BARRINGTON PETROLEUM LTD.

ANNUAL

INFORMATION FORM

Dated as of May 17, 1999

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ABBREVIATIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

"**m**"	thousands
"**mm**"	millions
"**mcf**"	thousands of cubic feet of natural gas
"**mcf/d**"	thousands of cubic feet of natural gas per day
"**mmcf**"	millions of cubic feet of natural gas
"**mmcf/d**"	millions of cubic feet of natural gas per day
"**bcf**"	billions of cubic feet of natural gas
"**bbls**"	barrels of oil and/or gas liquids
"**mbbls**"	thousands of barrels of oil and/or liquids
"**bbls/d**"	barrels per day
"**boe**"	barrels of oil equivalent (10 mcf of gas equals 1 barrel of oil)
"**mboe**"	thousands of barrels of oil equivalent
"**boe/d**"	barrels of oil equivalent per day
"**stb**"	stock tank barrels
"**mstb**"	thousands of stock tank barrels
"**MMBTU**"	millions of British Thermal Units
"**NGL**" or "**NGLs**"	natural gas liquids
"**ARTC**"	Alberta Royalty Tax Credit

THE CORPORATION

Barrington Petroleum Ltd. (the "Corporation" or "Barrington") was incorporated on July 27, 1982 under the provisions of the *Companies Act* (British Columbia) and was continued as a corporation under the *Business Corporations Act* (Alberta) (the “BCA”) by way of Certificate of Continuance on August 16, 1985. By Articles of Amendment on December 30, 1985 Barrington increased its authorized capital to an unlimited number of common shares and created a class of 2,000,000 Preferred Shares. Pursuant to an amalgamation made under the provisions of the BCA, effective June 30, 1987, Barrington was amalgamated with Interwest Resources Ltd. and continued as Barrington Petroleum Ltd. In 1989 Barrington reorganized certain of its asset holdings. Effective September 7, 1995, the Corporation acquired all of the issued and outstanding shares of THE RIMOIL CORPORATION ("Rimoil"). Pursuant to an amalgamation made under the provisions of the BCA, effective January 22, 1996 Rimoil was amalgamated with Barrington and continued as Barrington Petroleum Ltd. On May 27, 1996, the Corporation acquired all of the issued and outstanding shares of Sherritt Energy Corporation ("Sherritt Energy"). Pursuant to an amalgamation made under the provisions of the BCA, effective January 1, 1997 Sherritt Energy was amalgamated with Barrington and continued as Barrington Petroleum Ltd. On April 4, 1997, the Corporation acquired substantially all of the issued and outstanding shares of Cube Energy Corp. ("Cube"), acquiring the remaining Cube shares on April 21, 1997. Pursuant to an amalgamation made under the provisions of the BCA, effective May 1, 1997 Cube was amalgamated with Barrington and continued as Barrington Petroleum Ltd. On September 4, 1998, over 80% of the outstanding common shares of Barrington were tendered to on offer by Sunoma Energy Corporation (“Sunoma”). Sunoma extended the offer acquiring additional common shares and currently holds approximately 97% of the outstanding common shares of Barrington.

The address of Barrington's registered, principal and head office is Suite 2200, 400 - 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

THE BUSINESS

Barrington is a full cycle exploration and production company, whose principal business is the exploration for and development and production of natural gas and crude oil. The Corporation carries on business primarily in Western Canada and particularly in the provinces of Alberta and Saskatchewan. As at December 31, 1998, the Corporation employed no permanent personnel in its operations. Sunoma provides the required administrative and technical staff.

Barrington’s objective is growth of shareholder value through selective corporate and property acquisitions and dispositions combined with prudent medium to low risk development and exploration activity. To provide effective management of the Corporation’s assets, Barrington's properties are currently segmented into five geographic regions, principally in Alberta and Saskatchewan. The Corporation continually seeks development and exploration opportunities in its core areas which compliment existing assets or can be enhanced with the technical or managerial strengths and experience within Barrington. High working interests, large land positions and operatorship are some of the common characteristics sought by the Corporation. As part of the overall management of its assets, the Corporation also regularly reviews its properties to determine whether it has sufficiently assessed the extent of development opportunities in a project and its strategic value relative to the Corporation’s plans for the region. Mature and non-strategic assets are sold at appropriate market windows. The Corporation's strategy is to ensure that as each project matures or is sold, new projects in earlier phases of the cycle are coming up behind to ensure continued growth.

In April 1998, Barrington issued $50 million principal amount of Natural Gas Linked Subordinated Notes (the “Gas Notes”). The Gas Notes bear interest at a rate which varies quarterly from a minimum of 6.5% to a maximum of 12% per annum, depending on Alberta natural gas prices ranging between $2.00 and $2.69 per gigajoule. The actual interest rate on the Gas Notes was 6.5% from the date of issuance to September 30, 1998 and 9.24% for the fourth quarter. At maturity on July 30, 2003, Barrington will have the option of repaying the Gas Notes by issuing common shares. During 1998, Barrington proposed certain amendments to the terms of the Gas Notes which were approved by the note holders. At the time of the closing of a refinancing, which contemplates an ongoing public company, Barrington will relinquish its right to implement the previously proposed amendments to the Gas Notes.

With the acquisition of Barrington by Sunoma, Barrington is no longer eligible for Alberta Royalty Tax Credit benefits. As a result of its acquisition, Barrington has undertaken a review of its oil and gas properties to identify those which are of less significance to the consolidated entity. During 1999, Barrington anticipates the disposition of a number of these minor properties.

Land Holdings

A cornerstone of Barrington's operational strategy is control of a large undeveloped land base within its core areas. This critical asset provides the basis for the generation of prospects which fuel future growth.

The following table sets out the Corporation's undeveloped land holdings as at the dates indicated together with the value attributed thereto by Seaton-Jordan & Associates Ltd. in reports effective December 31, 1998 and December 31, 1997, respectively (the "Seaton-Jordan Reports"). The evaluations in the Seaton-Jordan Reports were based on a review of land sale activity at the time of the effective dates of the respective Seaton-Jordan Reports.

	December 31, 1998	December 31, 1997

Province	Gross[(1)] Acres	Net[(2)] Acres	Value m	Gross[(1)] Acres	Net[(2)] Acres	Value m
Alberta	888,158	574,514	$37,533	955,988	647,656	$37,515
Saskatchewan	326,045	297,491	13,276	288,596	274,740	16,821
Manitoba	37,474	37,414	1,075	37,790	37,573	1,725
British Columbia and N.W.T.				2,582	274	3
Total	1,251,677	909,419	$43,884	1,284,956	960,243	$56,064
Average working interest		72.7%			74.7%	

Notes:
(1) "Gross Acres" refers to the total acres in which Barrington has an interest.
(2) "Net Acres" refers to the total acres in which Barrington has an interest multiplied by the percentage working interest.

Major Properties

Barrington's project areas are grouped within five regions: Central Alberta, Northwest Alberta, Northeast Alberta, Southeast Saskatchewan and Southern Alberta.

In 1998, the Corporation continued its program to either sell or swap non-strategic and minor assets in order to streamline operations and redirect resources towards core areas of activity. By year end, the Corporation had sold properties for proceeds totaling approximately $8.5 million. In addition, Barrington exchanged certain producing assets for interests in plants and facilities. Barrington will continue this rationalization process in 1999, reducing the number of properties under management while recycling capital into areas that can be aggressively enhanced by the Corporation's technical teams.

An east-west line at township 73, from the fifth meridian to British Columbia, divides the Corporation's holdings into two distinct core growth regions, Central Alberta and Northwest Alberta. The Central Alberta region is centered on the Corporation's single largest natural gas project at Greencourt, while the Northwest Alberta region consists primarily of natural gas and light oil production from the Zama/Larne, Hotchkiss, and Rainbow areas.

Central Alberta Region

Central Alberta is the Corporation's second largest region as measured by production and reserves, with 27% of total proven plus risked probable reserves at year end. In 1994, an interest was acquired at Greencourt with one well producing 600 mcf/d of gas net to Barrington. In 1998, Greencourt was the Corporation's largest single producing area, averaging 1,500 boe/d.

Production in this region in 1998 averaged 17.8 mmcf/d of gas and 959 bbls/d of oil and NGLs. Exit production rates were 13.4 mmcf/d of gas and 575 bbls/d of oil and NGLs, representing 14% of total exit production on a boe basis. Barrington drilled 12 (8.9 net) wells in Central Alberta in 1998, resulting in three (2.5 net) oil wells, three (0.9 net) gas wells and six (5.5 net) dry holes. Capital expenditures totaled $14 million in 1998. As at December 31, 1998 the Corporation owned 140,392 net acres of undeveloped land in the region. Principal project areas in the Central Alberta region include Greencourt and Sakwatamau.

Greencourt Project Area

Greencourt is the Corporation's most significant individual project area, in terms of both reserve value and production potential. This property includes the adjacent Paddle River and Leaman areas and is located approximately 90 miles northwest of Edmonton. The main gas reservoir is the Jurassic Nordegg reservoir. Natural gas production averaged 9.5 mmcf/d in 1998, while liquids production averaged 536 bbls/d. Gas production fell in 1998, from 13.5 mmcf/d at the beginning of the year to 5.0 mmcf/d in December due to limited drilling success and overly aggressive production of wells. As a result, following the Sunoma takeover, Barrington deferred further drilling until an assessment of the property, including the results of a seismic program then in progress, was completed. In December 1998, the project was also contributing over 150 bbls/d of NGLs and 107 bbls/d of oil production. The Corporation's land position in this area totals 111,360 (85,751 net) acres, including 60,640 (56,077 net) undeveloped acres. Reserves at December 31, 1998 totaled 48.8 bcf of natural gas and 2.0 mmbbls of oil and liquids on a proven plus risked probable basis. The present value of future cash flow before income tax, administration and financing costs, discounted at 15%, is estimated at $41.1 million or 16% of total future cash flow.

Seven wells were drilled at Greencourt in 1998 resulting in six dry holes (5.5 net) and one (0.5 net) oil well. The Corporation added to its land position in the area and plans to drill a minimum of five additional wells in 1999. Barrington has become the single largest owner of the Paddle River gas plant with a 39% interest, equating to 32 mmcf/d of processing capacity. In March 1998, Barrington exchanged its deep sour gas reserves at Millarville for reserves and plant interests at Paddle River. The Corporation recently participated in a 48 square mile 3-D seismic program shot over its undeveloped acreage in this area. The program generated up to 28 locations for the 1999 and 2000 drilling programs.

Sakwatamau Project Area

The Sakwatamau property is located 125 miles northwest of Edmonton where Barrington has significant land holdings of 14,720 gross acres. The property consists of five 100% producing oil wells, one shut-in oil well and one 100% shut-in gas well. Natural gas production averaged 1 mmcf/d in 1998, while liquids production averaged 281 bbls/d. Production at the end of 1998 was approximately 198 bbls/d of liquids and 1 mmcf/d of solution gas. Net proven plus risked probable reserves are 1.4 mmbbls of oil and NGL and 4.6 bcf of gas. In 1998, Barrington drilled two 100% oil wells. Barrington has an average working interest of 90% in the remaining 13,200 acres of undeveloped lands. 3-D seismic data has the identified of an additional five locations which could add up to 1.0 million barrels of incremental oil reserves. Two wells are planned to be drilled during 1999 and 2000.

Northwest Alberta Region

Northwest Alberta is the Corporation's third largest region as measured by production and reserves, with 16% of Barrington's total proven plus risked probable reserves at year end 1998. The majority of the assets acquired with the Cube acquisition in April 1997 are located in this region. Production in 1998 averaged 15.5 mmcf/d of gas and 623 bbls/d of oil and NGLs. Exit production rates were 13.6 mmcf/d of gas and 694 bbls/d of oil and NGLs, representing 15% of total production on a boe basis. Barrington drilled 16 (8.5 net) wells in Northwest Alberta in 1998, resulting in 2 (0.5 net) oil wells, 6 (3.6net) gas wells and 8 (4.4 net) dry holes. Capital expenditures totaled $22 million in 1998. As at December 31, 1998, the Corporation owned 275,099 net acres of undeveloped land in the region. Principal project areas in the Northwest Alberta region include Zama/Larne, Hotchkiss and Rainbow.

Zama/Larne Project Area

Two (1.25 net) wells were drilled at Zama/Larne in the first quarter of 1998. Drilling resulted in one (1.0 net) gas discovery, and one (0.25 net) oil well. Barrington holds working interests ranging from 50%-90% interest in the wells in this area. Exit production at Zama/Larne was 9.1 mmcf/d of gas and 118 bbls/d of oil and NGLs. Field compression has been installed to maximize deliverability. Negotiations with the plant operator to improve the processing agreement have commenced.

Hotchkiss Project Area

Barrington's property interests at Hotchkiss, located 60 miles northwest of Peace River, were originally acquired in December 1995. Activity in this area has been evenly divided between development of moderate depth gas reserves and deeper light oil reserves, the latter in the Hotchkiss Gilwood sand pools. Barrington increased its land position in 1998 to 174,994 gross acres at year end. Most exploration activity in this area is confined to the winter months as it is dependent on frozen ground for access. The established road system in the producing fields allows for year-round access for development drilling.

At Hotchkiss, six wells were drilled in 1998, with a 50% working interest. Two wells were cased for gas in Debolt and Gething/Bluesky reservoirs with four dry holes. Natural gas production averaged 4.9 mmcf/d in 1998, while liquids production averaged 270 bbls/d. Production at the end of 1998 was 4.1 mmcf/d of natural gas and 273 bbls/d of oil and NGLs.

Rainbow Project Area

Three (2.1 net) wells were drilled at Rainbow early in the year. Drilling resulted in one (0.9 net) Slave Point gas discovery, one (0.9 net) Shunda gas discovery and one (0.4 net) dry hole. These two gas discoveries have potential for greater than 50 bcf of gas in place. Delineation of the two pools is planned for the upcoming winter drilling season with six potential wells.

Northeast Alberta

The Northeast Alberta Region is currently the Corporation's largest region as measured by production, and the second largest region as measured by reserves, with 24% of total proven plus risked probable reserves at year end. This region, from extreme western Saskatchewan, northward through the Cold Lake area of eastern Alberta, and on to Thornbury, west of Fort McMurray, was Barrington's main growth area in gas production from early 1992 to 1996. This region is mature and 1998 drilling essentially offset field declines. The majority of 1998 activity concentrated on two projects: Senlac/Hallam, targeting Sparky sand and Thornbury, targeting Grand Rapids and McMurray sands.

Production in this region in 1998 averaged 51.1 mmcf/d of gas, which represents 56% of the Corporation’s total gas production, and 653 bbls/d of oil. Exit production rates were 48.8 mmcf/d of gas and 571 bbls/d of oil, representing 40% of total production on a boe basis. Barrington drilled 19 (14.5 net) wells in the region in 1998, resulting in 15 (10.0 net) gas wells and five (4.5 net) dry holes. Capital expenditures totaled $13 million in 1998. As at December 31, 1998, the Corporation owned 141,605 net acres of undeveloped land in the region. Principal project areas in the Northeast Alberta include Peter/Meyer, Kent, Senlac, Hallam, Salvador, Thornbury and a number of heavy oil properties.

Peter/Meyer Project Area

Production from this area, located approximately 90 miles north of Edmonton, averaged 11.2 mmcf/d of gas in 1998 or 12.3% of the Corporation’s total average 1998 gas production. This area had proven plus risked probable reserves of 25.3 bcf at year end 1998, approximately 10% of the Corporation’s gas reserves. One 100% working interest well was drilled and abandoned in 1998. Capital expenditures in the area totaled approximately $300,000 in 1998. This area has the lowest operating cost in the Corporation, averaging $2.35 per boe for 1998. Based on the high net backs and undeveloped land position, Barrington has plans to drill up to eight wells in the area for the 1999/2000 winter drilling season.

Kent Project Area

Barrington operates 25 (24.8 net) producing gas wells at the Kent project area, located on the Cold Lake First Nation. Gas production began in 1993 and is primarily from the Grand Rapids formation, with reserves also existing in other Mannville sands and the Viking zone. Production in 1998 averaged 8.1 mmcf/d, or 9% of the Corporation’s total gas production for the year. Proven plus risked probable reserves attributed to this project area were 11.9 bcf at year end, approximately 5% of total gas reserves. In 1998 two (1.8 net) gas wells were drilled on this property. Activity for 1999 includes drilling one well and several compression and gathering system debottlenecking projects.

Senlac Project Area

Barrington drilled a total of nine (8.8 net) wells in 1998 in the Senlac area, which includes the adjacent Hallam and Salvador areas. This drilling program resulted in six (5.9 net) gas wells and three (2.9 net) dry holes. Production from this area, averaged 9.3 mmcf/d of gas in 1998, increasing to 11.7 mmcf/d at year end. Proven plus risked probable reserves totaled 22.3 bcf or 8% of total Corporation’s gas reserves. Capital expenditures at Senlac totaled $2.8 million in 1998. In 1999, Barrington plans to drill up to six wells in this project.

Thornbury Project Area

Located south of Fort McMurray, the Thornbury project was Barrington's entry into the Northeast Alberta region in 1989. The project is now largely non-operated, with an average working interest of 33% in the developed acreage. Average daily gas production was 4.5 mmcf/d during 1998, primarily from McMurray reservoirs supplemented by the Grand Rapids formation. Production has been flat for several years as the facilities are at capacity and enough wells are drilled each year to maintain that production level. Reserves in the area constitute 2% of the Corporation's total gas volumes on a proven plus risked probable basis. Six (2.3 net) gas wells were drilled in 1998, with 100% success. The Corporation owns interests in three (1.9 net) compressor facilities, of which one (1.0 net) is operated by Barrington.

Heavy Oil

From exploration activity in eastern Alberta and western Saskatchewan, and as a result of acquisitions in 1996 and 1997, Barrington holds an inventory of heavy oil exploration and development projects. While Barrington has targeted reserves that can be produced economically under primary recovery methods, the returns on many of these projects are improved by their long term potential for enhanced recovery. Heavy oil projects represent 22% of the Corporation's total proven plus risked probable reserves at year end 1998. Production in 1997 averaged 1,517 bbls/d of oil. As a result of low prices Barrington shut-in its lower net back heavy oil production from April to December. With the return of higher oil prices in the spring of 1999, some of the shut-in wells have been reactivated. Barrington did not drill any heavy oil wells in the region in 1998 due to low oil prices. Capital expenditures totaled $0.1 million.

Principal project areas include Cold Lake First Nations, Derwent/Swimming, the Meridian project area near Lloydminster and Lashburn in western Saskatchewan. As at December 31, 1998 the Corporation owned 8,060 net acres of undeveloped land in these areas. The Corporation continues to view heavy oil as an important long term strategic asset.

Derwent/Swimming Project Area

Most of Barrington's heavy oil production in 1998 was from wells at Derwent and Swimming. During 1998, production from these properties rose from 994 bbls/d at the beginning of the year to 1,157 bbls/d in December. Proven and risked probable oil reserves assigned to this area at year end were 1.7 mmbbls. Although operating costs averaged over $8.00/bbl in 1998, reductions are expected as volumes increase.

Cold Lake First Nations Project Area

In 1997, a significant heavy oil agreement was secured with Cold Lake First Nations. Although heavy oil had been identified in several Cretaceous zones as a result of earlier gas exploration and development on these lands, Barrington's main interest was in determining oil production capabilities from the Sparky and Grand Rapids reservoirs. The Corporation has five 100% wells in the area. Target reservoirs produce lower viscosity oils similar to those produced from immediately adjacent Beaverdam fields. The Corporation estimates that approximately 500 million barrels of Original Oil In Place underlie the Cold Lake First Nations project. A portion of this volume has now been proved as capable of primary production from the Grand Rapids and Sparky formations. At year end 1998, 5.9 mmbbls of proven plus risked probable oil reserves or 12% of the Corporation's total reserves were booked to this property. A major development initiative will be directed to these lands once margins improve to a level that justifies the expenditures. Barrington plans to re-activate its shut-in production in 1999 to reassess the technical and economic viability at current prices.

Meridian Project Area

This multi-zone heavy oil play is located in Alberta, near Lloydminster. Production in 1998 averaged 264 bbls/d and the waterflood program will be expanded when oil prices rise to increase both production rates and recovery factors. No development drilling activities are planned for 1999.

Lashburn Project Area

Barrington has a 41% working interest at Lashburn, located approximately 30 miles east of Lloydminster. A total of 19 wells were drilled in 1997 to initiate development of a Waseca sand pool containing estimated oil in place of 28 million barrels of 12 degree API oil of which only 552,000 barrels are recognized as proven and risked probable reserves. Fifteen of the wells were drilled from two pads and were equipped to begin cyclical steam injection. Peak production of 800 bbls/d was achieved under primary recovery before implementation of the steam flood was postponed due to the drop in world oil prices. The project was “shut in” in early 1998 and for that reason, only averaged 41 bbls/d production. Barrington has recently re-started the primary production and has plans to initiate steam injection in late 1999 or early 2000.

Southeast Saskatchewan Region

The southeast corner of Saskatchewan and the adjacent western extremities of Manitoba make up the Canadian portion of the Williston Basin. The centre of deposition of the Williston Basin lies just to the south, within the United States. The geology of the Williston Basin is considerably different than the Alberta Basin. Most of the established oil production in the Williston Basin is from Mississippian limestone reservoirs. The Cretaceous and Jurassic sections overlying the Mississippian are not generally oil bearing, unlike the Alberta Basin where these reservoirs make up a very large part of conventional oil and gas plays. Light oil production also occurs in several deeper zones.

Southeast Saskatchewan is the Corporation’s smallest region, with 9% of total proven plus risked probable reserves at year end. Oil production in 1998 averaged 1,910 bbls/d, and at year end was 1,537 bbls/d, representing 11% of total exit production on a boe basis. Barrington drilled three (2.0 net) wells in Southeastern Saskatchewan in 1998 which resulted in one (1.0 net) well for a 33% success rate. A further well was drilled under farmout and royalty arrangements at no cost to Barrington. Capital expenditures totaled $4 million in 1998. As at December 31, 1998, the Corporation owned 278,507 net acres of undeveloped land in the region, including lands in western Manitoba. Principal producing project areas in Southeastern Saskatchewan include working interests at Wapella, Weyburn and royalty interests, principally at Moose Valley.

Wapella Project Area

This property is located 120 miles east of Regina and straddles the Saskatchewan and Manitoba border. At Wapella, which is the largest property in this region, the Corporation’s objective is to maximize development of the Jurassic sand reservoir in which it owns and operates 45 oil wells which are produced into Barrington’s 100% owned and operated facility. During 1998, production at Wapella fell from 2,044 bbls/d at the beginning of the year to 1,235 bbls/d in December primarily due to declines exhibited by two very prolific 1997 wells. Average production was 1,499 bbls/d. Current production is limited by the water handling capacity which will be expanded in 1999. The Corporation expects transportation costs to be reduced because of the recent construction of a sales pipeline to the Wapella property. Barrington plans to conduct a five well development drilling program in 1999 along with 10 recompletions. While the first horizontal well ever attempted in this field produced oil at rates as high as 700 bbls/d, it had declined to 125 bbls/d by year end. Barrington is currently reviewing its plan to drill another horizontal well higher into the structural feature which could restore production to early 1998 levels.

Weyburn Project Area

This property is located 60 miles west of Wapella and 85 miles southeast of Regina. All three 100% owned and operated Barrington wells produce from the Mississippian aged, carbonate Midale zone to single well batteries with emulsion trucked to third party processing facilities. During 1998, production at Weyburn fell from 327 bbls/d at the beginning of the year to 212 bbls/d in December and averaged 263 bbls/d. Barrington intends to construct a battery including water disposal facilities to reduce operating costs during 1999. Barrington intends to drill several horizontal development wells in 1999 and 2000 to increase current production.

Moose Valley Project Area

The Corporation owns royalty interests varying from 5% to 20% on fee simple lands which have been leased to a third party operator of approximately 30 producing oil wells in the area. Moose Valley represents Barrington's largest royalty interest area, currently contributing approximately $60,000 per month cash flow of the Corporation's $230,000 per month royalty income.

Southern Alberta Region

During 1997, Barrington further reduced its activity in Southern Alberta. The properties were mature and did not offer the growth potential necessary to achieve corporate targets. The region comprised 3% of Barrington's total proved plus risked probable reserves at year end. Production in 1998 averaged 5.2 mmcf/d of gas and 523 bbls/d of oil and NGLs. Exit production rates were 3.7 mmcf/d of gas and 432 bbls/d of oil and NGLs, representing 6% of total production on a boe basis. Barrington drilled one (1.0 net) successful oil well in Southern Alberta in 1998. Capital expenditures in the region were $3 million. As at December 31, 1998, the Corporation owned 17,419 net acres of undeveloped land in the region. The most significant remaining project area is at Jumpbush. The Corporation's working interests in producing properties at Millarville were swapped for additional gas plant ownership at Paddle River effective April 1, 1998.

Jumpbush Project Area

Barrington has an eleven year history in this project area, located on the southern portion of the large Siksika Nation and adjacent lands southeast of Calgary. Successful discoveries of light to medium gravity crudes in the Glauconite and Basal Quartz reservoirs and gas in the Bow Island, Basal Quartz, Glauconite, Belly River and Medicine Hat zones have been made. A waterflood was initiated in 1995 and has been expanded since that time. Production averaged 411 bbls/d of oil and NGLs and 2.2 mmcf/d of natural gas in 1998. The waterflood is expected to increase the pool oil recovery factor from 30% under primary production methods to 40%.

Marketing

Natural Gas

Following the Sunoma takeover, the Corporation's natural gas strategy shifted to maintaining direct control of the marketing of Barrington's gas production which we expect will enable us to realize higher prices. Barrington has developed a geographically diverse portfolio of natural gas sales and transportation contracts that allows Barrington to benefit from sales price exposure in markets across North America.

The recent addition of approximately 1.2 bcf/d of new export pipeline capacity on the Northern Border Pipeline and the TransCanada Pipeline systems have been beneficial for the prices of spot gas sold in the Alberta market. The historic discount from US market prices attributed to "trapped" gas in

Alberta has been eliminated. Thus, Barrington's short term focus is to position a significant portion of its natural gas production to benefit from the higher prices being paid for Alberta index gas.

Throughout the calendar year Barrington was purchasing natural gas in excess of its production to fulfill its contractual sales commitments. As at September 4, 1998 when Sunoma acquired Barrington, Barrington was purchasing approximately 25 mmcf/d on the spot market. With production declining at 2% per month this shortfall was expected to grow to 35 mmcf/d by year end. Barrington has been able to renegotiate a number of contracts and make alternative purchase arrangements such that this obligation has been reduced to 10 mmcf/d of spot purchases and will be eliminated by the end of the current gas contract year, October 31, 1999.

Oil

Barrington markets light and medium crude oil to various buyers under purchase and sale agreements that may be terminated on either 30 or 60 days notice. Each buyer is responsible for ensuring that lease barrels are directed to the pipeline system returning the highest netback as well as assisting the Corporation in optimizing quality differentials and trucking charges to the lease. These arrangements have historically provided Barrington with crude oil prices that are at a premium to industry average postings.

At the end of 1998, heavy oil represented approximately 24% of Barrington's crude oil and liquids production and 10% of total production on a boe basis. Barrington markets its current heavy oil production to a heavy oil refiner located in Regina, Saskatchewan. Pricing under this contract is based on a higher of a floor price of US $10.50 per barrel at Hardisty or the market price. This pricing structure has ensured the economic viability of Barrington's heavy oil production. The Corporation is currently researching and evaluating various heavy oil risk management strategies and may implement a program to secure heavy oil production economics in the event of either continued low global crude oil prices or widening heavy oil differentials.

Oil and Gas Reserves

Sproule Associates Limited, independent geological and petroleum engineering consultants of Calgary, Alberta, has prepared a report (the "Sproule Report") addressed to the Corporation and dated January, 15, 1999, effective December 31, 1998, evaluating the crude oil, natural gas and NGL reserves attributable to the principal properties of the Corporation and the cumulative cash flow derived therefrom, based on both constant and escalating price assumptions.

The Sproule Report was generated to evaluate in detail Barrington's major properties, including Greencourt, Peter, Wapella, Sakwatamau, Rainbow, Hotchkiss, Kent, Zama, Senlac and Cold Lake. Some of the minor properties were evaluated by Barrington engineers. Approximately 83% of total proven reserves of the Corporation based on present worth discounted at 15% were evaluated by Sproule.

The Sproule Report is summarized below. **Future cash flow projections in the Sproule Report are after deduction of royalties, operating costs and anticipated capital expenditures and prior to provision for income taxes, administrative overhead, and reclamation and abandonment costs. It should not be assumed that the discounted net pre-tax cash flow estimated by the Sproule Report represents the fair market value of the reserves.** Other assumptions and qualifications relating to costs, prices of future production and other matters are summarized in the notes following the tables. There is no assurance that the price and cost assumptions will be attained and variations could be material.

The oil and gas reserve calculations and cash flow projections upon which the Sproule Report is based, were determined in accordance with generally accepted evaluation practices. The extent and character of ownership and all factual data supplied by the Corporation to Sproule Associates Limited for the preparation of the Sproule Report were accepted as represented. No field inspection was considered necessary by Sproule Associates Limited.

PETROLEUM AND NATURAL GAS RESERVES AND NET PRE-TAX CASH FLOW, (BASED ON ESCALATING PRICE ASSUMPTIONS)

	Corporation's Share of Remaining Reserves						Corporation's Share of Future Cash Flow[9]			
	Crude Oil		Natural Gas[3]		NGLs		Undis-counted	Discounted at		
	Gross[1] mstb	Net[2] mstb	Gross[1] mmcf	Net[2] mmcf	Gross[1] mbbl	Net[2] mbbl	m$	10% m$	15% m$	20% m$
Proven Developed										
Producing[4]	9,190	8,219	137,213	108,570	1,091	757	286,276	193,096	167,889	149,299
Non-Producing[5]	698	615	18,036	13,684	201	137	29,703	18,255	15,227	13,030
Proven Undeveloped[6]	4,540	4,069	82,148	63,909	1,133	793	113,285	61,851	47,562	37,235
Total Proven[7]	14,428	12,902	237,397	186,163	2,425	1,687	429,264	273,202	230,679	199,564
Probable Additional[8]	11,701	10,554	56,048	43,291	587	406	175,203	76,119	55,400	42,015
Total	26,129	23,456	293,445	229,454	3,012	2,093	604,467	349,321	286,078	241,579
50% Reduction due to Risk[8]	(5,850)	(5,277)	(28,024)	(21,646)	(294)	(203)	(87,602)	(38,060)	(27,700)	(21,008)
Total After Risk	20,278	18,179	265,421	207,808	2,718	1,890	516,865	311,261	258,378	220,571

PETROLEUM AND NATURAL GAS RESERVES AND NET PRE-TAX CASH FLOW, (BASED ON CONSTANT PRICE ASSUMPTIONS)

	Corporation's Share of Remaining Reserves						Corporation's Share of Future Cash Flow[9]			
	Crude Oil		Natural Gas[3]		NGLs		Undis-counted	Discounted at		
	Gross[1] mstb	Net[2] mstb	Gross[1] mmcf	Net[2] mmcf	Gross[1] mbbl	Net[2] mbbl	m$	10% m$	15% m$	20% m$
Proven Developed										
Producing[4]	8,907	7,991	136,042	107,987	1,088	754	243,215	173,069	152,770	137,398
Non-Producing[5]	674	602	17,968	13,711	201	137	24,635	15,980	13,553	11,746
Proven Undeveloped[6]	1,402	1,144	81,643	63,810	1,131	792	87,642	52,963	42,829	35,278
Total Proven[7]	10,983	9,737	235,653	185,508	2,420	1,683	355,492	242,011	209,151	184,421
Probable Additional[8]	10,340	9,602	54,551	42,533	575	397	107,478	50,903	37,791	28,913
Total	21,322	19,340	290,204	228,041	2,995	2,080	462,970	292,914	246,942	213,334
50% Reduction due to Risk[8]	(5,170)	(4,801)	(27,276)	(21,266)	(287)	(199)	(53,739)	(25,452)	(18,896)	(14,456)
Total After Risk	16,152	14,539	262,928	206,775	2,708	1,881	409,231	267,462	228,046	198,878

Notes:

(1) **"Gross Reserves"** are defined as those accruing to the Corporation before deduction of all royalties and interests owned by others.

(2) **"Net Reserves"** are defined as those accruing to the Corporation after deduction of all royalties and interests owned by others.

(3) **"Natural Gas Reserves"** are reported at a base pressure of 14.65 psia and a base temperature of 60 degrees Fahrenheit.

(4) **"Proven Producing Reserves"** are those reserves that are actually on production or, if not producing, that could be recovered from existing wells or facilities and where the reasons for the current non-producing status is the choice of the owner rather than the lack of markets or some other reasons. An illustration of such a situation is where a well or zone is capable, but is shut-in because its deliverability is not required to meet contract commitments.

(5) **"Proven Non-Producing Reserves"** are those reserves that are not currently producing either due to lack of facilities and/or markets.

(6) **"Proven Undeveloped Reserves"** are proved reserves which are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreages are limited to those drilling units offsetting productive units, which are reasonably certain of production when drilled.

(7) **"Proven Reserves"** are those reserves estimated as recoverable under current technology and anticipated economic conditions, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economically and technically successful in the subject reservoir.

(8) **"Probable Additional Reserves"** are those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and anticipated economic conditions, but where such analysis suggests the likelihood of their existence and future recovery. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery process which can be reasonably expected to be instituted in the future. A risk adjustment factor of 50% has been applied to probable additional reserves to allow for geological and engineering risks associated therewith.

(9) **"Future Cash Flow"** is, in respect to oil and gas reserves, cash flow forecasts after direct lifting costs, normal allocated field overhead and future investments but before income taxes. Lessor royalties (Crown or freehold where applicable) in the Provinces of Alberta, British Columbia and Saskatchewan, as applicable to petroleum and natural gas, as revised from time to time, have also been utilized. The Future Cash Flow includes all projected third party gas gathering, gas processing and marketing fee income, and ARTC before income taxes.

(10) Oil and natural gas prices in the Sproule Report are assumed to escalate as follows:

	Light Crude Oil			Heavy & Medium Oil			Western Canadian Natural Gas		Natural Gas Liquids and Sulphur F.O.B. Field Gate or Plant		
	(Prices in Canadian Dollars)										
Year	(1.) WTI	(2.) Edmonton Par Price 40° API	(3.) Alberta Royalty Par Price	Hardisty Heavy 12° API	Cromer Medium 29.3° API	Hardisty Medium 25.7° API	Alberta	Sask.	Propane	Butanes	Pentanes Plus
	$US/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/Mmbtu	$/Mmbtu	$/bbl	$/bbl	$/bbl
1999	17.34	23.95	22.95	14.46	19.95	18.45	2.10	2.10	14.52	15.71	24.31
2000	18.73	25.18	24.18	16.18	21.18	19.93	2.12	2.12	14.93	16.14	25.32
2001	20.16	26.41	25.41	17.90	22.40	21.41	2.20	2.20	15.31	16.54	26.41
2002	20.57	26.95	25.95	18.40	22.90	21.91	2.28	2.28	15.63	16.47	26.95
2003	20.98	27.50	26.50	18.91	23.42	22.43	2.37	2.37	15.94	16.81	27.50
2004	21.40	28.06	27.06	19.44	23.95	22.97	2.46	2.46	16.27	17.15	28.06
2005	21.83	28.63	27.63	19.98	24.49	23.51	2.53	2.53	16.60	17.50	28.63
2006	22.26	29.21	28.21	20.53	25.05	24.06	2.61	2.61	16.94	17.85	29.21
2007	22.71	29.81	28.81	21.10	25.62	24.63	2.68	2.68	17.29	18.22	29.81
2008	23.16	30.42	29.42	21.68	26.20	25.21	2.75	2.75	17.64	18.59	30.42
2009	23.62	31.04	30.04	22.27	26.79	25.81	2.83	2.83	18.00	18.97	31.04
2010	24.10	31.67	30.67	22.87	27.40	26.41	2.92	2.92	18.37	19.36	31.67
Thereafter	Escalation rate 2.0% Thereafter										

Year	Alberta Gas Reference Price	Alberta AECO	Alberta Plantgate	Alberta Empress	Sask. Plantgate	B.C. Plantgate	B.C. Wellhead	Huntingdon/ Sumas 30 d Spot	Henry Hub Price $US/MMBtu
	$US/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
1999	2.10	2.25	2.10	2.41	2.10	2.10	1.69	2.46	2.15
2000	2.12	2.28	2.12	2.43	2.12	2.12	1.71	2.49	2.18
2001	2.20	2.36	2.20	2.52	2.20	2.20	1.77	2.57	2.28
2002	2.28	2.45	2.28	2.61	2.28	2.28	1.85	2.66	2.38
2003	2.37	2.54	2.37	2.70	2.37	2.37	1.93	2.76	2.46
2004	2.46	2.62	2.46	2.79	2.46	2.46	2.00	2.85	2.53
2005	2.53	2.70	2.53	2.87	2.53	2.53	2.07	2.93	2.61
2006	2.61	2.79	2.61	2.96	2.61	2.61	2.14	3.02	2.69
2007	2.68	2.86	2.68	3.04	2.68	2.68	2.20	3.10	2.75
2008	2.75	2.94	2.75	3.12	2.75	2.75	2.27	3.18	2.80
2009	2.83	3.02	2.83	3.21	2.83	2.83	2.34	3.27	2.86
2010	2.92	3.11	2.92	3.30	2.92	2.92	2.41	3.36	2.92
Thereafter	Escalation Rate 2.0% Thereafter								

Notes:

1. West Texas Intermediate - Cushing, Oklahoma.
2. Alberta Field Oil Price D2S2, 40° API and 0.5% Sulphur adjusted for gravity and transportation.
3. Edmonton Par less $1.00 per barrel.
4. Inflation is estimated to be 2.0% per year and the $US/$Cdn. exchange rate is estimated to be 0.69 in 1999 rising to 0.730 in 2001 and thereafter per year.

(11) The costs used in the production and revenue forecasts have been escalated by 0% in 1999, and by 2% thereafter.

(12) The constant price assumptions in the Sproule Report are based on Sproule average 1999 prices.

The prices are:

Crude Oil		$23.95/bbl
Heavy Oil		$14.46/bbl
Gas		$2.10/Mmbtu
Propane		$14.52/bbl
Butanes		$15.71/bbl
Pentanes		$24.31/bbl

(13) The undiscounted capital requirements included in calculating the above-noted cumulative cash flow are estimated to be $77,011,000 on the escalating price case ($48,396,000 for proven reserves, $28,615,000 for probable reserves) and $56,146,000 on the constant price case ($30,165,000 for proven reserves, $25,981,000 for probable reserves). The aggregate capital requirements during 1999 and 2000 are estimated to be $52,095,000 assuming the escalating price case and $46,917,000 assuming the constant price case. No government incentives are included in these capital requirements.

(14) Lease clean-up costs and well abandonment costs are assumed to be offset by salvage values.

(15) The Sproule Report was based upon data supplied by the Corporation with respect to interests owned, royalties payable and contractual commitments. No field inspection was conducted.

Reconciliation of Oil and Gas Reserves

The following is a reconciliation of the reserves of the Corporation from December 31, 1997 to December 31, 1998 (using the escalated pricing case, before royalties).

	Natural Gas (mmcf)			Oil &NGLs (mstb)			Oil Equivalent (mboe)		
	Proven	Probable	Total	Proven	Probable	Total	Proven	Probable	Total
Reserves									
December 31, 1997	243,824	48,439	292,263	28,325	20,752	49,077	52,707	25,596	78,303
Discoveries	12,642	924	13,566	206	0	206	1,470	93	1,563
Acquisitions	10,171	0	10,171	0	0	0	1,017	0	1,017
Dispositions	(12,154)	(7,670)	(19,824)	(478)	(298)	(776)	(1,693)	(1,065)	(2,758)
Production	(33,279)	–	(33,279)	(2,109)	–	(2,109)	(5,656)	–	(5,656)
Revisions	16,191	14,354	30,545	(8,872)	(8,165)	(17,037)	(7,252)	(6,731)	(13,983)
Reserves									
December 31, 1998	237,395	56,047	293,442	16,853	12,289	29,142	40,593	17,893	58,486

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Corporation has a working interest as at December 31, 1998 that are producing or which the Corporation considers to be capable of production:

	Producing				Non-Producing[1]			
	Oil		Gas		Oil		Gas	
	Gross[2]	Net[3]	Gross[2]	Net[3]	Gross[2]	Net[3]	Gross[2]	Net[3]
Alberta	246	176	312	188	78	55	236	130
Saskatchewan	73	56	49	39	27	19	14	12
Total	319	233	361	227	105	75	250	142

Notes:

(1) "Non-producing" wells means wells which have encountered and are capable of producing crude oil or natural gas but which are not producing due to lack of available transportation facilities, available markets or other reasons.
(2) "Gross" wells are defined as the total number of wells in which the Corporation has an interest.
(3) "Net" wells are defined as the aggregate of the numbers obtained by multiplying each gross well by the Corporation's percentage working interest therein.

Drilling History

Barrington drilled or participated in the drilling of the following wells for the periods indicated:

	Years ended December 31			
	1998		1997	
	Gross[1]	Net[2]	Gross[1]	Net[2]
Oil	7	4.5	124	92.9
Gas	28	17.1	48	22.1
Dry & abandoned	19	13.3	47	40.1
Total	54	34.9	219	155.1

Notes:

(1) "Gross" wells are defined as the total number of wells in which the Corporation has an interest.
(2) "Net" wells are defined as the aggregate of the numbers obtained by multiplying each gross well by the Corporation's percentage working interest therein.

Expenditures on Oil and Gas Exploration and Development

For the year ended December 31, 1997, the Corporation spent $24.4 million on exploration and $40.0 million on development. For the year ended December 31, 1998, the Corporation spent $14.9 million on exploration and $16.8 million on development.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive regulation governing its operations including land tenure, exploration, development, production, refining, transportation and marketing imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta, Saskatchewan and British Columbia, all of which should be carefully considered by investors in the oil and gas industry. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing - Oil and Natural Gas

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The price depends in part on oil quality, prices of competing oils, distance to market the value of refined products and the supply/demand balance. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board ("NEB"). Any oil export to be made pursuant to a contract of longer duration requires an export license from the NEB and the issue of such a licence requires the approval of the Governor in Council.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and Government of Canada. Exporters are free to negotiate prices with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than 2 years or for a term of 2 to 20 years (in quantities of not more than 30,000 m^3/day), must be made pursuant to a NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Governor in Council.

The governments of British Columbia, Alberta and Saskatchewan also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere, based on such factors as reserve availability, transportation arrangements and market considerations.

The North American Free Trade Agreement

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, United States of America and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada - US Free Trade Agreement. Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not (i) reduce the proportion of energy resources exported relative to domestic use, (ii) impose an export price higher than the domestic price, or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on well productivity, geographical location and field discovery date.

From time to time the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty reductions and royalty holidays, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. The trend in recent years has been for provincial governments to allow such programs to expire without renewal, and consequently few such programs are currently operative.

Crude oil and natural gas royalty holidays for specific wells and royalty reduction reduce the amount of Crown royalties paid by the Corporation to the provincial governments.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses and permits for varying terms from two years and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Environmental Regulation

The oil and gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties. In Alberta, environmental compliance has been governed by the *Alberta Environmental Protection and Enhancement Act* ("AEPEA") since September 1, 1993. In addition to replacing a variety of older statutes which related to environmental matters, AEPEA also imposes certain new environmental responsibilities on oil and natural gas operators in Alberta and in certain instances also imposes greater penalties for violations. Barrington believes that it is in material compliance with the currently applicable environmental laws and regulations and will be taking such steps as are required to ensure compliance with the AEPEA.

DIVIDEND POLICY

The Corporation has not paid any dividends on its outstanding common shares to date and it is unlikely that dividends will be paid in the foreseeable future as the Corporation expects that earnings will be retained to finance the growth of the Corporation's business. The future payment of dividends will be dependent upon the financial requirements of the Corporation to fund future growth, the financial condition of the Corporation and other factors which the board of directors of the Corporation may consider appropriate in the circumstances.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

Summary of Operating Results

The following table sets forth selected consolidated financial information of the Corporation for the five years ended December 31, 1998.

	Year Ended December 31				
	1998	1997	1996	1995	1994
	(m$, except per share amounts)				
Revenue before royalties	94,319	128,901	93,462	39,776	40,959
Cash flow	14,906	57,134	43,923	17,304	22,154
Net earnings (loss) for year[(1)]	(85,454)	4,948	9,481	2,361	7,943
Basic earnings (loss) per share[(2)]	(1.46)	0.09	0.21	0.07	0.29
Fully diluted earnings (loss) per share[(2)(3)]	(1.46)	0.09	0.20	0.07	0.29
Total assets	331,103	426,323	296,951	166,783	123,552
Long term debt	131,975	134,430	80,188	51,759	22,269
Cash dividends declared per common share	0.00	0.00	0.00	0.00	0.00

Notes:

(1) There were no extraordinary items included in net earnings for the five years ended December 31, 1998.

(2) Net earnings per share were calculated using the weighted average number of common shares outstanding.

(3) Assumes exercise of employee and other stock options and all other convertible securities on their dates of issue. The effect of the outstanding stock options on earnings per share is not materially different.

Quarterly Information

	Unaudited Quarter Ended							
	Dec. 31, 1998	Sept. 30, 1998	June 30, 1998	Mar. 31, 1998	Dec. 31, 1997	Sept. 30, 1997	June 30, 1997	Mar. 31, 1997
	(m$, except per share amounts)							
Oil and gas sales	22,368	21,572	22,831	27,548	32,963	31,531	30,946	33,461
Net earnings(1)	(65,171)	(12,083)	(5,755)	(2,445)	195	209	62	4,482
Basic earnings per share(2)	(1.11)	(0.20)	(0.10)	(0.04)	0.00	0.00	0.00	0.08
Fully diluted earnings per share(2)(3)	(1.11)	(0.20)	(0.10)	(0.04)	0.00	0.00	0.00	0.08

Notes:
(1) There were no extraordinary items included in net earnings for the five years ended December 31, 1998.
(2) Net earnings per share were calculated using the weighted average number of common shares outstanding.
(3) Assumes exercise of employee and other stock options and all other convertible securities on their dates of issue. The effect of the outstanding stock options on earnings per share is not materially different.

The data set out above is comparative in all material respects.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

Reference is made to the information under the heading "Management's Discussion and Analysis of Results of Operations and Financial Condition" contained in Barrington's annual report for the year ended December 31, 1998, which information is incorporated herein by reference.

RISK FACTORS

An investment in Barrington should be considered speculative due to the nature of the Corporation's financial position, its involvement in the exploration and acquisition, development, production and marketing of oil, NGLs and natural gas and its current stage of development. Barrington operates in an industry in which there are significant inherent risks, including commodity price and associated exchange rate fluctuations, changes in the demand for its products, limits on the ability to transport its commodities to markets, exploration risk, uncertainty with respect to reservoir performance, political and regulatory changes, competition from industry and increasingly stringent environmental and health and safety laws.

Barrington was recently advised by its lead senior lender that the borrowing base available under Barrington's existing credit facility has been redetermined to a level below the current amount outstanding. Pursuant to the notice, Barrington currently has until mid-July 1999, to reduce the outstanding loans to the newly established borrowing base. Sunoma and Barrington are in the process of working with their existing lenders and significant creditors on the terms of a refinancing plan and eliciting their support in its implementation. It is anticipated that the refinancing plan will resolve any current credit issues of Sunoma and Barrington. Failure to implement the refinancing plan could lead to an acceleration in the payment of all long term debt. The future of Barrington will depend upon its ability to successfully implement the refinancing plan or identify and execute an alternative, including significant asset sales.

The marketability of oil and natural gas acquired or discovered will be affected by numerous factors beyond Barrington's control. These factors include reservoir characteristics, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulation. Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government which may be amended from time to time. See "Industry Conditions". Barrington's oil and natural gas operations may also be subject to compliance with federal, provincial and local laws and regulations controlling the discharge of material into the environment or otherwise relating to the protection of the environment. See “Industry Conditions – Environmental Regulation”. Barrington believes it is in compliance in all material respects with such laws. The marketability of crude oil is sensitive to quotas imposed upon the members of the Organization of Petroleum Exporting Countries (“OPEC”), government regulation of the industry, including regulations relating to prices, taxes, royalties, land tenure, allowable production, importing and exporting of oil, and matters associated with the protection of the environment. In addition, there can be no assurance that the composition of the crude oil produced will be suitable for many refineries or that the crude oil will not be subject to additional price fluctuations based upon quality differentials with reference crudes. Furthermore, the marketing of a new crude oil internationally may be subject to additional price uncertainties. The economics of producing from certain heavy oil wells has deteriorated as a result of lower oil prices and in 1998 Barrington elected not to produce from these wells until prices improve. To minimize its exposure to commodity price fluctuations, Barrington maintains a balance between its two primary product streams, natural gas and oil.

Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of Barrington’s net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of Barrington’s reserves. Barrington might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Barrington’s net production revenue causing a reduction in its oil and gas acquisition and development activities.

World oil prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canada/US dollar exchange rate that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact the Corporation's net production revenue.

Barrington has no assurance that the markets for its products will continue. However, natural gas is a fuel for which demand within the North American continent is increasing and supply, generally, is diminishing. Supply and transportation infrastructure is specific to the sub-continent, in contrast to oil, which is available and transportable from worldwide sources. Barrington therefore recognizes the strategic importance of natural gas relative to oil, and has determined its product mix based on this fundamental. Barrington takes steps to ensure that its markets are as secure as is both possible and prudent.

Barrington's ability to increase reserves in the future will depend not only on its ability to develop its present properties, but also on its ability to select and acquire suitable producing properties or prospects. There is no assurance that Barrington's future exploration and development efforts will necessarily result in the discovery and development of sufficient additional commercial accumulations of oil and natural gas.

Barrington's operations are subject to all of the inherent risks normally associated with the exploration, development and other operations conducted in respect of oil and natural gas properties. For example, in drilling wells, Barrington may encounter or experience unexpected formations or pressures, blowouts, cratering and fires. In producing wells, Barrington may encounter or experience premature decline of reservoirs and invasion of water into producing formations. Any of these occurrences could result in material losses, liabilities or costs to the Corporation. While Barrington carries insurance coverage in accordance with standard industry practice, it has not and cannot fully insure against all of these risks.

Exploration for oil and gas by its nature involves a high degree of risk, frequently resulting in unprofitable efforts, not only from dry holes, but also from wells which, while productive, will not produce oil or gas in sufficient quantities to return a profit on the costs incurred or because fiscal and economic terms will benefit other parties. Production problems associated with the coning of the water or other factors might also be experienced which would materially adversely affect the ability of Barrington to produce at its target production rate.

To reduce these uncertainties, Barrington places a heavy emphasis on the concentration of its technical expertise in a few core areas, where lower cost, shallow wells in contiguous trends which are prospective for multi zone targets increase the chances of encountering hydrocarbons. A key feature of Barrington's business strategy is that the Corporation consistently devotes a material portion of its capital budget to the acquisition of producing reserves and minor working interests which are adjacent to or contiguous with known producing trends in the Corporation's core areas. Barrington fully utilizes all current risk-reduction tools, including both conventional and three dimensional seismic data. Barrington's technical employees are all highly trained and fully conversant with the regional geology.

Barrington's oil and natural gas operations are also subject to extensive controls and regulations imposed by various levels of government. See "*Industry Conditions*". The future value of Barrington's properties depends on various local, national and international economic and political factors that are beyond the control of the Corporation. Barrington must compete in all aspects of its operations with a number of corporations, some of which may have greater technical and financial resources.

The oil and gas industry is currently subject to environmental regulations pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of material fines and penalties.

Numerous uncertainties are inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the control of the producer. The reserve data set forth in the Sproule Report represents only estimates based on available geological, geophysical, production and engineering data, the extent, quality and reliability of which may vary. Oil and gas reserve engineering is a subjective process of estimating accumulations of oil and gas that cannot be evaluated in an exact way, and estimates of other engineers might differ materially from those shown herein. The accuracy of any reserve estimate is a function of the quality and quantity of available data, engineering and geological interpretation and judgement. Proved reserves estimates include estimated oil recovery based on production processes which have not yet been implemented. In addition, the estimates of future net cash flow from Barrington’s proved reserves and the present value thereof are based upon certain assumptions about future production levels, prices, costs and participation, if any, by third parties in the development of Barrington’s reserves that may not prove correct over time.

From time to time the Corporation may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase the Corporation's debt levels above industry standards. Depending on future exploration and development plans, the Corporation may require additional financing which may not be available or, if available, may not be available on favourable terms.

Although title reviews will be done according to industry standards prior to the purchase of most natural gas and oil producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of Barrington which could result in a reduction of the revenue received by Barrington.

All of the directors of Barrington are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the BCA.

Barrington's success depends in large measure on certain key personnel provided by its parent, Sunoma, including Richard MacDermott, Peter Farkas, Darcy Anderson, Kurt Larsen, Eric Panchy, Hal Jamieson, and Ken Robinson. The loss of the services of such key personnel could have a material adverse effect on Barrington. Barrington does not have key person insurance in effect for management. The contributions of these individuals to the immediate operations of the Corporation are likely to be of central importance. In addition, competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that Barrington will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

MARKET FOR SECURITIES

The Corporation's common shares and Gas Notes are listed and posted for trading on The Toronto Stock Exchange under the trading symbol, "BPL" and "BPL.N". On May 17, 1999, the closing price of the Corporation's common shares on The Toronto Stock Exchange was $0.80. On May 17, 1999, the closing price of the Corporation's Gas Notes on the Toronto Stock Exchange was $73.00.

DIRECTORS AND OFFICERS

The following table sets forth all of the current directors and officers of the Corporation, all positions currently held by them with the Corporation and their principal occupation or employment within the preceding five years. The term of office of each director will expire at the end of the next annual meeting of shareholders of the Corporation to be held on June 14, 1999, or any adjournment thereof.

Name and Municipality of Residence	Office	Principal Occupation During Last Five Years	Served as a Director since
Richard N. MacDermott Dewinton, Alberta	Director, President, Chief Executive Officer	President & Chief Executive Officer of Barrington (since September 1998); President & Chief Executive Officer of Sunoma, (a private oil and gas company) (since July 1996); prior thereto Vice President, Operations of Independent Energy Inc. (oil and gas company).	September 1998
Peter T. Farkas Calgary, Alberta	Director, Executive Vice President & Chief Operating Officer	Executive Vice President & Chief Operating Officer of Barrington (since September 1998); Executive Vice President & Chief Executive Officer of Sunoma (since September, 1997); prior thereto Partner, Howard Mackie.	September 1998
Walter A. Dawson Calgary, Alberta	Director	Executive Chairman of Bonus Resource Services Corp. (an oil field services company) (since June 1998); prior thereto Chairman and Chief Executive Officer, (since May 1995) and prior thereto President.	September 1998
Mungo D. Hardwicke-Brown Calgary, Alberta	Director	Partner, Blake Cassels & Graydon, Barristers and Solicitors (since February 1995); prior thereto, Associate.	September 1998
Eric G. Panchy Calgary, Alberta	Vice President, Exploration	Vice President, Exploration of Sunoma (since May 1996); prior thereto, Vice President, Exploration of Independent Energy Inc. (December 1994 to April 1996) and Vice President, Exploration of Calex Resources Ltd., prior to November 1994.	-
Darcy R. Anderson Calgary, Alberta	Vice President, Finance	Vice President, Finance and Chief Financial Officer of Sunoma (since January 1997); prior thereto consultant (from April to December 1996), Controller and Chief Financial Officer of Independent Energy Inc. (from November 1994 to April 1996), Controller and Chief Financial Officer of Calex Resources Ltd., prior to November 1994.	-

Kurt Larsen Calgary, Alberta	Vice President, Marketing	Vice President, Marketing of Sunoma (since January 1998); prior thereto Vice President Marketing and Business Development of Orbit Oil and Gas Ltd. and Czar Resources Ltd.
Hal R. Jamieson Calgary, Alberta	Vice President, Operations	Vice President, Operations of Sunoma (since January 1997); prior thereto, Manager, Reservoir Engineering of Serenpet Inc. (an oil and gas company).
Kenneth A. Robinson High River, Alberta	Vice President, Land	Vice President, Land of Sunoma (since September 1998); prior thereto, Manager, Acquisitions Dispositions and International of Sunoma (since February 1998), and prior thereto, Consultant (since 1993).

The Corporation is required, pursuant to the BCA, to have an Audit Committee of the Board which consists of Messrs. Dawson, Hardwicke-Brown, and MacDermott.

As at December 31, 1998, the directors and officers of the Corporation, as a group, beneficially own, directly or indirectly, no common shares. As at December 31, 1998, the directors of the Corporation, as a group, exercise control or direction over 57.4 million common shares, which represents 97% of the issued and outstanding common shares, by virtue of their role as directors of Sunoma. The information as to shares beneficially owned, not being within the knowledge of the Corporation, has been furnished by the respective directors and officers of the Corporation individually.

ADDITIONAL INFORMATION

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities, options to purchase securities and interests of insiders in material transactions is contained in the Information Circular of the Corporation to be provided for the Annual Meeting of shareholders of the Corporation to be held on June 14, 1999 or any adjournment thereof. Additional financial information is provided in the Corporation's Consolidated Financial Statements for the year ended December 31, 1998, which are contained in the annual report of the Corporation for the year ended December 31, 1998.

Upon request, the Corporation will provide to any person:

1. one copy of this annual information form;

2. One copy of the Corporation's audited financial statements contained in the annual report for the year ended December 31, 1998, together with the report of the auditors thereon, and one copy of any of the Corporation's interim financial statements subsequent to such audited financial statements;

3. one copy of the Corporation's Information Circular to be provided for the Annual Meeting of the shareholders of the Corporation to be held on June 14, 1999 or any adjournment thereof; and

4. when the Corporation's securities are in the course of a distribution pursuant to a short form prospectus or when a preliminary short form prospectus has been filed in respect of a distribution of the Corporation's securities, also upon request to the Corporate Secretary, one copy of any other document that is incorporated by reference in the preliminary short form prospectus or short form prospectus.

Copies of these documents may be obtained in some cases upon payment of a reasonable charge upon request to the Corporate Secretary, Barrington Petroleum Ltd., Suite 2200, 400 - 3rd Avenue S.W., Calgary, Alberta, T2P 4H2 (403) 750-4400 or (403) 266-5794 (fax).