareholders may elect to reinvest the cash dividends paid on all or some of their common and convertible preferred shares in additional common shares of the Company, and are also entitled to make optional cash purchases of common shares through the Plan in amounts from \$50 to \$5,000 per calendar quarter.

The Plan allows participants to acquire new common shares through the reinvestment of dividends at 95% of the average market price as defined in the Plan. Optional cash purchases are made at the average market price. Participants do not pay any brokerage commissions or other fees on the reinvestment of dividends or the optional cash purchase of new shares through the Plan. All notices and enquiries relating to the Plan should be addressed to the Montreal Trust Company at:

Montreal Trust Company Stock Transfer Services

510 Burrard Street
Vancouver, British Columbia
Canada V6C 3B9
Telephone: (604) 661-0222
Facsimile: (604) 683-3694
Toll Free: (888) 661-5566

Shareholder and Corporate Relations

Shareholders or others wishing to obtain copies of this Annual Report, quarterly reports, the 1999 Annual Information Form, and other corporate documents should contact the Company either by letter, addressed to the attention of the Corporate Secretary, or by telephone at (604) 488-8000.

Portfolio managers, investment analysts, and other investors requesting financial information respecting the Company should contact:

Thomas M. Merinsky
Manager, Investor Relations
Telephone: (604) 488-8021
Facsimile: (604) 488-8192

All other enquiries by shareholders and others respecting the Company should be directed to:

Robert R. Foulkes
Vice President, Corporate Communications
Telephone: (604) 488-8093
Facsimile: (604) 488-8068

Stock Exchanges and Symbols

Westcoast Energy common shares are listed on the Toronto, Montreal, Vancouver, New York and Pacific stock exchanges.

In Canada – W

In the United States – WE

Westcoast Energy preferred shares are listed on the Toronto, Montreal and Vancouver stock exchanges.

8.08% First Preferred, Series 2 – W.PR.D

6.90% First Preferred, Series 4 – W.PR.E

4.90% First Preferred, Series 5 – W.PR.F

4.72% First Preferred, Series 6 – W.PR.G

5.50% First Preferred, Series 7 – W.PR.H

Auditors

Ernst & Young LLP

P.O. Box 10101, Pacific Centre
700 West Georgia Street
Vancouver, British Columbia
Canada V7Y 1C7

Registrars and Transfer Agents

Common Shares

Montreal Trust Company
Vancouver, Calgary, Regina, Toronto, Montreal

Registrar and Transfer Company
Cranford, New Jersey

Preferred Shares

Montreal Trust Company of Canada
Vancouver, Calgary, Regina, Winnipeg, Toronto, Montreal

Registrar and Trustee

Debentures

Montreal Trust Company of Canada
Vancouver, Calgary, Regina, Winnipeg, Toronto, Montreal

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%.



Westcoast Energy Inc.
1333 West Georgia Street
Vancouver, British Columbia
Canada V6E 3K9

Telephone: (604) 488-8000
Facsimile: (604) 488-8500
Internet: www.westcoastenergy.com

Vice President, Corporate Communications
Robert R. Foulkes (604) 488-8093

Manager, Investor Relations
Thomas M. Merinsky (604) 488-8021

Duplicate Publications

Registered holders of the Company's shares may receive more than one copy of Company publications. Shareholders can assist the Company in eliminating such duplication by contacting the Montreal Trust Company in Vancouver at (888) 661-5566 (Toll free).

Cover and Coated Stock:

Centura Gloss
10% total recovered fiber,
all post-consumer fiber

Uncoated Stock:

Resolve Premium Opaque
Over 50% recycled paper including
10% post-consumer fiber

Printed in Canada