Texaco Canada Inc.

Annual Report
1983

TEXACO

TEXACO

Texaco Canada Inc.
90 Wynford Drive
Don Mills, Ontario
M3C 1K5

A New Look for Texaco

The Texaco Star—bolder, bigger and brighter than ever—is a key element in the Company's new corporate identity program (see cover). The reborn star and the clean uncluttered look of Texaco Canada's new and remodelled service stations is strengthening public awareness of the Company, appealing to long-standing customers and attracting new ones.

The total design concept, which incorporates an attractive family of colors and contemporary graphics, is being applied in all facets of the Company's operations.

The Annual and Special General Meeting of Shareholders of Texaco Canada Inc. will be held at the Company's registered office at 90 Wynford Drive, Don Mills, Ontario, on Friday, April 27, 1984, at 10:30 a.m.

On peut obtenir un exemplaire français du présent rapport annuel en s'adressant au secrétaire général de la société, 90 Wynford Drive, Don Mills (Ontario) M3C 1K5

Contents

HIGHLIGHTS

Financial	1983	1982	1981
	(Millions of Canadian dollars)		
Revenues	**$5,726**	$4,842	$4,461
Net income	**344**	275	316
Cash dividends	**140**	136	119
Funds provided by operations	**449**	384	404
Taxes and Crown royalties	**1,885**	1,883	1,801
Capital and exploratory expenditures	**187**	197	209
Capital employed at year-end	**2,545**	2,335	2,239
Total assets at year-end	**3,288**	2,966	2,879
Common shareholders' equity at year-end	**1,822**	1,617	1,478
Working capital at year-end	**1,041**	835	757
Long-term debt at year-end	**87**	83	86
Rate of return on average capital employed	**14.3%**	12.2%	14.9%

Per Common Share Data			
Net income	**$ 2.74**	$ 2.15	$ 2.45
Cash dividends	**1.05**	1.00	0.82
Shareholders' equity at year-end	**15.09**	13.40	12.25

Operating			
	(Thousands of cubic metres daily)		
Gross production of crude oil and natural gas liquids	**23.4**	23.0	23.5
Refinery runs	**21.3**	23.5	28.2
Petroleum product sales	**28.4**	28.0	31.6
	(Millions of cubic metres daily)		
Natural gas sales	**3.2**	3.7	3.3
	(Cubic metres)		
Estimated gross proved recoverable reserves:			
Crude oil and natural gas liquids (millions)	**64.9**	67.1	71.8
Natural gas (billions)	**62.8**	63.3	65.2

The Metric System

Information in this Annual Report is provided in the International System of Units, commonly called the metric system. Approximate conversion factors to metric units are as follows:

One cubic metre contains about 6.29 barrels of liquids or about 35.3 cubic feet of gas.
One hectare is about 2.47 acres.
One kilometre is about 0.62 miles.
One tonne is about 2,205 pounds.

Nineteen eighty-three was an excellent year for Texaco Canada, as your Company led the way in the Canadian petroleum industry's improved profitability. Net income for the year rose to $344 million or $2.74 a common share, a 25 per cent increase over 1982. The improvement was the result of higher crude oil prices, somewhat lower royalties, and a company-wide commitment to very careful control of expenses.

Dividend payments on Texaco Canada common shares increased in 1983 to $127 million or $1.05 a share, compared to $121 million or $1.00 a share in 1982. The quarterly dividend was raised in October to $0.30 per share from $0.25 per share.

Your Company performed well despite a declining demand for petroleum products that persisted even with the improving economy. During 1983 major economic indicators began turning upward. The recession is receding and a healthier business climate is returning.

Concern remains about sustaining the economic recovery, and rightly so. Governments can be a major force in speeding the pace of recovery. What is needed is a commitment to realistic economic policies that will encourage the vitality of the private sector, attract investment, promote productivity gains and bring our level of growth to its potential.

There were some favourable government policy initiatives for the petroleum industry during 1983. Beneficial changes included royalty incentives and other relief from Alberta and Saskatchewan. The federal government extended the New Oil Reference Price to more crude production, approved oil exports to relieve the problem of shut-in production, provided some tax relief on enhanced oil recovery projects and instituted incentive pricing for natural gas.

Texaco Canada played an active role in the dialogue with governments which brought these changes and we will continue to press for further modifications that are needed, particularly to the National Energy Program.

While the Canadian petroleum industry saw a measure of profitability restored during 1983, refining and marketing operations faced continuing pressure from depressed demand and oversupply of petroleum products. Texaco Canada responded by bringing its refining and marketing operations into balance and streamlining them for greater efficiency.

Our key marketing and refining objective is to return to a profitable level. One major program to this end involves the ambitious marketing thrust begun last year to increase retail gasoline sales. We have a new Texaco image to present to the public, one which we feel will make a significant impact in the marketplace.

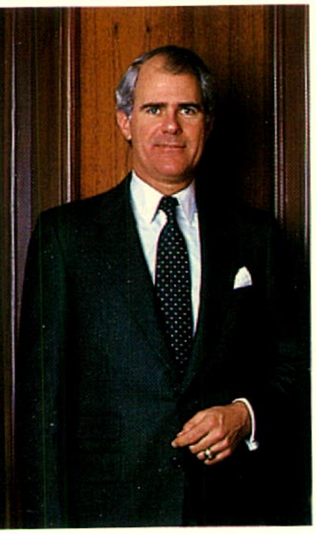
Our key exploration and production objective is to replace current production of crude oil and natural gas liquids with new reserves in order to maintain profitable levels of production. To accomplish this, we have stepped up our exploration and enhanced oil recovery efforts.

For the near term, we will concentrate on conventional oil in western Canada. Last year we made 14 oil and nine gas discoveries for a success ratio of 40 per cent. This year we plan to do more, significantly increasing both our exploration budget and the number of wells drilled.

Texaco's anticipated ultimate share of reserve increases from the enhanced oil recovery projects undertaken during 1983 will be about 6.4 million gross cubic metres from a total investment of some $33 million. For 1984 we have planned six additional projects.

While recovery in natural gas demand cannot be forecast with certainty at this time, we are maintaining an appropriate level of investment and activity, continuing to develop our established reserves and improve liquid extraction capability.

Frontier exploration will play a significant role as we broaden our search for petroleum to ensure we maintain our oil production and increase our reserves for the future.



Last year we joined with two prominent Canadian firms, Sun Life Assurance Company of Canada and ATCO Ltd., to create AT&S Exploration Ltd. to explore on our own and other frontier lands. Since the company is about 75 per cent Canadian owned, it is eligible for maximum incentive grants under the federal government's Petroleum Incentives Program. The new resource company has an aggressive exploration program underway.

Texaco Canada also has more than 200 000 hectares of oil sands leases in Alberta which will be very important to the Company in the future. Positive laboratory and field testing and technical advances have made progress toward the goal of economic recovery of the oil.

Your Company is in a good position to profit from the improving economy and the better business climate for the Canadian petroleum industry. Our strong financial position offers flexibility to take advantage of new opportunities.

Texaco Canada continues to benefit from the dedication and skills of its employees, strong leadership from its management and directors, and the continued support of shareholders.

A number of noteworthy changes have taken place on the Company's Board of Directors. With regret, we recall the death of the Honourable Victor deB. Oland on June 26, 1983. Mr. Oland, a former Nova Scotia Lieutenant-Governor and prominent businessman, was elected to the Texaco Canada Board of Directors in 1963 and served actively for 20 years until his death at age 69. His wise counsel will be missed.

Mr. Andrew Gray Farquharson retired from the Board in April of last year, after a long and distinguished career with the Company that spanned more than half a century. His loyal and dedicated service are greatly appreciated.

Mr. William A. Gatenby, President and Chief Executive Officer of Texaco Canada Resources Ltd., was appointed to the Board of Directors April 22, 1983. With the experience gained during his 27 years at Texaco and a wealth of expertise in the resource sector, Mr. Gatenby is a most welcome addition.

On your behalf, we would like to thank Mr. Roland M. Routhier for his strong leadership as this Company's President and Chief Executive Officer from 1982 to 1984. We wish him well in his new position as Senior Vice President of Texaco Inc. and look forward to his continued counsel on Texaco Canada's Board of Directors.

On January 20, 1984, the Board of Directors of Texaco Canada appointed the undersigned President and Chief Executive Officer. The employees of the Company and the predecessor Chief Executive Officers have built one of the finest business organizations in Canada. We are committed to a continued strengthening of the Company so that it will remain a major force in our industry.

Our goal is to enhance further the value of Texaco Canada to shareholders, employees and customers.

On behalf of the Board of Directors,

James L. Dunlap

James L. Dunlap,
President and Chief Executive Officer

Don Mills, Ontario
March 20, 1984

Texaco Canada's increasingly dynamic investment and development strategies in the resource sector provide the keys to future growth and profitability. The goal is to sustain production capability and maintain reserves, and the strategy to attain the goal covers six main areas which are discussed in this report. They are:

Aggressive exploration in western Canada.

Frontier exploration off the east coast and in northern Canada through joint venture programs and the new joint exploration company AT&S Exploration Ltd.

Identification of foreign opportunities in high potential areas.

Aggressive application of enhanced oil recovery techniques.

Development of gas reserves and improvement of liquid extraction capabilities.

Research and development of in-situ techniques for recovering bitumen from the Alberta oil sands.

Texaco Canada Resources Ltd. officers (from left) Orville C. Windrem, Vice-President, Corporate Affairs; Neal H. Eggen, Vice-President, Drilling and Production; William A. Gatenby, President and Chief Executive Officer; William B. O'Heran, Vice-President, Exploration.

Exploration

Texaco Canada accelerated its exploration activities in 1983, participating in a total of 58 exploratory wells compared with 29 in 1982. There were 14 oil discoveries and nine gas discoveries, for a success ratio of 40 per cent.

The Company also intensified its seismic activity, particularly in western Canada. Holdings of oil and gas rights increased by about 151 000 net hectares, principally through additions of Canada Lands offshore the east coast and in the Northwest Territories as a result of the conversion of leases to exploration agreements.

Western Provinces

The emphasis in Texaco Canada's exploration program in 1983 was on western Canada. Proprietary seismic programs focusing on oil prospects were conducted in southern and central Alberta and in northeastern British Columbia.

The Company upgraded its land holdings in western Canada by concentrating on acquisitions in high potential areas and by surrendering less prospective leases. Almost 47 000 hectares were added through purchases and farm-ins, while 50 000 hectares considered to have low potential were surrendered or the lease term was allowed to expire.

Turnover of petroleum rights in western Canada is accelerating as long-term leases under prior regulations are expiring and a large proportion of land becomes subject to the two to five year lease terms currently in effect.

Texaco Canada continued its exploration of the Cynthia-Pembina area of west-central Alberta, where the Company's initial discovery well was drilled in 1980. Twenty-four exploratory wells were completed in 1983, resulting in eight oil wells and two gas wells.

In the Valhalla region of northwestern Alberta, Texaco Canada participated in four exploratory wells completed in 1983. Near year-end, one of the wells in which the Company has a 25 per cent interest was completed as a significant light oil discovery in the Triassic Doig formation. It is located about five kilometres south of the Valhalla oil field which is currently being developed. Two of the Valhalla exploratory wells were gas discoveries, while the fourth was dry.

Additional drilling was carried out in northeastern British Columbia, where the Company participated in two wells which were dry holes, and in the Outram area of southern Saskatchewan, where a deep test well was drilled late in the year.

Frontier Areas

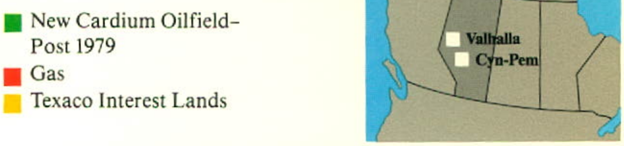
During 1983, Texaco Canada participated in the formation of AT&S Exploration Ltd. (AT&S), a joint exploration company created to explore for oil and gas on frontier lands in the north and off the east coast. Texaco Canada Resources Ltd. (TCRL) —a wholly-owned subsidiary of Texaco Canada—holds 25 per cent of the voting shares in AT&S.

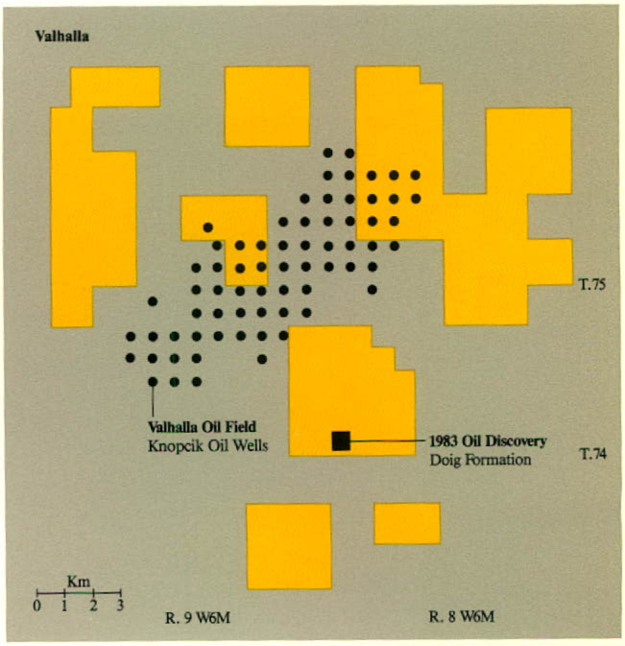
The new company's Canadian ownership of approximately 75 per cent qualifies it for the maximum Petroleum Incentives Grants offered by the federal government for exploration on Canada Lands under its jurisdiction. TCRL has farmed out a 700 000 hectare net interest in 2.8 million gross hectares of its frontier lands to AT&S. Included in the lands are three blocks in the Norman Wells area of the Northwest Territories and three blocks off the east coast, located on the Scotian Shelf, the Grand Banks and in the Newfoundland Basin.

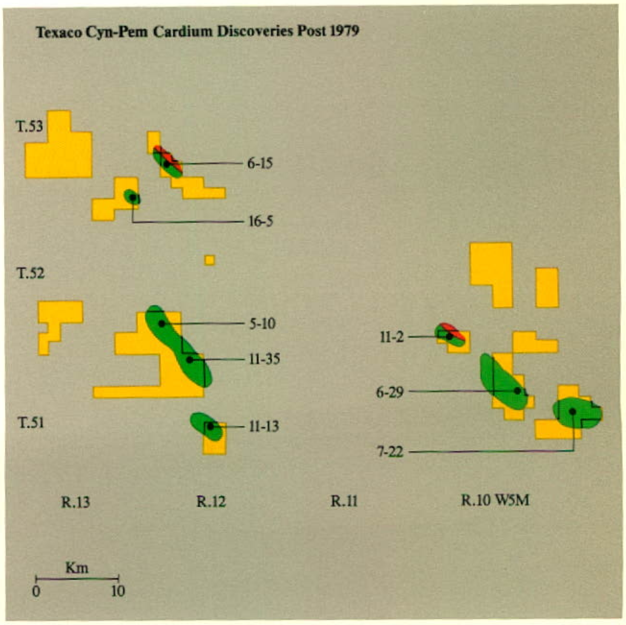
AT&S has the right to earn 50 per cent of TCRL's working interest in the blocks by carrying out exploration programs, including geophysical work and the drilling of up to 11 wells. During 1983, geophysical exploration was carried out in the Norman Wells area and on the Banquereau and Green Bank blocks. The first well in which AT&S is participating was spudded in early January, 1984 on the Banquereau block, about 400 kilometres east of Halifax.

The new company also is actively pursuing other exploration opportunities on Canada Lands, and has a number of proposals under review.

Valhalla and Cyn-Pem Areas

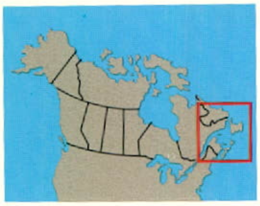


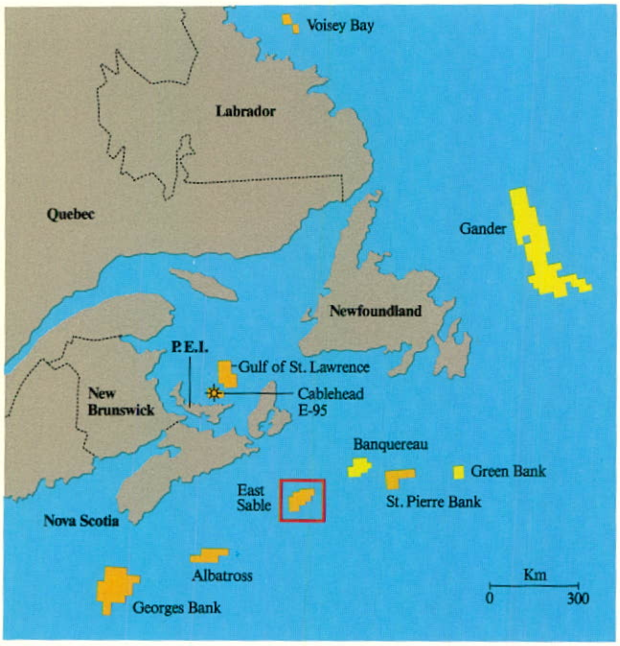


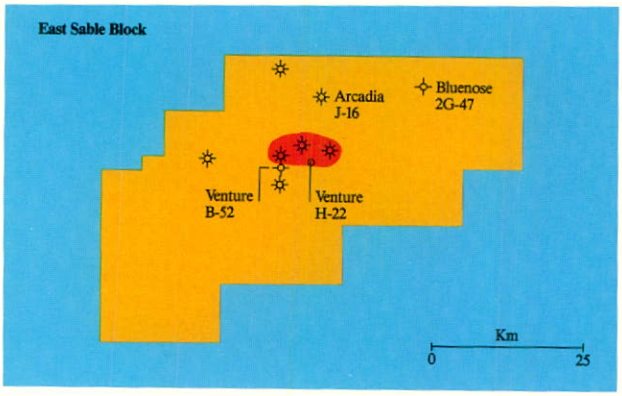


East Coast Area

- Texaco Lands Farmed Out to AT&S Exploration Ltd.
- Texaco Interest Lands
- Gas Discovery
- Dry Hole
- Testing at Year End







East Coast

Off the east coast, Texaco Canada participated in the drilling of five wells during 1983. Four were off Nova Scotia on the East Sable block, in which Texaco Canada has an 18 per cent working interest. Two of these were stepout wells on the Venture Structure and two were on separate geologic structures from the previous Venture discovery.

Natural gas was discovered in Arcadia J-16, an exploratory test located near the Venture Field. The well flowed gas at rates up to 399 000 cubic metres a day. Bluenose 2G-47, an exploratory well located 19 kilometres northeast of the Venture Field, was abandoned at a total depth of 5 797 metres.

Venture B-52, an exploratory stepout on the Venture structure, tested some gas but was subsequently abandoned because of insufficient reserves. Preparations for testing the other exploratory stepout on the structure, Venture H-22, were underway at year-end.

The Company participated in a detailed seismic program to delineate further the Venture and South Venture structures and the area adjacent to Sable Island.

The Venture field underwent continuing analysis during 1983 to establish reserves, determine economic parameters, develop proposed specifications for processing facilities, and establish the basis for marketing the gas. Production could begin in the late 1980s, depending upon results of delineation drilling, the development of gas markets, and agreement by federal and provincial governments to fiscal and regulatory terms which would allow the project to be economically viable.

The fifth east coast well drilled during 1983, Cablehead E-95 (50 per cent Texaco), was drilled on a 53 000 hectare block of Texaco land under the terms of a farmout agreement. Located in the Gulf of St. Lawrence about 30 kilometres north of Prince Edward Island, it was drilled to a total depth of 3 235 metres and abandoned after failing to encounter hydrocarbons.

Following the abandonment of the Cablehead E-95 well, the Company selectively reduced its Gulf of St. Lawrence land holdings from 1.37 million gross (685 000 net) hectares to 70 000 gross (35 000 net) hectares on February 1, 1984.

Conversion of leases to exploration agreements resulted in a net increase in Texaco Canada's year-end land holdings offshore Canada's east coast of approximately 150 000 hectares.

The jack-up rig Zapata Scotian drilling the Venture H-22 well, offshore Nova Scotia. Jack-up rigs are towed to offshore locations with the legs raised. On site, as in this photo, the legs are lowered to the sea bottom to raise the platform above water.

Donna Larsen, Texaco Drilling Supervisor, and Driller John Sedore examine a rotary drill bit at well site.

North

Seismic programs were conducted on the Norman Wells and Carcajou blocks, which were subsequently farmed out to AT&S Exploration Ltd. along with the Hoosier block.

Uviluk P-66, an exploratory well in the Beaufort Sea, was abandoned during 1983. No significant oil or gas was encountered. Uviluk P-66 was drilled through the farmout of a 105 000 hectare block. The Company's retained interest in the block is 50 per cent except in a 3 200 hectare block immediately surrounding the Uviluk well. In this area of the block the other participants earned 100 per cent of the rights to an 1 100 metre portion of a deeper zone.

In the Beaufort Sea, holdings of 6 000 hectares in which Texaco Canada held an interest were allowed to expire because neither current nor foreseeable technology will allow economic exploration of the blocks. The conversion of leases to exploration agreements in the Northwest Territories mainlands increased Texaco Canada's land holdings by about 65 000 net hectares.

Foreign

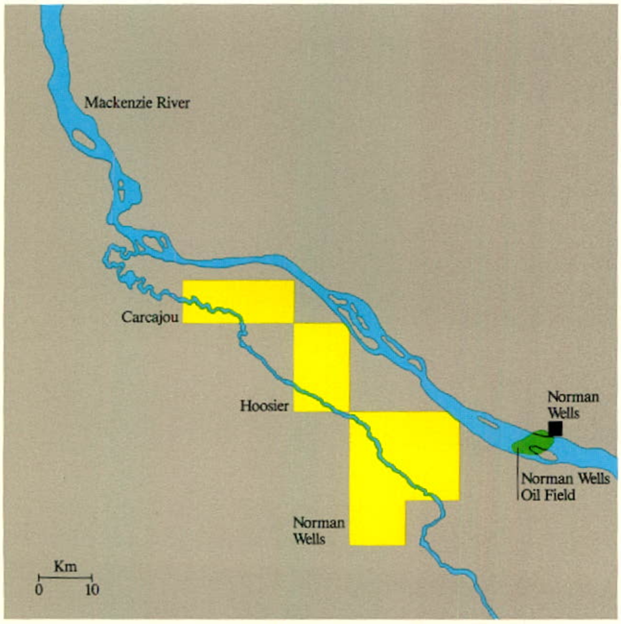
Texaco Canada continues to identify foreign opportunities in areas of significant oil and profit potential which offer a means of broadening the Company's investment program. In northwestern Guatemala, Texaco Canada acquired a 16.7 per cent interest in a 198 000 hectare block. Seismic programs were conducted on the block and an exploratory well was being drilled at year-end.

A separate block in Guatemala, containing 156 000 hectares in which the Company held a 25 per cent interest, was surrendered after exploratory drilling failed to find sufficient reserves for economic development.

The Company also is participating in negotiations to obtain exploration rights in Peru and Guinea-Bissau, where exploration is planned during 1984.

Norman Wells Area

Texaco Lands Farmed Out to AT&S Exploration Ltd.



Oil and Gas Rights

December 31	1983		1982	
	Thousands of Hectares			
	Gross	**Net**	Gross	Net
Canada				
Western Provinces	**1 199**	**725**	1 203	739
Quebec Onshore	**120**	**120**	149	131
Eastern Canada Offshore	**5 885**	**2 754**	5 273	2 578
Beaufort Sea	**106**	**53**	112	112
Other	**156**	**114**	70	49
Total	**7 466**	**3 766**	6 807	3 609
Guatemala	**198**	**33**	156	39
Total	**7 664**	**3 799**	6 963	3 648

This development well being drilled in the Wizard Lake Field, 60 kilometres southwest of Edmonton, will provide Texaco Canada with additional production from the field.

Development

Development activities are directed towards the delineation and maximum recovery of oil and gas from properties leased by the Company. This entails the drilling of development wells, the installation of gas processing facilities to optimize the recovery of natural gas liquids, the operation of oil and gas production facilities and pipelines, and the implementation of enhanced oil recovery projects to obtain maximum returns from the Company's resources.

Drilling

Development drilling in 1983 was concentrated in west-central and northwestern Alberta. Of 34 development wells drilled, 91 per cent were successful. Ten development oil wells were completed in the Cynthia-Pembina region of west-central Alberta, where the Company's exploration and development programs have been focused in recent years.

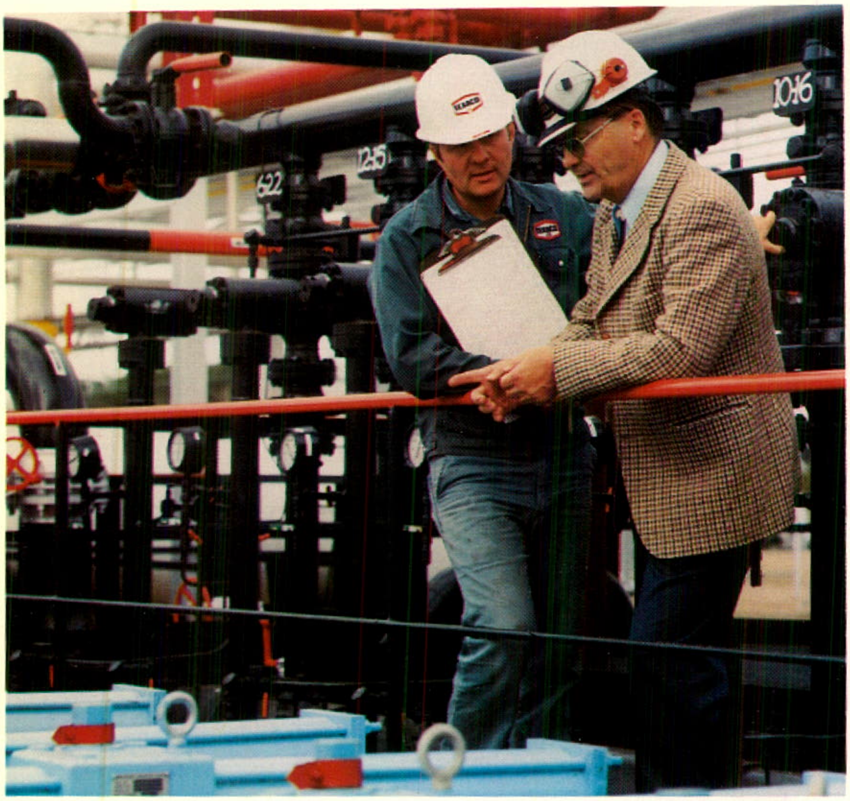
In the Valhalla area of northwestern Alberta, Texaco Canada has a 50 per cent working interest in nine development oil wells completed in the Knopcik sand. Two development gas wells were completed in the Deep Basin of northwestern Alberta.

Northwest of Edmonton, an extensive infill drilling program has been initiated in the Nipisi Unit in which Texaco Canada has a 13.3 per cent working interest.

Drilling Activity

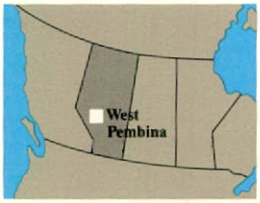
	1983		1982	
	Gross	**Net**	Gross	Net
Exploratory Wells				
Oil	**14**	**6.1**	6	4.4
Gas	**9**	**5.9**	6	5.1
Dry or Suspended	**35**	**18.9**	17	9.4
Total Exploratory Wells	**58**	**30.9**	29	18.9
Development Wells				
Oil	**28**	**18.0**	17	12.5
Gas	**3**	**1.0**	8	4.5
Dry or Suspended	**3**	**2.3**	4	2.2
Total Development Wells	**34**	**21.3**	29	19.2
Total Wells	**92**	**52.2**	58	38.1

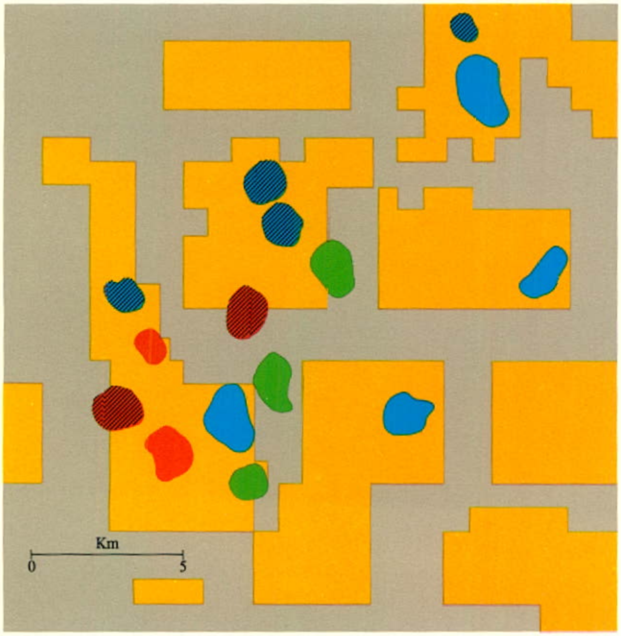
Senior Pumper Gerald Pydde (left) and Dan Claypool from Edmonton Operations discuss recent modifications to the Wizard Lake Crown "C" Battery.



West Pembina Area
Nisku Enhanced Oil Recovery Projects

- Texaco Interest Lands
- Waterflood
- Pool Under Primary Recovery
- Miscible Flood
- 1983 Projects





Enhanced Oil Recovery

Texaco Canada continued its extensive commitment to enhanced oil recovery projects in 1983, participating in the implementation of nine projects. These include three miscible floods, five waterfloods, and a pilot carbon dioxide flood. The majority of the projects are in the West Pembina area of west-central Alberta.

Largest of the 1983 projects is the Wizard Lake tertiary miscible flood, located southwest of Edmonton. The Wizard Lake field has been subjected to a highly successful secondary miscible flood since 1969. The target oil for the tertiary extension is located in a lower portion of the reservoir, which has been swept by water, but in which there is still about 30 per cent oil saturation. This oil will be displaced or stripped from the reservoir rock by injecting additional volumes of solvent and gas. The process will recover up to 4.5 million additional cubic metres of oil and is expected to result in an overall recovery factor for the pool of 96 per cent.

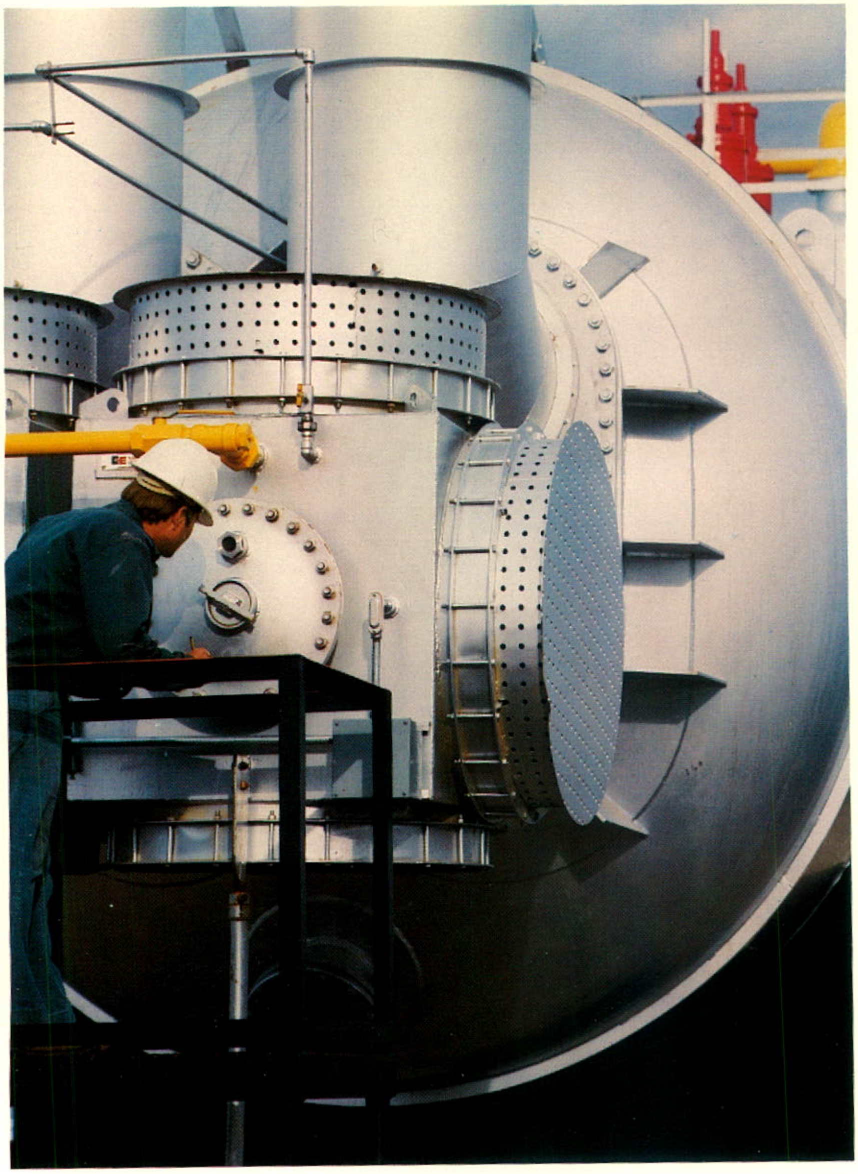
It is estimated that, in total, the nine 1983 enhanced oil recovery projects will increase the Company's reserves of crude oil by up to 6.4 million cubic metres. Most of these reserves have been recognized in the 1983 year-end figures. The remainder will be recognized in future years, commensurate with field performance.

Incremental oil production from miscible flood projects receives the New Oil Reference Price and is subject to reduced royalty rates. As well, various other provincial and federal incentives are in place to encourage investment in enhanced oil recovery. Additional projects are in the design stage for implementation in 1984 and 1985.

Production Facilities

Texaco Canada continued to upgrade existing facilities and install new equipment to maintain production efficiency and optimize recovery of its oil reserves. Major installations were added at two of the Company's important fields, Bonnie Glen and

Texaco Canada employee checks the burner flame on the emulsion treater at the Wizard Lake Crown "C" Battery. Oil and water are separated in the treater.



Wizard Lake. In order to compensate for declining reservoir pressures in the Bonnie Glen field, the Company is installing submersible pumps in producing wells to optimize oil production. Additional pumps will be installed in 1984 and 1985.

The Bonnie Glen and Wizard Lake fields are experiencing increased water production as the fields reach a mature stage of production. Equipment to separate the oil from the water has been installed at the two fields. The produced water is returned to the reservoirs to assist in maintaining pressure.

Gas Plants

Texaco Canada in 1983 continued to develop its established gas reserves and to improve its liquid extraction capability by participating in the construction of four significant gas plant projects. Two were completed during the year and two were under construction at year-end.

The Wabasca compression and gas gathering facilities, located 270 kilometres north of Edmonton, were completed in June. The facilities, wholly-owned by Texaco, have a processing capacity of 170 000 cubic metres a day.

At the Brainard Gas Plant northwest of Grande Prairie, installation of new sour gas handling facilities was completed. Texaco Canada's 50 per cent share increases the Company's new gas processing capability by 1.1 million cubic metres per day.

The expansion of the Elmworth Plant, also located northwest of Grande Prairie, will provide deep cut capability to remove ethane and heavier natural gas liquids from raw gas. Texaco Canada's share of the liquids recovered will be 830 cubic metres a day. When the plant expansion becomes operational in 1985, Texaco Canada's 31.6 per cent working interest will also provide the Company with added gas processing capability of 1.6 million cubic metres a day.

In the Brazeau River area southwest of Edmonton, Texaco Canada has a 15.1 per cent overall interest in a sour gas plant now in the initial stages of construction. The facility's projected May 1985 startup will increase the Company's raw gas processing capacity by 106 000 cubic metres a day and liquids production by about 129 cubic metres a day.

Explosive charges create ditch in bed of North Saskatchewan River for laying of a natural gas liquids pipeline.

Production

Liquids

Texaco Canada's crude oil and natural gas liquids production increased slightly over 1982, to an average of 23 400 cubic metres per day. The increased production, despite restrictions on exports during the early part of 1983, was due principally to higher industry crude oil exports authorized during the latter part of 1983.

The amount of oil produced from the West Pembina area increased as recent discoveries were placed on production and enhanced oil recovery projects were initiated.

During the final quarter of the year, injection of natural gas liquids (NGL's) increased substantially as three miscible flood projects were implemented. The resulting reduction in NGL sales was more than offset by the increased crude oil production resulting from the miscible floods. The injected NGL's will, for the most part, be recovered in the future.

Natural Gas Sales

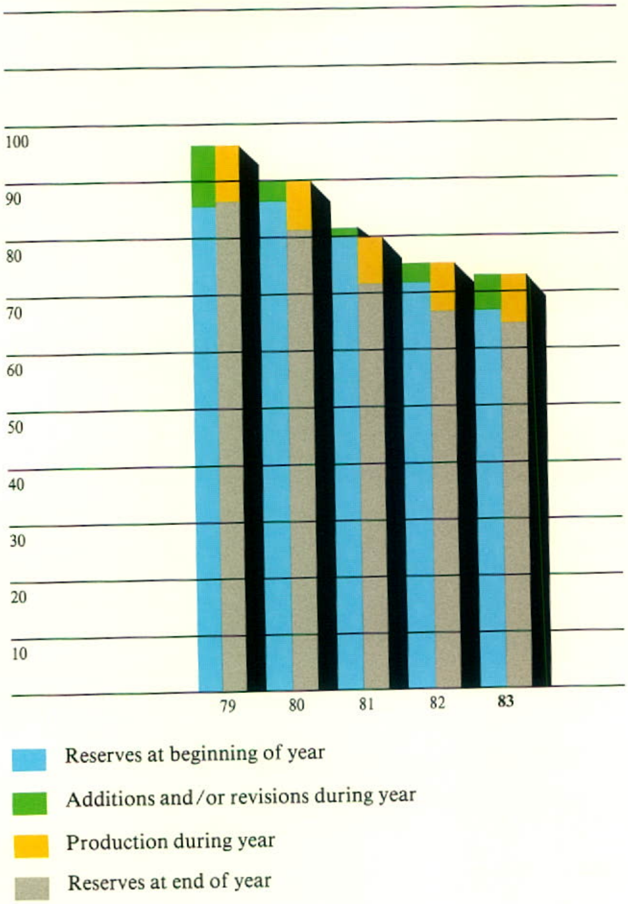
Natural gas sales by Texaco Canada declined 12.8 per cent from 1982 levels, to 3.2 million cubic metres per day. The reduction is attributable to decreased demand in both the domestic and export markets. The continuing recession, conservation and unusually warm weather at the beginning of 1983 in both eastern Canada and the United States all contributed to the decline in demand. In addition, government regulated non-competitive pricing of gas severely reduced exports to U.S. markets.

Gross Production of Crude Oil and Natural Gas Liquids

	Thousands of Cubic Metres Daily	
	1983	1982
Crude Oil		
Alberta		
Bonnie Glen	**8.3**	7.8
Wizard Lake	**6.3**	6.5
Pembina	**2.7**	2.5
Swan Hills	**1.3**	1.4
Other	**1.9**	2.0
Total Alberta	**20.5**	20.2
Other Provinces	**.3**	.3
Total Crude Oil	**20.8**	20.5
Natural Gas Liquids	**2.6**	2.5
Total Crude Oil and Natural Gas Liquids	**23.4**	23.0

Reserves

Replacement of Gross Reserves, Crude Oil and Natural Gas Liquids
Millions of cubic metres



At year-end, gross proved reserves of crude oil and natural gas liquids were estimated at 64.9 million cubic metres, a reduction of 3.4 per cent from the 1982 total.

Additions, which totalled 6.4 million cubic metres, were primarily due to implementation of enhanced oil recovery projects, notably the Wizard Lake tertiary miscible flood. Production of 8.5 million cubic metres was the major 1983 deduction.

Gross proved recoverable reserves of natural gas at the end of 1983 were estimated to be 62.8 billion cubic metres, a decline of 500 million cubic metres or less than one per cent from year-end 1982. The decrease resulted from production and downward revisions which, in total, exceeded additions.

Estimated Proved Reserves

December 31	**1983**		1982	
	Millions of Cubic Metres			
	Gross	**Net**	Gross	Net
Crude Oil	**50.8**	**33.8**	53.1	35.4
Natural Gas Liquids	**14.1**	**10.0**	14.0	9.9
Total Liquids	**64.9**	**43.8**	67.1	45.3
	Billions of Cubic Metres			
Natural Gas	**62.8**	**44.4**	63.3	44.7

Net reserves are the Company's share of reserves after deduction of royalties that will be due to others when the oil, gas or natural gas liquids are produced. Royalties on provincial and federal lands are subject to change by legislation or regulation and are generally partly dependent on selling price. Net reserves are therefore estimated annually, following generally accepted guidelines, to reflect the current regulations and pricing outlook.

Dr. Declan B. Livesey, Texaco Canada Research Associate, prepares to operate the Core Evaluation Facility (CEF) at the Alberta Research Council's Oil Sands Research Centre in Edmonton. The CEF subjects sample cores from the Athabasca tar sands to high pressure and temperature.

Oil Sands

Texaco Canada's Fort McMurray pilot project, which has been operating since 1972, is directed towards the development of methods for the recovery of bitumen, a thick, tar-like hydrocarbon, from the oil sands. Some 90 per cent of the Alberta oil sands are too deep for open pit mining operations. Therefore, technology must be developed whereby the bitumen is separated from the sands and moved to the surface through well bores while leaving the sand in place. This method of production is called in-situ recovery.

Three groups, or patterns, of wells have been drilled at the Fort McMurray project, each including production, injection, and observation wells. Various fluids are injected to cause the bitumen to flow. Pattern III, drilled in 1980-81, is comprised of three long, parallel, horizontal wells which were drilled to test recovery from horizontal drain holes.

During 1983, activity was concentrated on Patterns II and III. In Pattern II, steam injection was terminated, and injection of hot water was initiated as a supplementary recovery process. Encouraging production was achieved from one of the horizontal wells in Pattern III. Two of the wells have been recompleted in preparation for another production test.

Texaco Canada's in-situ field work is complemented by a number of laboratory research programs, including proprietary research carried out by the Alberta Research Council.

The Company's holdings of 227 000 net hectares of oil sands leases and permits in Alberta contain an estimated 12 billion cubic metres of bitumen. No reserves are attributed to this resource because no portion of the bitumen in Texaco Canada's oil sands land holdings is yet economically recoverable.

Minerals

Texaco Canada stepped up its exploration for uranium in Saskatchewan in 1983, entering into three additional joint venture agreements on several properties within the Athabasca Basin of northern Saskatchewan. Exploration during 1983 on these properties included geophysical surveys and drilling programs.

The Company has earned interests in two of these joint ventures–one-third in 104 000 hectares at Hatchet Lake and 15.1 per cent of the 132 000 hectare McArthur River Project. By funding exploration, Texaco Canada also will earn a 10 per cent interest in the 86 000 hectare Studer-Umpherville-Moore property.

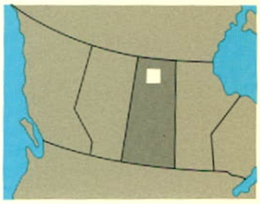
These joint ventures are close to the successful Key Lake Mine which has reserves of close to 80 000 tonnes of uranium oxide.

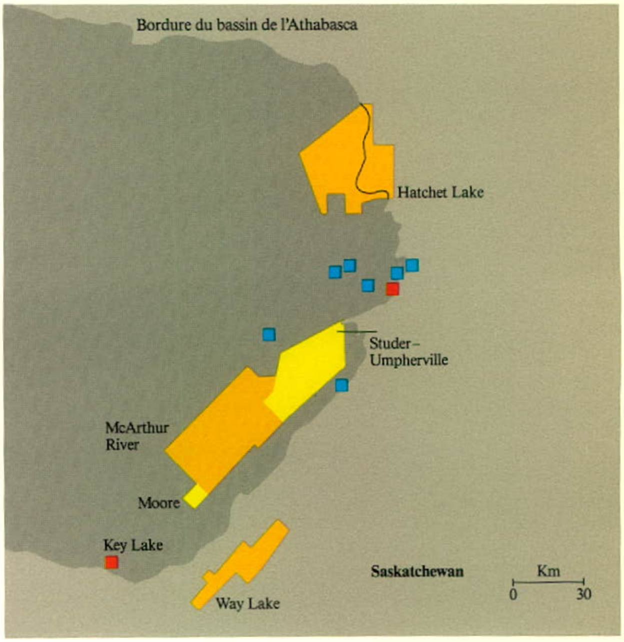
Mineral Interests

December 31	1983		1982	
	Thousands of Hectares			
	Gross	**Net**	Gross	Net
Oil Sands Rights				
Alberta	**234**	**227**	238	232
Coal Leases				
Alberta	**42**	**41**	44	44
Mineral Prospecting Rights				
Saskatchewan	**271**	**66**	99	36
Northwest Territories	**7**	**2**	25	7
Yukon and British Columbia	**6**	**6**	5	5
Total	**284**	**74**	129	48

Saskatchewan Uranium Exploration Joint Ventures

Texaco Interest Properties
Texaco Option Lands
Uranium Mine
Uranium Occurrences





Marketing

Productivity and consolidation were the bywords in 1983 as total industry sales of petroleum products in Canada fell by seven per cent, following earlier declines of 10.5 per cent in 1982 and 6.6 per cent in 1981. The return on marketing and refining operations was generally unsatisfactory, reflecting industry-wide problems of unstable prices, higher costs, and lower volumes.

Texaco Canada responded to the declining demand for refined products by carefully analyzing all of its downstream operations and implementing measures to improve efficiency and reduce costs. These include:

Modernization and rationalization of service stations.

Computerization of several operations, ranging from service station credit card verification to refinery process control.

A decision to close the Edmonton refinery.

Consolidation of supply points.

Increased automation of distribution processes.

Negotiation of reciprocal crude oil processing arrangements to reduce costs.

From left, Norman E. Taylor, Vice-President, Marketing; J. Lee Morrison, Executive Vice-President; John M. Murray, Vice-President and General Manager, Refining; Stuart J. Walker, Vice-President and General Manager, Supply and Distribution.

Texaco Canada's sales of petroleum products averaged 28 400 cubic metres daily during 1983 compared with 28 000 cubic metres daily in 1982, an increase of 1.3 per cent. Sales were considerably better than the industry average in the face of lower consumer demand caused by conservation measures, federal and provincial government "off-oil" programs, and high taxes on products (particularly gasoline).

The general surplus of refined products during the year created fierce price competition in the market place, especially for retail gasoline in Ontario and Quebec.

The Company's rationalization program for service stations continued during 1983 as low-volume uneconomic outlets were closed. The total number of Texaco Canada retail outlets was reduced from 2,769 to 2,661 as 141 outlets closed and 33 new service stations were opened. This program will continue to be a major marketing strategy.

Texaco Canada's service stations located in large urban areas began adopting a dramatic "new look," highlighting the Texaco Star with modern graphics to enhance sales by generating a powerful visual impact.

The Company's Operations Centre introduced major programs to improve the efficiency of the distribution system across Canada. The Automated Terminal Operation project at the Calgary sales terminal introduced micro processors to automate several bulk station operations, such as gate security, safety devices, tank truck loading, and the receipt of product into storage tanks.

The installation of point-of-sale transaction terminals at high volume service stations across Canada was completed during the year. This unique system speeds customer service by providing instant

Home heating oil driver Robert Boniface makes delivery from truck featuring Company's new graphics.

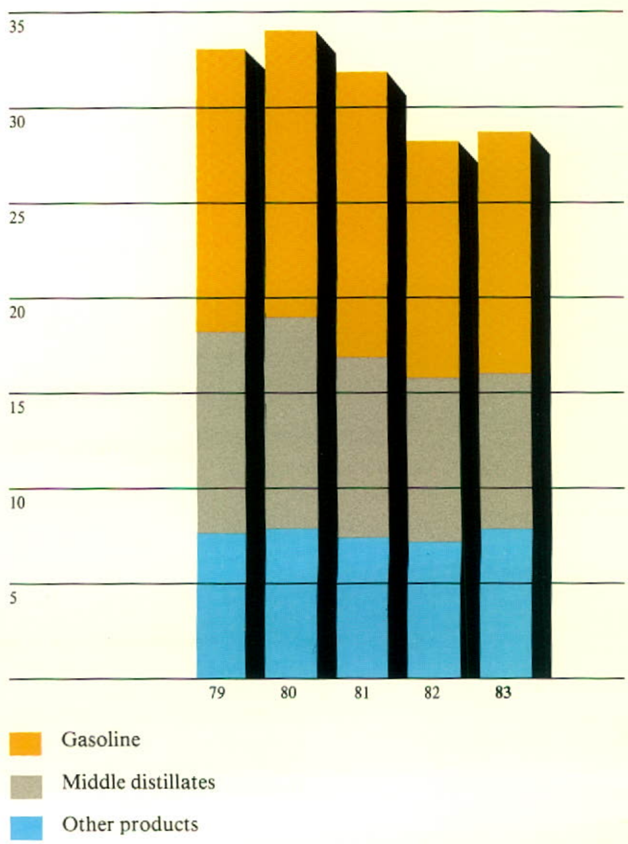
Ray van Winkle, Field Supervisor, discusses new fuel-efficient "Mectron" oil burner at Energy Lifestyle Show in Toronto.

credit checking of Texaco Canada credit card transactions and provides significant savings through the reduction of overdue accounts and of problems caused by stolen and delinquent cards.

Other productivity improvements resulted from the introduction of new on-line pricing and invoicing and accounts receivable systems. The two systems provide wholesale customers with more accurate and timely account information.

The Company's retail fuel oil division has begun marketing a new "Mectron" oil burner to help homeowners improve the efficiency of their home heating systems. The burner, which can reduce heating costs by up to 24 per cent without replacement of the existing furnace, is part of Texaco Canada's continuing effort to provide quality service to its home heating oil customers.

Sales of Petroleum Products
Thousands of cubic metres daily



Refining

Josiah Ho, Control Operator, monitors refining processes at Nanticoke Plant computer terminal.

Crude runs at the Company's refineries averaged 21 300 cubic metres daily in 1983, a decline of 9.3 per cent from the level of 23 500 cubic metres daily in 1982. Refinery utilization was at 93.6 per cent compared to 67.9 per cent in 1982 because of the closing of the Montreal refinery in 1982. Production of finished lubricating oils and greases increased by 1.7 per cent over 1982.

The use of computer technology in the Company's refineries increased during the year as part of a continuing drive to maximize efficiency by reducing costs in every area of operation. A computerized maintenance planning and storehouse control system to improve productivity and cost control was being installed at Nanticoke Plant at year-end, and inventory and manufacturing scheduling systems were installed in the lubricating oil blending plants at Toronto and Edmonton.

A computer-centred instrument system had been put into operation at Nanticoke Plant by year-end. It monitors refining processes and will eventually adjust temperatures, pressures and flow rates to optimum levels, providing improved yields and energy savings. Long range energy conservation programs being implemented will further reduce operating costs.

A program to install cost-efficient electric motors to replace steam turbines was undertaken at Nanticoke Plant. An upgrading of heaters, heat exchangers, pumps and other equipment was underway as the energy efficiency and cost efficiency of all refinery operations are continuously analyzed.

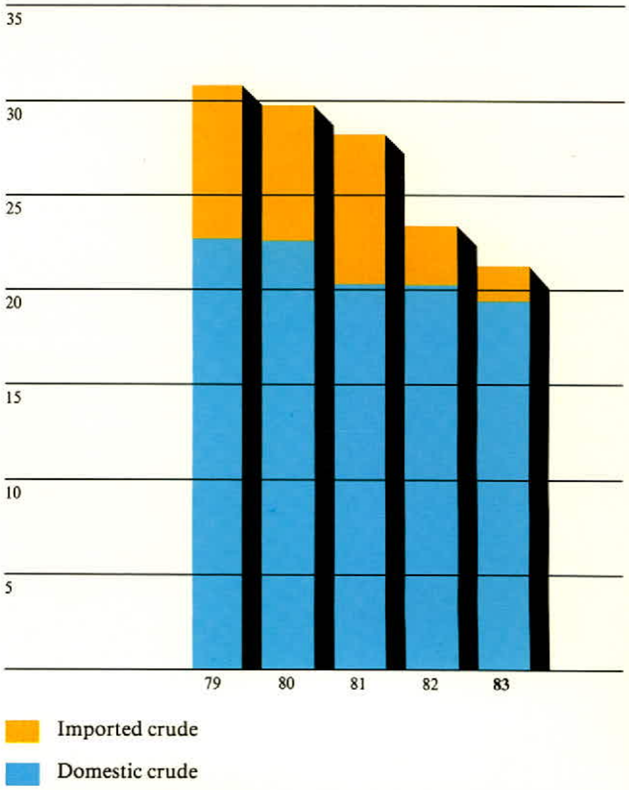
Planning continued on various ways to increase the flexibility of the refineries to meet changes in product demand.

The Nanticoke greenhouse operation, which utilizes waste heat from refinery process units to grow vegetables, began commercial production on a joint venture basis following completion of the research project by the University of Guelph.

The Company announced in November that it would cease refining operations at Edmonton Plant in the spring of 1984. The lubricating oil blending facility at the site will continue operating.

The decision to close the plant was taken because the refinery is too small to continue operating competitively and cannot be expanded economically.

Refinery Runs
Thousands of cubic metres daily



The Company will continue to supply products to its western Canadian customers after the closing of Edmonton Plant under supply arrangements negotiated with Gulf Canada Products Company, which will process Texaco Canada requirements in its Edmonton refinery. The processing agreement, which provides for increased volumes as required in the future, should be in full operation by mid-1984.

In eastern Canada, with manufacturing operations having ended at Montreal Plant in 1982, a key goal was the reduction of the cost of shipping refined products from Nanticoke Plant in Ontario to the Quebec market. The Company negotiated a long term processing arrangement with Gulf Canada Products Company in which Texaco Canada's Nanticoke refinery will supply product to Gulf in Ontario, and Gulf's Montreal refinery will supply product to Texaco Canada in Montreal.

Another exchange agreement, involving Gulf's Montreal refinery and Texaco Canada's Halifax Plant ensures that Texaco Canada's Quebec demand is manufactured in the Province of Quebec and that transportation costs are reduced to the maximum extent.

The Supply & Distribution Department and the Marketing Department's Operations Centre conducted a study of the Company's national product supply terminal network in 1983, which led to the closing of four terminals. The viability of five others was improved through the negotiation of storage and loading arrangements with other companies. This program is providing substantial cost reductions.

The Company implemented a computer simulation/optimization program in 1983 to improve the profitability of refining, marketing and transportation operations. The program, which had been under development for more than a year, can evaluate various options such as alternate refinery modes of operation, shifts in crude slate, changes in sales levels by market and class of trade, alterations in exchange, processing or purchase agreements, and alternate product distribution patterns. The program encompasses downstream functions from feedstock selection to market disposition, enabling the Company to effectively evaluate the economic impact of a change in marketing, refining or supply operations.

The Company's supply operations in 1983 involved the transportation of an average of 44 500 cubic metres of crude oil and petroleum products daily, compared with 49 200 cubic metres daily in 1982. This total volume included the movement of 21 900 cubic metres of finished products daily to customers in Company-owned and leased vehicles and ships or in equipment owned by outside haulers. The crude oil and natural gas liquids required by the Company in its refining and supply operations necessitated the transportation by pipelines, ships, and other carriers of 22 600 cubic metres daily.

Company-owned lake and coastal tankers carried an average 2 600 cubic metres of crude oil and products daily. Vessels chartered by the Company transported an additional 2 800 cubic metres daily.

The Alberta Products Pipeline system, in which Texaco Canada holds a 20 per cent interest, transported a daily average of 7 400 cubic metres of petroleum products.

Trans-Northern Pipelines Inc., one-third owned by Texaco Canada, carried 23 700 cubic metres of petroleum products daily. Through this system, products can be delivered to the Ottawa area from refining centres in either Montreal or Nanticoke.

A daily average of 12 300 cubic metres of imported crude oil was moved through the Montreal Pipe Line system, 16 per cent owned by Texaco Canada, to refineries in Montreal from its east coast terminal facilities in Portland, Maine.

Federated Pipe Lines Ltd., 50 per cent owned by Texaco Canada, carried 21 500 cubic metres daily of crude oil from Alberta producing fields to Edmonton refineries.

Texaco Canada's Rimbey-Edmonton Oil Pipeline carried an average of 25 000 cubic metres of crude oil daily from central Alberta to Edmonton.

The Company's commitment to physical fitness was extended to its product tankers Texaco Brave and Texaco Chief in 1983 as crews of both vessels were encouraged to participate in comprehensive fitness programs. Fitness and nutrition assessment, exercise counselling, and the installation of gymnasium equipment aboard ship made Texaco Canada a pioneer in this field in the Canadian marine industry.

The smallest of the Company's three tankers, the Texaco Warrior, was sold in 1983 after having been laid up in 1982.

Public and Government Relations

Texaco Canada's internal and external communications were increased in 1983 as circumstances and events attached greater importance to the Company's relationships with the general public and with the many special interest groups within our society.

The Company's social commitment was reflected in a wide variety of activities in 1983, including:

Counselling and other assistance for employees affected by the shutdown of Montreal Plant and the planned closing of Edmonton Plant.

Increased emphasis on industrial hygiene.

Consolidation of various responsibilities in a new Public and Government Relations Department.

Increased contributions to worthy organizations.

Sponsorship of radio broadcasts of performances of the Metropolitan Opera and the Canadian Opera Company.

The Public and Government Relations Department was formed during the year to focus the Company's interest in communicating more effectively with the diverse groups interested in Texaco Canada affairs. Existing departments such as Public Affairs and Environmental Affairs were incorporated into the new department and two new related groups were formed—Government Relations, and Advertising and Publications. The latter group was given responsibility for corporate advertising and internal communications.

Various functions such as Linguistic Services, Library Services, Donations and Contributions, and Sponsorships and Corporate Memberships were amalgamated by transferring key personnel from various departments.

Heightened interest in petroleum industry activities resulted in increased communications during the year with the Company's principal publics, including employees, governments, customers, shareholders, the investment community, the media, and the general public.

The Company's views on aspects of the National Energy Program and other government policies, decontrol of domestic crude oil prices, frontier development, and product prices and gasoline price wars were expressed through several channels. These included newspaper and television interviews, press releases, speeches, and articles in Company and external publications.

Texaco Canada's determination to voice its views on important petroleum industry affairs led to the activation of a Speakers' Bureau. Several senior managers had received training at year-end in public speaking and media interview techniques.

The Company increased its financial support to organizations across Canada in the fields of community service, education, health, culture and youth work. It also was an early supporter of Canada 1, Canada's entry in the America's Cup 12 metre yacht racing competition.

Considerable publicity resulted from the Company's sponsorship of "The Texaco Mile," which brought the world's elite runners to Toronto for a race that was covered nationally by the CTV television network. Additional events in the program included a celebrity/media race and a Texaco Canada Employees' race.

Jack Brill, Manager, Marketing Real Estate, and a member of the Texaco Canada Speakers' Bureau, hones communication skills at training session.

The Company in 1983 began its 44th consecutive year of sponsoring Metropolitan Opera radio broadcasts on the Canadian Broadcasting Corporation's English and French language networks. It also sponsored performances of the Canadian Opera Company.

Texaco Canada's Government Relations activities promoted the development of co-operative mutually beneficial relationships between the Company and all levels of government. Monitoring government initiatives and consultation with policy-makers are major activities. The objective is to avert counter productive regulatory actions through consultation with government agencies on issues or technical details related to the constantly changing business environment.

In Environmental Affairs, the Company continued its program to upgrade its air and water protection facilities. Capital expenditures exceeded $14 million in 1983.

Texaco Canada made submissions to government bodies on several environmental issues affecting the oil industry. In a brief to the Ministry of the Environment, the Company proposed a gasoline lead phasedown program which would achieve a significant reduction in lead emissions to the environment at a reasonable cost.

The Company also continued to participate in industry consultations with all levels of government on many other environmental issues such as acid rain, auto emissions, spill cleanup legislation, waste disposal and toxic substances.

Competing in The Texaco Mile employees' race are (from left) Daryl Lake, Darleen Pattison, Suzette Passailaigue, Sylvia Robinson, and Sheila O'Dell.

Art Heath, Senior Administrator Human Resources, counsels employee affected by the announced shutdown of Edmonton Plant.

Employee Relations

Texaco Canada had a total of 3,904 employees at year-end, compared with 4,418 at December 31, 1982. Payroll and benefit plan costs of $174 million were 5.7 per cent higher in 1983 than in 1982.

Relocation counselling for employees affected by the shutdown of Montreal Plant in late 1982 continued until the end of August, 1983. Counsellors succeeded in finding jobs outside the Company for 138 employees. At the end of 1983, 80 per cent of the 424 affected employees were working or receiving pensions.

Several specially-trained employees were assigned as counsellors to help the 225 employees affected by the announced shutdown of the Edmonton Plant. Guidance was offered to employees in their job search and various services related to this activity were provided. A separation plan based on age, years of service and job level was offered, similar to the one developed for the Montreal Plant shutdown.

Industrial hygiene received greater emphasis as environmental monitoring was extended to the office workplace. Tests were conducted at several locations to ensure that lighting conditions were adequate and to ensure that exposure levels to video display terminals did not constitute a health hazard.

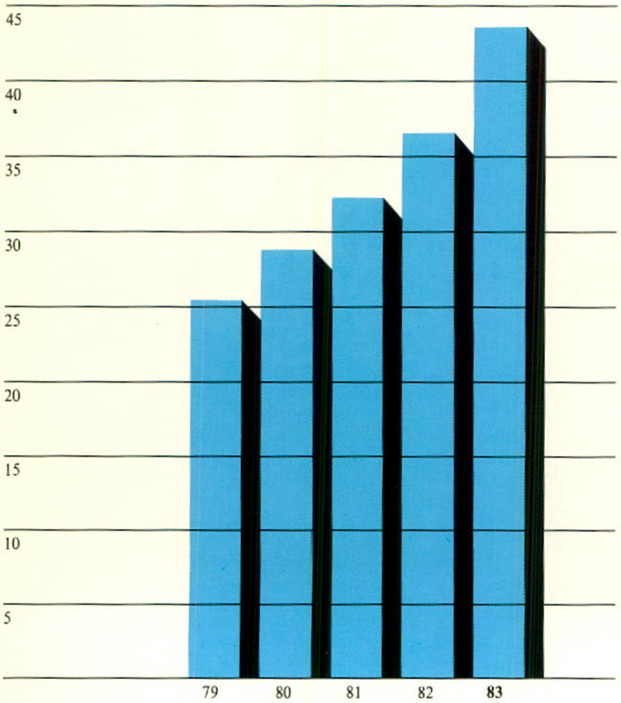
At year-end, 101 children of employees held active scholarships awarded under the Texaco Canada Merit Scholarship Program. The scholarship provides tuition assistance to the selected applicants who successfully complete each year towards a four year degree.

Forty-two employees received their 25-year Service Awards in 1983. There are 631 active employees with 25 or more years of Company service.

Pre-retirement counselling seminars were offered to selected employees, on a trial basis.

During the year 192 employees retired under the Company's retirement plans.

Salaries, Wages and Benefits per Employee
Thousands of dollars



Index to Financial Section

Net Income

Consolidated net income for the year ended December 31, 1983 was $344 million compared with $275 million in 1982 and $316 million in 1981. Net income per common share was $2.74 in 1983 compared with $2.15 in 1982 and $2.45 in 1981.

The increase in net income for 1983 compared with 1982 and 1981, was mainly due to increased crude oil and natural gas liquids production, lower provincial royalty rates on crude oil production, and higher prices for crude oil and natural gas liquids. These factors were partially offset by reduced natural gas sales volumes, increased expenses, and lower petroleum product margins caused by very competitive pricing conditions which were prevalent through most of 1983. Despite aggressive expense reduction programs implemented in 1983, expenses, including the Petroleum and Gas Revenue Tax (PGRT), were higher compared with the previous two years. PGRT, which is non-deductible for income tax purposes, increased to $169 million from $135 million in 1982 and $72 million in 1981.

Net income for 1982 included charges associated with the shut-down of surplus refinery capacity, principally the Montreal East plant, and the favourable impact of an upward revaluation of inventory due to a revision in estimates of the crude oil component included in inventory. The net effect of these items was not significant to the results for the year 1982. Net income for 1981 included inventory profits arising from the implementation of rate changes in the federal Petroleum Compensation Charge. The effect of these changes resulted in increased net income in 1981 of approximately $33 million, or $0.27 per common share.

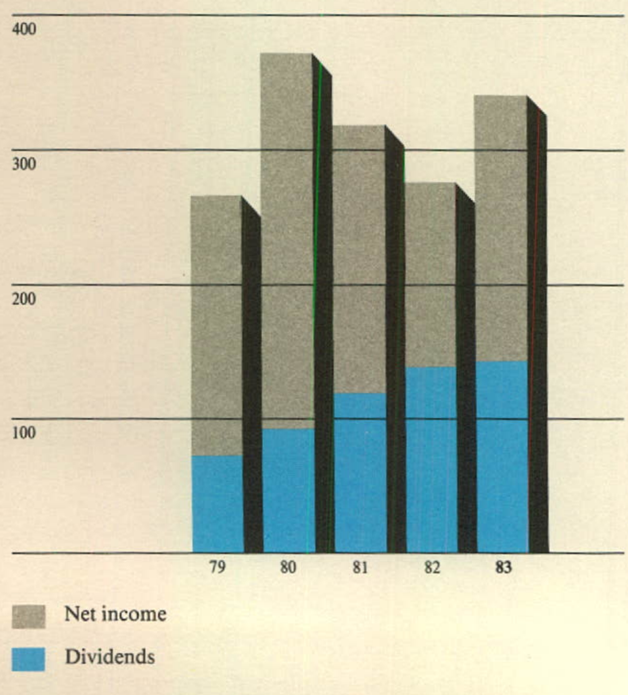
A discussion of the impact of changing prices on the Corporation's results of operations and financial position is set out on pages 45 and 46.

Revenues

Revenues amounted to $5,726 million in 1983, $4,842 million in 1982 and $4,461 million in 1981. These increases resulted from higher prices for crude oil and natural gas liquids as well as lower royalty rates for crude oil in 1983 and 1982. Prices for petroleum products, although higher in 1983 than in previous years, did not fully recover cost increases due to fierce competition in the marketplace especially for retail gasoline in Ontario and Quebec.

Production of crude oil and natural gas liquids increased over the previous two years. The increased production was due principally to higher industry crude oil exports authorized during 1983. In 1983 petroleum product sales volumes were marginally higher than 1982 levels, but 1982 volumes declined 11.3 per cent compared with 1981, and reflect the continued reduction in consumer demand, federal and provincial government "off-oil" programs and high taxes on products, particularly gasolines.

Net Income and Dividends
Millions of dollars



Costs and Operating Expenses

Costs and operating expenses, including selling, general and administrative expenses, amounted to $4,417 million in 1983, compared with $3,681 million in 1982 and $3,360 million in 1981. Higher prices paid for supplies of crude oil, other raw material and labour, principally contributed to these higher costs.

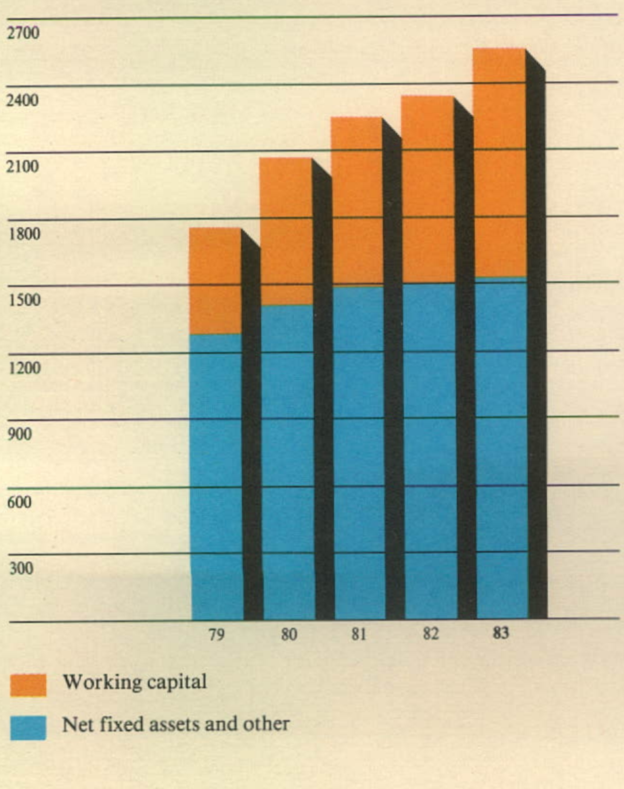
These expenses as a percentage of revenues were 77.1 per cent in 1983, compared with 76.0 per cent in 1982 and 75.3 per cent in 1981. Selling, general and administrative expenses, as a percentage of costs and operating expenses, were 4.1 per cent in 1983, 4.6 per cent in 1982 and 4.5 per cent in 1981.

Dry hole expenses decreased to $26 million in 1983, from $38 million in 1982 and $31 million in 1981. During 1983, 38 exploratory and development wells were declared dry as opposed to 21 wells in 1982 and 25 wells in 1981. Dry hole expenses in 1982 included the write-off of three wells in Guatemala.

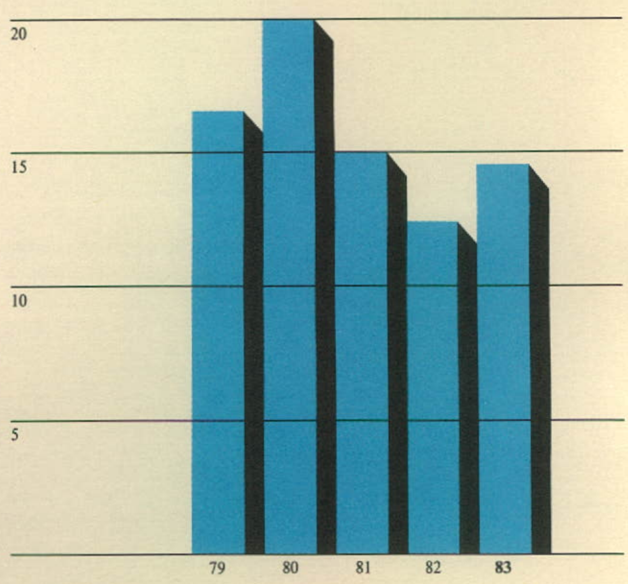
Depreciation, depletion, and amortization charges were $83 million in 1983, $72 million in 1982 and $64 million in 1981. The increase in 1983 is due principally to higher amortization of non-productive leases, while the increase in 1982 over 1981 reflects the increased capital expenditures.

The Corporation announced in November 1983 that its Edmonton Refinery would close in the Spring of 1984 because it was too small to operate competitively in the changing market and expansion was not economically viable. Also, in February 1984, the Corporation announced the intended closure of its refined products terminal in Montreal East about mid-1984 which was necessary because it was inefficient to operate as a terminal. Texaco Canada will supply refined products to its customers in Alberta and Quebec under a long term supply arrangement with another refiner. Texaco Canada, in turn, will supply that refiner with refined products in Ontario. These actions will provide increased refining capacity and more efficient distribution facilities to meet anticipated growth in demand for refined products.

Capital Employed
Millions of dollars



Rate of Return on Capital Employed
Percent



Taxes and Crown Royalties

Taxes and Crown royalties, including taxes collected for governments, amounted to $1,885 million in 1983, $1,883 million in 1982 and $1,801 million in 1981. The aggregate amount of these taxes in 1983 was equivalent to about 5.5 times the net income of the Corporation and approximately 13 times the amount that preferred and common shareholders received as dividends.

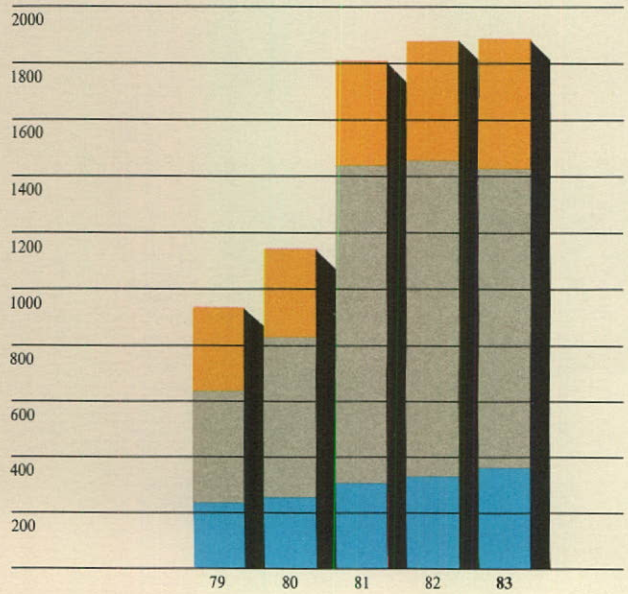
Income taxes increased to $446 million in 1983 from $389 million in 1982 and $370 million in 1981. The effective income tax rate was 56.5 per cent in 1983, 58.6 per cent in 1982 and 53.9 per cent in 1981. The decrease in the effective tax rate in 1983 compared to 1982 was mainly due to lower provincial royalty rates partially offset by an increase in the Petroleum and Gas Revenue Tax (PGRT). The increase in 1982 compared to 1981 was principally due to an increase in the PGRT. Neither Crown royalties nor PGRT are deductible in computing taxable income. PGRT increased to $169 million in 1983 from $135 million in 1982 and $72 million in 1981 as a result of higher prices, volumes and effective PGRT rates.

The Petroleum Compensation Charge amounted to $256 million in 1983, $391 million in 1982 and $513 million in 1981. The decrease of $135 million in 1983, compared to 1982, was attributable to a lower rate effective January 1983 and reduced crude oil receipts at the refineries. The decrease of $122 million in 1982, compared to 1981, was a result of reduced crude oil receipts at the refineries.

Crown royalties amounted to $361 million in 1983, $335 million in 1982 and $289 million in 1981. The increases were due mainly to higher crude oil and natural gas liquids prices. The increase in 1983, however, was partially offset by lower provincial royalty rates and reduced royalties during 1983 due to the Corporation's aggressive enhanced recovery projects.

Motor fuel, excise and federal sales taxes increased substantially since 1980. These increases resulted from the imposition by the federal and most provincial governments of motor fuel and sales taxes on an ad valorem basis. On this basis these taxes are calculated as a percentage of net selling price rather than as a fixed amount per volume. A detailed analysis of taxes and Crown royalties is contained in the Five-Year Review on page 30.

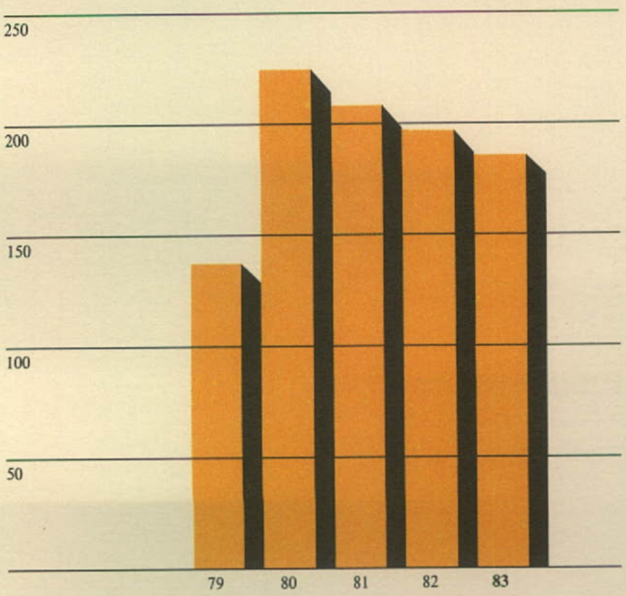
Taxes and Crown Royalties
Millions of dollars



Capital and Exploratory Expenditures

The Corporation's capital and exploratory expenditures amounted to $187 million in 1983 compared to $197 million in 1982 and $209 million in 1981. The decrease in these expenditures was principally due to the continuing negative effects of the National Energy Program. Notwithstanding improved price structures for oil from enhanced recovery projects and reduced royalty rates initiated by governments, cash flows available to the industry remain inadequate to finance more ambitious programs. However, during 1983, the Company joined with two Canadian firms to create AT&S Exploration Ltd. to explore on our land and other frontier lands. Since it is a 75 per cent Canadian-owned company, it is eligible for maximum grants under the federal government's Petroleum Incentives Program. An aggressive program by this new resource company is underway.

Capital and Exploratory Expenditures
Millions of dollars



Capital and Exploratory Expenditures

	(Millions of dollars)		
	1983	1982	1981
Exploration and Production	**$128**	$134	$140
Manufacturing	**18**	28	34
Marketing	**36**	30	31
Other	**5**	5	4
Total capital and exploratory expenditures	**187**	197	209
Deduct: Exploratory expenditures charged against current income	**52**	56	49
Total expenditures capitalized	**$135**	$141	$160

Liquidity and Capital Resources

The Corporation continues to maintain and improve its strong liquidity position, as evidenced by the level of working capital, the current ratio, and other generally applied balance sheet and cash flow ratios. It is anticipated that the Corporation's strong liquidity position will continue in 1984 and that working capital will provide adequate support for the ongoing operations.

In addition to the strong year-end 1983 cash, cash investments and marketable securities position, the Corporation's liquidity is enhanced by the nature of its accounts receivable and inventories. Rapid turnover of accounts receivable resulting from sound credit and collection policies and prudent collection follow-up, make these receivables highly liquid. Inventories of crude oil and petroleum products are, in the normal course of business, readily convertible to cash.

The Corporation has ample capacity to maintain liquidity and provide capital resources by virtue of its capacity to borrow. Continuing strong earnings again in 1983 has given the Corporation the availability of funds necessary to support planned increases in capital investment.

Stock Market and Dividend Information
Texaco Canada's Board of Directors has declared dividends on the common shares in every year since 1944. The total amount of dividends paid per common share was $1.05 in 1983, $1.00 in 1982, and $0.82 in 1981.

The Corporation's common shares are listed on the Toronto, Montreal, Alberta, Vancouver and American stock exchanges. The Toronto Stock Exchange is the principal market for trading these shares. The quarterly high and low prices as quoted on the Toronto Stock Exchange and the dividends paid on the common shares were:

1983	Price Range		Dividends
Quarter	High	Low	Paid
First	**$32⅜**	**$26¼**	**$0.25**
Second	**38**	**29¾**	**0.25**
Third	**41**	**36⅛**	**0.25**
Fourth	**42¾**	**36⅝**	**0.30**

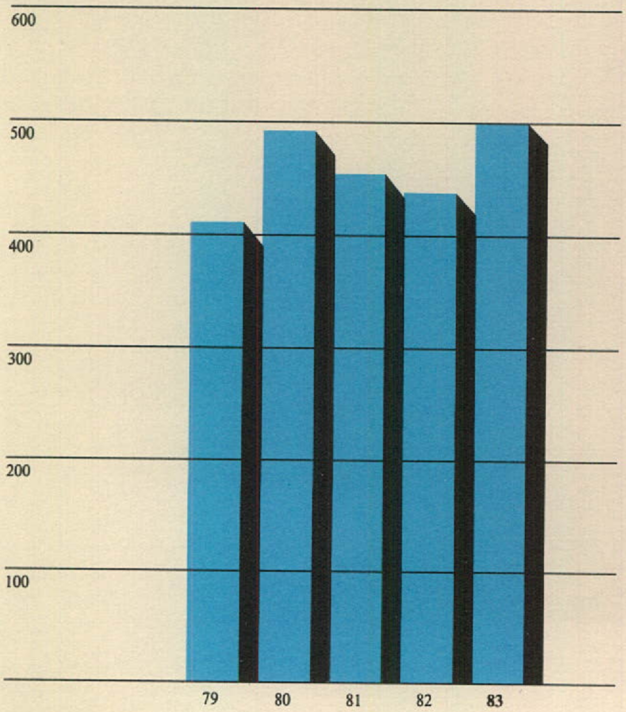
1982	Price Range		Dividends
Quarter	High	Low	Paid
First	$35¾	$22	$0.25
Second	27⅞	23⅝	0.25
Third	32⅞	26	0.25
Fourth	35	28	0.25

The quarterly high and low prices as quoted on the American Stock Exchange and the dividends paid on the common shares, expressed in U.S. dollars at the then current exchange rate, were:

1983	Price Range		Dividends
Quarter	High	Low	Paid
First	**$26¼**	**$21⅞**	**$0.20**
Second	**31**	**24⅛**	**0.20**
Third	**33**	**29½**	**0.20**
Fourth	**34¾**	**30**	**0.24**

1982	Price Range		Dividends
Quarter	High	Low	Paid
First	$31¼	$17⅝	$0.21
Second	22¼	19½	0.20
Third	27	20⅝	0.20
Fourth	28⅝	22¾	0.20

Funds Provided by Operations before Deduction of Net Exploratory Expenditures
Millions of dollars



On January 31, 1984, there were 4,266 individual, financial and other institutional holders of the Corporation's common shares. This compares with a total on December 31 of 4,338 in 1983, 5,049 in 1982, and 5,366 in 1981.

Dividends paid to United States security holders are subject to a 15 per cent Canadian withholding tax in accordance with the Canada-United States Income Tax Treaty. Capital gains on disposals are not taxable in Canada if the United States security holder has no permanent establishment in Canada. A proposed Canada-United States Income Tax Treaty, signed on September 26, 1980, has not yet been ratified.

Common Shareholders' Equity
Common shareholders' equity was $1,822 million or $15.09 per share, $1,617 million or $13.40 per share and $1,478 million or $12.25 per share as at December 31, 1983, 1982 and 1981 respectively. Net income for the year 1983 represented a 19.2 per cent return on average shareholders' equity which was higher than the return of 16.7 per cent for 1982 and lower than the return of 21.4 per cent for 1981.

Five-Year Review

Financial Summary	1983	1982	1981	1980	1979
	(Millions of Canadian dollars except where noted)				
Revenues					
Sales and services	**$5,652**	$4,768	$4,375	$3,503	$2,639
Investment and other income	**74**	74	86	69	46
	5,726	4,842	4,461	3,572	2,685
Net income	**344**	275	316	373	264
Per common share (dollars)	**2.74**	2.15	2.45	2.92	2.01
Per dollar of revenues (cents)	**6.0**	5.7	7.1	10.5	9.8
Dividends paid or accrued					
Common shares	**127**	121	99	70	51
Per common share (dollars)	**1.05**	1.00	0.82	0.585	0.42
Second preferred shares: Series A	**13**	13	13	13	13
Series B	**–**	2	7	9	9
Funds provided by operations	**449**	384	404	461	387
Capital and exploratory expenditures	**187**	197	209	224	137
Taxes and Crown royalties					
Income taxes	**446**	389	370	341	256
Federal sales tax	**138**	139	135	98	73
Petroleum and gas revenue tax	**169**	135	72	–	–
Petroleum compensation charge	**256**	391	513	101	33
Crown royalties	**361**	335	289	242	225
Other taxes and levies	**51**	55	50	41	36
	1,421	1,444	1,429	823	623
Motor fuel and excise taxes collected for governments	**464**	439	372	318	297
	$1,885	$1,883	$1,801	$1,141	$ 920

Financial Position (at year-end)	1983	1982	1981	1980	1979
Capital employed					
Current assets	**$1,784**	$1,466	$1,397	$1,198	$1,027
Current liabilities	**743**	631	640	537	549
Working capital	**1,041**	835	757	661	478
Net properties, plant, and equipment	**1,300**	1,290	1,280	1,204	1,081
Investments, long-term receivables and other assets	**204**	210	202	201	192
	2,545	2,335	2,239	2,066	1,751
Total assets	**3,288**	2,966	2,879	2,603	2,300
Long-term debt	**87**	83	86	98	110
Deferred gas production revenue	**63**	54	16	11	–
Deferred income taxes	**403**	410	408	384	349
Redeemable preferred stock	**170**	170	250	290	290
Preferred stock	**–**	1	1	3	3
Common stock and retained earnings	**1,822**	1,617	1,478	1,280	998
Equity per common share (dollars)	**15.09**	13.40	12.25	10.62	8.28
Rate of return on average capital employed	**14.3%**	12.2%	14.9%	19.9%	16.4%
Current working capital ratio	**2.4**	2.3	2.2	2.2	1.9

Share Ownership (at year-end)	1983	1982	1981	1980	1979
Common shares outstanding (thousands)	**120,768**	120,684	120,681	120,569	120,533
Common shareholders	**4,338**	5,049	5,366	5,592	4,038
First preferred shares outstanding	**–**	10,759	11,197	25,198	29,736
First preferred shareholders	**–**	87	132	308	409

Per common share information has been adjusted for the four-for-one split which occurred on August 15, 1980.

Operations Statistical Summary	1983		1982		1981		1980		1979	
	Gross	**Net**	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Production										
Crude oil (thousands of cubic metres daily)	**20.8**	**13.7**	20.5	12.9	21.2	12.9	21.9	13.5	24.7	15.4
*Natural gas liquids (thousands of cubic metres daily)	**2.6**	**2.6**	2.5	2.5	2.3	2.3	2.1	2.1	2.0	2.0
*Natural gas (millions of cubic metres daily)	**3.8**	**2.3**	4.3	2.6	4.0	2.3	3.1	1.8	3.2	1.8
Estimated Proved Reserves (at year-end)										
Crude oil (millions of cubic metres)	**50.8**	**33.8**	53.1	35.4	58.5	36.5	67.9	42.7	72.0	45.6
Natural gas liquids (millions of cubic metres)	**14.1**	**10.0**	14.0	9.9	13.3	9.3	13.7	9.7	14.3	10.2
Natural gas (billions of cubic metres)	**62.8**	**44.4**	63.3	44.7	65.2	44.3	60.9	43.7	58.8	41.7
Oil and Gas Landholdings (at year-end) (thousands of hectares)										
Producing	**489**	**223**	482	232	488	237	480	230	455	224
Undeveloped	**7175**	**3576**	6481	3416	6751	3695	5595	3215	6191	3663
Total	**7664**	**3799**	6963	3648	7239	3932	6075	3445	6646	3887
Wells Drilled										
Exploratory wells										
Oil	**14**	**6.1**	6	4.4	6	4.6	4	3.1	4	2.2
Gas	**9**	**5.9**	6	5.1	8	3.7	13	2.7	12	3.5
Dry	**35**	**18.9**	17	9.4	19	9.2	12	4.6	7	3.0
Development wells										
Oil	**28**	**18.0**	17	12.5	29	12.3	76	18.3	23	6.1
Gas	**3**	**1.0**	8	4.5	46	11.7	131	39.9	47	8.4
Dry	**3**	**2.3**	4	2.2	6	1.7	4	2.5	10	3.3
Total	**92**	**52.2**	58	38.1	114	43.2	240	71.1	103	26.5
Wells in the Process of Drilling (at year-end)	**9**	**4.1**	10	3.9	4	3.2	15	9.9	14	5.4
Wells Capable of Producing (at year-end)										
Oil	**4883**	**1077**	4806	1029	4819	1022	6184	1297	6104	1283
Gas	**1177**	**293**	1245	306	1173	288	1125	276	1048	243
Multiple completions included in the above	**136**	**15.6**	137	16.5	136	15.6	126	17.4	124	16.6
Refining and Sales		**1983**		1982		1981		1980		1979
Refinery runs (thousands of cubic metres daily)		**21.3**		23.5		28.2		29.8		30.8
**Refinery crude oil capacity at year-end (thousands of cubic metres daily)		**22.7**		22.7		34.6		33.9		33.9
Petroleum product sales (thousands of cubic metres daily)		**28.4**		28.0		31.6		33.8		32.9
Natural gas sales (millions of cubic metres daily)		**3.2**		3.7		3.3		2.4		2.2
Employees										
Number at year-end		**3,904**		4,418		4,522		4,442		4,265
Payroll and benefits (millions of Canadian dollars)		**$ 174**		$ 165		$ 147		$ 126		$ 109

*Does not include natural gas and natural gas liquids produced and reinjected into underground reservoirs for enhanced recovery or gas cycling.

**Refinery crude oil capacity as at December 31, 1979 through 1981 includes the refinery crude oil capacity at Montreal, Quebec.

Description of Significant Accounting Policies

The financial statements are prepared on the historical cost basis in accordance with accounting principles generally accepted in Canada and conform in all material respects with International Accounting Standards. The more significant accounting policies are set out below.

Principles of Consolidation
The consolidated financial statements include the accounts of Texaco Canada Inc. and its subsidiary companies. The premium paid on subsidiary companies' capital stock at date of acquisition is amortized on a straight-line basis over 20 years. Intercompany accounts and transactions are eliminated.

Foreign Currencies
Foreign currencies are translated into Canadian dollars as follows: (1) current assets except inventories, long-term receivables, current liabilities, and capital lease obligations, at the rate in effect at the end of the period; (2) inventories, properties, plant, and equipment and related depreciation, depletion, and amortization, and deferred charges at rates in effect when the assets were acquired; and (3) all other income accounts at rates in effect at the time of the transaction. Gains and losses on foreign currency transactions and charges and credits arising on translation of balance sheet accounts are reflected in income currently.

Inventories
Inventories of crude oil and petroleum products and other merchandise are stated at the lower of cost, determined on the first-in, first-out method, and net realizable value. Materials and supplies are stated at cost.

Investments and Advances
The Corporation uses the equity method of accounting for its investments in companies owned 50 per cent, and for all significant corporate joint ventures owned less than 50 per cent. Under this method, the Corporation's equity in the net income or losses of these companies is reflected currently in income rather than when realized through dividends. Investments in companies accounted for by this method reflect the Corporation's equity in the underlying net assets of the companies.

Investments in other non-subsidiary companies are accounted for at cost and the Corporation's interest in the net income of these companies is reflected in income when realized as dividends.

Long-term receivables arising under non-mineral leases are recorded as direct financing leases and are amortized in accordance with the respective lease agreement.

Properties, Plant, and Equipment and Accumulated Depreciation, Depletion, and Amortization
The Corporation follows the successful efforts method of accounting for its oil and gas exploration and producing operations. Under this method all exploratory costs, including geophysical and geological expenses, core drilling, lease rentals, and intangible drilling costs applicable to dry holes are charged to expense.

Lease acquisition costs, intangible drilling costs on productive wells, and tangible equipment costs related to the development of oil and gas reserves are capitalized and amortized. For lease acquisitions costing less than one million dollars, the portion of leasehold costs estimated to be non-productive based upon historical experience, is amortized on an average holding period basis. For lease acquisitions costing one million dollars or more, the portion of leasehold costs estimated to be non-productive is amortized over the initial exploration period. Leasehold costs which have been determined to be productive and other development costs related to producing activities, including tangible and intangible costs, are amortized on the unit-of-production basis by applying the ratio of produced oil and gas to estimated recoverable oil and gas reserves.

Depreciation of other properties, plant, and equipment is provided generally on the group plan, using the straight-line method, with depreciation rates based upon estimated useful life applied to the cost of each class of property.

Start-up costs of new facilities are capitalized and amortized in accordance with the Corporation's depreciation policy.

The Corporation accounts for significant leases, other than exploration and development of natural resource rights, that transfer all of the benefits and risks of ownership related to leased properties as capital leases. Properties, plant, and equipment include capital leases which are amortized over the estimated useful life of the asset or lease term, as appropriate, using the straight-line method.

Normal maintenance and repairs are charged to expense as incurred. Renewals, betterments, and major repairs that materially extend the life of properties are capitalized and the assets replaced, if any, are retired.

Research and Development Costs

Research costs are charged to income as incurred. Development costs are charged as an expense of the period in which they are incurred except when the project is expected to commence commercial production within the foreseeable future. When this occurs, the related development costs are deferred and amortized to match related revenues.

Deferred Income Taxes

The provision for deferred income taxes reflects the income tax effect on transactions recorded in the financial statements in a reporting period different from the period in which they are reported for income tax purposes. The principal transactions are depreciation, intangible drilling costs, leasehold costs and inventories.

Deferred income taxes as shown in the balance sheet represent the cumulative effect of net charges made against income to defer these income tax effects to appropriate future periods in the financial statements. This accounting policy allocates the income tax effect of transactions to the period in which such transactions are recorded for financial reporting purposes.

Pension Plan

A group pension plan is available to substantially all employees. Amounts charged to pension expense are based on amortizing the cost of pension benefits on an actuarial basis over the remaining estimated service of the employees involved.

Royalties

Crude oil and gas royalties payable in kind reduce volumes available to the Corporation and therefore are not reflected in the financial statements. Royalties payable in cash are accounted for as purchases.

Investment Tax Credits

Investment tax credits, other than tax rate reductions, are deducted from the related expenditure and amortized to income in accordance with the applicable accounting policy.

Federal Government Crude Oil Compensation Programs

Compensation received or recoverable under the programs for imported and synthetic domestic oil for consumption in Canada is deducted from cost of crude oil purchases. In order to be eligible for compensation the Corporation has complied with federal government legislation.

Consolidated Statements of Income and Retained Earnings

For the years ended December 31	1983	1982	1981
	(Millions of Canadian dollars except per share data)		
Revenues			
Sales and services	**$5,652**	$4,768	$4,375
Investment and other income	**74**	74	86
	5,726	4,842	4,461
Deductions			
Cost of sales and operating expenses (includes purchases from Texaco Inc. and subsidiary companies of $61 in 1983, $54 in 1982 and $528 in 1981)	**4,237**	3,513	3,210
Selling, general and administrative expenses	**180**	168	150
Maintenance and repairs	**53**	59	58
Dry hole expenses	**26**	38	31
Depreciation, depletion, and amortization	**83**	72	64
Interest charges	**9**	9	10
Petroleum and gas revenue tax	**169**	135	72
Taxes, other than income taxes (Note 10)	**179**	184	180
	4,936	4,178	3,775
Income before Income Taxes	**790**	664	686
Income Taxes (Note 11)			
–current	**438**	391	348
–deferred	**8**	(2)	22
	446	389	370
Net Income	**$ 344**	$ 275	$ 316
*Net income per common share	**$ 2.74**	$ 2.15	$ 2.45
Retained Earnings			
Beginning of year	**$1,581**	$1,442	$1,245
Add–Net income	**344**	275	316
Deduct–Dividends on preferred shares	**13**	15	20
–Dividends on common shares	**127**	121	99
End of year	**$1,785**	$1,581	$1,442
Cash dividends per share			
First Preferred, Series A	**$ 4.52**	$ 6.00	$ 6.00
Second Preferred, Series A	**7.50**	7.50	7.50
Second Preferred, Series B	–	5.44	7.25
Common	**1.05**	1.00	0.82

*Net income per common share is based on the average number of common shares outstanding (120,699,735 shares in 1983, 120,683,439 shares in 1982, and 120,632,882 shares in 1981).

See accompanying Description of Significant Accounting Policies and Notes to Consolidated Financial Statements.

Consolidated Balance Sheet

December 31	1983	1982
	(Millions of Canadian dollars)	
Assets		
Current Assets		
Cash	$ 7	$ 6
Cash investments and marketable securities, at cost which approximates market value	539	354
Accounts and notes receivable, less allowance for doubtful accounts of $8 in 1983 and $6 in 1982	650	549
Inventories (Note 2)	564	520
Prepaid expenses and deferred income taxes	24	37
Total current assets	1,784	1,466
Investments and Advances (Note 3)	180	190
Properties, Plant, and Equipment (Notes 4 and 8)	1,300	1,290
Deferred Charges	24	20
Total	$3,288	$2,966
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts payable	$ 417	$ 281
Accrued liabilities	88	92
Income and other taxes payable	234	254
Other	4	4
Total current liabilities	743	631
Long-term Debt (Note 5)	87	83
Deferred Gas Production Revenue	63	54
Deferred Income Taxes	403	410
Redeemable Preferred Stock (Note 6)	170	170
Preferred Stock–First Preferred Shares, Series A (Note 7)	–	1
Common Stock and Retained Earnings		
Common stock–Issued and outstanding: 1983, 120,768,176 shares and 1982, 120,684,376 shares (Note 7)	37	36
Retained earnings	1,785	1,581
Total common stock and retained earnings	1,822	1,617
Total	$3,288	$2,966

See accompanying Description of Significant Accounting Policies and Notes to Consolidated Financial Statements.

Approved on behalf of the Board

James L. Dunlap

James L. Dunlap, Director

Charles I. Rathgeb

Charles I. Rathgeb, Director

Consolidated Statement of Changes in Financial Position

For the years ended December 31	1983	1982	1981
	(Millions of Canadian dollars)		
Source			
Net income	$ 344	$ 275	$ 316
Depreciation, depletion, and amortization	83	72	64
Write-off of terminal facilities, marine vessel, and non-operating manufacturing assets, before deferred income taxes	31	41	–
Income taxes–deferred	(7)	2	23
Other	(2)	(6)	1
Provided by operations	449	384	404
Investments and advances (net)	12	–	6
Properties, plant, and equipment retirements, sales, and investment tax credits	11	18	20
Deferred gas production revenue	9	38	5
Long-term debt	9	–	–
	490	440	435
Disposition			
Properties, plant, and equipment expenditures	135	141	160
Long-term debt	5	3	12
Redeemable preferred stock	–	80	40
Dividends	140	136	119
Changes in working capital, excluding funds			
Accounts and notes receivable	101	48	48
Inventories	44	(63)	201
Accounts payable	(136)	18	(60)
Accrued liabilities	4	9	(30)
Income and other taxes payable	20	(18)	(17)
Other	(13)	9	4
Other net disposition	4	2	8
	304	365	485
Funds			
Increase (decrease) for year	186	75	(50)
Beginning of year	360	285	335
End of year	$ 546	$ 360	$ 285

Funds are defined as cash and cash investments and marketable securities.

See accompanying Description of Significant Accounting Policies and Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

(Millions of Canadian dollars except per share data)

1. Accounting Principles Generally Accepted in Canada Compared with the United States

As stated in the Description of Significant Accounting Policies, the consolidated financial statements are prepared in accordance with accounting principles generally accepted in Canada. These financial statements would not be materially different if they had been prepared using generally accepted accounting principles as promulgated in the United States.

2. Inventories

December 31	1983	1982
Crude oil	$164	$116
Petroleum products and other merchandise	390	392
Materials and supplies	10	12
Total	$564	$520

3. Investments and Advances

December 31	1983	1982
Non-subsidiary companies accounted for:		
On equity method	$ 20	$ 19
At cost	1	1
	21	20
Other investments		
Direct financing leases–affiliated company	144	152
Notes, mortgages and other long-term receivables	15	18
Total	$180	$190

Texaco Canada's equity in the net income of the non-subsidiary companies accounted for on the equity method aggregated $6 in 1983, $5 in 1982, and $5 in 1981. Dividends received from companies accounted for by this method amounted to $6 in 1983, $5 in 1982, and $5 in 1981. Undistributed income of these non-subsidiary companies included in Texaco Canada's retained earnings amounted to $16 as at December 31, 1983 and $16 as at December 31, 1982.

4. Properties, Plant, and Equipment

	Cost		Accumulated depreciation, depletion, and amortization	
December 31	1983	1982	1983	1982
Exploration and production	$ 836	$ 769	$286	$247
Manufacturing	639	666	137	133
Marketing	361	335	144	134
Marine	16	21	5	6
Pipelines	12	12	6	6
Other	25	22	11	9
Total	$1,889	$1,825	$589	$535
Net properties, plant, and equipment	$1,300	$1,290		

5. Long-term Debt

December 31	1983	1982
10¾% debentures, 1974 series, due 1994 ($5 annual sinking fund requirement 1984–1993)	$80	$85
5% debentures, from joint venture partner, due not later than 1997	9	–
Capital lease obligations (Note 8)	8	10
	97	95
Less:		
10¾% debentures held for sinking fund requirements	8	10
Capital lease obligations due within one year included in other current liabilities	2	2
Total	$87	$83

6. Redeemable Preferred Stock

December 31	1983	1982
Second Preferred Shares		
2,900,000 shares without nominal or par value, authorized and issuable in series:		
Series A–$7.50 cumulative, redeemable		
Issued and outstanding: 1,700,000 shares	$170	$170

Second Preferred Shares, Series A, are redeemable at $100.00 per share on the last day of February, May,

Notes to Consolidated Financial Statements

(Millions of Canadian dollars except per share data)

6. Redeemable Preferred Stock (continued)

August and November in each twelve-month period after June 1, 1984. At the option of the holders 400,000 shares may be redeemed each twelve-month period from June 1, 1984 through 1986 and 500,000 shares each twelve-month period thereafter. If certain dividend and working capital tests are met, the number of shares which may be redeemed at the option of the holders can be increased to 800,000 each twelve-month period from June 1, 1984 through 1986 and to 900,000 each twelve-month period thereafter.

During 1982, the Corporation redeemed all of the outstanding Second Preferred Shares, Series B, for a cash consideration of $100.00 per share. In February and May, 1982 there were mandatory redemptions totalling 400,000 shares and the remaining 400,000 shares were redeemed in August, 1982 at the holder's option.

In the event of a distribution of the assets of the Corporation among its shareholders for the purpose of winding up its affairs, the holders of the Second Preferred Shares shall be entitled to receive an amount equal to $100.00 per share plus all accrued and unpaid dividends thereon, the whole to be paid before any amount is paid or any assets of the Corporation are distributed to the holders of the Common Shares, or the shares of any other class ranking junior to the Second Preferred Shares.

The Corporation shall not solely at its own option redeem or purchase any Second Preferred Shares on or before June 1, 1988.

7. Capital Stock

December 31	**1983**	1982
Preferred Stock		
First Preferred Shares		
Unlimited number of shares without nominal or par value, authorized and issuable in series:		
Series A–$6.00 cumulative, redeemable, convertible		
Issued: 37,500 shares		
Outstanding: 1982, 10,759 shares	**$ –**	$ 1
Common Stock		
Common Shares		
Unlimited number of shares without nominal or par value, authorized:		
Issued and outstanding:		
1983, 120,768,176 shares and 1982, 120,684,376 shares	**$37**	$36

On November 15, 1983 the Corporation redeemed at its option all of the outstanding First Preferred Shares, Series A, for a cash consideration of $102.50 per share. Prior to the redemption date, these shares were convertible into fully paid and non-assessable common shares on the basis of eight Common Shares for each First Preferred Share. During 1983, 10,475 First Preferred Shares, Series A, were converted into 83,800 Common Shares.

During each of the three years ended December 31, 1983, 1982 and 1981, the following changes were reflected in the number of shares of First Preferred Stock, Series A, and Common Stock:

	1983	1982	1981
First Preferred Shares, Series A			
Outstanding at beginning of year	**10,759**	11,197	25,198
Deduct:			
Conversion of First Preferred Shares into Common Shares	**10,475**	438	14,001
Redemption of First Preferred Shares	**284**	–	–
Outstanding at end of year	**–**	10,759	11,197
Common Shares			
Outstanding at beginning of year	**120,684,376**	120,680,872	120,568,864
Add:			
Conversion of First Preferred Shares into Common Shares	**83,800**	3,504	112,008
Outstanding at end of year	**120,768,176**	120,684,376	120,680,872

8. Capital Leases, Lease Commitments and Rental Expense

As at December 31, 1983 the Corporation had non-cancellable leases expiring more than one year from such date covering service stations, office buildings and other facilities. Capital leases are reflected in the balance sheet as assets along with the related debt. The remaining lease obligations are considered to be operating leases and are reflected in the income statement as rental expense.

Leased capital assets included in Properties, Plant, and Equipment are:

December 31	1983	1982
Land	$ 9	$10
Buildings and equipment	23	23
	32	33
Less: Accumulated amortization	20	19
Net capital leases	$12	$14

Future minimum lease payments on non-cancellable operating leases and capital leases as at December 31, 1983 are:

	Operating leases	Capital leases
1984	$11	$ 2
1985	10	2
1986	9	1
1987	7	1
1988	4	1
After 1988	15	5
Total minimum lease payments	$56	12
Less: Amount representing interest		4
Present value of capital lease obligations (Note 5)		$ 8

Future minimum rental income from non-cancellable sub-leases amount to $24 in respect of operating leases and $11 in respect of capital leases.

Rental expense comprises:

Years ended December 31	1983	1982	1981
Minimum rentals	$39	$36	$28
Contingent rentals	5	6	6
	44	42	34
Less: Rental income from sub-leased properties	30	30	26
Net rental expense	$14	$12	$ 8

Rental expense includes minimum rental payments applicable to operating leases for service stations, office buildings and other facilities, charter hire payments in respect of tankers as well as rental payments which are contingent on such factors as litres sold. Rental payments on leases to retain mineral rights are excluded.

9. Contingent Liabilities

In the opinion of the Corporation's General Counsel, while it is impossible to ascertain the ultimate legal and financial liability with respect to contingent liabilities, including lawsuits, income taxes, claims, guarantees, etc., the aggregate amount of such liability would not be materially significant in relationship to the total consolidated assets of the Corporation and its subsidiaries.

10. Taxes, Other Than Income Taxes

Years ended December 31	1983	1982	1981
Federal sales tax	$138	$139	$135
Franchise taxes	4	10	16
Mineral tax–oil	14	13	11
Property and real estate	17	15	13
Social benefits	4	4	3
Other	2	3	2
Total	$179	$184	$180

In addition, federal excise tax and provincial motor fuel and oil taxes paid or due to taxing authorities for the years ended December 31, 1983, 1982 and 1981 in the amounts of $464, $439, and $372, respectively, have not been included in the income statement.

11. Income Taxes

The provision for current income taxes includes Incremental Oil Revenue Tax (IORT) for the period January 1, 1982 to May 31, 1982 amounting to $20. In the Corporation's opinion, this tax is considered to be a component of income tax. For the period June 1, 1982 to May 31, 1985, IORT has been suspended and all income during this period is subject to federal and provincial income taxes.

The provision for deferred income taxes relates to:

Notes to Consolidated Financial Statements

(Millions of Canadian dollars except per share data)

11. Income Taxes (continued)

Years ended December 31	**1983**	1982	1981
Intangible drilling costs	**$ 7**	$–	$ 9
Depreciation	**(9)**	1	22
Inventories	**16**	(4)	(1)
Other	**(6)**	1	(8)
Total	**$ 8**	$ (2)	$22

The following schedule reconciles the effective tax rates with the statutory income tax rates:

Years ended December 31	**1983**	1982	1981
Statutory income tax rate	**47.8%**	48.3%	49.8%
Petroleum and gas revenue tax	**10.3**	9.8	5.1
Resource allowance	**(21.6)**	(20.3)	(15.7)
Depletion	**(0.7)**	(0.8)	(1.4)
Disallowed royalties	**23.2**	24.9	21.9
Provincial tax credits and rebates	**(2.1)**	(2.1)	(2.4)
Other	**(0.4)**	(1.2)	(3.4)
Effective income tax rate as reflected in the Corporation's accounts	**56.5%**	58.6%	53.9%

12. Segmented Financial Data

Texaco Canada and its subsidiaries, an integrated organization in the petroleum industry, is engaged in the exploration for and production of crude oil and natural gas and in the refining, transportation and marketing of crude oil and petroleum products. A wholly-owned foreign subsidiary has capital assets related to the petroleum industry which it leases to an affiliated company on a long-term basis. The Corporation's sales revenues and net income as reflected in the consolidated statement of income are derived entirely from operations in the petroleum industry, which includes petrochemical activities and assets leased to an affiliated company associated with the petroleum industry, both of which are not material in relation to the total activities of the Corporation.

13. Pension Plan

As at December 31, 1983 costs, which will be incurred in future years in respect of prior service, amounted to approximately $10 on a present value basis. These costs are funded by annual payments of $2 which will amortize the liability by 1995. The assets of the plan exceed the actuarially computed value of vested benefits as of the last actuarial valuation date.

Auditors' Report

ARTHUR ANDERSEN & CO.
CHARTERED ACCOUNTANTS

To the Shareholders of Texaco Canada Inc.:
We have examined the consolidated balance sheet of Texaco Canada Inc. and subsidiary companies as of December 31, 1983 and 1982, and the related consolidated statements of income, retained earnings and changes in financial position for each of the three years in the period ended December 31, 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, the accompanying consolidated financial statements present fairly the financial position of Texaco Canada Inc. and subsidiary companies as of December 31, 1983 and 1982, and the results of their operations and changes in their financial position for each of the three years in the period ended December 31, 1983, in accordance with generally accepted accounting principles applied on a consistent basis.

Arthur Andersen & Co.

Toronto, Ontario
February 6, 1984

Oil and Gas Producing Activities

(Millions of Canadian dollars except where noted)

The information set out in this section is prepared in accordance with the United States Financial Accounting Standards Board Statement No. 69 (FASB 69). This Statement amends the disclosure requirements of FASB Statements 19 and 25. The Securities and Exchange Commission has also adopted these disclosures.

Capitalized Costs

December 31	**1983**	1982
Proved properties	**$707**	$651
Unproved properties	**88**	79
Support equipment and facilities	**14**	13
Gross capitalized costs	**809**	743
Less: Accumulated depreciation, depletion, and amortization	**276**	238
Net capitalized costs	**$533**	$505

Capitalized costs represent the costs of proved and unproved properties, including support equipment and facilities, along with the related accumulated depreciation, depletion, and amortization.

Costs Incurred

Years ended December 31	**1983**	1982	1981
Acquisition of unproved properties	**$ 17**	$ 7	$ 1
Exploration costs	**60**	54	51
Development costs	**46**	64	79
Total costs incurred	**$123**	$125	$131

Costs incurred include costs that are capitalized or charged to expense at the time they are incurred with the exception of support equipment and facilities, for which only appropriate depreciation is included.

Oil and Gas Producing Activities

(Millions of Canadian dollars except where noted)

Results of Operations from Producing Activities

Years ended December 31	1983	1982	1981
Revenues			
Sales to unaffiliated entities	$ 804	$542	$354
Transfers within Texaco Canada and sales to unconsolidated affiliates	401	388	335
Total	1,205	930	689
Production costs			
Petroleum and gas revenue tax	169	135	72
Other production costs	122	102	91
Total	291	237	163
Exploration and development expenses	49	55	48
Depreciation, depletion, and amortization	43	32	28
Results of operations from producing activities before estimated income tax	822	606	450
Estimated income tax	476	373	265
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 346	$233	$185

The results of operations from net production should not be construed to be total upstream operating income, as apart from excluding corporate overhead and interest costs, the cost of purchased oil and gas, including royalties, and the revenues from the sale thereof is not included in the table.

Estimated income tax has been computed by applying the statutory income tax rates to the pre-tax results of operations and reflects permanent differences and tax credits and allowances relating to the oil and gas producing activities.

Average Sales Prices and Production Costs

Years ended December 31	1983	1982	1981
	(Canadian dollars per cubic metre)		
Average sales prices			
Crude oil	$205.56	$162.79	$119.51
Natural gas liquids	157.38	121.17	108.39
Natural gas	.10	.10	.09
Average production costs	43.72	36.61	25.85

Average sales prices and average production costs per cubic metre are based on revenues and production costs, respectively, as reported in the Results of Operations from Producing Activities.

Production costs include cash lifting costs, excluding payments for royalties and income taxes. However, it is important to note that such royalties and income taxes substantially add to the total cost of producing operations and substantially reduce the profitability and cash flow from such operations.

Reserve Quantity Information

	Crude oil	Natural gas liquids	Natural gas
	(Millions of cubic metres)	(Millions of cubic metres)	(Billions of cubic metres)
Net proved developed and undeveloped reserves			
**As at December 31, 1980*	42.7	9.7	43.7
Increase (decrease) during 1981 attributable to:			
Revisions of previous estimates	(2.0)	–	(1.4)
Extensions, discoveries and other additions	0.6	0.1	2.9
Production	(4.8)	(0.5)	(0.9)
**As at December 31, 1981*	36.5	9.3	44.3
Increase (decrease) during 1982 attributable to:			
Revisions of previous estimates	3.5	0.3	0.8
Extensions, discoveries and other additions	0.2	1.0	0.5
Production	(4.8)	(0.7)	(0.9)
**As at December 31, 1982*	35.4	9.9	44.7
Increase (decrease) during 1983 attributable to:			
Revisions of previous estimates	**(0.2)**	**0.8**	**(0.4)**
Improved recovery	**3.2**	–	**0.4**
Extensions, discoveries and other additions	**0.3**	–	**0.5**
Production	**(4.9)**	**(0.7)**	**(0.8)**
**As at December 31, 1983*	**33.8**	**10.0**	**44.4**

*Includes net proved developed reserves of Texaco Canada Inc. and subsidiary companies:			
As at December 31, 1980	42.7	9.7	43.3
As at December 31, 1981	36.5	9.2	41.1
As at December 31, 1982	35.4	9.9	41.6
As at December 31, 1983	**33.6**	**9.9**	**41.2**

All of the Corporation's net proved reserves are located in Canada.

There are no crude oil and natural gas reserves applicable to long-term supply or similar agreements with governments or authorities in which the Corporation acts as producer.

The foregoing reserve quantities are believed to be reasonable estimates consistent with current knowledge of the characteristics and extent of proved production. They include only such reserves as can reasonably be classified as proved. Net reserves represent the volume estimated to be available after deduction of the royalty interests of others from gross reserves. The estimates of natural gas reserve quantities include the volume of the percentage of natural gas liquids which may be removed at locations beyond lease and/or field separation facilities. Estimates of reserve quantities are based on sound geological and engineering principles, but by their very nature are still estimates that are subject to upward or downward revision as additional information regarding producing fields and technology becomes available. Since estimating underground reserves is not, and does not purport to be an exact science, the potential for subsequent revisions in estimates is high, particularly as such reserves increase in maturity.

Prior to 1981, net reserves had been determined using the then current year-end prices and royalty structure. As at December 31, 1981 and 1982, net reserves have been computed giving consideration to known price increases in old oil resulting from pricing agreements between the governments of Canada and the producing provinces. These price increases for old oil have been limited to 75 per cent of the world crude oil prices existing as at December 31, 1981 and 1982. The effect of this change is reflected in the revisions of previous estimates in 1981. Net reserves as at December 31, 1983 have been determined using prices and the royalty structure in effect at that date.

Oil and Gas Producing Activities

(Millions of Canadian dollars except where noted)

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves

December 31	1983	1982	1981
Future cash inflows	$12,387	$12,855	$12,229
Future development and production costs	3,758	3,695	3,452
Future income tax expenses	4,910	5,422	5,519
Future net cash flows	3,719	3,738	3,258
10% Annual discount for estimated timing of cash flows	1,802	1,728	1,669
Standardized measure of discounted future net cash flows	$ 1,917	$ 2,010	$ 1,589

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

Years ended December 31	1983	1982	1981
Standardized measure at beginning of year	$2,010	$1,589	$1,808
Increases (Decreases):			
Sales and transfers of oil and gas produced, net of production costs	(914)	(693)	(526)
Net changes in prices and production costs	(212)	142	852
Changes in estimated future development costs	(5)	(61)	(84)
Extensions, discoveries, and improved recovery, less related costs	472	121	148
Development costs incurred during the year	41	57	70
Revisions of previous quantity estimates	(376)	629	(65)
Accretion of discount	517	449	369
Net change in income taxes	384	(223)	(983)
Standardized measure at end of year	$1,917	$2,010	$1,589

The reader is cautioned that extreme care be exercised in the use of the foregoing data on standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves. Texaco Canada is presenting this information in good faith in compliance with the requirements of FASB 69. While the Corporation has exercised due care in developing the data, it is necessary to caution investors and other users of this information to avoid its simplistic use. Users should carefully read the financial information presented in the foregoing tables in conjunction with the accompanying qualifications and caveats.

The above value-based information is based on future cash flows from production of proved reserves assuming certain economic and operating conditions. No value is assigned to the potential success Texaco Canada might enjoy from current exploration and/or from assets currently held which might benefit from future technological and economic conditions.

There are many variables, assumptions and imprecisions inherent in the development of future cash flow projections and these are affected by a multiplicity of factors which are subject to fluctuation, thereby unavoidably making the projections subject to the possibility of a wide range of variation. These factors include such items as revisions in the estimated quantities of producible reserves, timing of production, and future government actions regarding production, taxes, royalties, etc.

As at December 31, 1981 and 1982 the future cash inflows were based on prices and royalties in effect at year-end except for old oil. The prices and royalties for old oil have been increased in accordance with the pricing agreements between the governments of Canada and the producing provinces, but the prices have been limited to 75 per cent of current world price. As at December 31, 1983 future cash inflows were computed using year-end prices. The future costs were computed using year-end costs, and year-end statutory tax rates, adjusted for permanent differences, that relate to existing proved oil and gas reserves in which the Corporation has mineral interests.

The discount rate utilized in the foregoing tables is 10 per cent, as specified by FASB 69. The use of a specified uniform discount rate does not permit recognition of such factors as differences in the degree of risk of operating in different parts of Canada and its frontier areas, the availability of financing, and the state of the economy. The accretion of discount is the amount by which the present value of estimated future net revenues from estimated net production of proved oil and gas reserves at the beginning of the year increased during the year due to the passage of time. The amount of adjustment was computed under a compound interest method which resulted in an effective rate of approximately 10.5 per cent.

Financial Data Adjusted for Changing Prices

(Millions of Canadian dollars)

The usefulness of the Corporation's financial statements prepared on the historical cost basis is limited in prolonged periods of significant inflation. These statements do not reflect the impact on the financial position and operating results of changes in the general purchasing power of the dollar or in changes of specific prices of goods and other assets.

The Canadian Institute of Chartered Accountants (CICA) has issued a Recommendation which requires that supplemental data be presented to provide current cost adjusted information to reflect the effect of changing prices. The CICA has also recommended the disclosure of information relating to quantities of reserves of crude oil and natural gas as well as certain exploration costs. This information is disclosed as part of "Oil and Gas Producing Activities" on pages 41 to 44.

While Texaco Canada presents the current cost adjusted information in compliance with CICA requirements, and has exercised due care in developing such data, it is necessary to present the data with qualifications and cautions as to their interpretation and usefulness. Management cautions against the simplistic use of these data as a means of precisely measuring the effects of changing prices because of the imprecisions inherent therein.

Consolidated Statement of Income

For the year ended December 31, 1983	As reported in the Historical Cost Statements	Current Cost Basis
Revenues	**$5,726**	**$5,726**
Deductions		
Cost of sales and operating expenses	**4,237**	**4,261**
Depreciation, depletion, and amortization	**83**	**194**
Other expenses	**616**	**616**
	4,936	**5,071**
Income before Income Taxes	**790**	**655**
Income Taxes		
–current	**438**	**438**
–deferred	**8**	**8**
	446	**446**
Net Income	**$ 344**	**$ 209**

Consolidated Balance Sheet Items

December 31, 1983		
Inventories	**$ 564**	**$ 567**
Net properties, plant, and equipment	**1,300**	**2,566**
Net assets (common shareholders' equity)	**1,822**	**3,091**

Financial Data Adjusted for Changing Prices

(Millions of Canadian dollars)

Other Supplementary Information

For the year ended December 31	1983
Increase in the current cost of inventories and properties, plant, and equipment held during the year was attributed to:	
Effect of general inflation	$ 134
Increase in specific prices	46
Total increase in the current cost of inventories and properties, plant, and equipment	$ 180
Loss in general purchasing power from having net monetary assets	$ 10

Current Cost Estimates
In accordance with CICA requirements, only cost of goods sold included in the caption "Cost of sales and operating expenses" and depreciation, depletion, and amortization expense are adjusted for changing prices. Revenues, other expenses and income taxes are not required to be restated as it is assumed that these historical dollar amounts are stated in average dollars for the year.

In preparing the estimates of current costs, it was necessary to make many assumptions and rely upon judgmental estimates, which were inherently subjective in nature. The bases for calculating estimated current costs were as follows:

Inventories
Current cost values have been developed on the first-in, first-out (FIFO) method of accounting. Capitalized depreciation included in inventories has been adjusted to a current cost basis.

Cost of Goods Sold
Current cost of goods sold has been estimated by valuing inventories on a last-in, first-out (LIFO) basis. The resulting cost of sales is considered to be representative of current cost since the most recent acquisitions (current purchases) are deemed to be sold first.

Properties, Plant, and Equipment
Current cost estimates of properties, plant, and equipment have been largely developed by applying various indices to the historical cost of reasonably homogeneous groupings of assets. Due to the capital-intensive nature of the oil industry, it was considered not practical to attempt to develop current cost estimates for individual assets. While Texaco Canada is not in a position to attest to the accuracy, consistency weighting or other factors affecting published indices, it is believed that the indices used are not unreasonable. These current cost estimates are not to be construed as an indication of appraised or replacement values nor as a basis that these assets will necessarily be replaced in future.

Depreciation, Depletion, and Amortization
For purposes of calculating depreciation, depletion, and amortization both on a current cost and historical cost basis, the same useful lives and salvage values have been used.

Income Taxes
The CICA pronouncement does not require that the income taxes deducted in determining historical cost results be recalculated in the determination of current cost income. Income taxes as reported in the historical cost statements represent an effective tax rate of 56.5 per cent of income before income taxes. Since income taxes have not been adjusted in arriving at current cost net income, the effective income tax rate applicable to pre-tax income on a current cost basis is 68.1 per cent. This result demonstrates clearly that income taxes are paid on profits which in part arise from the effect of inflation.

Increase in Current Cost
Other Supplementary Information includes data analyzing the increase in the current cost of inventories and properties, plant, and equipment held during the year. This information indicates that the effect of general inflation in 1983 was greater than the increase in specific prices.

Loss in Purchasing Power
Other Supplementary Information also includes a caption "Loss in general purchasing power from having net monetary assets". Inflation not only affects the reported results of operations, but also affects the purchasing power of monetary assets held, such as cash and receivables, and monetary obligations, such as accounts payable and debt. During inflationary periods, monetary assets lose purchasing power and there is an opposite effect on monetary liabilities since less purchasing power will be needed to repay the obligations. The amount set forth as "Loss in general purchasing power from having net monetary assets" represents an estimate of how much the Corporation's purchasing power was effectively decreased as a result of having a greater amount of monetary assets than monetary liabilities.

Selected Quarterly Financial Data

For the three months ended:	Sales and services	Gross profit	Net income	Net income per common share
	(Millions of Canadian dollars except per share data)			
March 31, 1983	**$1,268**	**$157**	**$ 76**	**$0.61**
June 30, 1983	**1,344**	**160**	**75**	**0.59**
September 30, 1983	**1,473**	**231**	**107**	**0.86**
December 31, 1983	**1,567**	**177**	**86**	**0.68**
March 31, 1982	1,225	145	66	0.51
June 30, 1982	1,078	134	72	0.56
September 30, 1982	1,164	170	71	0.56
December 31, 1982	1,301	150	66	0.52
March 31, 1981	1,086	181	91	0.71
June 30, 1981	1,069	149	81	0.63
September 30, 1981	1,091	153	81	0.63
December 31, 1981	1,129	127	63	0.48

All deductions reported in the Consolidated Statement of Income, except for interest charges and current and deferred income taxes, have been reflected as costs and expenses associated directly with or allocated to sales and services to arrive at gross profit.

DIRECTORS OF TEXACO CANADA INC.

Peter I. Bijur
Vice-President, Texaco Inc.
and President, Texaco Oil Trading
and Supply Company
White Plains, New York

**Rodrigue J. Bilodeau*
Chairman of the Board and
Chief Executive Officer
Honeywell Limited
Toronto

Jacques Bock
President
Bock & Tetreau Inc.
Montreal

James E. Brazell
Staff Director
Exploration & Producing
Executive Committee
Texaco Inc.
White Plains, New York

†**Stanley D. Clarke*
President
Stanark Investments Inc.
Montreal

†**James L. Dunlap*
President and Chief
Executive Officer
Texaco Canada Inc.
Toronto

William A. Gatenby
President and Chief Executive Officer
Texaco Canada Resources Ltd.
Calgary

George W. Govier
President
Govier Consulting Services Ltd.
Calgary

†**Howard J. Lang*
Retired
Formerly Chairman of the Board
Canron Inc.
Toronto

J. Lee Morrison
Executive Vice-President
Texaco Canada Inc.
Toronto

†*Charles I. Rathgeb*
Chairman
Comstock International Ltd.
Toronto

Roland M. Routhier
Senior Vice-President
Texaco Inc.
White Plains, New York

†*Neil M. Shaw*
Group Managing Director
Tate & Lyle PLC
London, England

**R. W. Sparks*
Retired
Formerly Chairman of the Board
Texaco Canada Inc.
Calgary

†**William K. Tell, Jr.*
Senior Vice-President
Texaco Inc.
White Plains, New York

*Member of the Executive Committee
†Member of the Audit Committee

OFFICERS

Officers of Texaco Canada Inc.

James L. Dunlap
President and Chief Executive Officer

J. Lee Morrison
Executive Vice-President

G. Howard Agnew
Vice-President and Assistant to the Chief Executive Officer

Otto C. Cleyn
Vice-President
Quebec

André J. Galipeault
Vice-President and General Counsel

Kenneth D. Keegan
Vice-President and Treasurer

John M. Murray
Vice-President and General Manager, Refining

Charles S. Ramsay
Vice-President and General Manager,
Employee Relations

Norman E. Taylor
Vice-President, Marketing

Stuart J. Walker
Vice-President and General Manager,
Supply and Distribution

Ernest J. Little
Corporate Secretary

Donald A. Ross
Comptroller

Philip M. Taylor
Corporate Tax Officer

Subsidiary Companies
Texaco Canada Resources Ltd.
Oilship Limited
The Great Eastern Oil & Import Co. Ltd.
McColl-Frontenac Oil Co. Ltd.
Lowry Fuels Limited

Principal Investments and Percentage Interest
Federated Pipe Lines Ltd. 50%
Trans-Northern Pipelines Inc. 33.33%
Alberta Products Pipe Line Ltd. 20%
Montreal Pipe Line Company Limited 16%

Transfer Agents and Registrars in Canada:
Montreal Trust Company of Canada, Montreal, Toronto, Winnipeg, Regina, Calgary and Vancouver

Transfer Agents and Registrars in the United States:
The Royal Bank & Trust Company
68 William Street, New York, N.Y.

Officers of Texaco Canada Resources Ltd.
(a wholly-owned subsidiary of Texaco Canada Inc.)

James L. Dunlap
Chairman of the Board

William A. Gatenby
President and Chief Executive Officer

Neal H. Eggen
Vice-President,
Drilling and Production

William B. O'Heran
Vice-President, Exploration

Orville C. Windrem
Vice-President,
Corporate Affairs

Jack D. Beaton
Comptroller and Assistant Secretary

Jerald D. Palmer
Corporate Secretary and Manager,
Legal Services

J. Robert Steele
Corporate Tax Officer

The use in this report of such terms as *Texaco Canada, Corporation, Company, organization, we, us, our* and *its,* when referring to Texaco Canada Inc. or to its subsidiaries and affiliates either individually or collectively, is for convenience only and is not intended to be an accurate description of corporate relationships.

Printed in Canada