Hiram Walker Resources Ltd.

HIRAM WALKER RESOURCES LTD.

Annual Report 1983

ESTABLISHED 1858
HIRAM WALKER & SONS LIMITED
DISTILLERS OF "CANADIAN CLUB" WHISKY
"Canadian Club"
C.C.
Canadian Whisky Canadien
Distilled and Bottled in Bond under
Canadian Government Supervision by
Hiram Walker & Sons.
Limited
Walkerville, Ontario, Canada
TRADEMARKS AND LABEL STYLE REGISTERED
710 mL
40% alc./vol.

The year in brief

Financial	1983	1982	1981
	(Expressed in millions except per share amounts)		
Operations			
Revenue	**$3,402.8**	$3,359.8*	$2,900.8*
Operating income	**$ 537.7**	$ 523.8*	$ 475.9*
Net income applicable to common shares before unusual item	**$ 142.2**	$ 98.9	$ 222.3
Cash from operations	**$ 664.4**	$ 484.7*	$ 202.9*
Capital expenditures	**$ 262.5**	$ 358.4	$ 403.8
Per common share			
Net income before unusual item			
Basic	**$ 2.03**	$ 1.43	$ 3.23
Dividends	**$ 1.32**	$ 1.32	$ 1.32
Financial position			
Total assets	**$4,839.6**	$4,963.6	$4,918.2
Shareholders' equity	**$1,623.8**	$1,703.3	$1,821.8
Operating			
Distilled spirits			
Gross revenue less excise taxes and import duties (millions)	**$ 1,054**	$ 1,103*	$ 1,085*
Natural resources			
Crude oil and liquids production (barrels per day)	**31,249**	32,934	32,370
Natural gas sales (millions of cubic feet per day)	**155.3**	190.5	165.8
Gas utility			
Volume of gas sold (billions of cubic feet)	**284.1**	308.8	296.9
Number of active customers	**759,911**	724,158	678,279

*Amounts reclassified to conform with 1983 financial statement presentation.

Corporate profile

Hiram Walker Resources Ltd. (the "Company"), one of Canada's largest publicly-traded companies, operates internationally in three main business areas: distilled spirits, natural resources, and natural gas distribution. Its common shares are listed on major Canadian stock exchanges and on the New York Stock Exchange. Incorporated under the laws of the Province of Ontario, Canada, executive offices are maintained in Toronto, Ontario. The Company employs 10,200 people.

Canadian Club, a principal brand, portrayed against the background of the main office building of Hiram Walker-Gooderham & Worts Limited in Walkerville, Ontario.

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Annual meeting

The Annual and Special Meeting of Shareholders will be held in the Canadian Room of the Royal York Hotel, 100 Front Street West, Toronto, Ontario, on Wednesday, February 1, 1984, at 11:00 a.m.

A.E. Downing succeeds H. Clifford Hatch

On November 16, 1983, H. Clifford Hatch informed the Board of Directors of his desire to retire as President, Chief Executive Officer and Chairman of the Board at the Company's next annual meeting to be held on February 1, 1984. It is proposed by the Board to appoint A.E. (Bud) Downing, President of Hiram Walker-Gooderham & Worts Limited, as his successor on that date. Mr. Hatch has agreed to continue as a Director and serve as Chairman of the Executive Committee of the Board.

Mr. Downing has spent his entire business career with the Company, becoming President of Hiram Walker-Gooderham & Worts in 1978. When Hiram Walker-Gooderham & Worts merged in 1980 with The Consumers' Gas Company and its wholly-owned subsidiary, Home Oil Company Limited, Mr. Downing became a Director and Executive Vice President of the Company.

Born in Mount Elgin, Ontario, Mr. Downing interrupted his studies at the University of Toronto during World War II to serve with the Canadian Navy. At the end of the War, he returned to the university and graduated in 1947 in chemical engineering.

During the early part of his career, Mr. Downing was involved in the production side of the business at a time when substantial plant expansion was required to meet the large post war growth in the distilled spirits industry. Later he became increasingly involved in general management with particular interests in the marketing and financial aspects of business.

While serving on a two year assignment at the Company's distillery in Argentina, Mr. Downing became fluent in Spanish.

He was elected to the Board of Directors of Hiram Walker-Gooderham & Worts in 1971 and was named a Vice President in 1973 and a Senior Vice President in 1976.


A. E. Downing

Mr. Downing is a Director of Allendale Mutual Insurance Company, Providence, R.I., Corby Distilleries Limited, Interprovincial Pipe Line Limited, Liquid Carbonic Canada Ltd./Ltee. and Westinghouse Canada Inc.

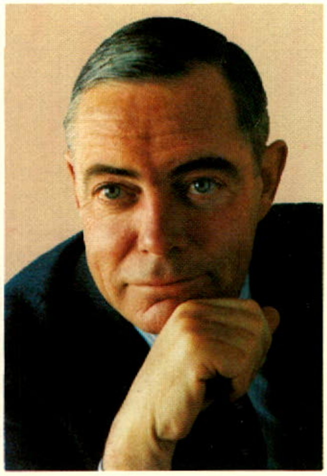
His community services include terms as President of the United Community Services of Greater Windsor, and board memberships of St. Clair College, Windsor, and the Metropolitan Hospital of Windsor.

The Directors also announced it is proposed to appoint H. Clifford Hatch, Jr., as President of Hiram Walker-Gooderham & Worts to succeed Mr. Downing.

Mr. Hatch, Jr., a Director and Executive Vice President of Hiram Walker Resources, and Vice President of Hiram Walker-Gooderham & Worts, is a native of Windsor and holds a Bachelor of Arts degree from McGill and a Masters of Business Administration degree from Harvard. He joined the Company in 1968 and served as President and Chief Executive Officer of Corby Distilleries, a subsidiary company, for three years before becoming Vice President of Hiram Walker-Gooderham & Worts in 1979.

Report to shareholders

H. Clifford Hatch



W. P. Wilder

Significant progress was made during 1983 on the Company's plan to reduce the heavy debt load and improve the performance of the natural resource portion of the business. Lower capital expenditures, coupled with internal cost control measures and effective cash management, provided sufficient funds to reduce non-utility debt by $260 million and thereby strengthen the Company's balance sheet.

A number of steps initiated in 1983 contributed to the improvement in the natural resource sector. The divestiture of marginal activities was completed. The consolidation or realignment of operating functions contributed to increased efficiencies. In the United States, capital expenditures were reduced and applied only to those projects which maximized the immediate value of assets. Expenditures in international areas were reduced but in Canada spending increased to expand both near and long term exploration and development opportunities in the western provinces as well as frontier areas. As a result, the Company will become one of the most active explorers in Canada.

Net income applicable to common shares in 1983 increased to $142.2 million, or $2.03 per share, from $98.9 million, or $1.43 per share, a year earlier, excluding the unusual item in 1982. The main factors contributing to the increase were the reduction in interest and finance charges brought about by lower debt and interest rates, as well as the improved performance in the natural resource segment.

In the distilled spirits segment, operating income declined due to lower sales in most world markets, which remain economically depressed, and to higher selling and general expenses. In Canada, sales continued to be adversely affected by high taxes which have increased by as much as 65 per cent over the past three years on a 25 ounce bottle of rye whisky. The industry should benefit from the economic recovery now underway, but excessive taxation remains an industry concern.

In the gas utility segment, operating income was lower due to the warm winter and depressed economic conditions. The utility would also benefit from an economic upturn, particularly in the industrial customer category.

After the year end, a share exchange was completed with Interprovincial Pipe Line Limited, the owner and operator of the longest crude oil pipeline system on the continent, making the Company the largest shareholder of Interprovincial, with a 34 per cent interest, and Interprovincial the largest shareholder of the Company, with a 16 per cent interest. The association with this financially strong company will provide growth potential and stability in earning power. The investment increases the Company's earnings per share modestly after taking into account the issuance of the additional shares and also improves the Company's financial position, principally by improving the debt to equity ratio. The Company is represented on the 15-member Interprovincial Board with five members and we look forward to having appropriate Interprovincial representation on our Board.

A more detailed description of Interprovincial is provided on page 11.

R. W. Martin, Executive Vice President of the Company and President of The Consumers' Gas Company Ltd., will stand for election to the Board at the annual meeting. Paul J. G. Kidd, Q.C., will not stand for re-election. Mr. Kidd, a former Senior Vice President of Hiram Walker-Gooderham & Worts Limited, has served the Company or its affiliates for 47 years. Appreciation is expressed for the valuable contribution he has made to the Company's progress.

The Company's success is due in large measure to its employees, shareholders and customers. The Board appreciates their continued loyalty and strong support.

On behalf of the Board of Directors:

H. Clifford Hatch

H. Clifford Hatch
Chairman

W. P. Wilder

W. P. Wilder
Deputy Chairman

November 16, 1983

Operating review

DISTILLED SPIRITS

The distilled spirits industry continued to operate in depressed economic markets throughout most of the world during 1983. High levels of unemployment and shrinking disposable consumer income combined to reduce demand, particularly for premium priced products. In some markets, higher prices resulting from increased government markups and taxes have added to the problem. The positive effects of the economic upturn underway in the United States, and to a lesser extent in Canada and some other countries, have not yet been reflected in higher volumes. Within the industry, the severity of the recession has contributed to heightened competition to maintain or improve share in a contracting market and price discounting has emerged as a prevalent practice.

Financial highlights: distilled spirits

millions

	1983	1982	1981
Operating revenue	**$1,405.7**	$1,454.8	$1,452.4
Operating income	**$ 266.6**	$ 293.8	$ 280.6
Assets	**$1,548.6**	$1,569.3	$1,540.3
Capital expenditures	**$ 23.7**	$ 52.7	$ 84.9

Although the Company's total sales, in line with the industry, were lower in 1983, the market share of most major brands was maintained or improved. The Company is well positioned to take advantage of a sustained economic upturn.

Principal brands

In the United States, sales of Kahlua continued to improve, maintaining its position as the top selling imported liqueur. In Canada, though sales were down, Kahlua also retained its position as the leading imported liqueur.

Sales volumes for Canadian Club were lower in North America, reflecting a general sales decline of higher priced premium Canadian whiskies.

Ballantine's Scotch maintained or improved its market share in major international markets. Though sales volumes decreased, Ballantine's continued to enjoy its position as the number one or two selling Scotch whisky in most European countries.

Sales of Courvoisier Cognac were also adversely affected by poor economic conditions in the important markets of North America, the United Kingdom, Europe and the Far East. Market share, however, was generally preserved. Courvoisier sales are expected to improve as more favorable conditions emerge.

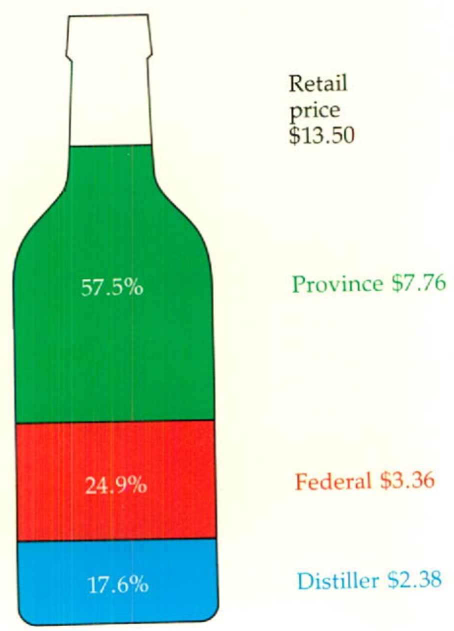
Sales of Hiram Walker domestic cordials increased in the United States, despite an industry sales decline in this category for the first time in recent years. The addition of new flavors, such as Sambuca, continued to expand the choices available to the consumer and helped maintain Hiram Walker cordials as the largest selling line in the United States.

Excise tax

In Canada, the federal excise duty increased automatically by 13.3 per cent on September 1, 1983, for a cumulative increase of 46.2 per cent since the duty was indexed to retail prices in 1982. Canadian distillers individually and through their trade association are attempting to persuade the federal government to change its formula or reduce the large tax increases that it has produced. As a direct result of these tax increases, the retail price of distilled spirits has increased significantly and industry sales to consumers have declined noticeably. The Association of Canadian Distillers launched a program to inform the public and elected representatives of the threat that these taxes pose to distilled spirits companies, shareholders and employees, suppliers and other industries such as tourism.

Retail price breakdown

25 ounce bottle of rye whisky sold in Ontario



The diagram illustrates how federal and provincial government taxes and markups combine to account for 82.4 per cent of the price of a typical 25 ounce bottle of rye whisky sold in Ontario. All manufacturing costs must be paid out of the distillers' 17.6 per cent share.

The industry has vigorously opposed attempts in the United States during the past two years to increase the federal excise tax on distilled spirits. The current Administration opposes an increase. However, future attempts to increase the tax are likely and opposition will be maintained through the industry trade association.

Operations

Early in the year, the new bottling plant at Kilmalid, near Dumbarton, Scotland, was put into production, completing the construction of a modern integrated blending and bottling facility for Scotch whisky. It is expected the facility will be adequate to meet production requirements over the next decade.

No further major capital programs are anticipated over the next few years as production facilities now rank among the industry's most modern and efficient.

Personnel

During the year, a number of appointments were made to strengthen the marketing organization. In the United States, J. F. Murphy was appointed Executive Vice President of Hiram Walker & Sons, Inc., with responsibility for the marketing of all distilled spirits products in the United States. Mr. Murphy, formerly President of W.A. Taylor & Company, which imports and sells premium products in the United States, was succeeded by J. J. Harcarufka.

L. A. Bardsley, President and Managing Director of Hiram Walker International Limited, was appointed Chairman. He was succeeded by D. J. Evans, formerly Director of Marketing. Messrs. M. Butterworth, E. P. Stahl and I. Braastad were appointed Vice Presidents.

J. D. Young became Executive Vice President of Hiram Walker & Sons Limited with responsibility for sales and marketing operations in Canada. Mr. Young replaces C. J. New who has assumed special project duties.

Anniversary

During the year, the Company observed the 125th anniversary of its founding with a series of receptions for employees and their families at selected plant and office locations. Hiram Walker, a grain merchant, established the distillery operation in Walkerville, Ontario, in 1858, which grew into one of the world's largest distilled spirits companies.

NATURAL RESOURCES

During 1983, the Company strengthened its position in Canada, rationalized operations further in the United States and pursued a more selective exploration and development program internationally.

Financial highlights: natural resources
millions

	1983	1982	1981
Operating revenue	**$ 458.7**	$ 476.6	$ 349.4
Operating income	**$ 90.8**	$ 41.9	$ 82.8
Assets	**$1,851.6**	$1,893.8	$2,076.3
Capital expenditures	**$ 145.9**	$ 207.9	$ 222.8

Canada

In Canada, increased exploration and development programs undertaken on existing properties and initiated on others by way of farmin significantly expanded the potential to add to oil and gas reserves in both the western provinces and frontier areas. The map on page 7 highlights land holdings in the western provinces, the Beaufort Sea and the Scotia Shelf off the East Coast.

Of the farmin agreements concluded during the year, the most important was with Dome Petroleum Limited. The Company will spend a minimum of $390 million over a three-year period to explore and develop 15 million net acres of land held by Dome in Canada. The Company's net outlay will be reduced substantially by federal and provincial incentive payments.

The Company's Canadian Ownership Rate, which at year end was 88 per cent, qualifies it for the maximum grants payable from the federal and provincial governments.

About two-thirds of the land is located in the western provinces where the Company will pay 40 per cent of Dome's drilling costs to earn 20 per cent of that company's share in the spacing unit containing each development well and in a maximum of nine sections surrounding each exploratory well. Of the 22 exploratory and development wells participated in by year end, 12 were oil and four were gas.

The balance of the Dome lands are located in the Beaufort Sea where six wells will be drilled. The Company will pay 15 to 35 per cent of Dome's share of the well costs to earn 7.5 to 17.5 per cent of Dome's interests in the structures drilled and approximately a five per cent interest in the remaining undrilled lands.

During 1983, drilling was conducted on two wells covered by the agreement, Siulik and Arluk, which are expected to be drilled to total depth and tested in

Working interest wells

Year ended September 30, 1983

	Canada		United States		Other		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploratory								
Oil	12	6.89	1	.20	2	.55	15	7.64
Gas	6	2.29					6	2.29
Dry	16	9.25	10	3.45	5	1.60	31	14.3
	34	18.43	11	3.65	7	2.15	52	24.23
Development								
Oil	77	22.83	34	6.17	10	.20	121	29.20
Gas	35	8.08	7	2.16			42	10.24
Dry	25	6.54	22	2.09			47	8.63
	137	37.45	63	10.42	10	.20	210	48.07
Total	171	55.88	74	14.07	17	2.35	262	72.30

Gross refers to the number of wells in which a working interest is held; net is the aggregate of the amounts for each gross well multiplied by the percentage of the working interest held.

1984. The agreement permitted the Company to retain a previous 20 per cent interest in lands where two additional wells, Natiak and Havik, commenced drilling. These wells will also be drilled to total depth and tested in 1984.

The addition of Dome's Beaufort Sea lands complements an already strong presence achieved in 1982 under a farmin agreement with Esso Resources Canada Limited. Under this farmin, the Company is paying 25 per cent of Esso's share of costs to earn 12.5 per cent of its interests in 4.4 million net acres of land. At least 13 wells will be drilled over a five year period. In the Itiyok well, drilled during the year as part of the program, drillstem tests conducted on three oil and four gas zones flowed at combined rates of 5,744 barrels of oil and 65 million cubic feet of gas per day.

Another farmin concluded in 1983, also with Dome, covers 593,000 acres in the East Sable block offshore Nova Scotia. The Company will earn a 21.9 per cent interest in 45,000 acres containing the earning well, the drilling of which began in November. In addition, similar interests can be earned by drilling two other wells .

An application was filed with the Alberta Energy Resources Conservation Board during the year to proceed with a major enhanced recovery project in a portion of the Swan Hills oilfield located in northwestern Alberta. A 17.2 per cent interest is held in the field. About 70 million additional barrels of oil, 12 million net to the Company, are expected to be recovered over a 30-year period. The oil will be recovered by injecting an ethane-based mixture of light hydrocarbons into the reservoir to improve the recovery of oil left behind by the current waterflood operations. Startup is expected in 1985.

United States

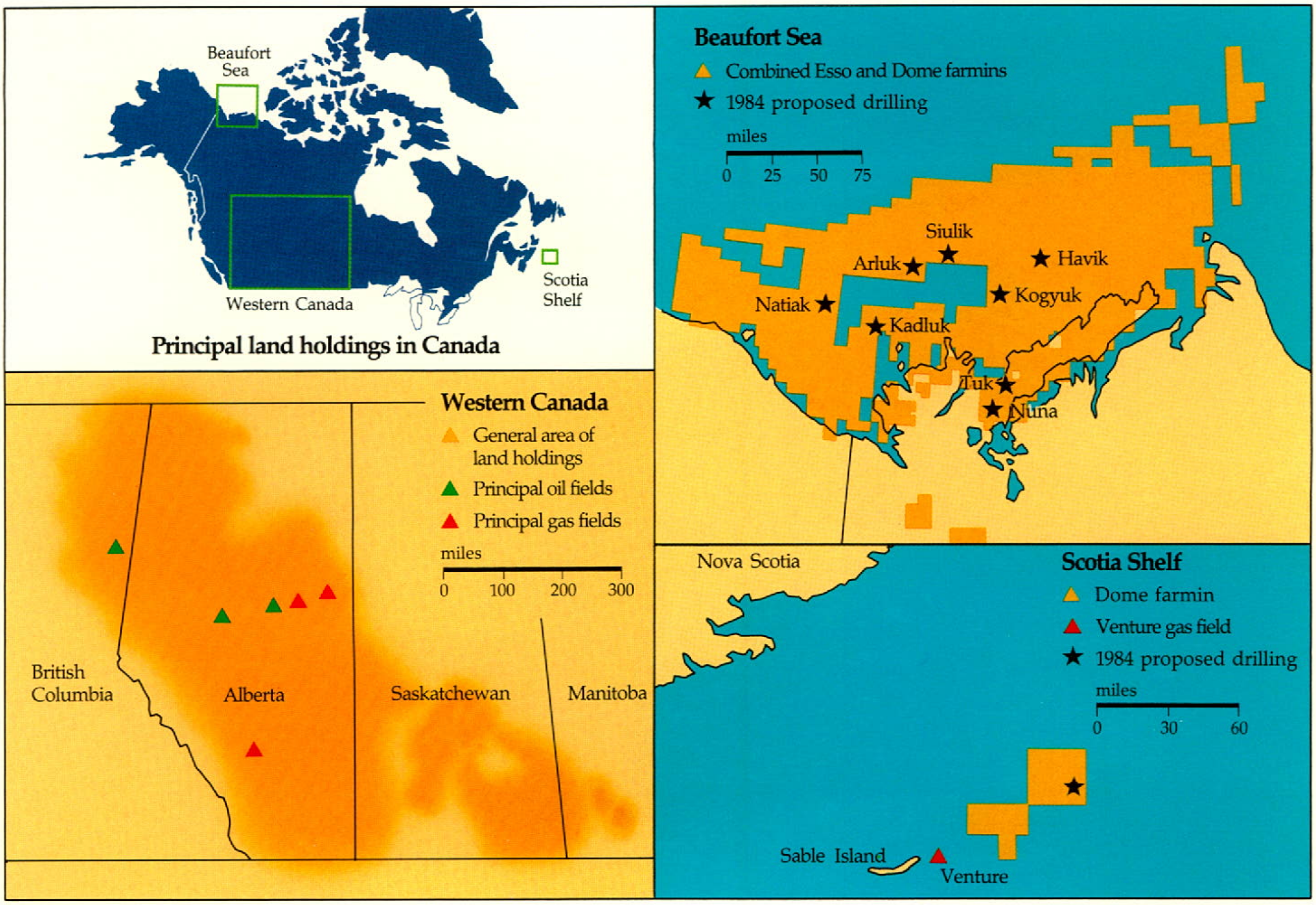
A number of steps taken during the year improved the performance of the oil and gas operations in the United States. Capital expenditures were reduced and directed only to those projects which maximized the immediate value of assets. The Company withdrew from the marketing of liquified petroleum gas as part of a plan to divest itself of marginal activities. Further savings were realized by consolidating or realigning operating functions.

A 13.5 per cent interest is held in a well drilled in Campbell County, Wyoming, which is producing at the rate of 3,200 barrels of oil and 5.5 million cubic feet of gas per day. A stepout well flowed at the rate of 2,000 barrels of oil and 3.6 million cubic feet of gas per day. At year end, three additional stepout wells were awaiting testing.

International

Expenditures in international areas were directed mainly to Australia. The 1981 Blina oil field discovery on permit EP-129 was placed on production at year end at the rate of 1,000 barrels per day. Production from the Sundown oil field, discovered on the same permit, began in November of 1983 from two wells at the initial combined rate of 250 barrels per day. Additional development drilling will be undertaken to delineate the Sundown field. A 27.5 per cent interest is held in the permit.

After the year end, the Company sold 40 per cent of its Australian energy interests, held by a wholly-owned subsidiary, through a share offering



limited to residents of Australia. In addition to raising approximately $22.5 million to fund an ongoing program, the sale satisfied the requirements of Australia's Foreign Investment Review Board.

Interests are held in a number of exploration areas in Australia. Interests ranging from 0.25 to 8.25 per cent are held in various sub-blocks of the offshore NT/P2 permit on the Northwest Shelf; a 10 per cent interest can be earned in permit ATP-299P(A), which covers 1.8 million acres in the Cooper Basin of Queensland, and a 25 per cent interest can be earned in permit WA-128-P, covering 865,000 acres offshore Western Australia. A well will be drilled on each permit in 1984. Following the drilling of an unsuccessful exploratory well, an interest in permit WA-117-P was relinquished after the year end.

Additional development wells were drilled offshore Indonesia to delineate further the Lalang oil field in the Malacca Strait. Production from the Lalang field is expected to start in mid 1984 at the initial rate of 23,000 barrels per day. A 1.95 per cent interest is held.

Production

Production of crude oil and natural gas liquids, before royalties, averaged 31,249 barrels per day in 1983 compared with 32,934 barrels per day a year earlier. The decrease resulted mainly from normal production declines in mature fields, partially offset by continued improvement in the performance of the West Eagle field in British Columbia and successful development drilling in both Canada and the United States. In Canada, crude oil qualifying for the Special Old Oil Price was reclassified on July 1, 1983, and now qualifies for the New Oil Reference Price, which is essentially the world price. Approximately 21 per cent of the Company's Canadian oil production qualifies for the New Oil Reference Price, compared with about two per cent in 1982.

Natural gas sales, before royalties, declined 18.5 per cent to 155.3 million cubic feet per day. The mild winter and lower demand, particularly in the United States, were contributing factors.

Though natural gas sales to the United States were expected to increase due to the startup of the eastern leg of the Alaska Highway Gas Pipeline Project, gas exports in 1983 were only 45 per cent of authorized export volumes. In an effort to stimulate additional sales to the United States, the Canadian government reduced the export price by 11 per cent and introduced a one-year volume related incentive price. Furthermore, the federal and provincial governments are examining additional initiatives to increase domestic sales in Canada.

Production summary

	1983	1982	1981
Crude oil and liquids (barrels per day)			
Canada	**25,811**	26,664	27,908
United States	**5,438**	6,255	4,462
Other		15	
Total	**31,249**	32,934	32,370
Natural gas (millions of cubic feet per day)			
Canada	**96.7**	108.3	106.5
United States	**58.6**	82.2	59.3
Total	**155.3**	190.5	165.8

Reserves

In 1983, the Company was able to replace over 85 per cent of its crude oil and natural gas liquids production through reserve additions and net upward revisions resulting from drilling and improved reservoir performance.

Proved reserves(1)

	1983	1982	1981
Crude oil and natural gas liquids (millions of barrels)			
Canada	**101.7**	104.9	117.7
United States	**13.2**	11.6	13.3
Other	**1.5**	1.5	
Total	**116.4**	118.0	131.0
Natural gas (billions of cubic feet)			
Canada	**944.0**	913.0	949.0
United States	**145.0**	128.0	159.0
Total	**1,089.0**	1,041.0	1,108.0

(1) Before the deduction of royalties.

Total proved reserves of crude oil and natural gas liquids, before royalties, declined marginally to 116.4 million barrels in 1983 from 118.0 million barrels in 1982. In Canada, additions from successful development activities were insufficient to offset production, whereas in the United States additions and net upward revisions exceeded production.

Total proved reserves of natural gas, before royalties, increased by five per cent to 1,089 billion cubic feet, as additions through successful drilling and net upward revisions more than offset production.

Proved reserves are the estimated quantities of crude oil and natural gas liquids, and natural gas which geological and engineering data demonstrate with reasonable certainty to be economically recoverable in future years from known reservoirs under existing operating and economic conditions.

Land holdings (acres) at September 30, 1983

	Gross	Net
Canada		
Alberta	4,747,911	1,522,906
Arctic Islands	4,752,519	350,400
Beaufort/Mackenzie Delta	995,533	153,223
British Columbia	1,250,908	333,344
East Coast offshore	1,972,884	147,966
Newfoundland	5,565,586	278,617
Saskatchewan	839,886	729,847
Other	1,090,371	302,457
	21,215,598	3,818,760
United States		
Alaska	106,512	105,528
Montana	1,501,255	490,382
North Dakota	661,550	136,950
Texas	402,190	66,223
Wyoming	1,043,617	327,852
Other	1,066,926	388,573
	4,782,050	1,515,508
International		
Australia	6,751,128	877,699
Guyana	1,496,320	1,077,350
Indonesia	2,946,732	57,461
Other	437,083	41,335
	11,631,263	2,053,845
Total	37,628,911	7,388,113

GAS UTILITY

Total volumes of gas sold in 1983 decreased 8.0 per cent to 284.1 billion cubic feet, due principally to the mild winter and to a lesser extent to the continued adverse impact of the recession.

Financial highlights: gas utility
millions

	1983	1982	1981
Operating revenue	**$1,538.4**	$1,428.4	$1,099.0
Operating income	**$ 180.3**	$ 188.1	$ 112.6
Assets	**$1,439.4**	$1,500.5	$1,301.6
Capital expenditures	**$ 93.0**	$ 97.8	$ 96.1

Despite the lower level of economic activity, the number of customers served by the utility continued to grow, though not at a rate as high as that experienced in recent years. The number of customers served increased by 35,753, bringing the total number of active customers to a record 759,911.

All market sectors—residential, commercial and industrial—contributed to the volume decline.

In the residential sector, which accounted for 27.5 per cent of total sales volumes, the benefit of customer additions was offset by the warm weather. Conversions from oil to gas totalled 12,417 compared with 25,107 in 1982, but customer additions from new housing starts improved to 20,323 from the 14,646 achieved in 1982, reflecting greater buoyancy in the housing industry. Natural gas service continues to be installed in more than 85 per cent of new homes constructed within the franchised area.

Gas sales
millions of cubic feet

	1983	1982	1981
Residential	**78,144**	87,949	81,121
Commercial	**106,709**	115,598	109,205
Industrial	**99,239**	105,283	106,535
Total	**284,092**	308,830	296,861

Sales revenue
thousands

	1983	1982	1981
Residential	**$ 500,962**	$ 478,574	$ 342,618
Commercial	**530,017**	484,897	370,601
Industrial	**459,745**	416,826	343,613
Total	**$1,490,724**	$1,380,297	$1,056,832

Both the commercial sector, which accounted for 37.6 per cent of sales, and the industrial sector, which accounted for the remaining 34.9 per cent, continued to suffer from depressed economic conditions and consequent reduced demand.

A full line of gas and other appliances are retailed through 17 stores in franchised areas. In 1983, merchandising revenue, boosted by the temporary removal of the Ontario Retail Sales Tax, increased 22 per cent to $13.8 million.

Supply

Long term purchase contracts are entered into to secure natural gas supplies for existing customers and to provide for orderly growth in future years. Substantially all requirements are purchased from TransCanada PipeLines Limited which, in turn, obtains its supplies from abundant reserves in western Canada, principally Alberta. Purchases of natural gas from Ontario producers and Company-owned reserves supplement supply.

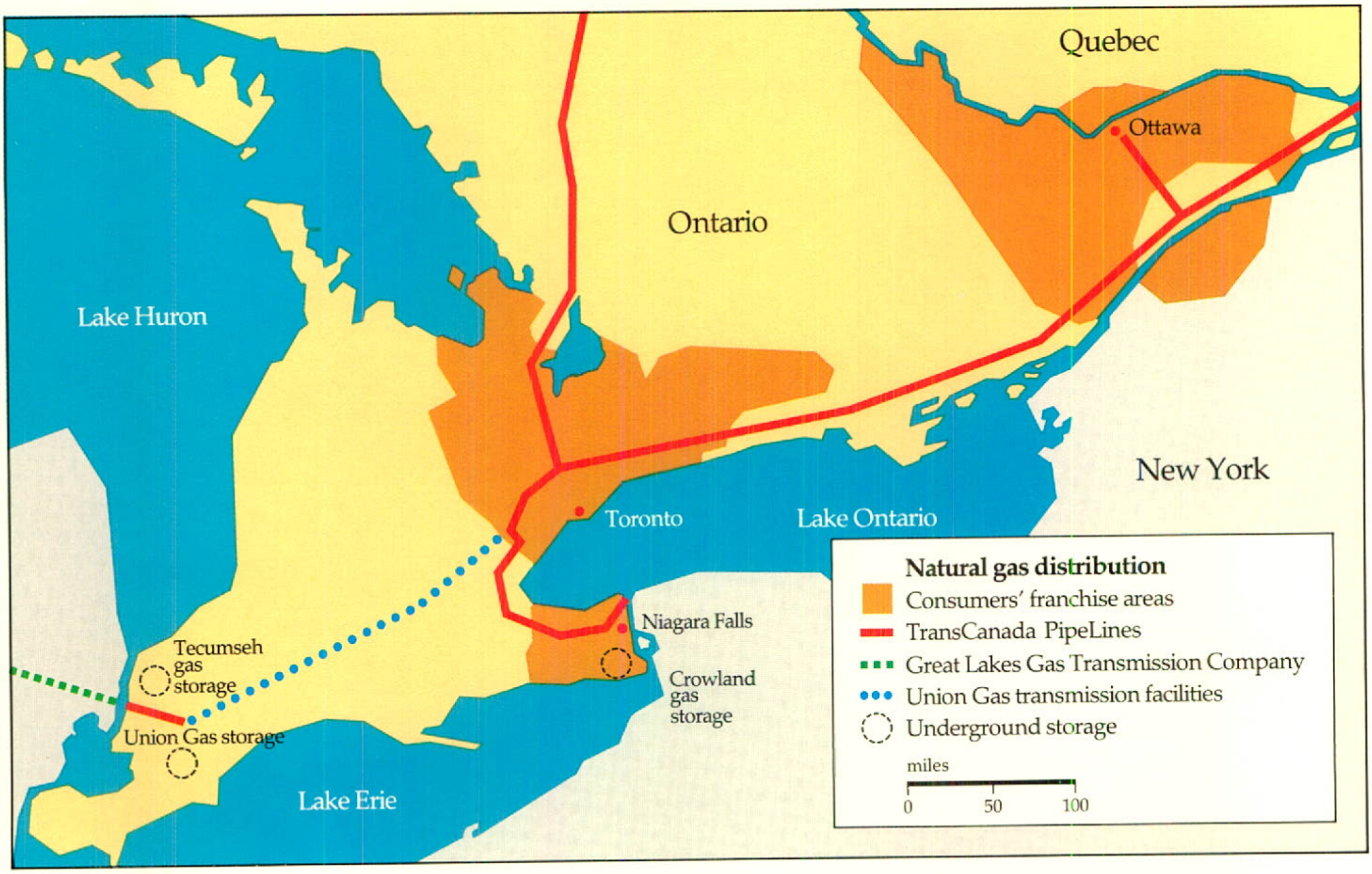
The contracts with TransCanada provide for annual deliveries of up to 309 billion cubic feet, subject to the Company's right to reduce total contract volumes by nine billion cubic feet in any contract year. This right has been exercised since 1980 and will be exercised for the 1984 contract year.

As a result of the inability to take complete delivery in 1983 of the reduced annual contracted volume, the Company paid TransCanada $20.0 million for the fixed cost component of its price and entered into a contract with that company which provides the opportunity to apply the payment against purchases in future years. It is anticipated the relevant volumes of gas will be delivered by TransCanada from April of 1985 to October of 1987.

Pricing

The cost of gas purchased at the Toronto City Gate increased one per cent to $4.134 per thousand cubic feet in 1983, compared with a 28.5 per cent increase a year earlier. The smaller increase resulted from changes to the federal and Alberta government pricing agreement which establishes the price paid by the Company.

The price paid comprises the Alberta Border Price (a commodity cost), the TransCanada transportation toll, and two federal excise taxes, the Canadian Ownership Special Tax, and the Natural Gas and Gas Liquids Tax. On June 30, 1983, the federal and Alberta governments amended their 1981 pricing agreement. The price of old oil was frozen until the end of 1984, provided world oil prices do not change significantly. Provisions were included to ensure the Toronto City Gate price of natural gas does not exceed 65 per cent



of the Toronto Refinery Gate price of crude oil. To meet this ratio, the federal government will adjust the Natural Gas and Gas Liquids Tax to zero, if necessary, and pay part of any increases in TransCanada's transportation tariff. If further measures are required, Alberta agreed to forego all or a portion of the Alberta Border Price increases scheduled for February and August of 1984. Thereafter, the Alberta Border Price will continue to escalate semi-annually as provided for in the 1981 agreement.

Regulation

In Ontario, the rates charged to customers result from public hearings before the Ontario Energy Board which determine the utility's rate base and a fair rate of return on this investment.

On January 26, 1983, the Board allowed a rate of return on the rate base of 12.52 per cent which provided for a return on common equity of 15.75 per cent. By applying the allowable return to the 1983 average net investment in Ontario utility assets of $1,156 million, the Board found that the Company was entitled to a revenue increase of $20 million which was granted by way of an interim increase effective December 20, 1982.

In April of 1983, evidence was filed for approval of a revenue increase of $28 million, subsequently reduced to $19 million, to recover expected increases in the cost of providing service during 1984. On November 3, 1983, the Board determined that the allowable rate of return for 1984 should be 12.8 per cent on the rate base, including a return to the common shareholder of 15.3 per cent. By applying the allowable return to the average net investment in the rate base, which was estimated to be $1,212 million for the year ended September 30, 1984, the Board found that current customer rates would generate the allowable rate of return. As a result, no increase in rates was allowed.

The Board disallowed the recovery through higher 1984 rates of $13.2 million related to the fixed cost component of contracted gas volumes not taken in 1983. As discussed under the caption, "Supply", the Company has entered into a contract with TransCanada to offset this cost against future deliveries of additional volumes of gas.

INTERPROVINCIAL PIPE LINE

Interprovincial Pipe Line Limited, organized in 1949 to transport the extensive oil reserves discovered in Alberta to eastern markets, has grown into the longest crude oil and liquid hydrocarbon pipeline system on the North American continent, utilizing some 6,000 miles of pipe and extending 2,300 miles from Edmonton to Montreal.

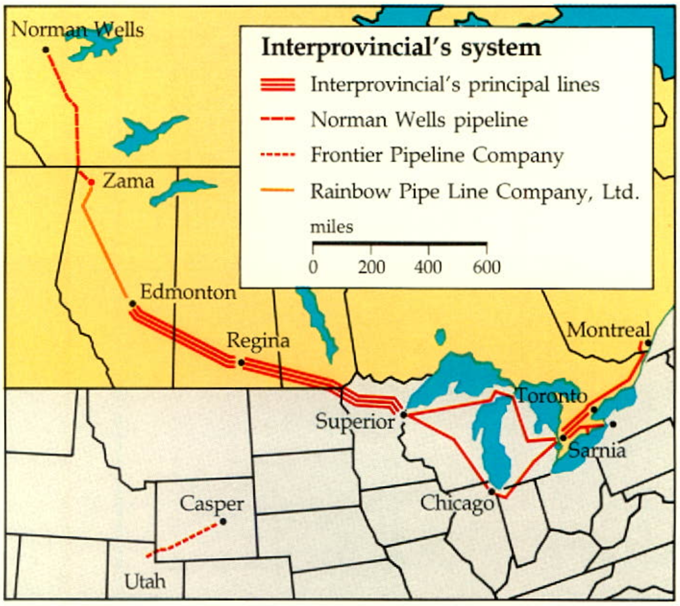
Interprovincial's system consists of three parallel lines of pipe from Edmonton to Superior, Wisconsin, and two lines from this point to Sarnia, Ontario, one via the Strait of Mackinac, the other via Chicago. Extension lines from Sarnia serve other Ontario and Montreal refineries, as well as those in the Buffalo area of New York State.

Production in Canada is received from all the principal oilfields in Alberta, Saskatchewan and Manitoba. United States domestic production is received at locations in Minnesota, Michigan and Indiana. In addition, offshore oil is received in Indiana.

In Canada, Interprovincial is regulated by the National Energy Board. In the United States, Interprovincial's wholly-owned subsidiary, Lakehead Pipe Line Company, Inc., is regulated by the Federal Energy Regulatory Commission.

Interprovincial has potential to grow in both pipeline and non-pipeline areas.

This winter, construction will begin on a 12 inch diameter line from the Norman Wells oilfield in the Northwest Territories to join the line of another company, Rainbow Pipe Line Company, Ltd., at Zama, Alberta, some 538 miles south. Cost of the project is estimated to be $450 million. In addition,



Interprovincial is a 35 per cent partner of Frontier Pipeline Company which is completing a $60 million, 290 mile line from Utah to Casper, Wyoming.

As as result of the share exchange, Interprovincial is able to acquire a Canadian business or establish a new business without being subject to the Foreign Investment Review Act. As well, should Interprovincial diversify into the natural resource business it would be eligible for greater exploration and development incentive grants under The National Energy Program.

The strong financial performance of Interprovincial is illustrated in the table below.

Financial highlights

	Nine months ended September 30		Year ended December 31				
	1983	1982	1982	1981	1980	1979	1978
	(millions except per share amounts)						
	(unaudited)						
Revenue	$318.5	$281.7	$386.7	$327.4	$321.1	$330.8	$294.5
Expenses	(180.2)	(167.5)	(232.1)	(214.6)	(220.2)	(217.0)	(195.8)
Income taxes	(72.5)	(59.4)	(79.9)	(56.4)	(52.2)	(58.3)	(51.9)
Net income	$ 65.8	$ 54.8	$ 74.7	$ 56.4	$ 48.7	$ 55.5	$ 46.8
Net income per share	$ 2.55	$ 2.13	$ 2.90	$ 2.19	$ 1.90	$ 2.17	$ 1.83
Dividends per share	$ 1.20	$ 1.125	$ 1.60	$ 1.50	$ 1.50	$ 1.475	$ 1.35
Assets	$957.2	$849.4	$857.4	$823.0	$828.3	$840.9	$850.1

Financial review

The following discussion of the results of operations and financial position of the Company for the three year period ended September 30, 1983, should be read in conjunction with the consolidated financial statements and related notes, the supplementary information, and the five year financial and operating review.

As announced at the end of the first quarter, the accounting policy for foreign currency translation was changed prospectively to conform with the recommendations of the Canadian Institute of Chartered Accountants (''CICA''). (see note 3 to the consolidated financial statements)

Results of operations

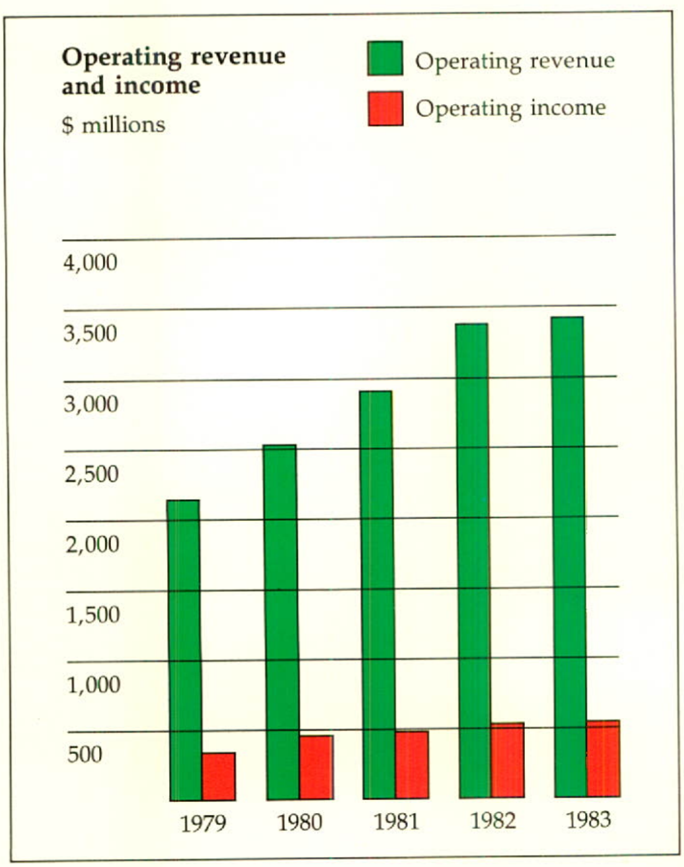
In 1983, net income applicable to common shares was $142.2 million, compared with the 1982 loss applicable to common shares of $78.0 million and the 1981 net income of $222.3 million. Excluding a 1982 provision for impairment of United States natural resource properties of $177.0 million and a 1981 non-recurring United Kingdom tax benefit of $37.0 million, net income applicable to common shares would have been $98.9 million in 1982 and $185.3 million in 1981.

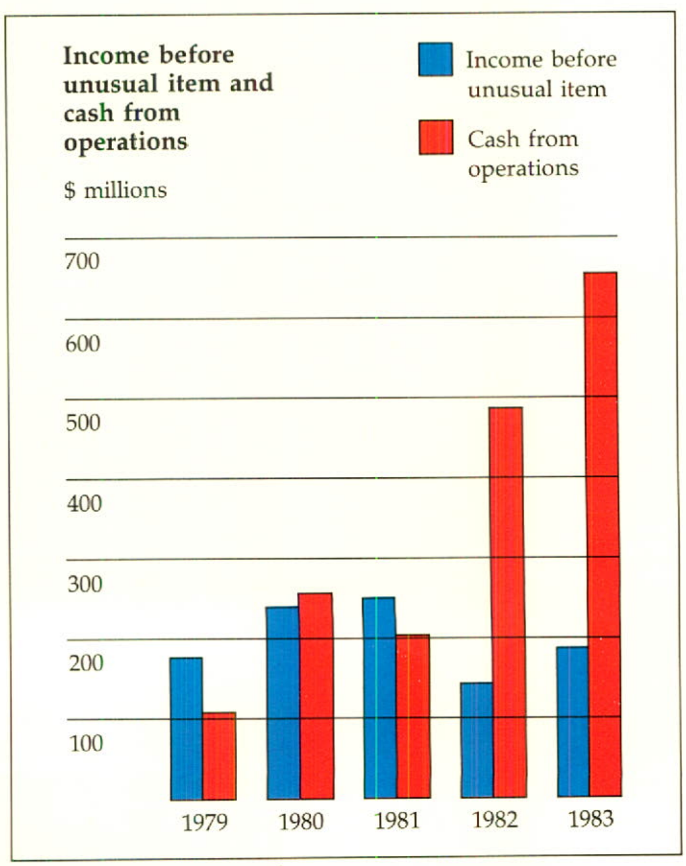
The improvement of $43.3 million in 1983 was primarily attributable to a significant reduction in interest and finance charges, lower effective income tax rates and increased operating income in the natural resources segment. The increase in income was partially offset by lower operating incomes in the distilled spirits and gas utility segments, as well as an increased minority interest.

In 1982, the decline of $86.4 million occurred primarily in the natural resources segment with the impact of a full year's operations of the United States properties acquired in March of 1981, the related financing costs, and the $32.2 million charge to operating income of all exploration expenditures incurred in Guyana. The unfavourable effect of these factors, however, was mitigated by significantly higher earnings of the gas utility segment.

Distilled spirits

During the past three years, operating revenues remained relatively unchanged as the impact of higher selling prices in most markets was offset by lower volumes and the changes in foreign currency translation rates applied to the sales of European subsidiaries. In 1983, increases in selling prices were





generally restricted to markets outside North America. The prevailing economic environment and the resulting competitive conditions have adversely affected operations.

Operating revenue
millions

	1983	1982	1981
Distilled spirits	**$1,405.7**	$1,454.8	$1,452.4
Natural resources	**458.7**	476.6	349.4
Gas utility	**1,538.4**	1,428.4	1,099.0
Total	**$3,402.8**	$3,359.8	$2,900.8

Sales volumes of Kahlua continued to increase in 1983. Although sales volumes of other principal brands declined modestly, market share was generally maintained.

After modest increases in 1981 and 1982, operating income declined by $27.2 million in 1983, primarily as a result of lower gross profit and increased selling and general expenses.

Natural resources

Operating revenue declined in 1983 as a result of significantly reduced volumes and the phase-out of the LPG marketing operations in the United States, offset in part by higher prices for crude oil and natural gas and reductions in Crown royalties. In 1982, operating revenues increased primarily because of higher prices for crude oil and natural gas as well as the impact of the full year's operations of the United States oil and gas properties acquired in 1981.

In 1983, despite a revenue decline, operating income improved considerably due to lower depletion charges resulting primarily from lower production volumes. Reduced general expenses in the United States, resulting from administrative efficiencies, offset a gross profit decline. Operating income in 1982

Operating income
millions

	1983	1982	1981
Distilled spirits	**$ 266.6**	$ 293.8	$ 280.5
Natural resources	**90.8**	41.9	82.8
Gas utility	**180.3**	188.1	112.6
Total	**$ 537.7**	$ 523.8	$ 475.9

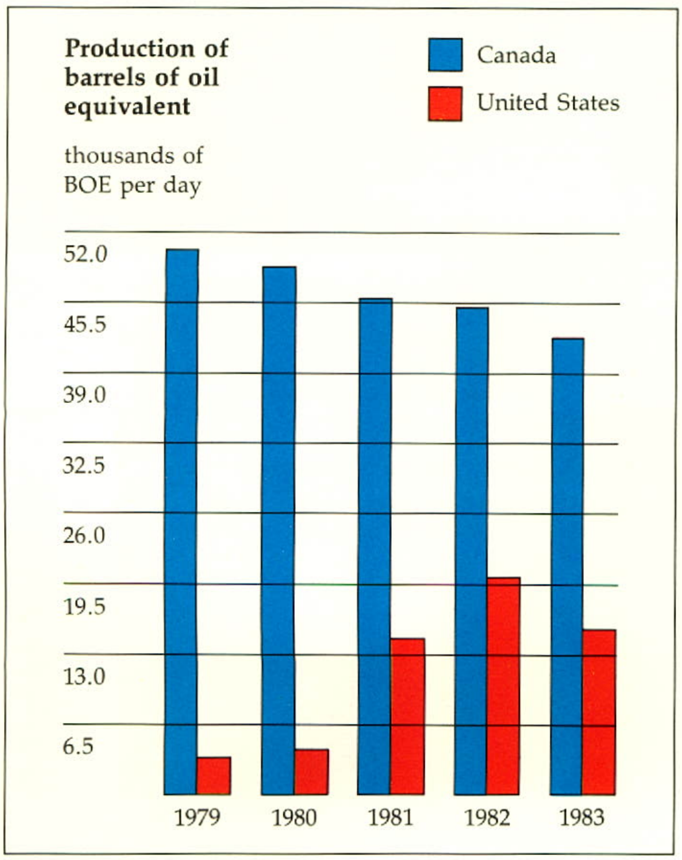
declined as a result of the $32.2 million charge of all expenditures incurred in Guyana as well as the effect of a full year's depletion of a larger investment in natural resource properties.

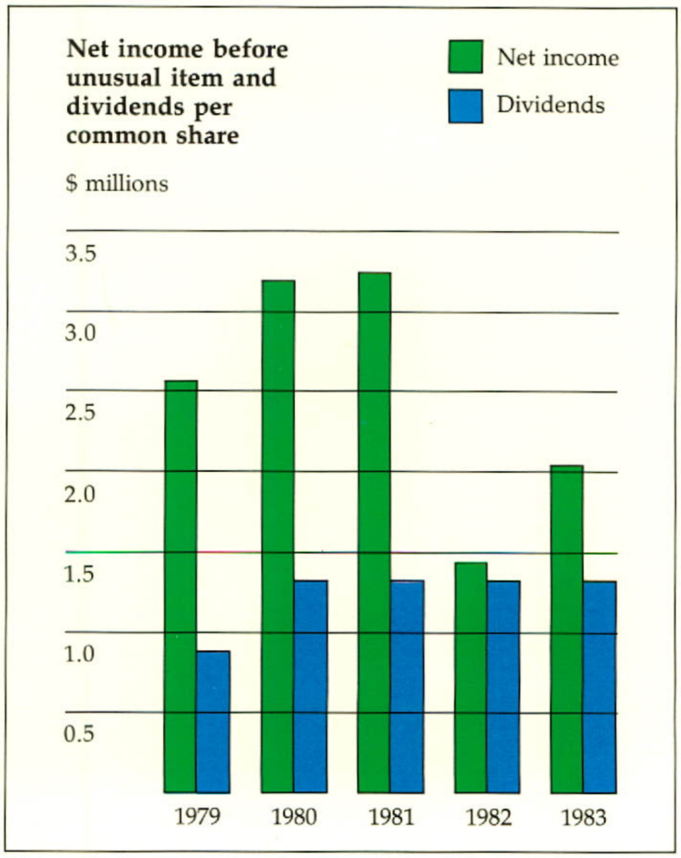
Gas utility

Operating revenues increased during the three year period ended September 30, 1983, due mainly to the expeditious approval from the Ontario Energy Board to recover in rates the higher cost of purchasing natural gas, including higher transportation tariffs.

However, in 1983, operating income declined as a result of reduced sales volumes. Volumes were adversely affected by the exceptionally mild heating season and the impact of the economic recession on industrial customers which more than offset the effects attributable to an increased number of customers and higher rates.

In 1982, rate relief and increased gas sales volumes were the primary factors responsible for the increase in operating income. The higher sales volumes were





due to the very cold weather and additional customers.

Interest and finance charges

Interest and finance charges decreased significantly to $213.4 million in 1983 from $269.0 million in 1982. Lower average interest rates for short term debt and overall lower average borrowing levels contributed to the decline. In addition, foreign exchange gains arose from the retirement of sterling denominated debt and from the amortization of unrealized foreign exchange gains on other foreign currency denominated long term debt. The increase in expense in 1982 over 1981 levels primarily reflected a full year's impact of the 1981 acquisition of natural resource properties, and the issue of additional utility debt.

Income taxes

Despite a significant increase in 1983 income, income taxes remained relatively unchanged from 1982. The reduction in the effective income tax rate was attributable in part to increased income in foreign subsidiaries with lower tax rates, as well as to an increase in tax-deductible items as a percentage of income in the gas utility segment.

Income taxes increased to $135.7 million in 1982 from $98.7 million in 1981, excluding a non-recurring credit of $37.0 million in 1981. The increase reflects higher effective tax rates, resulting primarily from the unfavorable impact of foreign currency translation rates in the distilled spirits segment, increased earnings and the application in 1981 of previous years' tax losses in the gas utility segment. The increase was offset partially by losses incurred in the United States natural resources segment.

Foreign currency translation

In applying the new accounting policy for foreign currency translation, adjustments arising upon the translation of foreign subsidiaries' financial statements are now generally excluded from income. These adjustments, referred to as cumulative translation adjustments, are included as a separate component of shareholders' equity.

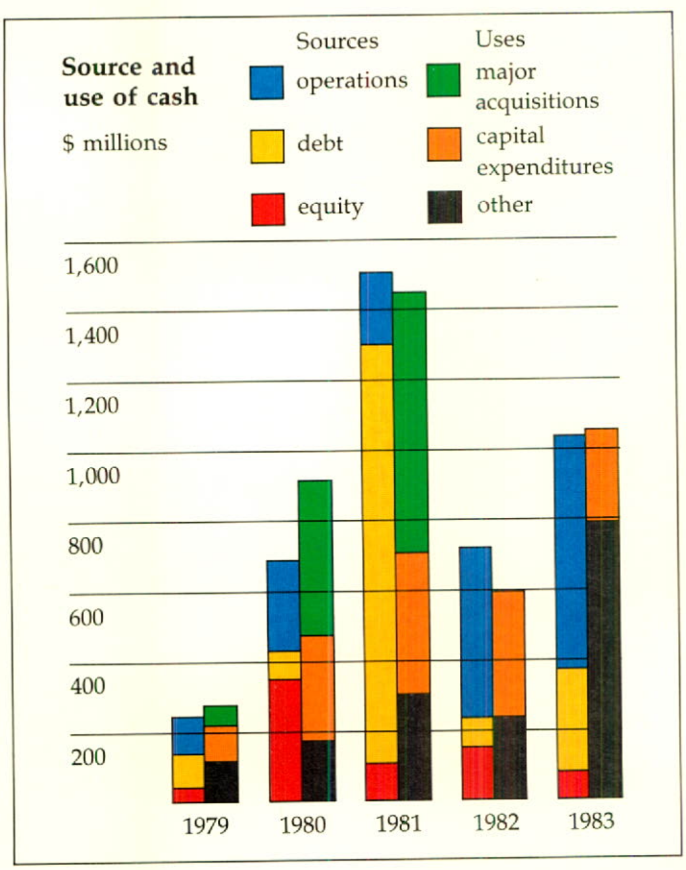
The initial reduction in shareholders' equity of $85.7 million increased to $147.0 million by September 30, 1983, due to the strengthening of the Canadian dollar relative to the French franc and the British pound. The future impact on shareholders' equity will vary with the fluctuations in the value of the Canadian dollar.

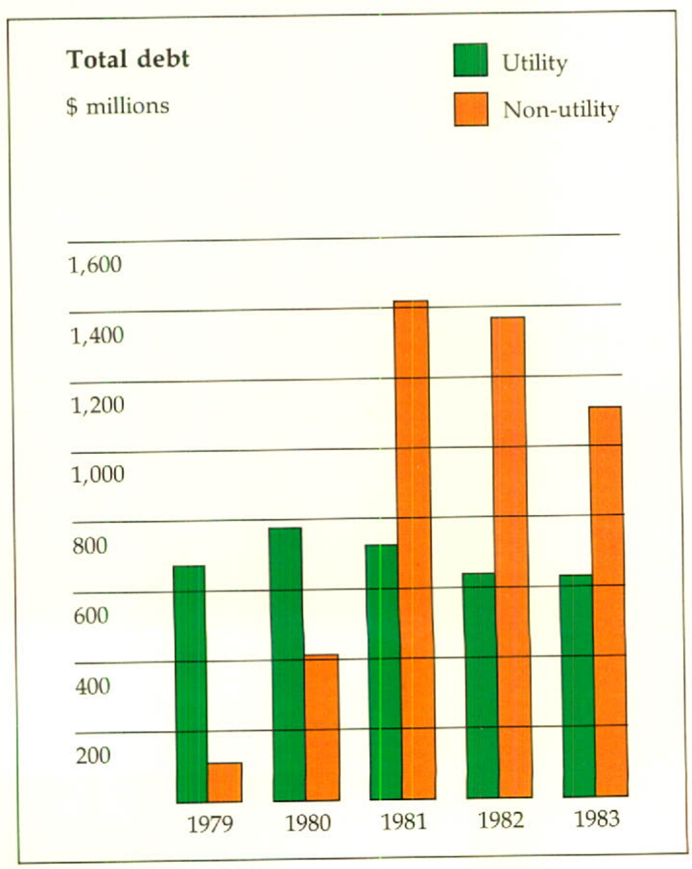
The foreign currency translation gain in 1982 of $9.6 million arose principally from a modest decrease in the value of the French franc and the increase in the value of the United States dollar relative to the Canadian dollar. The gain in 1981 of $24.5 million arose from significant changes in the value of foreign currencies relative to the Canadian dollar.

Inflation

Inflation, though moderating in 1983, continued to have an impact on operations. However, the Company's financial statements are based on historical costs and do not reflect the full impact of inflation and changing prices. Although historical cost provides a basic measure of financial results, the matching of current revenues with the amortization of the original cost of assets generally overstates earnings during periods of inflation.

In recognition of this deficiency in historical cost





financial statements, the CICA issued recommendations for reporting the effects of changing prices, effective for fiscal periods commencing on or after January 1, 1983.

In the distilled spirits business, inflation continued to affect operating costs and expenses in all areas. Competitive conditions permitting, selling prices will continue to be adjusted to maintain profit margins.

In the Canadian natural resource business, where prices are established by federal and provincial government, prices have increased steadily in recent years, but remain substantially below world price at the producer level. At the same time, operating and capital costs have escalated rapidly.

The main portion of the gas utility business is regulated by the Ontario Energy Board and the impact of inflation on operating costs is reflected in the regulatory process. This enables the Company to react to inflation and price on a timely basis.

Financial position

During 1983, the program to reduce debt, particularly in the non-utility operations, was continued. In addition, as a number of debt issues cannot be repaid prior to maturity, the Company invested accumulated cash resources in interest-bearing securities to be used generally for satisfying the debt service and repayment requirements of these issues. The combination of debt retirement and the accumulation of cash and investments available for the eventual retirement of debt resulted in a reduction of approximately $260 million in the net borrowing position of the non-utility operations.

This improvement was derived generally from the increase in cash generated from operations, due primarily to reduced working capital requirements, the reduction in capital expenditures and the receipt of $12.1 million from shareholders in response to the Stock Dividend, Dividend Reinvestment and Stock Purchase Plan.

In 1982, the recovery of United States income taxes paid in prior years, which resulted from the application of the operating losses in the United States natural resource segment, as well as reduced working capital requirements, contributed to the increase in cash from operations over 1981 levels.

Capital expenditures were significantly reduced in 1983 by $95.9 million to $262.5 million. In the natural resources segment, spending decreased in the United States and internationally but increased in Canada as a result of the Dome and Esso farmin programs. Major capital projects in the distilled spirits segment were completed in early 1983.

Capital expenditures will increase modestly in the natural resources segment during 1984 as a result of the Dome farmin.

The cash from operations of the distilled spirits and natural resources segments in 1984 should be sufficient to cover both planned capital expenditures and dividend requirements as well as provide excess funds with which to further reduce the level of non-utility borrowings.

The gas utility during the past two years has independently financed its expansion. In 1982, the utility issued three million common shares to the public, representing approximately 10 per cent of the total shares outstanding. Additional preference shares and long term debt were issued during 1982 and 1983.

In October of 1983, the Company issued 13.6 million shares in exchange for the same number of common shares of Interprovincial Pipe Line Limited. This transaction, along with the program to reduce overall debt, will enable the Company to achieve a more conservative debt to equity ratio.

It is expected that the cash requirements of the Company, which are primarily dividend payments to its shareholders, will be satisfied from dividends paid from earnings of the operating subsidiaries. The payment of dividends to the Company by one of its principal subsidiaries, Walker-Home Oil Ltd., is subject to certain restrictions described in note 16(a) to the consolidated financial statements. These restrictions, at September 30, 1983, limit transfer of funds to the Company to future consolidated net income of that subsidiary plus $347.8 million.

Outlook

Management's discussion of the outlook for the Company is incorporated in the report to shareholders on page 3 of this report.

Statement of responsibility and auditors' report

Management's responsibility for financial statements

The accompanying consolidated financial statements of the Company were prepared by management in accordance with accounting principles generally accepted in Canada applied, except for the change in the method of accounting for foreign currency translation (see note 3, page 22), on a basis consistent with that of the preceding years. The significant accounting policies, which management believes are appropriate for the Company, are described in the accompanying Summary of Significant Accounting Policies. The financial information contained elsewhere in this annual report is consistent with that in the financial statements.

Management is responsible for the integrity and objectivity of the financial statements. In the preparation of these statements, estimates are sometimes necessary when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Management believes such estimates are based on careful judgements and have been properly reflected in the accompanying consolidated financial statements. Management has established systems of internal control which are designed to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for the preparation of financial information.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board is assisted in this responsibility by the Audit Committee of the Board, which comprises directors who are not employees of the Company. The Committee meets with management as well as with the internal and external auditors to satisfy itself that each group is properly discharging its responsibilities and to review the financial statements and the independent auditors' report. The Committee reports its findings to the Board for consideration in approving the financial statements for issuance to the shareholders.

Management recognizes its responsibility for conducting the Company's affairs in compliance with established financial standards and applicable laws and the maintenance of proper standards of conduct in its activities.

H. Clifford Hatch
Chairman

A. R. McCallum
Senior Vice President and
Chief Financial Officer

Auditors' report

To the Shareholders of Hiram Walker Resources Ltd.

We have examined the consolidated balance sheets of Hiram Walker Resources Ltd. as at September 30, 1983 and 1982 and the consolidated statements of income, retained earnings and changes in financial position for each of the three years in the period ended September 30, 1983. Our examinations were made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the Company as at September 30, 1983 and 1982 and the results of its operations and the changes in its financial position for each of the three years in the period ended September 30, 1983 in accordance with generally accepted accounting principles in Canada applied, except for the change, with which we concur, in the method of accounting for foreign currency translation as explained in note 3 to the consolidated financial statements, on a basis consistent with that of the preceding years.

Toronto, Canada
November 16, 1983

Price Waterhouse
Chartered Accountants

Summary of significant accounting policies

Hiram Walker Resources Ltd.

The Company's accounting policies, which conform with accounting principles generally accepted in Canada, are summarized below:

Principles of consolidation

The consolidated financial statements include the accounts of the Company and all of its subsidiary companies. The principal subsidiary companies are listed on page 44.

Substantially all of the Company's natural resource activities are conducted jointly with others. These financial statements reflect the Company's proportionate interest in such activities. Investments in companies over which the Company exercises significant influence are accounted for on the equity method. Other investments are stated at cost.

Inventories

Inventories are stated at amounts not exceeding manufactured or purchased cost. They include substantial quantities of whiskies and cognac which will remain in storage over a period of years, but are classified as current assets in accordance with the general practice of the distilling industry.

Property, plant and equipment

Property, plant and equipment is stated at cost. Normal retirements of assets are recorded by relieving the asset account for the cost of the asset and charging this amount, net of any proceeds, to accumulated depreciation or depletion. Upon retirement or sale of major items of property, the asset accounts are relieved of the cost of such property together with accumulated depreciation or depletion. The difference between the depreciated value of such major items and the proceeds, if any, is included in income.

Maintenance and repair expenditures are charged to cost of production or other expense accounts. Costs of improvements which increase the service capacity or prolong the service life of the asset are capitalized.

Interest is capitalized on costs of acquiring and evaluating individually significant unproved properties and major development projects during the period of exploration and development and on costs incurred during construction of major additions to property, plant and equipment.

Depreciable property, plant and equipment (except for certain petroleum production equipment) is depreciated on a straight line basis at rates varying from 2.5% to 10% for buildings, 1.6% to 7.5% for utility plant and 1.9% to 30% for other equipment. Production equipment used in petroleum operations is depreciated using the unit of production method.

The Company follows the full cost method of accounting for oil and gas operations whereby all exploration and development costs are capitalized and charged against income as set out below. Capitalized costs include land acquisition costs, geological and geophysical costs, lease rentals and related charges applicable to non-producing property, costs of drilling both productive and non-productive wells and overhead charges related to exploration and development activities. Such costs are generally limited to the future net revenues from estimated production of proved reserves at current prices and costs and the estimated fair market value of unproved properties. A separate cost centre is established for each country in which the Company is engaged in exploration or production activities. Such costs are depleted using the unit of production method based upon estimated proved reserves, as determined by independent and company petroleum engineers. Natural gas reserves and production are converted to equivalent barrels of crude oil based on the relative energy content. Costs of acquiring and evaluating significant unproved properties and costs of major development projects are excluded from the computation of depletion until such time as additional reserves are proved, the project is complete or an impairment in value has occurred.

Foreign currency translation

The accounts of foreign subsidiaries are translated into Canadian dollars on the following basis: Assets and liabilities are translated into Canadian dollars using exchange rates at the balance sheet dates. Translation adjustments are reflected in shareholders' equity. Revenue and expense items are translated using the average rates of exchange throughout the year.

Transactions in a currency other than a domestic currency are translated into that domestic currency on the following basis: At the transaction date, each asset, liability, revenue or expense is translated using exchange rates in effect at that date. At each balance sheet date, monetary assets and liabilities are translated using exchange rates at that date. Foreign exchange gains and losses are included in income in the current period, except for unrealized gains and losses related to monetary items with a fixed or ascertainable life extending beyond the end of the following fiscal year. These unrealized gains and losses are deferred and subsequently included in income over the remaining life of the assets and liabilities. (see note 3, page 22, change in accounting policy)

Pension plans

The Company has various pension plans covering a majority of its employees. The plans, certain of which require contributions by participating employees, provide pension benefits at normal retirement age. Unamortized prior years' service costs for these plans are being funded and charged to operations over periods varying from 5 to 30 years.

Consolidated statement of income

Hiram Walker Resources Ltd.

	Year ended September 30		
	1983	1982	1981
	(Expressed in thousands except per share amounts)		
Revenue			
Distilled spirits	**$1,405,668**	$1,454,769	$1,452,412
Natural resources	**458,723**	476,566	349,386
Gas utility	**1,538,435**	1,428,427	1,099,049
	3,402,826	3,359,762	2,900,847
Operating costs and expenses			
Cost of sales			
Distilled spirits	**770,942**	812,143	810,817
Natural resources	**150,411**	160,408	130,021
Gas utility	**1,248,188**	1,136,176	898,083
Selling and general	**445,577**	433,747	420,038
Depletion and depreciation	**250,037**	293,517	165,962
	2,865,155	2,835,991	2,424,921
Operating income	**537,671**	523,771	475,926
Other income	**22,055**	22,398	29,154
Interest and finance charges, net (notes 3 and 11)	**(213,394)**	(268,998)	(209,314)
Income before undernoted items	**346,332**	277,171	295,766
Income taxes (note 13)	**(137,826)**	(135,681)	(61,656)
Foreign currency translation gain (note 3)		9,645	24,540
Minority interest	**(22,478)**	(8,925)	(8,589)
Income before unusual item	**186,028**	142,210	250,061
Provision for impairment – United States natural resource properties, net of deferred income taxes of $99,106 (note 6)		(176,985)	
Net income (loss)	**186,028**	(34,775)	250,061
Dividends on preference shares	**43,820**	43,271	27,752
Net income (loss) applicable to common shares			
Before unusual item	**$ 142,208**	$ 98,939	$ 222,309
Including unusual item	**$ 142,208**	$ (78,046)	$ 222,309
Net income (loss) per common share			
Before unusual item			
Basic	**$ 2.03**	$ 1.43	$ 3.23
Fully diluted	**$ 2.01**	$ 1.43	$ 3.02
Including unusual item			
Basic	**$ 2.03**	$ (1.13)	$ 3.23
Fully diluted	**$ 2.01**	$ (1.13)	$ 3.02
Weighted average number of common shares outstanding	**70,048**	69,217	68,881

Consolidated balance sheet

Hiram Walker Resources Ltd.

	September 30 1983	1982
	(Expressed in thousands)	
Assets		
Current assets		
Cash and short term investments	**$ 142,441**	$ 202,090
Income taxes recoverable	**13,894**	73,250
Accounts receivable	**464,787**	524,165
Inventories (notes 3 and 4)	**1,049,078**	1,196,407
Prepaid expenses	**35,069**	40,951
	1,705,269	2,036,863
Investments (note 5)	**318,046**	134,423
Property, plant and equipment (note 6)	**2,739,303**	2,742,737
Other assets and deferred charges	**76,958**	49,529
	$4,839,576	$4,963,552
Liabilities and shareholders' equity		
Current liabilities		
Loans and notes payable (note 7)	**$ 338,826**	$ 382,519
Income and other taxes payable	**117,016**	148,542
Accounts payable and accruals	**394,654**	382,852
Dividends payable	**35,043**	34,175
Current portion of long term debt	**25,434**	25,932
	910,973	974,020
Deferred production revenue	**37,846**	25,804
Long term debt (note 7)	**1,620,647**	1,722,320
Deferred foreign exchange gain (note 3)	**22,091**	
Deferred income taxes (note 13)	**339,026**	308,959
Minority interest	**102,010**	90,186
Preference shares of subsidiary companies (note 8)	**183,133**	138,945
Subsequent event (note 2)		
Commitments and contingencies (note 16)		
Shareholders' equity		
Capital stock (notes 9 and 10)		
Preference shares	**507,920**	508,497
Common shares	**184,804**	165,088
Cumulative translation adjustments (note 3)	**(146,961)**	
Retained earnings	**1,079,850**	1,032,194
	1,625,613	1,705,779
Deduct common shares held by Trustees at cost (note 10)	**1,763**	2,461
	1,623,850	1,703,318
	$4,839,576	$4,963,552

Approved by the Board:

H. Clifford Hatch, Director

Gordon C. Gray, Director

Consolidated statement of changes in financial position

Hiram Walker Resources Ltd.

	Year ended September 30		
	1983	1982	1981
	(Expressed in thousands)		
Cash was obtained from			
Operations			
Income before unusual item	$ 186,028	$ 142,210	$ 250,061
Charges (credits) not affecting cash			
Depletion and depreciation	250,037	293,517	165,962
Deferred income taxes	42,606	120,713	(1,175)
Minority interest	22,478	8,925	8,589
Other	(14,288)	(109)	(1,845)
Changes in other working capital	177,503	(80,537)	(218,649)
	664,364	484,719	202,943
Cash was used for			
Dividends			
By the Company	136,786	134,718	118,655
By subsidiaries to minority shareholders	14,615	6,018	2,078
	151,401	140,736	120,733
Cash remaining for investment	512,963	343,983	82,210
Investment			
Acquisition of United States natural resource properties			736,987
Property, plant and equipment	262,499	358,413	403,798
Increase in cumulative translation adjustments (note 3)	58,346		
Increase in other items, net	22,694	3,455	514
	343,539	361,868	1,141,299
Cash (deficiency) before financing	169,424	(17,885)	(1,059,089)
Financing			
Issue of long term debt on acquisition of United States natural resource properties			758,834
Issue of other long term debt	291,571	83,428	430,810
Issue of preference and common shares of subsidiary company	57,593	92,000	
Issue of preference and common shares	19,139	56,135	104,730
Reduction in long term debt	(369,018)	(87,038)	(178,381)
Purchase of securities for debt repayment (notes 5 and 7)	(184,665)		
	(185,380)	144,525	1,115,993
Increase (decrease) in cash*	$ (15,956)	$ 126,640	$ 56,904

*For the purposes of this statement, cash is defined as cash and short term investments less loans and notes payable.

The 1982 and 1981 data has been reclassified to conform with the cash flow basis now being used. In prior years, a consolidated statement of changes in financial position on a working capital basis was presented.

Consolidated statement of retained earnings

Hiram Walker Resources Ltd.

	Year ended September 30		
	1983	1982	1981
	(Expressed in thousands)		
Balance at beginning of year	**$1,032,194**	$1,206,338	$1,079,975
Net income (loss)	**186,028**	(34,775)	250,061
Other	**110**	333	130
	1,218,332	1,171,896	1,330,166
Deduct			
Dividends			
Preference shares	**43,820**	43,271	27,752
Common shares	**92,966**	91,447	90,903
Share issue expenses, net of income taxes	**1,696**	4,984	5,173
	138,482	139,702	123,828
Balance at end of year	**$1,079,850**	$1,032,194	$1,206,338

Consolidated changes in other working capital

	Year ended September 30		
	1983	1982	1981
	(Expressed in thousands)		
Income taxes recoverable	**$ 59,356**	$ (35,059)	$ (38,191)
Accounts receivable	**59,378**	(80,405)	(90,479)
Inventories (note 3)	**71,743**	(59,014)	(159,152)
Prepaid expenses	**5,882**	10,676	(17,009)
Income and other taxes payable	**(31,526)**	52,348	39,625
Accounts payable and accruals	**11,802**	26,514	46,527
Dividends payable	**868**	4,403	30
	$ 177,503	$ (80,537)	$ (218,649)

Notes to consolidated financial statements

Hiram Walker Resources Ltd.

(Tabular amounts expressed in thousands except shares and per share amounts)

1. Accounting policies

The summary of significant accounting policies on page 17 forms an integral part of these financial statements.

2. Subsequent event – Interprovincial Pipe Line Limited

On September 20, 1983, the Company entered into a share exchange agreement with Interprovincial Pipe Line Limited, pursuant to which, in October of 1983, Interprovincial issued 13,600,000 common shares in exchange for 13,600,000 Class D Preference Shares, Second Series, of the Company. This series of voting preference shares participates equally with and receives the same dividends as the Company's common shares. As a result of this share exchange, the Company owns 34 per cent of the outstanding common shares of Interprovincial. This transaction will be accounted for using the equity method of accounting.

Interprovincial, the shares of which are publicly traded, owns and operates the longest crude oil and liquids pipeline system on the North American continent. As a result of the transaction, Interprovincial is the single largest shareholder of the Company with 16 per cent ownership.

3. Change in accounting policy

Effective October 1, 1982, the Company prospectively changed its accounting policy for foreign currency translation to conform with the recommendations of the Canadian Institute of Chartered Accountants. This change affects the method of translating financial statements of foreign operations and of recognizing unrealized foreign exchange gains and losses related to monetary items with a fixed or ascertainable life, as outlined in the summary of significant accounting policies on page 17.

The prospective application of this change in accounting policy on October 1, 1982 resulted primarily in a reduction in inventories of $75,586,000, deferred foreign exchange gains of $17,447,000 and cumulative translation adjustments which decreased shareholders' equity by $85,683,000.

Under the method used prior to October 1, 1982, the accounts of foreign subsidiaries and transactions of the Company denominated in foreign currencies were translated into Canadian dollars on the following basis:

Current assets, except maturing distilled spirits inventories, and current liabilities were translated using the exchange rates at the dates of the balance sheets. Maturing distilled spirits inventories and other assets and liabilities were translated at the rates in effect at the time the original transaction took place. Revenue and expense items (excluding matured distilled spirits inventories charged to cost of sales, depreciation and depletion, all of which were translated at the rate of exchange applicable to the related assets) were translated using the average rates of exchange throughout the period. Translation gains and losses were included in income.

4. Inventories

	September 30	
	1983	1982
Finished goods	**$ 104,445**	$ 119,107
Natural gas in storage	**309,198**	307,094
Maturing whiskies and cognac	**516,425**	631,894
Raw materials and supplies	**119,010**	138,312
	$1,049,078	$1,196,407

5. Investments

	September 30 1983	1982
Investments accounted for on the equity method	**$ 45,991**	$ 54,424
Other investments - at cost	**87,390**	79,999
Marketable securities - at cost which approximates market (1)	**184,665**	
	$318,046	$134,423

(1) These securities have been set aside to satisfy the debt service and repayment requirements of certain outstanding debt obligations. (see note 7 (d), page 25)

6. Property, plant and equipment

	September 30 **1983**			1982		
	Cost	**Accumulated depreciation and depletion**	**Net**	Cost	Accumulated depreciation and depletion	Net
Distilled spirits	**$ 527,110**	**$ 230,220**	**$ 296,890**	$ 535,839	$ 219,023	$ 316,816
Natural resources	**2,389,272**	**892,954**	**1,496,318**	2,185,478	653,682	1,531,796
Gas utility	**1,215,399**	**269,304**	**946,095**	1,133,768	239,643	894,125
	$4,131,781	**$1,392,478**	**$2,739,303**	$3,855,085	$1,112,348	$2,742,737

The cost of acquiring and evaluating significant unproved properties and costs of major development projects at September 30, 1983 and 1982, which were $148,833,000 and $189,837,000, respectively, are excluded from the amounts being depleted, as described in the summary of significant accounting policies. The recovery of such investment in future periods depends upon the successful exploitation of the properties. These properties are currently under various stages of exploration and development, and it is anticipated that the cost of all significant unproved properties will be included in the depletion computation by September 30, 1986.

In 1982, the carrying value of the United States oil and gas assets was reduced by $276,091,000. A provision for impairment of $176,985,000, net of deferred income tax relief of $99,106,000, was recorded as a charge against income.

7. Indebtedness

(a) Loans and notes payable

	September 30 1983	1982
Bank loans	**$101,586**	$140,572
Commercial paper	**237,240**	240,977
Other		970
	$338,826	$382,519

(b) Long term debt

	Maturity(1)	September 30 **1983**	1982
Non-utility			
Debentures			
9.5% (1983, US$20,201; 1982, US$20,951)	1986	**$ 24,894**	$ 24,504
9.875%	1998	**59,120**	60,000
14.25% (1983, £12,583; 1982, £25,000)	1986	**23,448**	67,009
15.5% Series A(2)	1986	**125,000**	125,000
15.75% (1983, US$61,984; 1982, US$65,000)	1984	**76,494**	78,116
16% (1983, US$68,372; 1982, US$75,000)	1986	**84,378**	89,954
16% (1983, US$70,174; 1982, US$75,000)	1989	**86,601**	90,821
Zero coupon(3) (1983, US$20,866; 1982, US$2,079)	1989	**25,751**	2,489
Bank loans			
11.25% (1983, £3,208; 1982, £3,749)	1987	**6,021**	9,445
12.45% (1983, £11,272; 1982, £12,000)	1988	**21,158**	33,855
13% (£25,000)	1989	**46,080**	
Revolving credit facility(4) (1983, £20,000; 1982, £50,000)	1985	**35,806**	108,120
Revolving credit agreement (US$205,000)	1985		245,672
Revolving credit facility(5)	1988	**178,875**	
Notes			
7.25% (SF 75,000)(6)	1987	**49,991**	48,747
7.5% (SF 100,000)(6)	1988	**65,429**	64,487
7.75% (SF 100,000)(6)	1986	**61,557**	57,475
14.5% (£10,000)	1986	**18,635**	22,916
Other(7)		**46,208**	52,059
		1,035,446	1,180,669
Utility			
Bonds			
5.5% - 11.5% first mortgage sinking fund, secured(8)	1983-1996	**164,829**	181,376
4.85% - 8.0% first mortgage sinking fund, secured(8) (1983, US$22,238; 1982, US$23,163)	1985-1993	**27,402**	23,758
Debentures			
6.5% - 17.75% sinking fund(8)	1984-1999	**278,404**	287,449
13.25%	1993	**65,000**	
18.5%(2)	1986	**75,000**	75,000
		610,635	567,583
		1,646,081	1,748,252
Less amounts due within one year		**25,434**	25,932
		$1,620,647	$1,722,320

(1) Maturity dates reflect calendar years.

(2) These issues are extendable, at the option of the holder, until 1991.

(3) These debentures were issued at a discount which results in an effective interest rate of 15.5%.

(4) The rate of interest under this facility is a variable rate based upon the London interbank offered rate ("LIBOR"). The weighted average interest rate was 14.34% during 1983 and 14.93% at September 30, 1983. This loan is hedged as to principal and interest to Canadian dollars.

(5) Pursuant to this facility, proceeds can be drawn in Canadian or United States dollars. The rate of interest under this facility is based upon rates prevailing from time to time in Canada, the United States and/or LIBOR. The average interest rate was 10.4% during 1983 and 9.69% at September 30, 1983.

(6) The notes are hedged as to principal and interest to United States dollars. The hedge contract increases the effective average interest rate to 14.5% at September 30, 1983.

(7) Loans of certain subsidiaries amounting to $4,125,000 at September 30, 1983, are secured.

(8) The Company is obligated to ensure that all amounts due on the First Mortgage Sinking Fund Bonds and $213,378,000 of the Sinking Fund Debentures of a subsidiary are paid to the holders of these securities. The Company's obligation to the holders of these First Mortgage Sinking Fund Bonds is secured by the shares of another subsidiary company.

(c) Long term debt maturities and sinking fund requirements for each of the five years subsequent to September 30, 1983, are as follows:

1984	$ 25,434
1985	135,302
1986	245,574
1987	154,228
1988	100,966

(d) During 1983, the Company acquired certain interest-bearing investments to be used for satisfying the debt service and repayment requirements of a number of its outstanding debt obligations. The investments comprise deposits with major Canadian and United States banks and highly-rated government and corporate securities. The specific debt issues and the related investments are as follows:

		Long term debt	Marketable securities
14.25%	£ 12,583, due 1986	$ 23,448	$ 26,598
16%	US$68,372, due 1986	84,378	93,504
7.75%	SF 100,000, due 1986	61,557	64,563
		$169,383	$184,665

(e) The Company has lines of credit at September 30, 1983 and 1982, of $886,438,000 and $778,708,000, respectively. Of the lines available at September 30, 1983 and 1982, commitments, in various currencies, of $260,902,000 and $117,000,000, respectively, have terms of up to 10 years.

8. Preference shares of subsidiary companies

	September 30 **1983**	1982
Group 1 Redeemable Preference Shares, comprising Series A and Series B with a $5.50 cumulative dividend and Series C with a $5.00 cumulative dividend(1)	**$11,520**	$ 11,745
Group 2 Redeemable Preference Shares, comprising retractable Series A with a $3.375 cumulative dividend	**50,000**	50,000
Group 3 Redeemable Preference Shares, comprising retractable Series A with a $2.3125 cumulative dividend	**50,000**	
Group 5 Redeemable Preference Shares, comprising convertible, retractable Series A with a $2.125 cumulative dividend	**2,013**	
Cumulative Redeemable First Preference Shares(2)	**36,000**	42,000
Cumulative Redeemable Second Preference Shares(3)	**33,600**	35,200
	$183,133	$138,945

(1) The Company is obligated to ensure that all amounts due on these Group 1 Preference Shares are paid to holders of these securities.

(2) Dividends are payable at an annual rate of one-half of the Canadian bank's prime lending rate plus 1.25%. Annual redemption requirements are $6,000,000 to 1985 and $8,000,000 to 1988.

(3) Dividends are payable at an annual rate of one-half of the Canadian bank's prime lending rate plus 1%. Annual redemption requirements are $4,800,000 to 1986 and $6,400,000 to 1989.

9. Capital stock

The new Business Corporations Act for Ontario became effective on July 29, 1983. Under the terms of this Act, all classes of the Company's shares are without nominal or par value.

(a) Authorized

Preference shares (issuable in series)

Class A – 1983 and 1982: 10,000,000 shares
Class B – 1983 and 1982: 10,000,000 shares
Class C – 1983: 19,881,874 shares; 1982: 19,924,605 shares
Class D – 1983: 49,988,397 shares; 1982: 49,998,116 shares

Common shares – 1983: 150,108,350 shares; 1982: 150,042,713 shares

(b) Outstanding

	September 30			
	1983		1982	
	Shares	**Amount**	Shares	Amount
Preference shares				
Class A				
$3.54 cumulative dividend, first series, retractable at $25.00 per share on September 30, 1984 or September 1, 1989, redeemable at varying premiums reducing from $1.00 commencing October 1, 1986	**2,000,000**	**$ 50,000**	2,000,000	$ 50,000
Class B				
$2.375 cumulative dividend, first series, convertible into common shares at $31.50 per share up to September 30, 1988, redeemable at $25.00 per share after September 30, 1984	**4,000,000**	**100,000**	4,000,000	100,000
Class C				
$1.80 cumulative dividend, first series, convertible into common shares at $15.00 per share up to November 1, 1984, redeemable at varying premiums reducing from $1.00	**525,117**	**10,502**	567,848	11,357
Class D				
$1.875 cumulative dividend, voting, first series, convertible into common shares at $28.00 per share up to December 31, 1989, redeemable at varying premiums reducing from $1.875	**13,896,699**	**347,418**	13,885,616	347,140
	20,421,816	**$507,920**	20,453,464	$508,497
Common shares (including shares held by Trustees)	**70,554,376**	**$184,804**	69,623,786	$165,088

(c) Changes in capital stock	Preference shares		Common shares	
	Shares	Amount	Shares	Amount
Balance at October 1, 1980	14,610,187	$361,588	68,899,823	$151,132
Issued for cash	4,000,000	100,000		
Conversion of preference to common	(200,433)	(4,433)	229,669	4,433
Issued on exercise of stock options, for cash	92,685	2,316	78,380	2,414
Balance at September 30, 1981	18,502,439	459,471	69,207,872	157,979
Issued for cash	2,000,000	50,000		
Conversion of preference to common	(55,135)	(1,127)	71,306	1,127
Issued pursuant to Stock Dividend, Dividend Reinvestment and Stock Purchase Plan	1,727	43	272,276	4,734
Issued pursuant to employees' Stock Purchase and Savings Plan			58,442	1,081
Issued on exercise of stock options, for cash	4,433	110	13,890	167
Balance at September 30, 1982	20,453,464	508,497	69,623,786	165,088
Conversion of preference to common	(52,450)	(1,097)	65,637	1,097
Issued pursuant to Stock Dividend, Dividend Reinvestment and Stock Purchase Plan	16,432	411	561,609	12,070
Issued pursuant to employees' Stock Purchase and Savings Plan			299,656	6,487
Issued on exercise of stock options, for cash	4,370	109	3,588	59
Issued on exercise of warrants, for cash			100	3
Balance at September 30, 1983	**(1)20,421,816**	**$507,920**	**70,554,376**	**$184,804**

(1) See note 2, page 22, subsequent event – Interprovincial Pipe Line Limited.

At September 30, 1983, 1,999,900 Common Share Purchase Warrants were outstanding. Each warrant entitles the holder to buy one common share at $31.50 on or before September 30, 1986.

10. Stock options

Under the terms of a Share Option Plan, adopted on October 1, 1980, 4,136,850 common shares were reserved for issuance to certain employees. At September 30, 1983, 2,985,325 common shares remain available to be granted under the plan. During the year ended September 30, 1983, options were granted for 967,600 shares under the plan at prices varying from $21.37 per share to $26.125 per share, options for 3,588 shares were exercised and options for 844,075 shares were cancelled. At September 30, 1983, options were outstanding for 1,082,937 shares.

Hiram Walker-Gooderham & Worts Limited has a stock option plan for certain key employees. Shares of the Company are purchased by Trustees on the open market to satisfy the outstanding options. Options outstanding are exercisable at various dates to 1989 at prices ranging from $9.64 to $15.69 per share. At September 30, 1983, options were outstanding for 138,058 shares. During the year ended September 30, 1983, options for 37,570 shares were exercised and options for 13,300 shares were cancelled. The cost of shares held by the Trustees has been deducted from shareholders' equity in the consolidated balance sheet. Shares held by the Trustees at September 30, 1983 and 1982, amounted to 93,530 shares and 129,380 shares, respectively.

At September 30, 1983, the Company is obligated to issue up to 53,217 of its Class D Preference Shares to satisfy Home Oil Company Limited employees' stock options exercisable until 1989 at an average price of $14.85 per share. During the year ended September 30, 1983, 26,582 options were exercised for which the Company issued 4,370 shares and paid $555,300 in cash. Options for 3,040 shares were cancelled during the year.

The following table summarizes the changes in options outstanding for the above plans during the year ended September 30, 1983.

	Common shares	Class D Preference shares
Shares under option at October 1, 1982	1,151,928	82,839
Options granted	967,600	
Options exercised	(41,158)	(26,582)
Options cancelled	(857,375)	(3,040)
Shares under option at September 30, 1983	1,220,995	53,217

11. Interest and finance charges

	Year ended September 30		
	1983	1982	1981
Interest on long term debt	**$228,726**	$234,096	$142,915
Dividends on term preferred shares	**5,396**	7,812	8,391
Other interest	**35,775**	61,169	84,482
	269,897	303,077	235,788
Capitalized interest	**(495)**	(4,944)	(11,033)
	269,402	298,133	224,755
Foreign exchange gain (note 3)	**(23,823)**		
Interest income	**(32,185)**	(29,135)	(15,441)
	$213,394	$268,998	$209,314

12. Pension plans

Pension expense during the three years ended September 30, amounted to $19,932,000 in 1983, $19,160,000 in 1982 and $20,141,000 in 1981. Unfunded prior years' service costs, which have not been charged to operations, amounted to $34,532,000 at September 30, 1983.

13. Income taxes

(a) The geographic components of income before income taxes and other items, and current and deferred income taxes are as follows:

	Year ended September 30		
	1983	1982	1981
Income before income taxes and other items			
Canada	**$220,259**	$224,387	$144,643
United States	**8,994**	(56,242)	48,423
Other (principally Europe)	**117,079**	109,026	102,700
	$346,332	$277,171	$295,766
Current income taxes			
Canada	**$ 65,742**	$ 65,367	$ 33,744
United States	**3,954**	(74,756)	(4,078)
Other (principally Europe)	**25,524**	24,357	33,165
	95,220	14,968	62,831
Deferred income taxes			
Canada	**40,538**	32,550	23,834
United States	**(51)**	68,786	25,362
United Kingdom – stock appreciation relief			(37,042)
Other (principally Europe)	**2,119**	19,377	(13,329)
	42,606	120,713	(1,175)
Total income tax expense	**$137,826**	$135,681	$ 61,656

(b) The provision for income taxes is based on financial statement income, except in regulated gas utility operations. This provision differs from income taxes currently payable because certain items of income and expense are reported in the consolidated statement of income in years different from those in which they are reported on income tax returns.

The aggregate of the tax effect of these timing differences is referred to in the consolidated balance sheet as deferred income taxes. Components of the change in these amounts during the three years ended September 30, 1983, are as follows:

	Year ended September 30		
	1983	1982	1981
Exploration and development expenditures deducted for income tax purposes in excess of depletion	**$43,460**	$ 96,954	$36,116
Capital cost allowances deducted for income tax purposes in excess of depreciation	**3,209**	18,866	12,097
Stock appreciation relief - United Kingdom			(37,042)
Interest capitalized in the accounts, expensed for income tax purposes		2,250	5,077
Other	**(4,063)**	2,643	(17,423)
	$42,606	$120,713	$ (1,175)

In the gas utility operations, rate and revenue structures are designed and approved not to recover deferred taxes in current revenues. Accordingly, the above amounts exclude deferred income taxes of $11,000,000 in 1983 and 1982 and $13,000,000 in 1981 and an accumulated amount of $171,000,000 at September 30, 1983. These deferred income taxes are primarily based on timing differences between capital cost allowances and depreciation.

(c) Income tax expense differs from the amount which would be obtained by applying the Canadian statutory federal income tax rate to income before income taxes and other items. This difference results from the following:

	Year ended September 30		
	1983	1982	1981
Income before income taxes and other items	**$346,332**	$277,171	$295,766
Canadian expected income tax rate	**46.0%**	46.0%	46.0%
Computed income tax expense	**$159,313**	$127,499	$136,052
Add:			
Petroleum and Gas Revenue Tax, royalties and other similar payments to governments not deductible for tax purposes	**65,073**	54,039	45,487
Unrecognized tax benefit available for application against future years' income	**610**	20,007	
Non-deductible depletion	**7,636**	5,958	6,350
	232,632	207,503	187,889
Deduct:			
Release of prior years' deferred income taxes relating to United Kingdom stock appreciation relief			37,042
Federal resource allowance	**38,625**	32,082	27,546
Alberta Royalty Tax Credit	**8,241**	7,193	2,035
Depletion allowances on Canadian oil and gas production income	**4,363**	5,129	9,771
Inventory allowance	**13,929**	15,291	21,393
Items capitalized in gas utility accounts expensed for income tax purposes for which no deferred taxes are provided	**9,420**	9,182	11,984
Difference in effective tax rates for foreign subsidiaries	**19,707**	7,045	7,256
Investment tax credits	**2,638**	4,493	6,957
Other	**(2,117)**	(8,593)	2,249
Actual income tax expense	**$137,826**	$135,681	$ 61,656
Actual income tax expense as a percentage of income before income taxes and other items	**39.8%**	49.0%	20.8%

(d) The potential income tax benefits associated with losses of certain United States subsidiaries in the current and prior years have not been recorded in the accounts. Net operating losses of $144,544,000, relating to these subsidiaries, are available to reduce taxable income in future years. The majority of these losses will expire between 1993 and 1998. In addition, the Company has recorded $4,782,000 of expenses in its books which have not yet been claimed for tax purposes. The tax benefits will be realized in future years provided that the respective United States subsidiaries have sufficient income.

(e) No provision has been made for taxes on undistributed earnings of foreign subsidiaries not currently available for paying dividends inasmuch as such earnings have been reinvested in the businesses.

14. Business segments

Company operations consist of three business segments: distilled spirits, natural resources and gas utility. Presented below are financial data by business segment and geographic area for each of the three years in the period ended September 30, 1983.

	Year ended September 30		
Business segments	**1983**	1982	1981
Operating revenue			
Distilled spirits	**$1,405,668**	$1,454,769	$1,452,412
Natural resources	**458,723**	476,566	349,386
Gas utility	**1,538,435**	1,428,427	1,099,049
	$3,402,826	$3,359,762	$2,900,847
Operating income			
Distilled spirits	**$ 266,617**	$ 293,828	$ 280,561
Natural resources	**90,741**	41,875	82,790
Gas utility	**180,313**	188,068	112,575
Total before undernoted items	**537,671**	523,771	475,926
Interest and finance charges, net	**(213,394)**	(268,998)	(209,314)
Income taxes	**(137,826)**	(135,681)	(61,656)
Other income	**22,055**	22,398	29,154
Foreign currency translation gain		9,645	24,540
Minority interest	**(22,478)**	(8,925)	(8,589)
Provision for impairment - United States natural resource properties		(176,985)	
Net income (loss)	**$ 186,028**	$ (34,775)	$ 250,061
Identifiable assets			
Distilled spirits	**$1,548,572**	$1,569,279	$1,540,283
Natural resources	**1,851,578**	1,893,760	2,076,345
Gas utility	**1,439,426**	1,500,513	1,301,610
	$4,839,576	$4,963,552	$4,918,238
Capital expenditures			
Distilled spirits	**$ 23,676**	$ 52,673	$ 84,901
Natural resources(2)	**145,856**	207,923	222,766(1)
Gas utility	**92,967**	97,817	96,131
	$ 262,499	$ 358,413	$ 403,798
Depletion and depreciation			
Distilled spirits	**$ 26,507**	$ 24,348	$ 21,158
Natural resources	**182,533**	232,193	112,388
Gas utility	**40,997**	36,976	32,416
	$ 250,037	$ 293,517	$ 165,962

Geographic areas	Year ended September 30 1983	1982	1981
Operating revenue			
Canada	**$2,070,016**	$1,924,741	$1,535,638
United States	**1,173,858**	1,233,472	1,145,674
Other (principally Europe)	**313,254**	393,000	406,233
Eliminations(3)	**(154,302)**	(191,451)	(186,698)
	$3,402,826	$3,359,762	$2,900,847
Operating income			
Canada	**$ 358,329**	$ 359,438	$ 264,957
United States	**93,041**	80,957	110,062
Other (principally Europe)	**86,301**	83,376	100,907
	$ 537,671	$ 523,771	$ 475,926
Identifiable assets			
Canada	**$2,916,384**	$2,811,570	$2,538,310
United States	**1,121,153**	1,305,898	1,560,484
Other (principally Europe)	**802,039**	846,084	819,444
	$4,839,576	$4,963,552	$4,918,238
Capital expenditures			
Canada(2)	**$ 201,961**	$ 178,020	$ 179,160
United States	**33,638**	121,762	178,473(1)
Other (principally Europe)	**26,900**	58,631	46,165
	$ 262,499	$ 358,413	$ 403,798
Depletion and depreciation			
Canada	**$ 104,367**	$ 90,387	$ 83,570
United States	**134,992**	163,371	74,467
Other	**10,678**	39,759	7,925
	$ 250,037	$ 293,517	$ 165,962

(1) Excludes the acquisition of United States natural resource properties amounting to $736,987,000.
(2) Net of applicable government grants for the three years ended September 30, 1983, 1982 and 1981 of $82,007,000, $36,578,000 and $16,205,000, respectively.
(3) Inter-company sales between geographic areas are at approximate market prices.

15. Comparative figures

Certain 1982 and 1981 comparative figures in the consolidated statement of income and note 14, business segments, have been reclassified to conform with the Company's current financial statement presentation.

16. Commitments and contingencies

(a) The indentures and agreements relating to certain long term debt obligations of Walker-Home Oil Ltd., a principal subsidiary of the Company, contain covenants limiting the transfer of funds by Walker-Home Oil Ltd., and its subsidiaries to the Company. Under the most restrictive of these covenants, as at September 30, 1983, such transfers of funds to the Company were limited to future consolidated net income of Walker-Home Oil Ltd. and its subsidiaries plus $347,802,000. The Company's consolidated net assets at September 30, 1983, include $1,206,072,000 of net assets of consolidated subsidiaries, which were restricted against transfer to the Company.

(b) Due to the size, complexity and international scope of the Company's operations, a number of lawsuits are pending at any point in time in which the Company may be the plaintiff or defendant. In the opinion of management, the ultimate resolution of any current lawsuits would not have a material effect on the Company's consolidated financial position or results of operations.

17. Supplementary information

The Company has security holders resident in the United States and uses capital markets in that country. Supplementary information that is in conformity with the reporting practices of companies in the United States follows:

United States accounting principles

The financial statements of the Company have been prepared in accordance with accounting principles generally accepted in Canada. These principles differ in some respects from those applicable in the United States. These differences are as follows:

(a) Provision for impairment – United States natural resource properties

In 1982, the provision for impairment in the consolidated statement of income would be included as a component of operating income under United States generally accepted accounting principles. Specifically, the gross amount of the impairment of $276,091,000 would be disclosed as a separate component of operating costs and expenses and the related deferred income tax relief of $99,106,000 would be offset against income taxes. However, these reclassifications would not change the Company's loss.

(b) Basic net income per common share

The calculation of basic net income per share under United States generally accepted accounting principles would include the common stock equivalent of the Class D Convertible Voting Preference Shares, Class B Convertible Preference Shares, Common Share Purchase Warrants and any outstanding stock options granted where the average price for the year exceeds the option price. Basic net income (loss) per common share on a Canadian and United States basis is as follows:

	Year ended September 30		
	1983	1982	1981
Canadian basis			
Before unusual item	**$2.03**	$ 1.43	$3.23
Including unusual item	**$2.03**	$(1.13)	$3.23
United States basis	**$1.98**	$(1.13)	$3.05

(c) Foreign currency translation

The Company prospectively changed its accounting policy for foreign currency translation on October 1, 1982. (see note 3, page 22) The Company follows the practice of deferring unrealized foreign exchange gains or losses on those long term monetary assets and liabilities with a fixed or ascertainable life and denominated in a currency other than a domestic currency. These gains or losses are subsequently amortized over the remaining life of the related assets and liabilities. Under accounting principles generally accepted in the United States, pursuant to Financial Accounting Standard No. 52, such exchange gains and losses would be included immediately in the determination of net income.

Under its former accounting policy, the Company followed the practice of translating long term debt obligations, which were fixed in foreign currencies, net of current maturities, at exchange rates applicable when the original obligations were assumed. This method differed from accounting principles generally accepted in the United States, pursuant to Financial Accounting Standard No. 8, inasmuch as such obligations would be translated into Canadian dollars at rates in effect at the balance sheet dates and the resultant gain or loss would be included in the determination of net income.

If United States generally accepted accounting principles were followed by the Company in respect of deferred foreign exchange gains and losses, during 1983, and long term debt obligations, prior to October 1, 1982, net income (loss) and basic and fully diluted net income (loss) per share would be as follows:

	Year ended September 30		
	1983	1982	1981
Net income (loss) as reported	**$186,028**	$(34,775)	$250,061
Foreign exchange (loss), net of tax	**(7,569)**		
Foreign currency translation gain (loss)		(16,972)	19,391
Net income (loss) on a United States basis	**$178,459**	$(51,747)	$269,452
Net income (loss) per common share			
Basic			
Canadian net income (loss) basis			
Before unusual item	**$ 2.03**	$ 1.43	$ 3.23
Including unusual item	**$ 2.03**	$ (1.13)	$ 3.23
United States net income (loss) basis	**$ 1.92**	$ (1.37)	$ 3.51
Fully diluted			
Canadian net income (loss) basis			
Before unusual item	**$ 2.01**	$ 1.43	$ 3.02
Including unusual item	**$ 2.01**	$ (1.13)	$ 3.02
United States net income (loss) basis	**$ 1.92**	$ (1.37)	$ 3.25

In addition, reported retained earnings would decrease by $8,783,000 to $1,071,067,000 at September 30, 1983, $1,214,000 to $1,030,980,000 at September 30, 1982 and increase by $15,758,000 to $1,222,096,000 at September 30, 1981.

(d) Pension plans

Under United States generally accepted accounting principles, additional information, as set out below, available only in respect of the Company's United States pension plans, would be disclosed. The data is based upon reports of independent consulting actuaries, as of the most recent valuation dates, generally January 1 of each year.

	1983	1982
Actuarial present value of accumulated plan benefits of which $94,807 (1982 $84,736) are vested	**$ 97,846**	$ 87,240
Net assets available for benefits	**$161,594**	$134,700
Assumed weighted average interest rate used in calculating plan benefits	**10.0%**	10.0%

(e) Preference shares

Under United States generally accepted accounting principles, the Company's preference shares, all of which are subject to mandatory redemption requirements, would be reported under a separate caption redeemable preference shares rather than under the general heading shareholders' equity in the consolidated balance sheet.

Supplemental oil and gas information (unaudited)

In 1983, the Financial Accounting Standards Boards in the United States issued Statement 69 which establishes a comprehensive set of disclosures for oil and gas producing activities. This statement was adopted by the Securities and Exchange Commission in place of its own disclosure requirements for oil and gas producing activities. The following information was prepared in accordance with the provisions of Statement 69 and, accordingly, replaces the cost and revenue data previously disclosed.

Oil and gas exploration activities are carried out principally in Canada and the United States and to a lesser extent in Indonesia, Australia and other areas. Producing activities are currently concentrated in Canada and the United States.

(a) Capitalized costs

	September 30		
	1983	1982	1981
Petroleum and natural gas properties			
Canada	**$1,006,713**	$ 916,582	$ 846,053
United States	**1,213,555**	1,107,661	1,003,013
Other	**58,064**	49,857	21,994
	2,278,332	2,074,100	1,871,060
Accumulated depletion and depreciation			
Canada	**160,371**	110,313	66,571
United States	**680,889**	498,158(1)	67,970
Other	**32,910**	32,365	130
	874,170	640,836	134,671
Net book value			
Canada	**846,342**	806,269	779,482
United States	**532,666**	609,503	935,043
Other	**25,154**	17,492	21,864
	$1,404,162	$1,433,264	$1,736,389

(1) Includes provision for impairment of $276,091,000. (see note 6, page 23)

(b) Costs incurred

	Year ended September 30		
	1983	1982	1981
Acquisition of proved properties			
United States			$437,538
Acquisition of unproved properties			
Canada	**$ 6,714**	$ 3,436	5,246
United States	**4,930**	10,340	318,826
Other		66	
	11,644	13,842	324,072
Exploration costs			
Canada	**52,120**	23,931	28,920
United States	**19,467**	40,890	41,841
Other	**9,060**	26,255	16,471
	80,647	91,076	87,232
Development costs			
Canada	**32,152**	42,121	46,292
United States	**21,047**	52,580	52,165
Other	**1,695**	1,663	11
	54,894	96,364	98,468
Total			
Canada	**90,986**	69,488	80,458
United States	**45,444**	103,810	850,370
Other	**10,755**	27,984	16,482
	$147,185	$201,282	$947,310

(c) Results of operations for oil and gas producing activities

	Year ended September 30		
	1983	1982	1981
Revenues, net of royalties			
Canada	**$272,790**	$235,181	$192,361
United States	**134,654**	169,178	74,201
Other		206	
	407,444	404,565	266,562
Production (lifting) costs			
Canada	**40,750**	38,913	33,774
United States	**31,952**	31,097	12,629
Other	**29**	204	
	72,731	70,214	46,403
Petroleum and Gas Revenue Tax - Canada	**35,470**	32,854	13,460
Depletion and depreciation			
Canada	**50,227**	43,899	41,061
United States	**120,621**	150,333(1)	60,867
Other	**3,198**	32,195	
	174,046	226,427	101,928
Income (loss) before income taxes			
Canada	**146,343**	119,515	104,066
United States	**(17,919)**	(12,252)	705
Other	**(3,227)**	(32,193)	
	125,197	75,070	104,771
Income taxes (recovery)			
Canada	**79,031**	72,946	57,653
United States	**(8,074)**	(5,636)	324
Other	**(1,539)**	(15,710)	
	69,418	51,600	57,977
Results of operations for oil and gas operations (2)			
Canada	**67,312**	46,569	46,413
United States	**(9,845)**	(6,616)	381
Other	**(1,688)**	(16,483)	
	$ 55,779	$ 23,470	$ 46,794

(1) Excludes provision for impairment of $276,091,000. (see note 6, page 23)
(2) The above revenues and costs exclude corporate overhead, interest and other operating costs and revenues not directly related to conventional oil and gas exploration and producing activities and consequently differ from those reported in the financial results of the natural resources segment.

(d) Crude oil and natural gas reserves

Proved reserves are based on estimates made by Company engineers. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. The process of estimating reserves is complex, requiring significant subjective judgements in the evaluation of available geological, engineering, economic, contractual and other data in respect of each reservoir. Proved reserves are located in Canada, United States, Indonesia and Australia. The proved reserves in Indonesia and Australia are included in the caption "other" in the table on the following page.

The calculation of net reserves of crude oil and natural gas liquids and natural gas is based on the Company's share of proved reserves after the deduction of royalties. The federal and provincial governments' royalty rates vary depending on prices, production volumes, the timing of initial production and changes in legislation. Due to the uncertainty of future royalty rates, the net reserves set forth below have been calculated on the basis of royalty rates in effect as of the dates the estimates were made.

Proved reserves	Canada Oil(1)	Canada Gas(2)	United States Oil(1)	United States Gas(2)	Other Oil(1)	Total Oil(1)	Total Gas(2)
October 1, 1980	65,271	539	947	34		66,218	573
Revisions of previous estimates and improved recovery	7,429	21	845	11		8,274	32
Purchases of minerals in place			8,215	88		8,215	88
Discoveries and extensions	642	21	1,422	6		2,064	27
Production	(6,713)	(28)	(851)	(13)		(7,564)	(41)
September 30, 1981	66,629	553	10,578	126		77,207	679
Revisions of previous estimates and improved recovery	9,758	115	(399)	(24)		9,359	91
Discoveries and extensions	1,087	37	994	26	1,119	3,200	63
Production	(6,612)	(29)	(1,932)	(25)		(8,544)	(54)
September 30, 1982	70,862	676	9,241	103	1,119	81,222	779
Revisions of previous estimates and improved recovery	2,121	37	2,231	27	(297)	4,055	64
Discoveries and extensions	2,763	16	552	6	230	3,545	22
Production	(6,476)	(26)	(1,657)	(18)		(8,133)	(44)
September 30, 1983	**69,270**	**703**	**10,367**	**118**	**1,052**	**80,689**	**821**
Proved developed reserves October 1, 1980	65,271	539	901	32		66,172	571
September 30, 1981	66,629	553	9,967	111		76,596	664
September 30, 1982	70,862	676	8,620	94	1,054	80,536	770
September 30, 1983	**65,807**	**649**	**9,300**	**107**	**1,052**	**76,159**	**756**

(1) Oil includes condensate and natural gas liquids and is stated in thousands of barrels.
(2) Gas is stated in billions of cubic feet.

(e) Discounted future net cash flows and changes therein from proved reserves

Estimated future cash flows are computed by applying year end prices, except for fixed and determinable escalation provisions in contracts, to year end quantities of proved oil and gas reserves. Estimated future development costs, production costs, Petroleum and Gas Revenue Tax ("PGRT") and income taxes are deducted from estimated future cash inflows to arrive at estimated future net cash flows. Future development and production costs have been computed by estimating the expenditures to be incurred in developing and producing the proved reserves at each year end, based on year end costs and assuming continuation of existing economic conditions. Estimated future PGRT, levied on Canadian oil and gas production from proved reserves, is computed based on rates and legislation in effect at each year end. Future income tax expense has been computed by applying the appropriate year end statutory rates, to the future taxable income estimated to be generated from proved reserves after making provision for the tax basis of the oil and gas properties. Future net cash flows are discounted at an annual rate of 10 per cent to arrive at the discounted future net cash flows.

The Company cautions that the discounted future net cash flows from proved oil and gas reserves is neither an indication of fair market value of oil and gas properties, nor of the future cash flows expected to be generated from such properties. The calculation does not include the fair market value of exploratory acreage and probable and possible oil and gas reserves, nor does it include the impact of anticipated future changes in crude oil and natural gas prices, development and production costs, and possible changes to tax and royalty legislation. The prescribed discount rate of 10 per cent used in arriving at the discounted net cash flow may not appropriately reflect future interest rates. The computation excludes values attributable to marketing, storage and pipeline activities related to oil and gas production activities.

The discounted net cash flow cannot be compared with the net book value of capitalized costs of petroleum and natural gas properties because it is calculated on an after tax basis and excludes the fair market value of exploratory acreage and probable and possible oil and gas reserves.

Discounted future cash flows relating to proved oil and gas reserves at September 30

	1983	1982	1981
Estimated future cash inflows			
Canada	**$4,076,183**	$4,106,444	$3,214,910
United States	**861,995**	786,223	889,490
Other	**32,998**	46,699	
	4,971,176	4,939,366	4,104,400
Estimated future production and development costs			
Canada	**808,040**	678,744	696,445
United States	**221,394**	187,841	228,209
Other	**12,640**	15,649	
	1,042,074	882,234	924,654
Estimated future PGRT - Canada	**572,390**	662,000	477,244
Estimated future cash flows before income taxes			
Canada	**2,695,753**	2,765,700	2,041,221
United States	**640,601**	598,382	661,281
Other	**20,358**	31,050	
	3,356,712	3,395,132	2,702,502
Estimated future income taxes			
Canada	**1,441,021**	1,501,130	1,110,277
United States			
Other	**2,587**	14,037	
	1,443,608	1,515,167	1,110,277
Estimated future net cash flows			
Canada	**1,254,732**	1,264,570	930,944
United States	**640,601**	598,382	661,281
Other	**17,771**	17,013	
	1,913,104	1,879,965	1,592,225
Discount at 10% per annum for estimated timing of future net cash flows			
Canada	**746,844**	739,984	531,160
United States	**243,293**	203,001	240,056
Other	**3,574**	5,962	
	993,711	948,947	771,216
Discounted future net cash flows			
Canada	**507,888**	524,586	399,784
United States	**397,308**	395,381	421,225
Other	**14,197**	11,051	
	$ 919,393	$ 931,018	$ 821,009

Changes in discounted future net cash flows relating to proved oil and gas reserves

	Year ended September 30		
	1983	1982	1981
Revisions to reserves proved in prior years			
Revisions in quantity and timing estimates	**$ 78,777**	$(170,136)	$ 46,104
Net change in prices, net of lifting costs and PGRT related to production	**(61,142)**	470,781	(19,455)
Change in estimated future development costs	**10,018**	(13,834)	30,689
Introduction of PGRT			(184,945)
Other	**(6,194)**	25,640	(18,458)
	21,459	312,451	(146,065)
Accretion of discount	**158,294**	130,352	129,651
Discoveries and extensions, net of related costs	**76,217**	123,775	57,853
Purchase of minerals in place			290,230
Previously estimated development costs incurred during the year	**24,141**	14,344	27,211
Revenue, net of lifting costs and PGRT from production	**(299,243)**	(301,497)	(206,741)
Net change in income taxes	**7,507**	(169,416)	(15,025)
Net change	**(11,625)**	110,009	137,114
Balance at beginning of year	**931,018**	821,009	683,895
Balance at end of year	**$919,393**	$931,018	$821,009

Quarterly financial information (unaudited)

	Year ended September 30							
	1983				1982			
	Quarter							
	First	**Second**	**Third**	**Fourth**	First	Second	Third	Fourth
Revenue	**$983,941**	**$1,011,406**	**$808,423**	**$599,056**	$918,304	$988,732	$812,116	$ 640,610
Gross margin	**$360,892**	**$ 336,024**	**$289,155**	**$247,214**	$328,173	$329,024	$292,888	$ 300,950
Income (loss) before unusual item	**$ 59,699**	**$ 70,944**	**$ 33,810**	**$ 21,575**	$ 47,822	$ 70,168	$ 33,992	$ (9,772)(1)
Net income (loss)	**$ 59,699**	**$ 70,944**	**$ 33,810**	**$ 21,575**	$ 47,822	$ 70,168	$ 33,992	$(186,757)(2)
Net income (loss) per common share								
Basic								
Before unusual item	**$0.70**	**$0.86**	**$0.32**	**$0.15**	$0.54	$0.86	$0.33	$(0.30)
Including unusual item	**$0.70**	**$0.86**	**$0.32**	**$0.15**	$0.54	$0.86	$0.33	$(2.86)
Fully diluted								
Before unusual item	**$0.67**	**$0.73**	**$0.32**	**$0.15**	$0.54	$0.80	$0.33	$(0.30)
Including unusual item	**$0.67**	**$0.73**	**$0.32**	**$0.15**	$0.54	$0.80	$0.33	$(2.86)

(1) Includes the write off of expenditures of $32,195,000 in Guyana

(2) Includes the provision for impairment in the carrying value of the Company's United States natural resource properties of $276,091,000, net of deferred income tax relief of $99,106,000

Market price of common shares and related security holder matters

The principal trading markets of the common shares in Canada and the United States are the Toronto and New York stock exchanges, respectively. The common shares of the Company are also listed on the Montreal, Alberta and Vancouver stock exchanges.

The following table sets forth the reported high and low sales prices of the common shares on the Toronto and New York stock exchanges, as reported by the Toronto Stock Exchange Review and the New York Stock Exchange Monthly Market Statistics Report, respectively:

	Year ended September 30							
	1983				1982			
	Quarter							
	First	**Second**	**Third**	**Fourth**	First	Second	Third	Fourth
Toronto Stock Exchange (Canadian dollars)								
High	**$21½**	**$23⅝**	**$27⅛**	**$27**	$25	$23½	$18	$20⅝
Low	**17¾**	**19½**	**21⅞**	**24¼**	20⅞	13⅞	14⅞	15¾
New York Stock Exchange (United States dollars)								
High	**17½**	**19¼**	**22**	**22**	21	19⅞	14½	16½
Low	**14¼**	**15⅞**	**17¾**	**19⅝**	17½	11⅜	12	12¼

Quarterly dividends of $0.33 per common share were paid in 1983 and 1982.

At September 30, 1983, there were 47,358 registered holders of common shares.

There are no restrictions on the export or import of capital which affect the remittance of dividends, interest or other payments to non-resident holders of the Company's securities.

The Foreign Investment Review Act requires prior approval by the government of Canada of the acquisition by, or transfer to, non-residents of Canada of direct or indirect control of a Canadian business entity, such as the Company. The Act does not apply to the purchase of shares or securities of a corporation where such purchases would not give the purchasers effective control of the corporation.

Cash dividends paid to shareholders resident in the United States, the United Kingdom and most western European countries are generally subject to Canadian withholding tax at a rate of 15 per cent. Cash dividends paid to other non-residents of Canada are generally subject to Canadian withholding tax at a maximum rate of 25 per cent, depending upon applicable tax treaties. Interest payable on the Company's debt securities held by non-Canadian residents may also be subject to Canadian withholding tax depending upon the terms and provisions of such securities. Stock dividends paid to non-Canadian residents are generally not subject to Canadian withholding tax.

Five year financial and operating review

FINANCIAL

	1983	1982	1981	1980	1979
	(Expressed in thousands except per share amounts)				
Revenue					
Distilled spirits	**$1,405,668**	$1,454,769	$1,452,412	$1,430,658	$1,329,451
Natural resources	**458,723**	476,566	349,386	231,817	
Gas utility	**1,538,435**	1,428,427	1,099,049	862,605	815,910
	$3,402,826	$3,359,762	$2,900,847	$2,525,080	$2,145,361
Operating income					
Distilled spirits	**$ 266,617**	$ 293,828	$ 280,561	$ 264,410	$ 238,982
Natural resources	**90,741**	41,875	82,790	92,612	
Gas utility	**180,313**	188,068	112,575	94,257	97,359
	$ 537,671	$ 523,771	$ 475,926	$ 451,279	$ 336,341
Income before undernoted items	**$ 346,332**	$ 277,171	$ 295,766	$ 371,741	$ 260,139
Income taxes	**(137,826)**	(135,681)	(61,656)	(130,922)	(93,366)
Other items, net	**(22,478)**	720	15,951	(1,297)	10,391
Income before unusual item	**186,028**	142,210	250,061	239,522	177,164
Provision for impairment		(176,985)			
Net income (loss)	**$ 186,028**	$ (34,775)	$ 250,061	$ 239,522	$ 177,164
Net income (loss) per common share					
Basic					
Before unusual item	**$ 2.03**	$ 1.43	$ 3.23	$ 3.18	$ 2.56
Including unusual item	**$ 2.03**	$ (1.13)	$ 3.23	$ 3.18	$ 2.56
Fully diluted					
Before unusual item	**$ 2.01**	$ 1.43	$ 3.02	$ 3.01	$ 2.52
Including unusual item	**$ 2.01**	$ (1.13)	$ 3.02	$ 3.01	$ 2.52
Dividends declared per common share	**$ 1.32**	$ 1.32	$ 1.32	$ 1.32	$ 0.88
Cash from operations	**$ 664,364**	$ 484,719	$ 202,943	$ 256,609	$ 108,797
Cash from operations per common share Basic	**$ 9.48**	$ 7.00	$ 2.95	$ 3.75	$ 1.60
Capital expenditures(1)	**$ 262,499**	$ 358,413	$ 403,798	$ 301,316	$ 103,527
Identifiable assets					
Distilled spirits	**$1,548,572**	$1,569,279	$1,540,283	$1,440,034	$1,296,861
Natural resources	**1,851,578**	1,893,760	2,076,345	1,100,380	
Gas utility	**1,439,426**	1,500,513	1,301,610	1,070,246	1,150,586
Total assets	**$4,839,576**	$4,963,552	$4,918,238	$3,610,660	$2,447,447
Long term debt (including current portion)	**$1,646,081**	$1,748,252	$1,753,370	$ 742,466	$ 556,636
Shareholders' equity					
Preference	**$ 507,920**	$ 508,497	$ 459,471	$ 361,588	$ 18,444
Common	**1,115,930**	1,194,821	1,362,300	1,227,331	1,098,978
	$1,623,850	$1,703,318	$1,821,771	$1,588,919	$1,117,422
Number of common shares outstanding (including shares held by Trustees)	**70,554**	69,624	69,208	68,900	68,788
Weighted average number of common shares outstanding	**70,048**	69,217	68,881	68,465	68,205

(1) Excludes acquisitions of Home Oil Company Limited in 1980 and United States natural resource properties in 1981.

OPERATING

	1983	1982	1981	1980	1979
Distilled spirits					
Gross revenue less excise taxes and import duties (millions)	**$ 1,054**	$ 1,103	$ 1,085	$ 1,021	$ 916
Natural resources					
Production (before royalties)					
Crude oil and natural gas liquids production (barrels per day)					
Canada	**25,811**	26,664	27,908	30,426	30,552
United States	**5,438**	6,255	4,462	627	311
Other		15			
	31,249	32,934	32,370	31,053	30,863
Natural gas sales (millions of cubic feet per day)					
Canada	**96.7**	108.3	106.5	109.3	117.8
United States	**58.6**	82.2	59.3	20.6	18.5
	155.3	190.5	165.8	129.9	136.3
Drilling activity					
Gross working interest wells	**262**	245	307	450	426
Net oil wells	**37**	27	48	36	27
Net gas wells	**12**	20	23	37	44
Net dry wells	**23**	31	40	29	20
Proved reserves (before royalties)					
Crude oil and natural gas liquids (millions of barrels)	**116**	118	131	120	123
Natural gas (billions of cubic feet)	**1,089**	1,041	1,108	938	941
Gross acreage (thousands)(1)					
Canada	**21,216**	22,647	23,373	26,442	26,148
United States	**4,782**	3,995	3,657	2,562	2,700
Other	**11,631**	10,161	9,924	11,245	9,703
	37,629	36,803	36,954	40,249	38,551
Net acreage (thousands)(1)					
Canada	**3,819**	3,962	4,296	4,391	4,350
United States	**1,515**	1,868	1,840	1,328	1,365
Other	**2,054**	1,913	2,210	1,435	1,435
	7,388	7,743	8,346	7,154	7,150

(1) Prior years restated to include only land in which an interest has been earned.

	1983	1982	1981	1980	1979
Gas utility					
Revenue (thousands)					
Gas sales					
Residential	**$ 500,962**	$ 478,574	$ 342,618	$ 261,112	$ 234,422
Commercial	**530,017**	484,897	370,601	283,408	260,264
Industrial	**459,745**	416,826	343,613	283,427	291,812
	1,490,724	1,380,297	1,056,832	827,947	786,498
Other revenue	**47,711**	48,130	42,217	34,658	29,412
	$1,538,435	$1,428,427	$1,099,049	$ 862,605	$ 815,910
Gas cost (thousands)	**$1,191,029**	$1,080,965	$ 851,025	$ 654,845	$ 622,439
Gas sales (millions of cubic feet)					
Residential	**78,144**	87,949	81,121	73,756	73,519
Commercial	**106,709**	115,598	109,205	101,663	101,156
Industrial	**99,239**	105,283	106,535	110,637	128,921
	284,092	308,830	296,861	286,056	303,596
Daily sendout (millions of cubic feet)					
Maximum	**1,937**	1,958	1,856	1,735	1,781
Minimum	**257**	243	249	249	257
Average	**788**	850	825	793	840
Number of active customers (year end)					
Residential	**687,023**	654,260	611,823	568,984	530,636
Commercial	**66,312**	63,381	60,041	55,590	51,555
Industrial	**6,576**	6,517	6,415	6,173	5,987
	759,911	724,158	678,279	630,747	588,178
Average revenue (per thousand cubic feet)					
Residential	**$6.41**	$5.44	$4.22	$3.54	$3.18
Commercial	**$4.97**	$4.20	$3.39	$2.79	$2.57
Industrial	**$4.63**	$3.96	$3.22	$2.56	$2.26
Miles of mains in use (year end)	**10,929**	10,718	10,233	9,871	9,398
Average use per residential customer (thousands of cubic feet)	**113.9**	134.8	134.1	130.4	137.8
Degree day deficiency(1)	**3,756**	4,322	4,202	4,040	4,246

(1) Degree day deficiency figures, expressed in Celsius, are for the Toronto area. The deficiency is a measure of coldness during the heating season and is calculated by adding together the total number of degrees by which the daily mean temperature fell below 18 Celsius (65°F).

Corporate information

Executive office

Hiram Walker Resources Ltd.
Suite 600, 1 First Canadian Place
P.O. Box 33, Toronto, Ontario
M5X 1A9
Telephone (416) 864-3300

Principal offices

Hiram Walker-Gooderham & Worts Limited
2072 Riverside Drive East
P.O. Box 2518, Windsor, Ontario
N8Y 4S5
Telephone (519) 254-5171

Home Oil Company Limited
2300 Home Oil Tower
324 Eighth Avenue South West,
Calgary, Alberta T2P 2Z5
Telephone (403) 232-7100

The Consumers' Gas Company Ltd.
Suite 4200, 1 First Canadian Place
P.O. Box 90, Toronto, Ontario
M5X 1C5
Telephone (416) 864-3399

Auditors

Price Waterhouse

Stock exchange listings and symbol

Common shares - Toronto, Montreal, Alberta, Vancouver, New York

The listing symbol for common shares on all stock exchanges is HWR and is reported in Canadian newspapers under the W's as Walker R, and in United States newspapers under the W's as WkHRs.

Form 10-K

A Form 10-K Annual Report is filed with the United States Securities and Exchange Commission. This report will be made available to shareholders, without charge, upon written request to The Secretary of the Company.

Registrar and transfer agents

Common shares and warrants

Canada Permanent Trust Company
20 Eglinton Avenue West, Toronto
M4R 2E2 and in Montreal, Calgary and Vancouver

Morgan Guaranty Trust Company of New York
Stock Transfer Department
30 West Broadway
New York, N.Y. 10007

14.16% Retractable Class A Preference Shares

National Trust Company, Limited
21 King Street East, Toronto M5C 1B3
and in Montreal, Calgary and Vancouver

9½% Convertible Class B Preference Shares

Canada Permanent Trust Company
20 Eglinton Avenue West, Toronto
M4R 2E2 and in Montreal, Calgary and Vancouver

9% Convertible Class C Preference Shares

The Canada Trust Company
110 Yonge Street, Toronto M5C 1T4
and in Montreal, Calgary and Vancouver

7½% Convertible Class D Preference Shares

Canada Permanent Trust Company
20 Eglinton Avenue West, Toronto
M4R 2E2 and in Montreal, Calgary and Vancouver

Dividend plan

Registered shareholders of common shares are eligible to participate in the Stock Dividend, Dividend Reinvestment and Stock Purchase Plan. Details may be obtained by writing to The Secretary of the Company.

Directors

Richard E. Cross(3)
Counsel
Cross, Wrock, Miller & Vieson

A. E. Downing
Executive Vice President of the Company
President
Hiram Walker-Gooderham & Worts Limited

Charles T. Fisher, III
Chairman and President
National Bank of Detroit

Gordon C. Gray(1)(2)
Chairman and Chief Executive Officer
A.E. LePage Limited

Richard F. Haskayne
Executive Vice President of the Company
President
Home Oil Company Limited

H. Clifford Hatch(1)
Chairman, President and
Chief Executive Officer of the Company

H. Clifford Hatch, Jr.
Executive Vice President of the Company
Vice President
Hiram Walker-Gooderham & Worts Limited

Robert S. Hurlbut(2)(3)
Chairman and President
General Foods, Inc.

Henry N. R. Jackman(4)
Chairman
The Empire Life Insurance Co.

Paul J. G. Kidd, Q.C.(4)
Corporate Director

Allen T. Lambert(1)(4)
Chairman and Chief Executive Officer
Trilon Financial Corp. Ltd.

Peter L. P. Macdonnell, Q.C.
Partner
Milner & Steer

Edmond G. Odette(2)
President
Eastern Construction Company Limited

Stanley G. Olson(1)(3)
Corporate Director

John T. Sapienza
Partner
Covington & Burling

Robert C. Scrivener(3)
Corporate Director

Noah Torno(1)(3)
Corporate Director

William P. Wilder(1)(4)
Deputy Chairman of the Company
Chairman
The Consumers' Gas Company Ltd.

Member of:

1. Executive Committee
2. Audit Committee
3. Management Resources and Compensation Committee
4. Pension Committee

Executive officers

H. Clifford Hatch, Chairman, President and Chief Executive Officer
W. P. Wilder, Deputy Chairman
A. E. Downing, Executive Vice President
R. F. Haskayne, Executive Vice President
H. Clifford Hatch, Jr., Executive Vice President
R. W. Martin, Executive Vice President
A. R. McCallum, Senior Vice President and Chief Financial Officer
E. W. H. Tremain, Vice President and Secretary
W. R. Fatt, Treasurer
J. B. Petrie, Corporate Comptroller

Principal subsidiaries

- Walker-Home Oil Ltd.
  - Hiram Walker-Gooderham & Worts Limited
    - Hiram Walker & Sons Limited
    - Corby Distilleries Limited (52.8%)
    - Maidstone Essex Limited
      - Courvoisier S.A.
      - Kahlua S.A.
      - Hiram Walker Holdings N.V.
      - Walker-Home Petroleum, Inc.
        - Maidstone Wine & Spirits, Inc.
        - HPC, Inc.
          - Home Petroleum Corporation
        - Hiram Walker & Sons, Inc.
          - Hiram Walker Incorporated
          - W.A. Taylor & Company
    - Hiram Walker & Sons (Scotland) P.L.C.
  - Home Oil Company Limited
    - Home Exploration Limited
    - Home Energy Company Ltd. (60.0%)
    - Home Oil (U.K.) Limited
    - Scurry-Rainbow Oil Limited (88.5%)
      - Plains Petroleums Limited (72.2%)
    - Federated Pipe Lines Ltd. (50.0%)
- The Consumers' Gas Company Ltd. (89.9%)
  - Niagara Gas Transmission Limited
  - St. Lawrence Gas Company, Inc.
  - Gazifere Inc.
  - Tecumseh Gas Storage Limited (50.0%)
  - Underwater Gas Developers Limited


VSOP
Fine Champagne
COURVOISIER
Le Cognac de Napoléon
COGNAC


Ballantine's
FINEST
SCOTCH WHISKY
George Ballantine & Son, Limited
Distillers—Dumbarton, Scotland
710mL
Ballantine's
TWELVE 12 YEARS OLD
VERY OLD
SCOTCH WHISKY


KAHLUA
IMPORTED
FROM SUNNY MEXICO
KAHLÚA
LICOR DE CAFÉ
LIQUEUR
PRODUCT OF MEXICO
KAHLUA, S. A.
FABRICA DE LICOR DE CAFE
MAIDSTONE IMPORTERS, LOS ANGELES, CALIFORNIA


DRAMBUIE
LIQUEUR
THE ISLE
OF SKYE LIQUEUR
Prince Charles Edward's Liqueur
TRADE MARK
DRAMBUIE
REG. U.S. PAT. OFF.
A LINK WITH THE "45"

Principal Brands

Hiram Walker-Gooderham & Worts Limited

CANADA

Canadian Whiskies
Canadian Club
Walker's Special Old
Gooderham's Bonded Stock

Imported Scotch Whiskies
Ballantine's
Lauder's

Liqueurs
Hiram Walker's

Imported Liqueurs
Kahlua
Drambuie
Tia Maria

Cognac
Courvoisier

London Dry Gin
Hiram Walker's Crystal

Vodkas
Hiram Walker's Crystal
Skol

Rums
Government House
Maraca

Imported Wines
J. Moreau et Fils (France)
Langenbach and Company (Germany)
Tarride Ledroit & Cie (France)

UNITED STATES

Imported Canadian Whiskies
Canadian Club
Royal Canadian
Northern Light
Gooderham's Rich & Rare

Imported Scotch Whiskies
Ballantine's
Lauder's
Old Smuggler

Straight Bourbon Whiskeys
Walker's DeLuxe
Ten High

American Sour Mash Bourbon Whiskey
Maker's Mark

American Blended Whiskey
Imperial

Tequila
Two Fingers
Arandas

London Dry Gins
Hiram Walker's Crystal Palace
Booth's

Vodka
Hiram Walker's Crystal Palace

Cordials and Fruit Flavoured Brandies
Hiram Walker's

Cognacs
Courvoisier
Salignac

Imported Liqueurs
Kahlua
Drambuie
Tia Maria

Premium California Wines
Callaway Vineyards

Imported Fine Wines
Those represented by
Frederick Wildman & Sons, Limited

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