Scurry-Rainbow Oil Limited

1985 annual report

Scurry-Rainbow Oil Limited

Corporate Profile

Scurry-Rainbow Oil Limited (Scurry-Rainbow) is a Canadian company incorporated in 1954 under the laws of the Province of Alberta. The Company is engaged primarily in the exploration for, and the development and production of crude oil, natural gas and natural gas liquids. Exploration activities are conducted mainly in Alberta, British Columbia, Saskatchewan and the Beaufort Sea. The major producing properties are located in the three western provinces. In addition, the Company owns substantial undeveloped coal reserves in southern Alberta and British Columbia.

On July 22, 1985, Plains Petroleums Limited, a junior Canadian oil and gas company operating primarily in Alberta, was amalgamated with Scurry-Rainbow. The transaction reduced Home Oil Company Limited's ownership of Scurry-Rainbow from 88.5 to 88.1 percent of the outstanding common shares. Home Oil is a wholly-owned subsidiary of Hiram Walker Resources Ltd.

Scurry-Rainbow has a Canadian Ownership Rate of 87 percent and is defined as Canadian controlled. This qualifies the Company for the maximum level of Petroleum Incentives Program (PIP) grants.

Contents

Metric Conversion Factors

1 kilometre	= 0.62 mile
1 metre	= 3.28 feet
1 hectare	= 2.47 acres
1 cubic metre	= 6.2898 barrels (petroleum liquids)
1 cubic metre	= 35.49373 cubic feet (natural gas)
1 tonne	= 0.984 long tons (sulphur)

Annual General Meeting

The Annual General Meeting of Shareholders will be held on Monday, February 3, 1986 at 10:30 a.m. in the Company's head office, 29th floor Auditorium, Home Oil Tower, 324 Eighth Avenue S.W., Calgary, Alberta, Canada. Formal notice of this meeting and proxy materials have been mailed to all registered shareholders with this annual report.

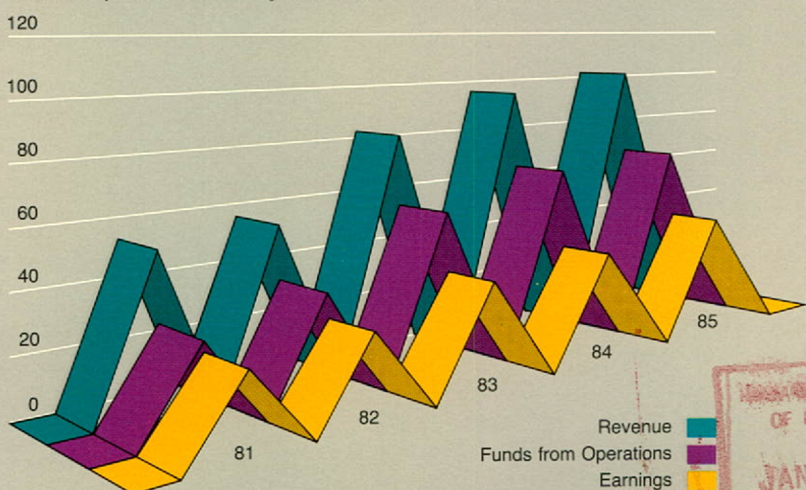
Form 10-K

The Company files annually with the Securities and Exchange Commission of the United States a report on operations known as the Annual Report on Form 10-K. Copies of the Form 10-K are available to shareholders free of charge upon written request to Mr. E. Jorgensen, Comptroller, Scurry-Rainbow Oil Limited, 1700 Home Oil Tower, 324 Eighth Avenue S.W., Calgary, Alberta, Canada, T2P 2Z5.

Highlights

	Year ended September 30, 1985	1984	1983
Financial (thousands of dollars)			
Revenue	102,882	95,508	82,346
Net earnings	30,132	24,898	22,463
Funds generated from operations	62,213	61,831	52,704
Capital expenditures			
Before PIP grants	80,296	91,868	43,170
After PIP grants	46,236	45,192	20,203
Working capital	63,427	53,877	35,688
Per Common Share (dollars)			
Net earnings	2.25	1.86	1.68
Funds generated from operations	4.64	4.62	3.94
Operating			
Average Daily Production/Sales			
Crude oil (barrels)	7,101	7,304	7,227
Natural gas liquids (barrels)	369	405	371
Natural gas (thousands of cubic feet)	24,391	21,711	20,622
Sulphur (long tons)	104	67	62
Proved Reserves			
Crude oil (millions of barrels)	19.7	17.2	15.9
Natural gas liquids (millions of barrels)	2.2	2.0	1.6
Natural gas (billions of cubic feet)	202	193	179
Sulphur (thousands of long tons)	324	341	367
Working Interest Wells Drilled			
Gross	413	272	53
Net	29.0	31.2	11.9
Undeveloped Oil and Gas Landholdings			
Gross (thousands of acres)	4,424	3,388	3,561
Net (thousands of acres)	1,143	1,072	1,350
Developed Oil and Gas Landholdings			
Gross (thousands of acres)	639	776	730
Net (thousands of acres)	97	131	124

Revenue, Funds from Operations & Earnings (millions of dollars)



To The Shareholders

Financial Results

Scurry-Rainbow's financial performance during 1985 improved for the fourth consecutive year. Net earnings amounted to $30.1 million or $2.25 per share, an increase of 21 percent due to higher operating revenue and greater investment income. Funds generated from operations remained essentially unchanged at $62.2 million or $4.64 per share, because increased revenue was offset by higher current income taxes. Revenue reached $102.9 million, up eight percent as a result of increased gas sales and additional investment income.

Capital expenditures totalled $80.3 million, a decline of 13 percent primarily reflecting reduced spending in the frontier regions of Canada. Petroleum Incentives Program (PIP) grants amounted to $34.1 million in 1985, resulting in net capital expenditures of $46.2 million, up slightly from 1984. Funds generated from operations exceeded current capital expenditures, and working capital thus reached $63.4 million, an 18 percent increase. During the next few years, however, working capital is expected to be reduced significantly by the termination of PIP grants and aggressive capital spending programs.

Operating Performance

Drilling activity increased 52 percent with Scurry-Rainbow participating in 413 working interest wells. On Company lands, drilling activity more than doubled to 124 wells, in which the Company's interests averaged 14.5 percent. The remaining 289 wells were drilled on farmin lands and earned Scurry-Rainbow an average interest of 3.8 percent. In addition, the Company retained gross overriding royalty interests in 48 successful oil and gas wells drilled during the year.

Crude oil and natural gas liquids production decreased marginally to 7,470 barrels per day. The natural decline in mature fields was partially offset by production from successful drilling. Gas sales rose by 12 percent to 24.4 million cubic feet per day due to increased domestic and export demand.

Proved reserves of crude oil and natural gas liquids reached 21.9 million barrels at year end, a 14 percent increase from last year. Discoveries and extensions from successful drilling added 3.2 million barrels which more than replaced the 2.7 million barrels produced. This was the first time in many years that additions to both crude oil and natural gas liquids reserves exceeded yearly production. Net upward revisions based on improved reservoir performance added a further 2.2 million barrels. Proved reserves of natural gas reached a record high of 201.5 billion cubic feet, a five percent gain over last year. Additions of 18.4 billion cubic feet far exceeded sales of 8.9 billion cubic feet.

Amalgamation

The Company's principal subsidiary for some time was Plains Petroleums Limited (Plains), in which a 72.2 percent interest was held. Effective July 22, 1985, Scurry-Rainbow acquired the 27.8 percent minority interest and amalgamated Plains with the Company. The minority shareholders were given the option of exchanging 22 common shares of Plains for one common share of Scurry-Rainbow, or receiving $1.00 for each common share of Plains. The total cost of the acquisition to Scurry-Rainbow was $5.9 million, consisting of $4.4 million in cash and 70,349 common shares of Scurry-Rainbow valued at $1.5 million.

The amalgamation resulted in a more simplified corporate structure, and eliminated duplication of administrative procedures and regulatory compliance requirements. In addition, the minority shareholders which accepted Scurry-Rainbow shares gained access to a more extensive oil and gas exploration and development program, and a broader market for their shares.

Industry Review

During 1985 significant improvements were made to Canada's oil and gas policies by the federal and provincial governments. Scurry-Rainbow applauds these policy initiatives and the new spirit of constructive consultation existing between the various governments and the petroleum industry.

The Western Accord, signed in March 1985 by the federal government and the governments of Alberta, British Columbia and Saskatchewan, deregulated crude oil prices and markets on June 1, 1985; phases out the Petroleum and Gas Revenue Tax (PGRT) on existing production over a three-year period beginning January 1, 1986; eliminated the PGRT on new production from wells spudded after March 31, 1985; and terminates PIP grants on April 1, 1986 with grandfathering for existing exploration commitments. In October 1985, the federal government introduced new measures for the frontier regions which include a refundable 25 percent Exploration Tax Credit to replace PIP grants; a sliding scale royalty regime to reduce the financial burden during the early years of production; and elimination of the 25 percent interest reserved for the federal government in successful ventures. Also during October, the federal government and the three western provinces signed a separate agreement to deregulate prices and markets gradually for both domestic and export sales of natural gas. The agreement specifies a one-year transition period.

In keeping with the spirit of the Western Accord, the three western provinces also introduced new policy initiatives. Alberta began reducing marginal royalty rates in stages over a two-year period, expanded royalty holidays to include virtually all exploratory wells, and will significantly increase the Royalty Tax Credit on April 1, 1986. British Columbia adopted a new natural gas royalty, pricing and marketing program, and introduced an oil royalty holiday which applies to most development wells. Saskatchewan extended the current oil royalty holidays, and announced a new natural gas policy which raised the wellhead price for new gas and made the royalty rate sensitive to production rates.

Scurry-Rainbow is well-positioned to benefit from the 1985 federal and provincial policy initiatives. Deregulation of oil prices increased the average wellhead price received by the Company. Because of its aggressive drilling strategy, Scurry-Rainbow will derive maximum benefit from the elimination of PGRT on new production and from the various improved provincial royalty holidays on new production. These measures, coupled with the phase out of PGRT on existing production and the increase in the Alberta Royalty Tax Credit, will provide Scurry-Rainbow with increased cash flow to reinvest. The elimination of PIP grants is not detrimental to the Company's current frontier program, since its remaining commitments will be covered by the PIP grandfathering provision.

Corporate Outlook

The operating strategies developed in prior years will be continued during 1986. Exploration efforts in Western Canada will be directed primarily towards oil prospects, but high quality gas prospects with early cash flow potential will also be pursued. Exploration will be continued in the Beaufort Sea to test the most promising geological prospects before the grandfathered frontier PIP grants expire on December 31, 1987. Development activities will be focused on optimizing production from existing fields. In addition, development of exploration successes and shut-in gas properties will be aggressively pursued.

Production of crude oil and natural gas liquids is expected to increase modestly during 1986. The results of expanded drilling programs and the new waterflood project in the East Eagle field should more than offset the natural production decline in mature fields. World oil prices are not expected to stabilize in the short term and some further erosion is likely in 1986.

Sales of natural gas are expected to increase as a result of the October federal and provincial deregulation agreement. Although the domestic price of natural gas is frozen for one year, the average Canadian price for export sales into the United States will be allowed to drop in response to competitive market forces. Additional export sales should result which would act to neutralize the impact of lower prices.

Net capital expenditures of about $60 million are planned for 1986, a significant increase from the $46 million in 1985. The majority of the funds will be directed towards expanded exploration activities in the western provinces.

Dividend Payment

As a result of the Company's continued strong financial performance, on November 27, 1985 the Board of Directors approved the commencement of a semiannual dividend of $0.25 per common share.

Submitted on behalf of the Board of Directors.

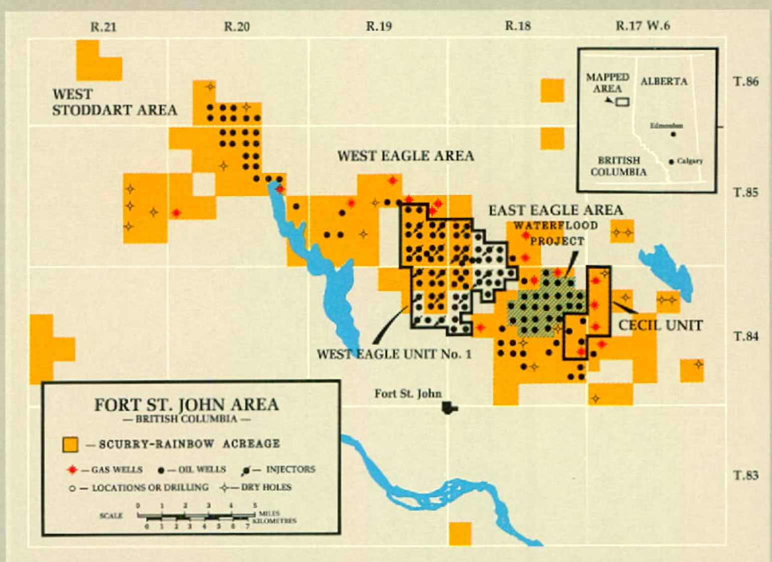
R. F. Haskayne

R.F. Haskayne,
President and Chief
Executive Officer.

Calgary, Alberta, Canada.
November 27, 1985.

Review of Operations

The freshwater treatment plant at West Eagle Unit No. 1



Exploration and Development

During 1985 Scurry-Rainbow expanded its exploration and development programs both on Company properties and on lands where interests were earned through farmins. The Company was involved in 413 working interest wells in 1985 compared with 272 last year. On a net well basis, however, Scurry-Rainbow's drilling activity decreased marginally to 29.0 wells compared with 31.2 in 1984. This decline resulted from the high activity and generally low interests earned on farmin lands. The net well count is expected to climb substantially as the information acquired from the farmin activity is used to generate prospects on higher interest Company lands. Exploration and development expenditures in 1985 totalled $80.3 million compared with $91.9 million last year. After deducting Petroleum Incentives Program (PIP) grants, net expenditures were $46.2 million and $45.2 million, respectively.

Drilling Activity

Drilling activity in 1985 consisted of 210 (14.6 net) exploratory and 203 (14.4 net) development wells. Exploration successes totalled 65 (6.7 net) oil and 51 (2.7 net) gas wells. Development drilling added 129 (9.4 net) oil and 27 (0.7 net) gas wells. In addition, Scurry-Rainbow retained gross overriding royalty interests in 64 wells drilled during the year. These yielded 44 oil and four gas wells.

Two years ago, Scurry-Rainbow gained access to large landholdings in Western Canada, the Beaufort Sea and offshore Nova Scotia through farmin agreements with Dome Petroleum Limited (Dome). Of the 413 wells drilled in 1985, 289 wells (11.0 net) were on lands owned by Dome. The agreement covering Western Canada runs to July 1989 and commits Scurry-Rainbow to total expenditures of $80 million. In 1985, $18.2 million was spent, with an additional $50 million to be expended throughout the duration of the agreement.

British Columbia

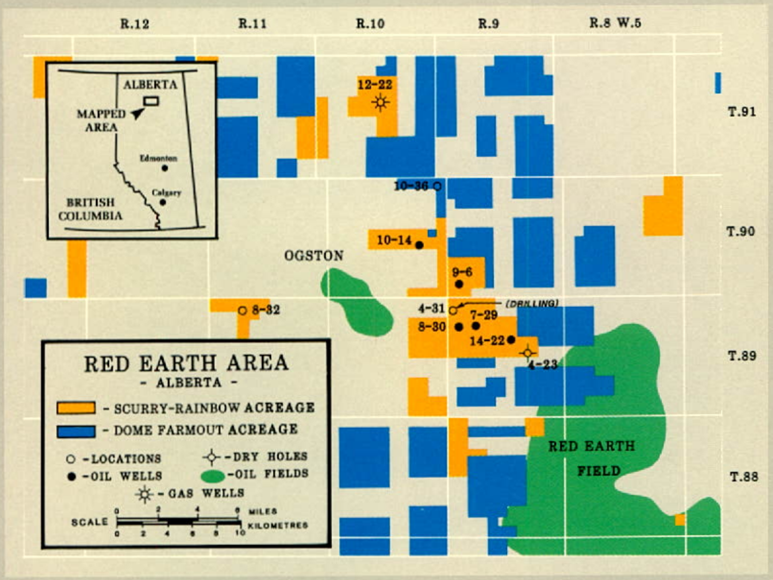
An active drilling program was maintained in British Columbia during 1985. The Company participated in 15 exploratory and 21 development wells drilled during the year. Exploratory drilling resulted in one oil well and five gas wells, while development drilling yielded 13 oil and two gas wells.

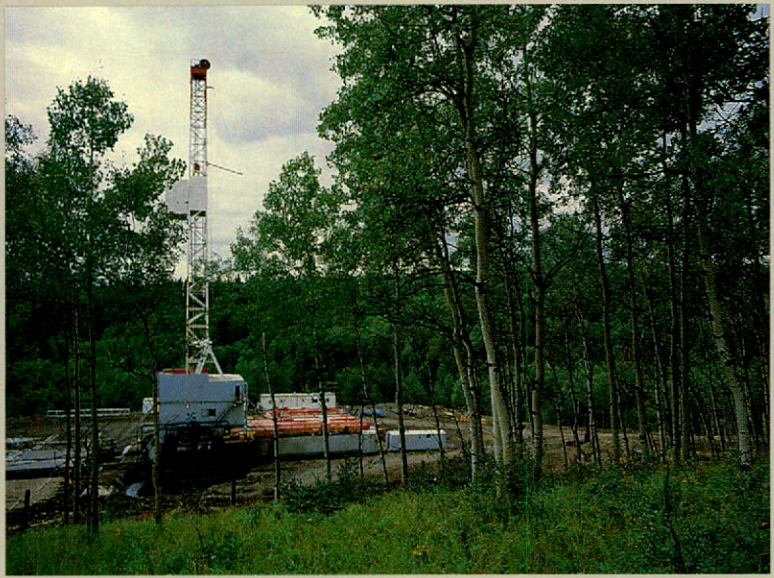
Scurry-Rainbow holds a 28.4 percent working interest in an oil discovery in the Osprey area of northeastern British Columbia. The Company will drill up to six exploratory wells on the same play where interests averaging 25 percent are held.

Twelve of the 21 development wells were operated by the Company in northeastern British Columbia, and yielded eight oil producers. The producing wells are in the Eagle and Flatrock areas and interests ranging from 31.5 to 50 percent are held.

The first phase of a waterflood project at East Eagle was completed during 1985 and is expected to result in the recovery of an additional one million barrels of oil net to Scurry-Rainbow. This phase consisted of drilling four infill wells, converting two existing producers to injection service, and constructing fresh water transfer and injection facilities. The Company's 50 percent share of capital costs totalled $3.5 million.

The second phase of the East Eagle project, proposed for 1986, is expected to yield a further 1.9 million barrels to Scurry-Rainbow. The Company's share of expenditures for this phase will be about $5 million and will include the drilling of nine wells and the conversion of six producers to injection service.





Drilling southwest of Calgary

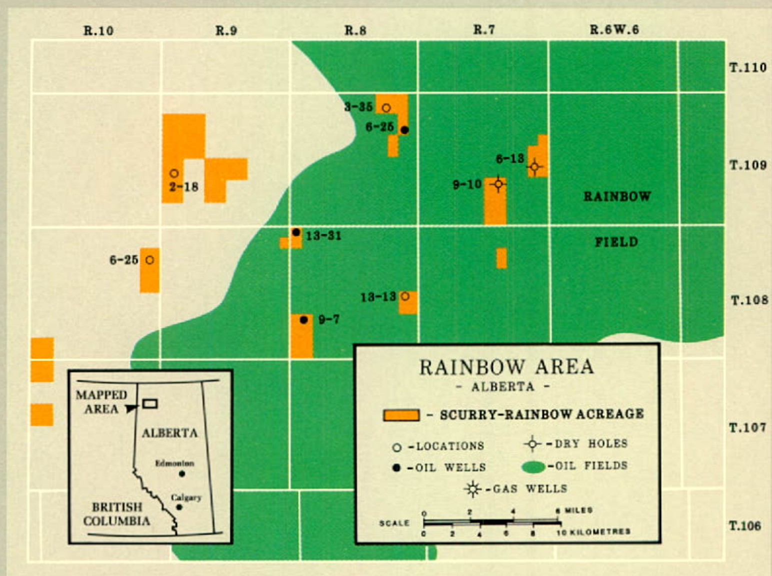
Alberta

During 1985, Scurry-Rainbow participated in 175 exploratory and 133 development wells drilled in Alberta. The exploratory activity resulted in 54 oil and 45 gas wells. Of the development wells, 69 were oil and 25 were gas.

In the Red Earth area of northern Alberta where Scurry-Rainbow holds interests averaging 5.5 percent in several prospective parcels of land, five of six wells drilled encountered oil. Further exploratory and development drilling is planned in the forthcoming year.

As a result of Scurry-Rainbow's 1984 drilling successes in the Rainbow area of northwestern Alberta, four additional wells were drilled in 1985. The Company's interests range from 7.7 percent to 16.7 percent. The prospect covers at least six separate structures. Three exploratory wells and a development drilling program are planned for this winter.

To follow up last year's drilling successes in the Garrington area northwest of Calgary, the Company participated in the drilling of another 20 wells in the region. Nineteen gas wells resulted. The presence of substantial quanti-



ties of natural gas and natural gas liquids, combined with Scurry-Rainbow's strong land position in the area, make the Garrington region highly promising. Working interests in the wells range from 3.3 percent to 6.7 percent.

An encouraging oil discovery was made by Scurry-Rainbow in the Chain area of southern Alberta this year. A seismic survey and follow-up drilling are planned along the geological trend of the discovery. Scurry-Rainbow holds interests ranging from 4.2 to 33.3 percent in the area.

A drilling rig operating in southern Saskatchewan

A step-out well on the Shouldice prospect, southeast of Calgary, is currently producing oil at a rate of 150 barrels per day. Scurry-Rainbow is the sole interest holder in the well. Further development is under review.

Discoveries in the Seal, Lubicon, Loon and Joan areas of the Eastern Peace River Arch exhibited encouraging flow rates during production testing. Scurry-Rainbow will participate in the drilling of up to 30 additional wells in these areas during the 1985/86 winter season. Working interests vary from 1.9 percent to 11.7 percent.

Saskatchewan

The Company participated in 63 working interest wells, of which 14 were exploratory and 49 were development. Exploratory drilling resulted in nine oil wells, while development drilling yielded 47 oil wells.

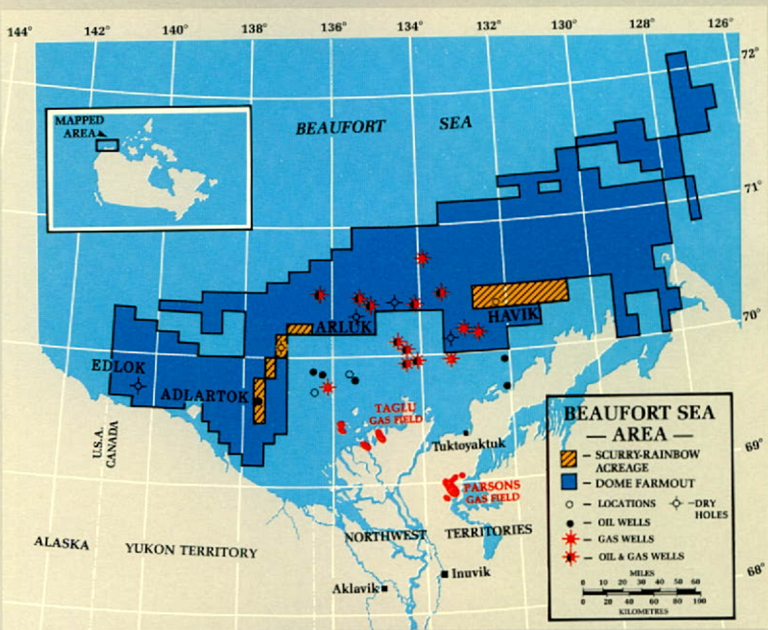
In the Tableland area of southeastern Saskatchewan, a well was drilled which resulted in an oil discovery. The well is scheduled to be placed on production shortly. Scurry-Rainbow owns and operates this well, and retains substantial landholdings in the surrounding area. A multi-well exploratory drilling program is being considered for this region.

The Company also recorded drilling successes in the Antler and Weyburn areas of southeastern Saskatchewan. Exploratory drilling in the Antler area yielded a potential oil discovery in which the Company holds a 50 percent interest. Two delineation wells drilled in the Weyburn field encountered oil. One of these was completed after fiscal year end. The Company earned an average 24.3 percent interest.

In 1983, Scurry-Rainbow farmed out approximately 40,000 acres in southeastern Saskatchewan. Forty-three commitment wells were drilled on this acreage during 1985 resulting in 39 oil wells and one gas well. Scurry-Rainbow retains gross overriding royalty interests in the properties varying from five to 30 percent. The farmees have committed to drill a minimum of 14 additional wells prior to April 30, 1987.

Beaufort Sea

The Company participated in the drilling of two wells in the Beaufort Sea under the farmin agreement with Dome. Two additional wells were completed subsequent to the fiscal year end and a third is suspended. The sum-



mer drilling program, although severely constrained by ice and weather conditions, concluded with a potentially significant oil find.

The Adlartok P-09 well was completed in October 1985 and encountered thick oil bearing sands yielding cumulative flow rates of 4,130 barrels per day from four zones on test. The Company holds a 10.1 percent working interest in the land block which includes several other large prospective structures. Studies are now underway to determine if further drilling is economically feasible.

Both the Arluk E-90 well, which was completed after the fiscal year end, and the Edlok N-56 well were dry and abandoned.

Testing of the Havik B-41 well was prevented by ice conditions and will remain suspended until the 1986 summer drilling season. The well is located on a parcel of land in which Scurry-Rainbow holds a 20 percent working interest.

Nova Scotia

On the East Sable block offshore Nova Scotia, the Citadel H-52 well failed to encounter hydrocarbons and was abandoned. The first well on this block, Louisbourg J-47, tested non-commercial quantities of natural gas. Further drilling is not scheduled.

Netherlands

On Block K/4 in the Dutch sector of the North Sea, an appraisal well encountered uneconomic quantities of natural gas and was abandoned without testing. The Company holds a 3.3 percent interest in the block. A development project was under consideration but has been cancelled due to the disappointing outcome of the drilling program.

Oil and Gas Landholdings

	Undeveloped Acreage	
	Gross	**Net**
Canada		
Alberta	1,757,601	215,843
Arctic Islands	726,620	83,270
Beaufort Sea	769,750	129,264
British Columbia	285,661	59,741
East Coast	49,154	3,592
Saskatchewan	700,811	622,999
Other	29,522	26,707
	4,319,119	1,141,416
International		
Netherlands Offshore	104,770	1,604
Total	4,423,889	1,143,020

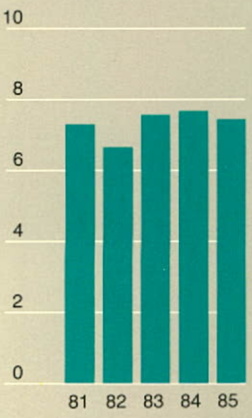
Undeveloped acreage is defined as exploratory lands on which wells have not been drilled or completed to a point that would permit production.

Gross includes the interests of others; net excludes the interests of others. Overriding royalty interests are included in gross acres, but excluded in net acres.

The table excludes 638,945 gross acres (97,157 net) of developed lands in Western Canada. Developed acreage is defined as lands from which production is being obtained or is capable of being obtained.

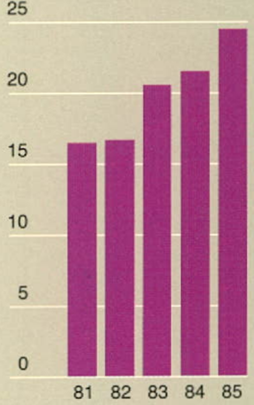
A drillship being readied for the summer drilling season in the Beaufort Sea

Average Daily Production Petroleum Liquids*
(thousands of barrels)



* Includes crude oil and natural gas liquids.

Average Daily Sales Natural Gas
(millions of cubic feet)



Production/Sales

Production of crude oil and natural gas liquids averaged 7,470 barrels per day in 1985 compared with 7,709 barrels per day the previous year. This decrease resulted from natural decline in mature fields which was only partially offset by new production.

A $37 million addition to the Wapiti natural gas processing plant, situated approximately 260 miles northwest of Edmonton, was placed on stream in mid-October. The new facility is designed to extract up to 18,000 barrels per day of natural gas liquids. A 6.3 percent interest is held in the project and Scurry-Rainbow's share of initial production is expected to average 330 barrels per day in 1986.

Natural gas sales averaged 24.4 million cubic feet per day, an improvement of 12.3 percent over last year. The increased sales originated from the South Wapiti, Coleman, Karr and Crossfield-Turner Valley fields in Alberta. These increases more than offset lower sales at Gold Creek and the West Provost Unit, also located in Alberta. The Company's exports of natural gas in 1985 rose by five percent over the previous year and represented about 60 percent of its total sales.

Average Daily Production/Sales

(Before Royalties and Minority Interests)

	1985		1984		1983	
	Petroleum Liquids *	Natural Gas	Petroleum Liquids *	Natural Gas	Petroleum Liquids *	Natural Gas
	(barrels)	(thousands of cubic feet)	(barrels)	(thousands of cubic feet)	(barrels)	(thousands of cubic feet)
Alberta	1,460	19,526	1,541	16,730	1,455	16,732
British Columbia	4,129	4,636	4,307	4,718	4,200	3,403
Saskatchewan	1,780	229	1,761	263	1,841	457
Other	101	—	100	—	102	30
Total	7,470	24,391	7,709	21,711	7,598	20,622

* Includes crude oil and natural gas liquids

Proved Reserves

Proved reserves of crude oil totalled 19.7 million barrels at the year end, an increase of 14.4 percent over the previous year. Discoveries and extensions from successful drilling added 2.8 million barrels which more than replaced the 2.6 million barrels produced during 1985. This was the first time in many years that additions from drilling exceeded annual production. Some of the major additions were in the Shouldice area of Alberta, and the Tableland and Weyburn areas of Saskatchewan. Net upward revisions from improved reservoir performance, primarily from the West Eagle field, added a further 2.2 million barrels.

Proved reserves of natural gas liquids rose by eleven percent to a total of 2.2 million barrels. Discoveries and extensions added 340,000 barrels compared with sales of 135,000 barrels. The major additions resulted from successful drilling in the Garrington area.

Natural gas reserves reached 201.5 billion cubic feet, an increase of 4.5 percent over the previous year. Successful drilling in the Strachan, Calais and Garrington areas of Alberta more than replaced total sales during the year.

Proved reserves of sulphur declined by 4.9 percent to 324,000 long tons because additions and revisions were insufficient to replace production.

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

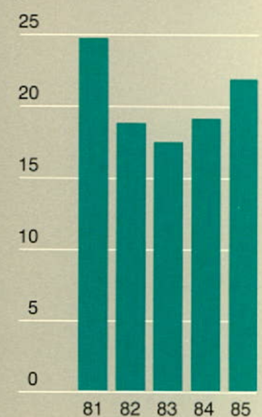
Part of the facilities at the Carstairs Natural Gas processing plant north of Calgary

Proved Reserves

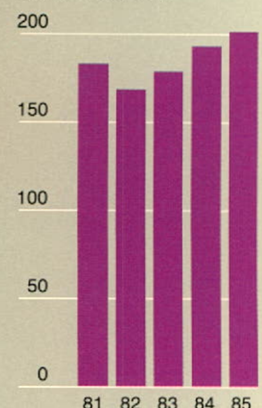
(Before Royalties and Minority Interests)

	Crude Oil (thousands of barrels)	Natural Gas Liquids (thousands of barrels)	Natural Gas (billions of cubic feet)	Sulphur (thousands of long tons)
September 30, 1984	17,203	1,975	192.8	340.7
Discoveries/ Extensions	2,837	340	18.4	1.0
Revisions	2,227	3	(0.8)	20.3
Production/Sales	(2,592)	(135)	(8.9)	(38.0)
September 30, 1985	**19,675**	**2,183**	**201.5**	**324.0**

Proved Reserves Oil and Gas Liquids
(millions of barrels)



Proved Reserves Natural Gas
(billions of cubic feet)



Financial Review

Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's discussion relates to the results of operations, financial condition and changes in financial condition for the three years ended September 30, 1985. These comments should be read in conjunction with the consolidated financial statements, the unaudited supplementary information and the five-year financial and operating reviews.

Earnings

Scurry-Rainbow continued its positive performance in 1985 with net earnings of $30.1 million, up from $24.9 million in 1984 and $22.5 million in 1983.

Net earnings in 1985 were 21.0 percent higher than 1984 due to increased natural gas sales, higher sulphur revenue, and additional investment income.

Earnings per share amounted to $2.25 compared with $1.86 in 1984 and $1.68 in 1983. These results were based on 13,462,129 shares outstanding at September 30, 1985 compared with 13,391,780 in the prior periods.

The rate of return on average shareholders' equity was 18.9 percent, unchanged from 1984, but down from the 20.8 percent recorded in 1983.

Revenue

Crude oil revenue at $68.1 million was marginally higher than in 1984 and 19.4 percent greater than in 1983. Higher prices and lower royalty rates were the main factors contributing to the increased oil revenue. Improved prices resulted from deregulation of Canadian crude oil prices and markets on June 1, 1985, and a larger percentage of production qualifying for the New Oil Reference Price prior to deregulation. Declining royalty rates were attributable to the larger percentage of production classified as new oil. Crude oil production averaged 7,101 barrels per day compared with 7,304 in 1984 and 7,227 in 1983.

Natural gas revenue during 1985 increased to $20.5 million compared with $18.7 million in 1984 and $17.9 million in 1983. Gas prices averaged $2.73 per thousand cubic feet compared with $2.84 in 1984 and $2.80 in 1983. The 1985 decrease was influenced by lower industry prices for gas sold into United States markets, as well as sales in Alberta domestic markets at less than the Alberta Border Price. Natural gas sales averaged 24.4 million cubic feet per day in 1985, up 18.3 percent from the 20.6 million cubic feet per day recorded in 1983.

Natural gas liquids revenue remained relatively constant over the three-year period, while sulphur revenue increased to $2.9 million in 1985 from approximately $1.3 million in 1984 and 1983, primarily due to higher prices.

As a result of higher levels of short term investments, other income totalled $8.3 million, up from $5.1 million in 1984 and $3.4 million in 1983.

Expenses and Taxes

Total expenses, exclusive of income and revenue taxes, at $35.0 million were 8.0 percent higher than 1984 and 14.8 percent greater than 1983. Higher operating expenses were associated with greater volumes of natural gas production. Depletion rates increased to $3.82 per equivalent barrel from $3.59 in 1983 due to higher finding and development costs.

Income and revenue taxes were $37.7 million in 1985, down marginally from $38.2 million in 1984 and up from the $29.4 million recorded in 1983. Income tax as a percentage of pre-tax earnings declined in 1985 reflecting lower Crown royalty rates and higher Investment Tax Credits. The Petroleum and Gas Revenue Tax (PGRT) increased to $11.0 million in 1985 from $9.6 million in 1983 reflecting higher operating revenue. Effective January 1, 1984, the Alberta Royalty Tax Credit was reduced to a maximum of $2 million from a maximum of $4 million, accounting for the decline in the Royalty Tax Credit.

Capital Expenditures and Corporate Liquidity

During 1985, the Company continued its high level of capital expenditures which, after Petroleum Incentives Program (PIP) grants, totalled $46.2 million compared with $45.2 million in 1984 and $20.2 million in 1983. The 1985 exploration program accounted for $30.3 million of which $5.4 million was spent in the Beaufort Sea, $1.0 million offshore Nova Scotia and $0.4 million in the North Sea, with the balance being invested in the Western Canadian Sedimentary Basin. Development outlays in 1985 totalled $15.7 million which compares with $17.4 million in 1984 and $9.4 million in 1983. During the past three years, a large portion of the development activity took place in the Fort St. John area of British Columbia. Capital expenditures for 1986 are expected to be $61.4 million after PIP grants and Investment Tax Credits.

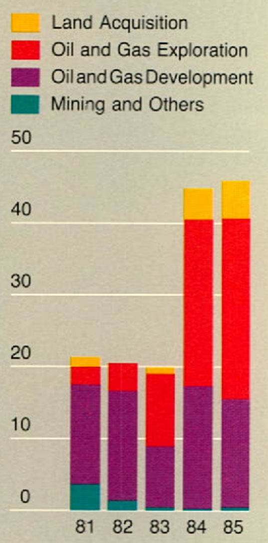
The Company qualified for maximum PIP payments since inception of the program. PIP grants totalled $34.1 million in 1985 compared with $46.7 million in 1984 and $23.0 million in 1983.

On July 22, 1985, the Company acquired the minority shares of Plains Petroleums Limited for a cash consideration of $4,356,000 and the issuance of 70,349 shares of the Company. For additional information on this acquisition reference is made to Note 6 of the Consolidated Financial Statements.

Internally generated cash flow was more than sufficient to finance the 1985 capital program, financial obligations, and further enhance the Company's strong financial position. At year end, the Company had working capital of $63.4 million which provides adequate support for ongoing obligations.

During 1985, the governments of Canada and the major producing provinces announced changes to their respective oil and gas policies. These changes include the phased elimination of the PGRT on existing production; exemption from the PGRT on production from wells drilled after March 31, 1985; a five percent reduction in Alberta's marginal royalty rates over the next two years; an increase in the Alberta Royalty Tax Credit to 75 percent of royalties payable subject to a maximum of $3 million per year; and the phasing out of provincial incentive grants in favour of royalty holidays. Scurry-Rainbow's present drilling commitments in the Beaufort Sea will be completed before the grandfathering provision for PIP grants expires in 1987. These changes will have a positive effect on the financial results of Scurry-Rainbow in future years.

Capital Expenditures
(millions of dollars)



Consolidated Statement of Financial Position

	September 30, 1985	September 30, 1984
	(Expressed in thousands of dollars)	
Assets		
Current Assets		
Short term investments	**$ 15,066**	$ 14,041
Advances to parent company (Note 10)	**40,086**	8,310
Accounts receivable		
Trade	**13,736**	14,793
Petroleum incentives program	**34,808**	41,742
Inventories, at lower of cost or net realizable value	**698**	1,062
	104,394	79,948
Investment in 50% Owned Company	**951**	1,053
Property, Plant and Equipment (Note 2)	**202,957**	170,753
Other Assets (Note 2)	**4,201**	4,846
	$312,503	$256,600
Liabilities		
Current Liabilities		
Bank indebtedness	**$ 1,481**	$ 2,031
Accounts payable	**21,858**	17,884
Taxes payable	**14,834**	4,709
Due to parent company	**2,794**	1,447
	40,967	26,071
Deferred Production Revenue (Note 4)	**3,831**	4,319
Long Term Debt (Note 5)	**4,189**	6,897
Deferred Income Taxes	**87,889**	72,999
Minority Interest (Note 6)	**—**	2,367
Shareholders' Equity		
Capital Stock (Note 7)	**10,922**	9,374
Contributed Surplus	**23,334**	23,334
Retained Earnings	**141,371**	111,239
Capital Commitments (Note 11)		
	175,627	143,947
	$312,503	$256,600

Approved by the Board

R. T. Hardcastle Director

Robert G. Black Director

Consolidated Statement of Earnings and Retained Earnings

	Year ended September 30,		
	1985	**1984**	**1983**
	(Expressed in thousands of dollars except per share amounts)		
Revenue			
Operating	**$ 94,567**	$ 90,431	$78,979
Other (Note 10)	**8,315**	5,077	3,367
	102,882	95,508	82,346
Expense			
Operating	**13,765**	13,159	12,134
General and administrative	**3,535**	2,591	2,303
Depletion and depreciation (Note 2)	**16,942**	15,715	15,029
Interest (Note 5)	**420**	520	702
Minority interest	**372**	445	338
	35,034	32,430	30,506
Earnings Before Taxes	**67,848**	63,078	51,840
Taxes (Note 8)	**37,716**	38,180	29,377
Net Earnings	**30,132**	24,898	22,463
Retained Earnings at Beginning of Year	**111,239**	86,341	63,878
Retained Earnings at End of Year	**$141,371**	$111,239	$86,341
Earnings Per Share	**$ 2.25**	$ 1.86	$ 1.68

Auditors' Report

To the Shareholders of Scurry-Rainbow Oil Limited

We have examined the consolidated statement of financial position of Scurry-Rainbow Oil Limited as at September 30, 1985 and 1984 and the consolidated statements of earnings and retained earnings, changes in financial position and changes in non-cash working capital for each of the three years in the period ended September 30, 1985. Our examinations were made in accordance with generally accepted auditing standards in Canada, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the Company as at September 30, 1985 and 1984 and the results of its operations and the changes in its financial position for each of the three years in the period ended September 30, 1985 in accordance with generally accepted accounting principles in Canada, consistently applied.

Price Waterhouse

Calgary, Alberta, Canada.
November 15, 1985.

Chartered Accountants

Consolidated Statement of Changes in Financial Position

	Year ended September 30,		
	1985	1984	1983
	(Expressed in thousands of dollars)		
Cash Was Obtained From			
Operations			
Net earnings	**$30,132**	$24,898	$22,463
Charges (credits) not affecting funds			
Depletion and depreciation	**16,942**	15,715	15,029
Deferred income taxes	**14,890**	20,919	15,280
Other	**249**	299	(68)
Funds from operations	**62,213**	61,831	52,704
Changes in non-cash working capital	**23,801**	(20,678)	(14,872)
	86,014	41,153	37,832
Cash Was Used For			
Investment			
Capital expenditures	**46,236**	45,192	20,203
Disposal of property, plant and equipment	**(255)**	(311)	(9,123)
Purchase of minority interest	**5,904**	—	—
Other	**(702)**	(479)	4,433
	51,183	44,402	15,513
Increase (decrease) in cash before financing	**34,831**	(3,249)	22,319
Financing			
Deferred production revenue	**(488)**	1,459	941
Reduction of long term debt	**(2,540)**	(699)	(1,487)
Issue of common shares	**1,548**	—	—
	(1,480)	760	(546)
Increase (Decrease) in Cash*	**$33,351**	$(2,489)	$21,773

* Cash is defined as short term investments and advances to parent company, less bank indebtedness.

Consolidated Statement of Changes in Non-Cash Working Capital

	Year ended September 30,		
	1985	1984	1983
	(Expressed in thousands of dollars)		
Changes in Non-Cash Working Capital			
Accounts receivable			
Trade	**$ 1,057**	$ (1,172)	$ 1,188
Petroleum incentives program	**6,934**	(17,910)	(16,286)
Inventories	**364**	(412)	1,019
Accounts payable	**3,974**	3,346	(1,289)
Taxes payable	**10,125**	(5,041)	1,299
Due to parent company	**1,347**	542	(803)
Current portion of long term debt	**—**	(31)	—
	$23,801	$(20,678)	$(14,872)

Notes to 1985 Consolidated Financial Statements

(Tabular amounts, except per share amounts, are expressed in thousands)

1. Summary of Significant Accounting Policies

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

Principles of Consolidation

The consolidated financial statements include the accounts of all companies in which the Company has ownership of more than 50 percent of the voting capital stock.

The Company follows the equity method of accounting for its investment in a 50 percent owned company. Under this method, the Company's investment is carried at cost plus its share of undistributed earnings since the date of acquisition.

The excess of the cost, of shares of subsidiaries and the company accounted for by the equity method, over the underlying net book value at dates of acquisition has been allocated to property, plant and equipment.

Substantially all of the exploration and production activities of the Company are conducted jointly with the parent company and other companies and these financial statements reflect the Company's proportionate interest in such activities.

Oil and Gas Operations

The Company follows the full cost method of accounting for oil and gas operations whereby all exploration and development costs are capitalized and charged against earnings as set out below. Capitalized costs include land acquisition costs, geological and geophysical costs, lease rentals and related charges applicable to non-producing property, costs of drilling both productive and non-productive wells, and overhead charges related to exploration and development activities. Such costs are generally limited to the future net revenues from estimated production from proved reserves at current prices and costs and the estimated fair market value of unproved properties. A separate cost centre is established for each country. Proceeds of disposals are generally credited to cost and no gains or losses are recognized unless such disposals constitute a major disposition. Costs are depleted using the unit of production method based upon estimated proved reserves, as determined by Company engineers. Natural gas reserves and production are converted to equivalent volumes of crude oil based on the relative energy content. Costs of acquiring and evaluating significant unproved properties and costs of major development projects are excluded from the computation of depletion until such time as additional reserves are proved, the project is completed, or an impairment in value has occurred.

Buildings and equipment, other than production equipment, are depreciated on a straight-line basis at rates which are estimated to amortize the costs of the assets, less salvage values, over their useful lives. Production equipment is depreciated using the unit of production method.

Mining Costs

Mining costs are charged to earnings in the year incurred (included in depletion) until such time as the presence of economically recoverable reserves is established. Proceeds on partial disposition of properties are generally deducted from the related costs without recognition of gain or loss.

2. Property, Plant and Equipment

	September 30, 1985		
	Cost	Accumulated depletion and depreciation	Net
Petroleum and natural gas properties and equipment	**$314,288**	**$116,277**	**$198,011**
Mining properties and equipment			
Developed	**4,603**	**1,602**	**3,001**
Undeveloped	**2,380**	**598**	**1,782**
Land, buildings and other equipment	**506**	**343**	**163**
	$321,777	**$118,820**	**$202,957**

	September 30, 1984		
	Cost	Accumulated depletion and depreciation	Net
Petroleum and natural gas properties and equipment	$273,743	$108,371	$165,372
Mining properties and equipment			
Developed	4,603	1,142	3,461
Undeveloped	4,772	2,993	1,779
Land, buildings and other equipment	448	307	141
	$283,566	$112,813	$170,753

Costs of petroleum and natural gas properties at September 30, 1985 have been reduced by credits of $111,249,000 (1984 — $77,189,000) with respect to Petroleum Incentives Program grants. Exploration and development expenditures for the year ended September 30, 1985, have been reduced by grants of $34,060,000 (1984 — $46,676,000).

Costs of evaluating unproved properties excluded from the computation of depletion amounted to $3,826,000 at September 30, 1985 (1984 — Nil).

Oil and gas depletion and depreciation expense per equivalent unit of production for the year ended September 30, 1985, amounted to $3.82 per barrel (1984 — $3.54; 1983 — $3.59).

The developed mining properties and equipment pertain to mining operations in Nevada. On January 10, 1983, the Company sold the Gooseberry gold and silver mine in Nevada for a cash consideration of U.S. $3 million and non-interest bearing notes aggregating U.S. $6 million payable equally over ten years ending January 31, 1993. In recording the transaction, the proceeds were credited to cost and the Canadian value of the notes was discounted at a rate of 10 percent to $4,535,000; currently $4,044,000 is included in other assets. The Company has retained a net profits interest in the mine ranging from 15 percent to 30 percent depending on the price of gold.

3. Operating Lines of Credit

As at September 30, 1985, the Company had unused operating lines of credit totalling $5,000,000, which upon drawdown would bear interest at prime rate.

4. Deferred Production Revenue

Amounts paid to the Company by purchasers, for annual contracted gas volumes not taken, are recorded as deferred production revenue. These amounts will be reported as revenue when the gas to which the payments relate is delivered to the purchaser. Deliveries or repayments are to be made over a maximum 10-year period ending November 1, 1994.

5. Long Term Debt

The long term debt consists of 7.25 percent Subordinated Debentures, due in 1988. Interest on long term debt for the year ended September 30, 1985 amounted to $317,000 (1984 — $452,000; 1983 — $673,000).

As at September 30, 1985, the Company had an unused bank revolving capital loan facility of $10,000,000, which upon drawdown would bear interest at prime rate. The loan can be drawn on a revolving basis for two years and thereafter will be convertible into a six-year term loan with interest at prime plus one-quarter percent.

6. Purchase of Minority Interest

As of July 22, 1985, the Company acquired the 27.8 percent minority interest in its subsidiary company, Plains Petroleums Limited (Plains), and subsequently amalgamated Plains with the Company. The minority shareholders were given the option of exchanging 22 common shares of Plains for one common share of the Company or receiving one dollar for each common share of Plains. The acquisition price of $5,904,000 was settled by payment of $4,356,000 cash and issuance of 70,349 common shares of the Company valued at $1,548,000. This transaction gave rise to $3,165,000 in excess costs which have been allocated to property, plant and equipment. There would have been no material effect on net earnings had the transaction occurred October 1, 1984.

7. Capital Stock

The authorized capital stock of the Company consists of 100,000,000 preferred shares, without par value, and 200,000,000 common shares, without par value. As at September 30, 1985, the Company had 13,462,129 common shares issued and outstanding (1984 — 13,391,780 shares).

8. Taxes

Taxes are comprised of the following:

	Year ended September 30,		
	1985	**1984**	**1983**
Income taxes			
Current	**$14,169**	$ 8,628	$ 8,660
Deferred	**14,890**	20,919	15,280
	29,059	29,547	23,940
Petroleum and gas revenue tax	**10,970**	12,051	9,616
Alberta royalty tax credit	**(2,313)**	(3,418)	(4,179)
Total taxes	**$37,716**	$38,180	$29,377
Total taxes as a percentage of earnings before taxes	**55.6%**	60.5%	56.7%

Deferred income taxes arise mainly from deducting exploration and development costs for income tax purposes in excess of the related provision for depletion.

Income taxes differ from the amounts which would be obtained by applying the Canadian statutory federal income tax rate of 46 percent to pre-tax earnings. These differences result from the following:

	Year ended September 30,		
	1985	**1984**	**1983**
Earnings before taxes	**$67,848**	$63,078	$51,840
Computed "expected" income taxes	**$31,210**	$29,016	$23,846
Royalties and other non-deductible payments to provincial governments	**10,553**	11,037	9,535
Federal resource allowance	**(10,079)**	(10,917)	(9,280)
Depletion allowances on Canadian oil and gas production income	**(943)**	(1,125)	(1,333)
Provincial income taxes, net of federal income tax abatement	**2,274**	1,549	1,267
Investment tax credits	**(2,103)**	(581)	(871)
Other	**(1,853)**	568	776
Income taxes	**$29,059**	$29,547	$23,940
Income taxes as a percentage of earnings before taxes	**42.8%**	46.8%	46.2%

9. Business and Geographic Segments

The Company has only one significant business segment being its oil and gas operations which are conducted principally in Canada.

10. Related Party Transactions

Home Oil Company Limited (Home) owns approximately 88.1 percent of the issued and outstanding shares of the Company. During the year ended September 30, 1985, Home provided certain management, accounting, administrative, technical and other services to the Company at cost, which amounted to $10,216,000 (1984 — $9,200,000; 1983 — $6,111,000). Of this amount, $7,002,000 has been capitalized and allocated to property, plant and equipment (1984 — $6,218,000; 1983 — $3,899,000).

Advances to parent company carry interest at one-quarter percent above the cost of funds in the commercial paper market and are repayable on demand. Interest received from the parent company for the year ended September 30, 1985, amounted to $4,963,000 (1984 — $3,605,000; 1983 — $1,573,000).

11. Capital Commitments

During 1984, several amendments were made to the farmin agreement between Home, the Company, and Dome Petroleum Limited and its affiliates covering the Company's activities in Western Canada. The expenditure commitment in Western Canada was increased to $80 million from $55 million and the term of the agreement was extended to July, 1989. In the Beaufort Sea, the maximum expenditure commitment of $108 million remained unchanged. The Company qualifies for maximum grants under the Petroleum Incentives Program. Accordingly, eligible expenditures incurred in Western Canada entitle the Company to grants of 35 percent of exploration costs and 20 percent of development costs. Eligible exploration costs in the Beaufort Sea entitle the Company to grants of 80 percent. The Company's commitment to the Beaufort Sea program is contingent on the availability of Petroleum Incentives Program grants which are being phased out subject to certain grandfathering provisions. Under both programs, gross expenditures of $122 million have been incurred to September 30, 1985, entitling the Company to Petroleum Incentives Program grants of $82 million.

(a) Selected Quarterly Financial Data

	Quarter ended			
	September 30, 1985	June 30, 1985	March 31, 1985	December 31, 1984
Revenue	**$24,747**	**$25,742**	**$26,716**	**$25,677**
Gross margin	**$19,347**	**$21,802**	**$22,460**	**$21,973**
Net earnings	**$ 7,505**	**$ 7,527**	**$ 7,448**	**$ 7,652**
Earnings per share	**$ 0.56**	**$ 0.56**	**$ 0.56**	**$ 0.57**

	Quarter ended			
	September 30, 1984	June 30, 1984	March 31, 1984	December 31, 1983
Revenue	$22,975	$27,866	$24,206	$20,461
Gross margin	$19,284	$23,812	$19,598	$17,064
Net earnings	$ 5,767	$ 7,783	$ 5,850	$ 5,498
Earnings per share	$ 0.43	$ 0.58	$ 0.44	$ 0.41

(b) Oil and Gas Exploration and Production Activities

The Company's oil and gas exploration and production activities are carried out principally in Canada. The following unaudited supplementary oil and gas information is provided in accordance with the United States' Statement of Financial Accounting Standards No. 69, "Disclosures about Oil and Gas Producing Activities".

Capitalized Costs

	September 30,		
	1985	1984	1983
Petroleum and natural gas properties	**$314,288**	$273,743	$226,311
Accumulated depletion and depreciation	**(116,277)**	(108,371)	(90,928)
Net capitalized costs	**$198,011**	$165,372	$135,383

Costs Incurred

	Year ended September 30,		
	1985	1984	1983
Acquisition of unproved properties	**$ 5,203**	$ 4,421	$ 773
Exploration	**24,994**	23,194	9,760
Development	**15,741**	17,438	9,355
	$45,938	$45,053	$19,888

Results of Operations

	Year ended September 30,		
	1985	**1984**	**1983**
Revenue, net of royalties	**$94,567**	$90,431	$78,979
Production costs	**13,765**	13,159	11,813
Petroleum and gas revenue tax	**10,970**	12,051	9,616
Depletion and depreciation	**16,240**	14,870	14,627
	40,975	40,080	36,056
Income before income taxes from oil and gas operations	**53,592**	50,351	42,923
Income taxes (net of Alberta royalty tax credit)	**23,733**	25,887	20,031
Results of oil and gas operations (excluding general and administrative overhead and interest costs)	**$29,859**	$24,464	$22,892

Proved Oil and Gas Reserve Quantities

The Company's proved reserves are based on estimates made by Company engineers. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. The process of estimating reserves is complex, requiring subjective judgements in the evaluation of available geological, engineering, economic, and other data. All of the Company's proved reserves are located in Canada.

The calculation of reserves of crude oil, including condensate and natural gas liquids, and natural gas is based on the Company's share of proved reserves, after the deduction of royalties. The net reserves set forth below have been calculated on the basis of royalty rates and regulations in effect on the dates the estimates were made.

	Crude Oil (thousands of barrels)			Natural Gas (billions of cubic feet)		
	1985	**1984**	**1983**	**1985**	**1984**	**1983**
Proved Reserves						
Beginning of year	**14,225**	13,733	14,183	**145**	146	134
Revisions of previous estimates and improved recovery	**2,182**	742	478	**15**	(6)	15
Extensions and discoveries	**2,640**	1,882	1,127	**14**	12	3
Production	**(2,097)**	(2,132)	(2,055)	**(7)**	(7)	(6)
End of year	**16,950**	14,225	13,733	**167**	145	146
Proved Developed Reserves						
Beginning of year	**14,202**	12,936	14,183	**133**	132	134
End of year	**16,834**	14,202	12,936	**152**	133	132

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

Future cash inflows are computed by applying year-end prices, except for fixed and determinable escalation provisions in contracts, to year-end quantities of proved oil and gas reserves. Future development costs, production costs, Petroleum and Gas Revenue Tax (PGRT), and income taxes (net of Alberta Royalty Tax Credit), are deducted from future cash inflows to arrive at future net cash flows. Future development and production costs are based on year-end costs and assume continuation of existing economic and operating conditions. Future PGRT is computed based on rates and regulations in effect at year end. Future income taxes are computed by applying the year-end statutory rates to the future pretax net cash flows, after making provision for the tax basis of the oil and gas properties. Future net cash flows are discounted at a rate of 10 percent per annum to arrive at discounted future net cash flows.

The Company cautions that the discounted future net cash flows from proved oil and gas reserves is neither an indication of fair market value of the Company's oil and gas properties, nor of the future net cash flows expected to be generated from such properties. The discounted future net cash flows do not include the fair market value of exploratory properties and probable or possible oil and gas reserves, nor give consideration to the effect of anticipated future changes in crude oil and natural gas prices, development and production costs, and possible changes to tax and royalty regulations. The prescribed discount rate of 10 percent may not appropriately reflect future interest rates.

Standardized Measure of Discounted Future Net Cash Flows

	September 30,		
	1985	**1984**	**1983**
Future cash inflows	**$1,056,934**	$872,770	$854,872
Future costs			
Production	**(210,502)**	(175,206)	(171,300)
Development	**(35,477)**	(24,306)	(28,731)
PGRT	**(22,254)**	(114,361)	(104,601)
Future pretax cash flows	**788,701**	558,897	550,240
Future income taxes	**(328,631)**	(239,808)	(243,535)
Future net cash flows	**460,070**	319,089	306,705
10% annual discount for estimated timing of cash flows	**(270,597)**	(172,348)	(153,986)
Discounted future net cash flows	**$189,473**	$146,741	$152,719

Changes in Standardized Measure of Discounted Future Net Cash Flows

	Year ended September 30,		
	1985	**1984**	**1983**
Revisions to reserves proved in prior years			
Revisions of previous quantity and timing estimates	**$ 6,759**	$ (8,310)	$ 17,388
Net changes in prices, net of production costs and PGRT	**83,392**	(3,323)	29,738
Net changes in estimated future development costs	**(19,615)**	(4,321)	8,085
Other	**110**	1,097	857
Accretion of discount	**27,181**	28,052	23,266
	97,827	13,195	79,334
Changes during the year			
Extensions, discoveries and improved recovery, net of related costs	**45,702**	34,468	19,317
Previously estimated development costs incurred during the year	**8,989**	8,845	6,762
Sales of oil and gas produced, net of production costs and PGRT	**(69,832)**	(65,221)	(57,550)
	(15,141)	(21,908)	(31,471)
Total revisions and changes before income taxes	**82,686**	(8,713)	47,863
Net changes in income taxes	**(39,954)**	2,735	(26,051)
Total revisions and changes	**42,732**	(5,978)	21,812
Discounted future net cash flows, at beginning of year	**146,741**	152,719	130,907
Discounted future net cash flows, at end of year	**$189,473**	$146,741	$152,719

Five-Year Financial Review

	1985	1984	1983	1982	1981
		(Expressed in thousands of dollars except per share amounts)			
Statement of Earnings					
Revenue					
Crude oil	**$ 68,137**	$ 67,356	$ 57,056	$ 40,727	$ 30,106
Natural gas	**20,461**	18,722	17,943	12,503	10,449
Natural gas liquids	**3,038**	3,036	2,599	1,406	1,202
Sulphur	**2,931**	1,317	1,381	1,149	2,258
Mining	**—**	—	—	310	7,731
Other	**8,315**	5,077	3,367	832	1,099
	102,882	95,508	82,346	56,927	52,845
Expense					
Operating and general	**17,300**	15,750	14,437	14,144	22,179
Depletion and depreciation	**16,942**	15,715	15,029	9,713	9,111
Other	**792**	965	1,040	2,452	3,621
	35,034	32,430	30,506	26,309	34,911
Earnings before taxes	**67,848**	63,078	51,840	30,618	17,934
Taxes	**37,716**	38,180	29,377	16,294	9,352
Net earnings	**$ 30,132**	$ 24,898	$ 22,463	$ 14,324	$ 8,582
Earnings per share	**$ 2.25**	$ 1.86	$ 1.68	$ 1.07	$ 0.64
Statement of Changes in Financial Position					
Funds from operations	**$ 62,213**	$ 61,831	$ 52,704	$ 29,709	$ 21,552
Changes in non-cash working capital	**23,801**	(20,678)	(14,872)	(344)	3,029
Cash used for investment	**(51,183)**	(44,402)	(15,513)	(20,188)	(21,311)
Cash obtained from (used for) financing	**(1,480)**	760	(546)	(5,860)	(8,583)
Increase (decrease) in cash*	**$ 33,351**	$(2,489)	$ 21,773	$ 3,317	$(5,313)
Funds from operations per share	**$ 4.64**	$ 4.62	$ 3.94	$ 2.22	$ 1.61
Capital Expenditures After PIP Grants					
Oil and gas					
Land acquisition	**$ 5,203**	$ 4,421	$ 773	$ —	$ 1,407
Exploration	**24,994**	23,194	9,760	3,594	2,476
Development	**15,741**	17,438	9,355	15,325	13,771
Mining	**142**	44	213	1,692	3,752
Other	**156**	95	102	106	261
	$ 46,236	$ 45,192	$ 20,203	$ 20,717	$ 21,667
Working capital (deficiency)	**$ 63,427**	$ 53,877	$ 35,688	$ (957)	$(4,618)
Total assets	**$312,503**	$256,600	$211,535	$177,412	$153,112
Long term debt (including current portion)	**$ 4,189**	$ 6,897	$ 7,720	$ 9,417	$ 15,908
Shareholders' equity	**$175,627**	$143,947	$119,049	$ 96,586	$ 82,262
Shares outstanding at end of year	**13,462,129**	13,391,780	13,391,780	13,391,780	13,391,780
Return on average shareholders' equity	**18.9%**	18.9%	20.8%	16.0%	11.0%

The above data incorporates retroactive adjustments.

* Cash is defined as short term investments and advances to parent company, less bank indebtedness.

Five-Year Operating Review

	1985	1984	1983	1982	1981
Production/Sales Data[1]					
Crude oil					
— barrels per day	**7,101**	7,304	7,227	6,460	7,070
— average price per barrel	**$34.26**	$33.42	$29.16	$23.19	$16.18
— average royalty rate	**23.3%**	24.6%	26.1%	25.6%	29.4%
Natural gas liquids					
— barrels per day	**369**	405	371	264	253
— average price per barrel	**$28.37**	$26.92	$24.82	$18.67	$16.29
— average royalty rate	**20.6%**	23.8%	22.2%	21.8%	20.0%
Natural gas					
— thousands of cubic feet per day	**24,391**	21,711	20,622	16,824	16,593
— average price per thousand cubic feet	**$2.73**	$2.84	$2.80	$2.46	$2.34
— average royalty rate	**16.0%**	16.9%	14.9%	17.4%	26.3%
Sulphur					
— long tons per day	**104**	67	62	53	90
— average price per long ton	**$90.23**	$63.74	$67.10	$72.70	$75.34
— average royalty rate	**14.4%**	15.3%	9.6%	19.3%	9.0%
Drilling Activity (working interest wells)[2]					
Gross exploratory					
Oil	**65**	31	4	2	2
Gas	**51**	23	1	1	3
Dry	**94**	59	4	4	2
Gross development					
Oil	**129**	102	28	15	22
Gas	**27**	22	7	12	14
Dry	**47**	35	9	8	4
Total	**413**	272	53	42	47
Net exploratory[3]					
Oil	**6.68**	5.07	1.20	0.28	0.76
Gas	**2.69**	2.23	0.08	0.67	1.43
Dry	**5.25**	4.99	1.49	0.49	0.03
Net development[3]					
Oil	**9.40**	15.81	6.87	6.49	5.09
Gas	**0.74**	0.61	0.42	1.67	2.17
Dry	**4.24**	2.45	1.87	5.47	1.31
Total	**29.00**	31.16	11.93	15.07	10.79
Proved Reserves (before royalties)					
Crude oil — thousands of barrels	**19,675**	17,203	15,945	17,259	21,847
Natural gas liquids — thousands of barrels	**2,183**	1,975	1,610	1,686	2,937
Natural gas — billions of cubic feet	**201.5**	192.8	178.9	169.0	183.1
Sulphur — thousands of long tons	**324.0**	340.7	366.9	366.0	581.5
Oil and Gas Landholdings (thousands of acres)[2, 4]					
Gross Undeveloped	**4,424**	3,388	3,561	4,054	4,369
Net Undeveloped	**1,143**	1,072	1,350	1,395	1,550
Gross Developed	**639**	776	730	739	683
Net Developed	**97**	131	124	126	131

[1] Average daily production/sales and average prices are before the deduction of royalties.

[2] Gross includes the interests of others; net excludes the interests of others.

[3] The 1981 data incorporates adjustments to net well calculations.

[4] Overriding royalty interests are included in gross acres, but excluded in net acres.

Corporate Information

Board of Directors

+ **Robert G. Black, Q.C.,**
Calgary, Alberta.
Barrister and Solicitor

Richard F. Haskayne,
Calgary, Alberta.
President and Chief Executive Officer of Home Oil Company Limited.
President and Chief Executive Officer of the Company.

+ **J. Gordon Hutchison, F.C.A.,**
Calgary, Alberta.
Financial Consultant

+ **John F. Langston,**
Calgary, Alberta.
Petroleum Engineer

Brian F. MacNeill,
Calgary, Alberta.
Vice President Finance of Home Oil Company Limited.
Vice President Finance of the Company.

Stanley G. Olson,
Spokane, Washington.
Corporate Director

David E. Powell,
Calgary, Alberta.
Senior Vice President Exploration of Home Oil Company Limited.
Senior Vice President Exploration of the Company.

William P. Wilder,
Toronto, Ontario.
Chairman of the Board of Consumers' Gas Company Ltd. and Director of Hiram Walker Resources Ltd.

+ Member of Audit Committee

Senior Officers

R. F. Haskayne
President and Chief Executive Officer

D. E. Powell
Senior Vice President Exploration

H. Alfaro
Vice President Production

F. Callaway
Vice President Corporate Affairs

B. F. MacNeill
Vice President Finance and Chief Financial Officer

K. A. McNeill
Vice President Administration

R. G. Watkins
Vice President Government and Industry Relations

D. E. Deakin
Corporate Secretary

A. R. Hagerman
Treasurer

E. Jorgensen
Comptroller

Principal Affiliate

Minerals Limited (50.0 percent)
P.O. Box 2850
Calgary, Alberta, Canada
T2P 2S5

Auditors

Price Waterhouse
Calgary, Alberta

Registrar and Transfer Agents

Guaranty Trust Company of Canada.
Calgary, Toronto, Montreal, Vancouver

The Canadian Imperial Bank of Commerce Trust Company.
New York, N.Y.

Share Information

Common Shares

	Prices			
	Toronto Stock Exchange (Cdn dollars)		American Stock Exchange (U.S. dollars)	
	High	Low	High	Low
Fiscal Year Ended September 30, 1985				
1st quarter	19¾	16¾	14⅞	12½
2nd quarter	21½	16⅞	16⅛	12¼
3rd quarter	22½	20½	17	14⅞
4th quarter	27	21½	20	15⅜
Fiscal Year Ended September 30, 1984				
1st quarter	19¾	16½	16¼	13⅛
2nd quarter	20	17⅞	16⅞	14¼
3rd quarter	19½	17	15⅛	12⅞
4th quarter	18¾	14½	14½	11

At September 30, 1985, the Company had 13,462,129 common shares issued and outstanding, held by 3,864 shareholders. Effective November 27, 1985, the Board of Directors authorized an annual payment of dividends of $0.50 per common share.

Stock Exchange Listings	Symbols
Toronto Stock Exchange	SCR
American Stock Exchange	SRB

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