# DYNEX
Petroleum Ltd.

1982 Annual Report

DYNEX
Petroleum Ltd.

# Corporate Profile

Dynex Petroleum Ltd. is an Alberta corporation which was originated in 1974 to develop and produce shallow gas in the Medicine Hat field of southern Alberta. This area still provides the reserves and cash flow basis for the Company. A management team specializing in the technology and production management ability necessary to maximize the profitability of the shallow, tight gas zones was assembled, and as interests expanded to include all of Alberta, B.C. and the western U.S., professionals with abilities in exploration and production in other types of prospects were added.

During 1979, the Company established a wholly-owned U.S. subsidiary, Dynex Energy, Inc. The following year, in anticipation of the National Energy Program, a very substantial effort to expand the U.S. subsidiary culminated in the assembly of a Denver exploration staff. Dynex also operates a marketing division which carries on an active trading operation in liquefied petroleum gases (LPG's). Dolphin Drilling, the Company's contract drilling division, operates four drilling rigs in Alberta.

On February 6, 1980, Dynex completed a public offering of its shares in Canada. This and a subsequent sale reduced the interest of its majority shareholder, Dalco Petroleum Corporation of Tulsa, from 100 percent to 66 percent. As of August 31, 1982, the 14,780,000 outstanding common shares of Dynex were held by 967 registered shareholders with a broad distribution across Canada. Dalco Petroleum Corporation, a U.S. public company, held 9,710,000 of those shares.

# Quarterly Summary of Stock Prices and Volumes

TRADED ALL EXCHANGES

| | High | Low | Shares Traded |
|---|---|---|---|
| June/81 - August/81 | $5.63 | 3.50 | 615,000 |
| September/81 - November/81 | $4.50 | 1.50 | 825,600 |
| December/81 - February/82 | $1.65 | 0.85 | 817,700 |
| March/82 - May/82 | $1.20 | 0.69 | 770,100 |

DYNEX
Petroleum Ltd.

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# Annual General Meeting

The ANNUAL General Meeting of the Shareholders will be held at

Four Seasons Hotel
110 - 9th Ave. S.E.
Calgary, Alberta

on Thursday, October 14, 1982 at 3:00 p.m. M.D.T.

# Report to the Shareholders

On behalf of the Board of Directors, we wish to present your Company's annual report and audited financial statements to May 31, 1982. While the last year's operations did not produce the gains experienced in past years, there are some positive results to report in conjunction with the overall outcome.

Dynex recorded increases in production revenues, as well as increases in the value of proven and probable reserves. There have also been increases in operating expenses, tax and interest expense which more than offset these revenue gains.

Gross revenue for the year totalled $41,505,000, up $5,354,000 or 14.8 percent from $36,151,000 last year. A loss of $5,935,000 (40¢ per share) was experienced compared with earnings of $553,000 (4¢ per share) for the previous period. Cash flow from operations showed a deficiency of $2,104,000 (14¢ per share) compared with a surplus of $4,278,000 (29¢ per share) for the fiscal year ending May 31, 1981. Capital expenditures, primarily for oil and gas ventures, totalled $13,052,000 compared with $35,769,000 in 1981.

During the past year, Dynex participated in the drilling of 28 wells which resulted in 11 oil wells, 9 gas wells and 8 dry holes, for an overall success ratio of 71 percent and a success ratio of 67 percent on its exploration wells. Revenue from oil and gas production increased to $12,735,000 from $11,201,000 during the previous year.

In Canada we have proceeded with further exploration on the Brock Lake, Thunder and Cherhill properties. In these cases, absence of gas markets has deferred further development.

In the United States our Wyoming and Montana exploration has resulted in two highly productive oil plays. Dynex Energy Inc. is concentrating efforts on developing plays in this area. Drilling results in East Texas have been mixed. The deeper, tight Cotton Valley sands have not met expected rates and prices are well below 1980 projections. However, some of the shallower zones, i.e.Travis Peak gas and Pettet oil, are producing a very attractive return. Two other areas which have not met their potential are the Brazoria County, Texas, Frio sand play and the Dewey County, Oklahoma, Redfork and Morrow sands. Both will require the re-drilling of lost or damaged wells to meet the full potential of the prospects.

The extreme depression in the investment climate of Canada has resulted in a dramatic decline in drilling activity. Nevertheless, the Dolphin drilling division continues to enjoy a better than average share of the Canadian market and remains a very healthy operation. We hope to see an upturn in drilling activity resulting from the extension of the Alberta grant to development drilling.

Our Marketing division has suffered a reduction in profits due to reduced demand and profit margins of LPG's in Canada and the U.S.A. We attribute this to the general recession which has lessened demand for alternate fuel or chemical feedstock as well as a minor glut of natural gas in the U.S.A.

The impact of high interest rates on the profitability of Dynex Petroleum Ltd. cannot be overemphasized. At May 31, 1982, the Company had total long-term debt of $62,789,000, an increase of $11,355,000 or 22 percent during the year. Interest on this debt cost $11,873,000 for the fiscal year at a weighted average rate of 19.4 percent. For the prior year the interest cost was $5,914,000 at a weighted average rate of 16.9 percent. While plans call for reductions in this debt, the current effect of a 1 percent decrease in interest rates is an annual cash flow increase of $625,000.

Several other factors contributed to the Company's decreased cash flow during the past year. One of these was the Alberta oil production cutback during the summer of 1981 and the ensuing reduction in Canadian demand due to high imports of foreign oil. The Federal government's unofficial boycott of Alberta crude, implemented through the excessive subsidy paid to refiners of foreign crude, was as damaging as Alberta's cutback. The net result was that all during fiscal 1982 our best oil wells were reduced to partial rates of production. The world glut of oil caused falling crude prices, particularly in the U.S.A., with the resulting loss in projected income. This price softening had many ripple effects which disrupted the Company's plans from drilling to financing. We also suffered from gas price decreases in Canada; our Medicine Hat price ranged from $2.49/MCF in June, 1981 to $2.44/MCF in May 1982 with a low of $2.26/MCF in September, 1981. This price drop was caused by frozen gross prices, higher cost of transportation allowed the gathering and transportation companies, cost of take or pay gas borne solely by producers and the reduction of exports to the

U.S. due to the excess commodity value of Canadian gas set by the Federal government. The Alberta net gas price is composed of two factors: approximately 60 percent from domestic sales price and 40 percent from a redistribution to producers of the excess of the export price over the domestic price. Thus any decrease in exports impacts directly on our net revenue. The Federal Petroleum and Gas Revenue Tax further reduced net revenue.

The absence of new equity in the marketplace has had a detrimental effect on Dynex. Efforts to reorganize debt or raise equity have met with no success. Several proposals were developed, but all were deemed by management and the Board to cause excessive dilution to the shares outstanding.

## Outlook

There have been several recent developments that give us a great deal of encouragement regarding a return by Dynex to a better financial condition. One of the most significant of these is the previously announced merger of our majority shareholder, Dalco Petroleum Corporation, with Lonnie Dunn International Inc. into a new company, Dunoco Corporation, headquartered in Houston, Texas. This merger brings many strengths to the organization which will result in associations affording Dynex opportunities to participate in attractive prospects and to attract joint venture investors and equity participation. A new corporate philosophy will soon become evident to our shareholders. It will be our intent to reduce debt from the sources discussed below. Dynex has attracted outside investors in the U.S. since the fiscal year end and plans to make further use of these sources of funds. We intend to actively pursue a course of restructuring our debt into equity as soon as it is possible to do so without the present shareholder suffering undue dilution of equity. We will embark on efforts to provide growth through acquisitions, in particular those efforts requiring little cash expenditure which will result in further Canadianization of Dynex.

During the past few months, the Federal and Provincial governments have made some efforts to improve the poor climate generated by the National Energy Program and their September, 1981 pricing agreement. The effects of those changes on Dynex will be to increase revenue and decrease capital costs during the balance of 1982 and all of 1983.

The Federal announcements of May, 1982 will reduce the rate of PGRT and other taxes, and will provide a basic exemption of $250,000 per year. Dynex has a considerable amount of oil production drilled after 1973, thereby qualifying for higher prices. The combined effect of federal reductions will result in an annual cash flow increase of $900,000 for Dynex. The reduction of provincial royalties on marginal wells particularly impacts Dynex. The increase in royalty tax credits, plus the advance in timing of payments, will result in a cash receipt of $2,300,000 in September, 1982, which will be used to reduce debt.

The plan advanced by TransCanada PipeLines to provide a cash prepayment for take-or-pay gas will result in Dynex receiving $4,700,000 prepaid revenue in the next four months.

The Board of Directors has approved a change in corporate year end to December 31, 1982 so that Company results can be more readily compared to those of other companies. This will result in a seven month fiscal year ending December 31, 1982.

At this time we wish to thank the Board of Directors for their support and assistance during the past year. We also wish to thank our employees for their loyal efforts and high morale during a rather trying year. Through the combined efforts of these two groups we expect a recovery in the Company's fortunes and continued success.

On behalf of the Board

Wayne Sharp

Wayne Sharp
President

September 16, 1982


NORTHWEST TERRITORIES
ALBERTA
BRITISH COLUMBIA
SASKATCHEWAN
UNITED STATES
Evie Lake
Dahl
Pickell
Beaton
Umbach
Nig
Nettle
Bull Rush
Buick Creek
Rigel
Boundary Lake
Hotchkiss
Cub
Northern
Little Cadotte
West Utikuma
Nipisi
Swan Hills
Freeman. R.
Lator
Thunder
Little Paddle
Oldman
Smokey Lake
Cherhill
Brock Lake
North Lamont
Alexis
Isle Lake
EDMONTON
Stoney Plain
Thorsby
Holborn
Ferrybank
Leedale
Ferrier
Sylvan Lake
Castor
Caroline
Nevis
Penhold
Sedalia
CALGARY
Buffalo
Atlee
Countess
Medicine Hat
Enchant
Turin
Rattlesnake
North Wrentham
Sapphire
Del Bonita
WESTERN CANADA
GAS PRODUCING PROPERTY
OIL PRODUCING PROPERTY
UNDEVELOPED PROPERTY

# Exploration and Development

During the fiscal year ending May 31, 1982 Dynex participated in the drilling of 28 gross wells (6.7 net). Of these, six wells were drilled in Alberta and 22 wells were drilled in the United States.

This is a marked reduction in drilling activity but shows a continuation of a good success ratio of 71 per cent.

## DRILLING ACTIVITY — GROSS WELLS

| | Oil | Gas | Dry | Total |
|---|---|---|---|---|
| **Canada** | | | | |
| Exploratory | 1 | 1 | 0 | 2 |
| Development | 1 | 3 | 0 | 4 |
| **United States** | | | | |
| Exploratory | 7 | 5 | 7 | 19 |
| Development | 2 | 0 | 1 | 3 |
| | 11 | 9 | 8 | 28 |

## WESTERN CANADA

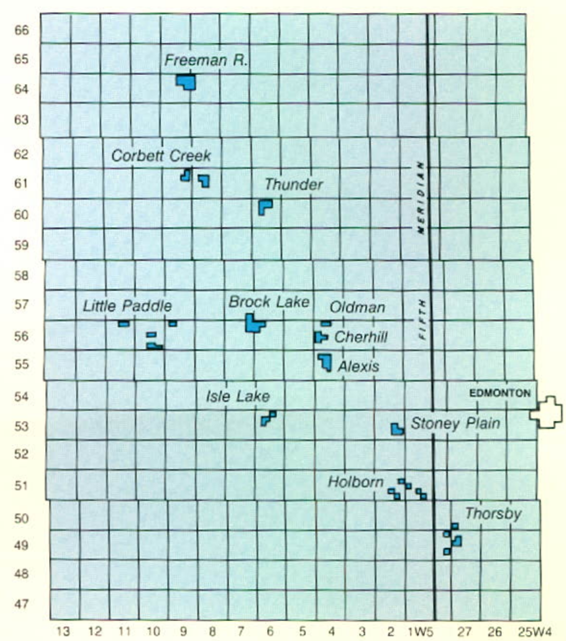
Of the six successful wells drilled in Alberta, two were completed in the general West Edmonton area. The West Edmonton area, which includes the Cherhill properties, now contains eleven Dynex interest wells.

### Cherhill

Four successful multi-zone wells have been completed, one of which was converted to water injection. The waterflood project, which was approved effective June 1, 1982, has increased the recoverable reserves by 133 percent and increased the allowable daily project production from 220 to 520 barrels of oil per day. The behind pipe gas reserves of this project, which are classified as proven, total 5.6 BCF and are waiting on a market with sales scheduled to commence in early 1984. Two offset wells are scheduled; one will be drilled early in the fall of 1982. Both wells will qualify for New Oil Reference Price (N.O.R.P.) of approximately $41.50 per barrel. Dynex has a 23.75 percent interest in this prospect.

### Brock Lake

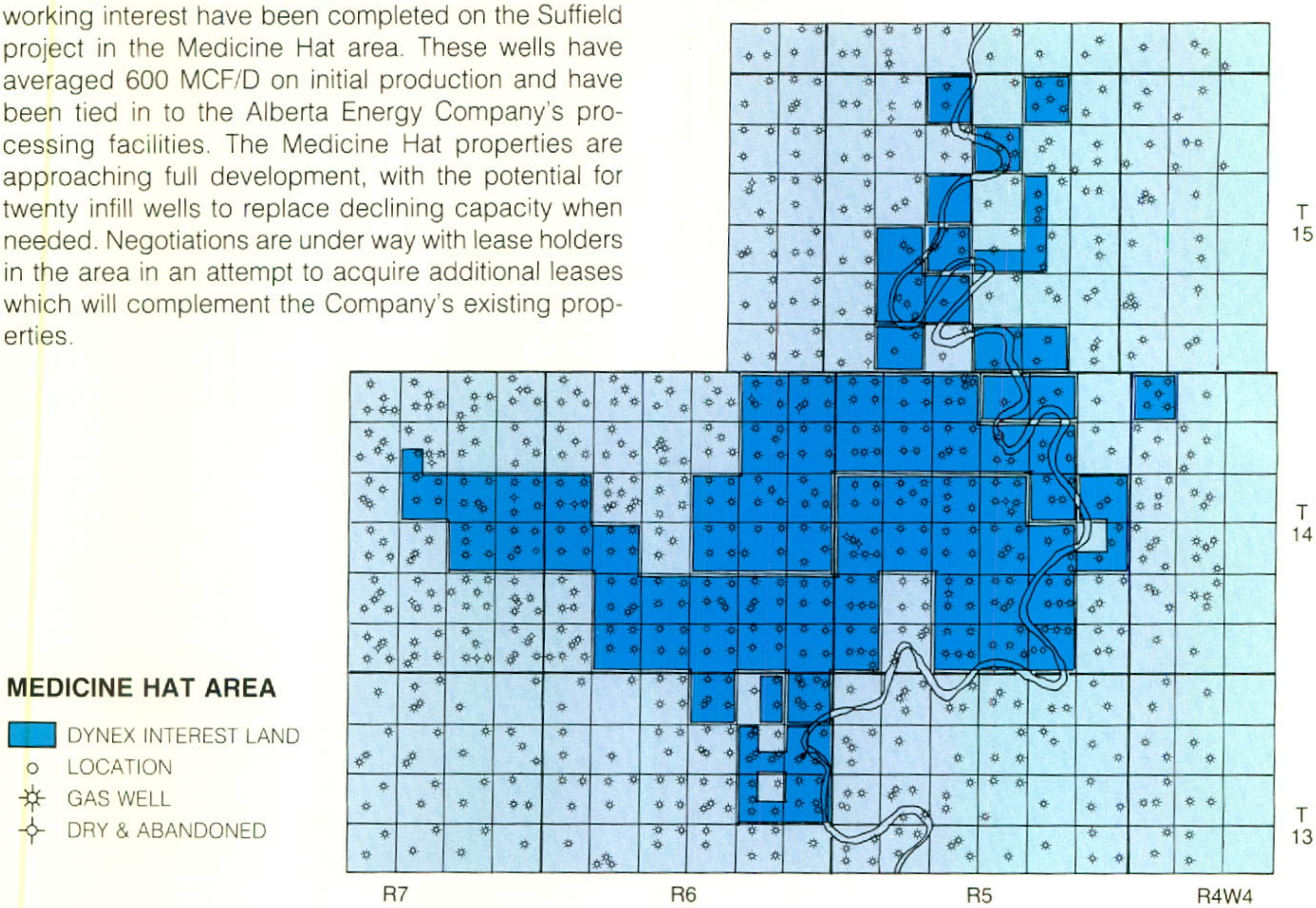
A step-out well was drilled at Brock Lake and has been completed as a shut-in Belly River gas well after failing to encounter the Nordegg formation.

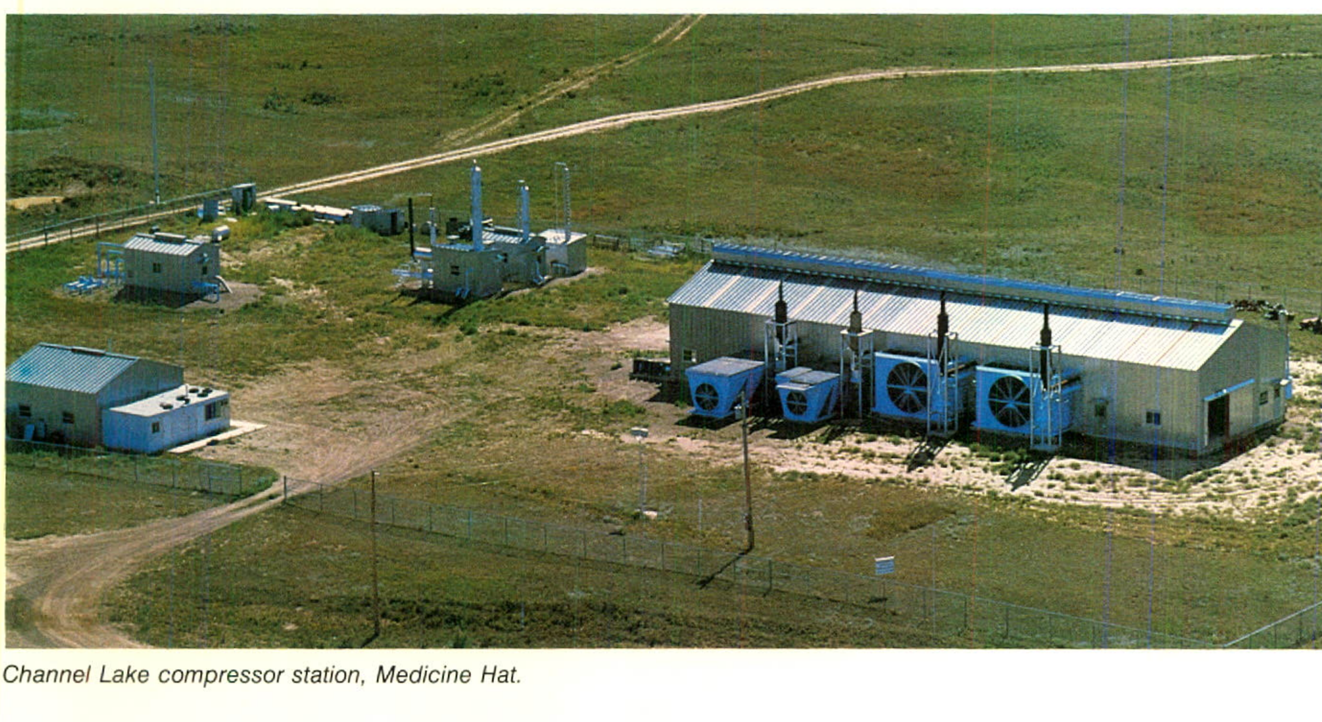



**WEST EDMONTON PROJECT**

## Medicine Hat Area

Two gas wells in which Dynex has a 35.59 percent working interest have been completed on the Suffield project in the Medicine Hat area. These wells have averaged 600 MCF/D on initial production and have been tied in to the Alberta Energy Company's processing facilities. The Medicine Hat properties are approaching full development, with the potential for twenty infill wells to replace declining capacity when needed. Negotiations are under way with lease holders in the area in an attempt to acquire additional leases which will complement the Company's existing properties.

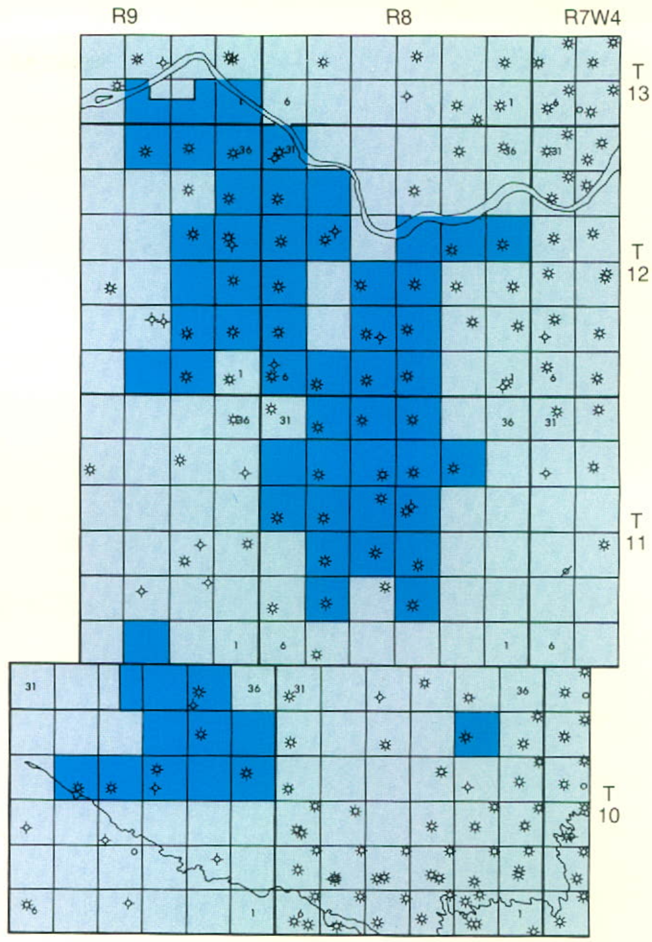


*Channel Lake compressor station, Medicine Hat.*

## Rattlesnake

During the year production averaged 1.73 MMCFD and exhibited very stable rates with low decline in productivity. Evaluation and testing of procedures to remove water from the wellbore of the gas wells occupied our staff most of the past year. We have determined that the installation of pumping equipment is a viable and profitable venture with long term benefits. This will make further drilling of at least a portion of the project a commercially successful proposal. The project has been in a suspended state pending the outcome of the pumping equipment tests. It will now move forward with additional development which can be accomplished with minimal incremental costs due to the prior installation of a gas gathering system. Recent developments such as lower royalty rates and increased drilling grants also have increased the value of the property to Dynex. We are formulating plans for a development drilling program for the fall of 1982.

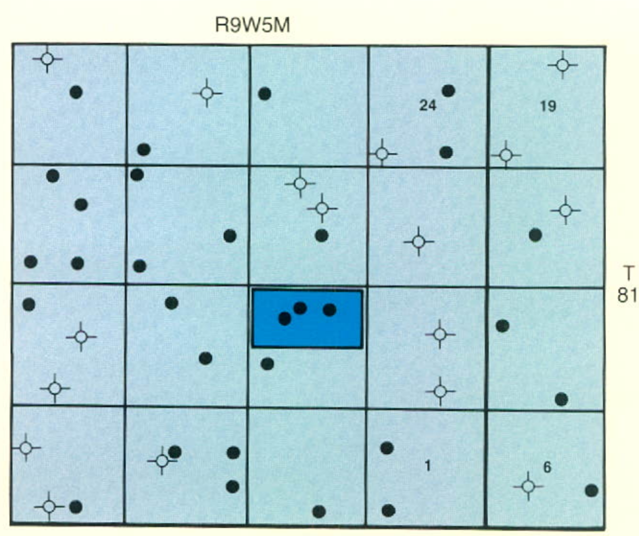



**RATTLESNAKE AREA**

DYNEX INTEREST LAND
LOCATION
GAS WELL
DRY & ABANDONED

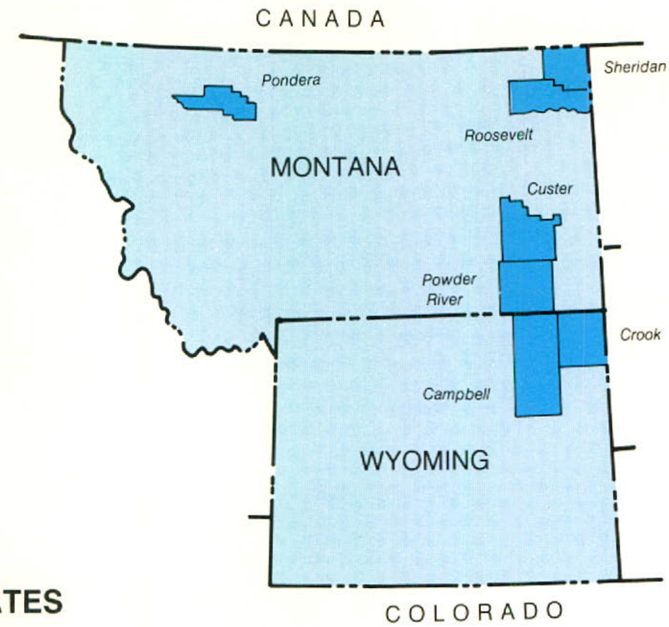
## Nipisi

Dynex holds a 47.5 percent working interest in three producing oil wells in the Nipisi area. Although the acreage position is only 320 acres, gross reserves assigned to the Gilwood and Keg River zones are 2,045,200 barels of oil and 0.6 BCF of gas. Dynex was successful in having the recognized recovery factor increased to 35 percent from 20 percent during the year, and thus increased the daily allowable to in excess of 500 barrels of oil per day from 285 barrels of oil per day.



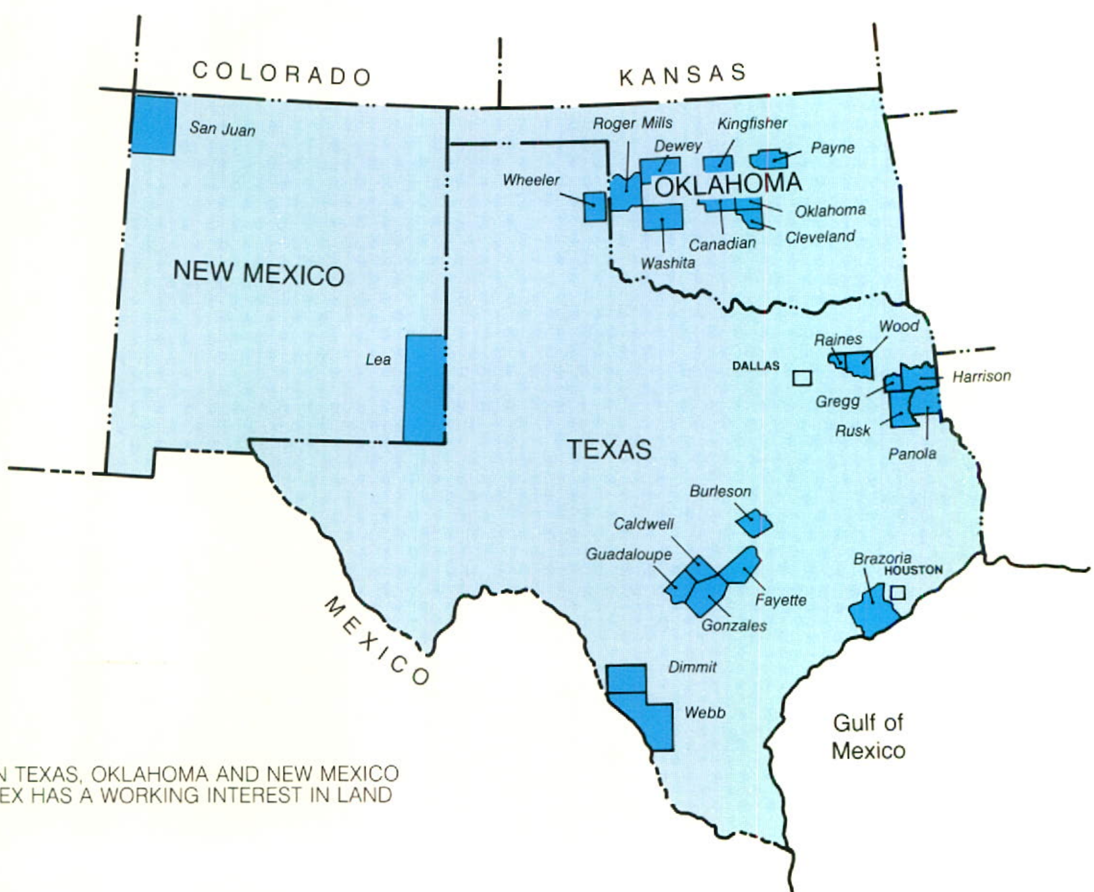

**NIPISI AREA**

DYNEX INTEREST LAND
LOCATION
GAS WELL
OIL WELL
DRY & ABANDONED

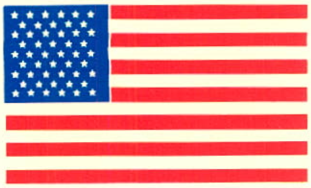



## UNITED STATES

COUNTIES IN WYOMING AND MONTANA WHERE DYNEX HAS A WORKING INTEREST IN LAND




COUNTIES IN TEXAS, OKLAHOMA AND NEW MEXICO WHERE DYNEX HAS A WORKING INTEREST IN LAND

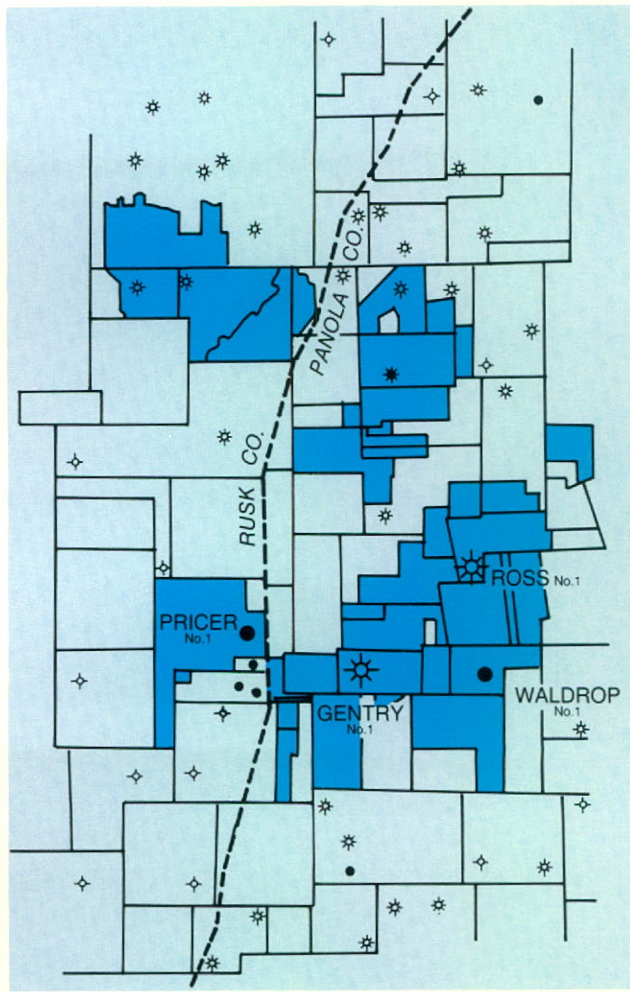


## UNITED STATES

Dynex established a Denver office in July 1981 to facilitate the management and development of its U.S. properties. The past fiscal year was highlighted by efforts to concentrate exploration and development in those areas which appear to provide the best potential for profitable exploration and larger reserves. Certain leases in Oklahoma have been sold along with leases in the Austin Chalk trend of Texas. Continued effort will be made to dispose of marginal properties. Of the 22 gross wells drilled in the U.S., nine were completed as oil wells, five were completed as gas wells, and eight wells were abandoned.

### Panola County, Texas

Of particular importance to the Company was the completion of the Pricer #1 and Waldrop #1 wells which defined Pettet zone oil production. The Pricer #1 well was placed on production in December 1981, and by fiscal year end had provided an average daily oil production rate of 118 barrels with cumulative production of 20,074 barrels. Although our working interest in these wells is small (5.7 percent), leases are held encompassing the successes in which the Company retains up to 95 percent working interest. Two additional wells, the Gentry #1 and the Ross #1 were drilled on these properties at no cost to the Company. Dynex retains a 23.75 percent carried interest in the wells with the right to participate at 38 percent in any offset wells drilled in the subject units. Subsequent to fiscal year end the Gentry #1 was completed as a flowing gas well in the Travis Peak zone at rates of 1.0 MMCF/D, and is being monitored to determine decline rates.



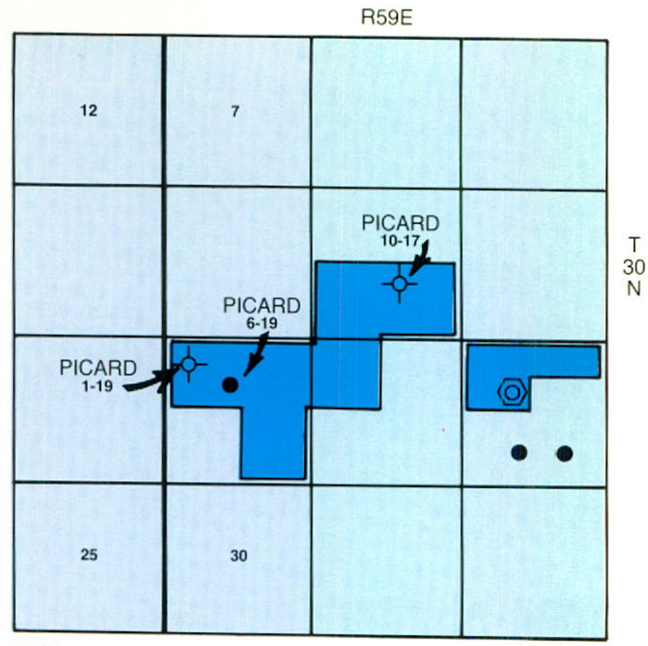

**PANOLA & RUSK COUNTIES**

- DYNEX INTEREST LAND
- ● OIL WELL
- o LOCATION
- DRY & ABANDONED
- GAS WELL

## Montana

A wildcat well, Picard #10-17, was drilled and abandoned on the Picard Prospect in Roosevelt County. A successful offset to the junked #1-19 well was completed as the #6-19 Red River oil well flowing oil at initial rates of 367 BOPD and 227 MCF/D. Additional drilling is planned to offset recent discoveries by other operators on the east side of the properties. Dynex has a 0.78 percent royalty interest before payout and a 5 percent working interest after payout on the 6-19 well. On the remaining prospect acreage, Dynex retains a 12.5 percent interest in 1,040 gross acres.

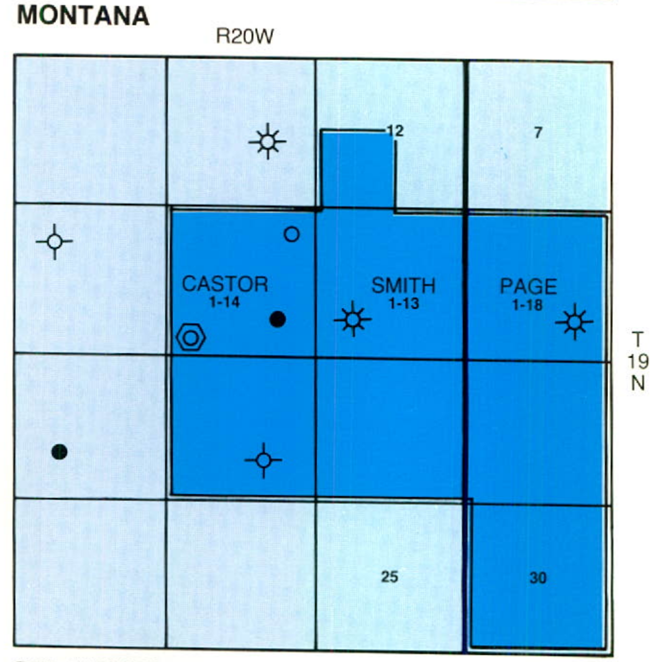
DYNEX INTEREST LAND
PLANNED DRILLING AFTER MAY 31, 1982
LOCATION
GAS WELL
OIL WELL
DRY & ABANDONED




**MONTANA**

## Oklahoma

Two successful wells were drilled in the Vici area of Dewey County, Oklahoma. The Smith #1-13 and the Page #1-18 were completed with initial flow rates of 153 BOPD and 500 MCF/D and 37 BOPD and 200 MCF/D respectively. Plans are being formulated for the drilling of an offset well to the Castor #1 which has encountered some mechanical problems to test both the Morrow and Red Fork zones. Gross proven and probable reserves assigned to this project are 2.87 BCF and 199,300 barrels of oil. The net proven and probable gas and oil reserves assignable to Dynex are 1.06 BCF and 75,440 barrels of oil respectively.

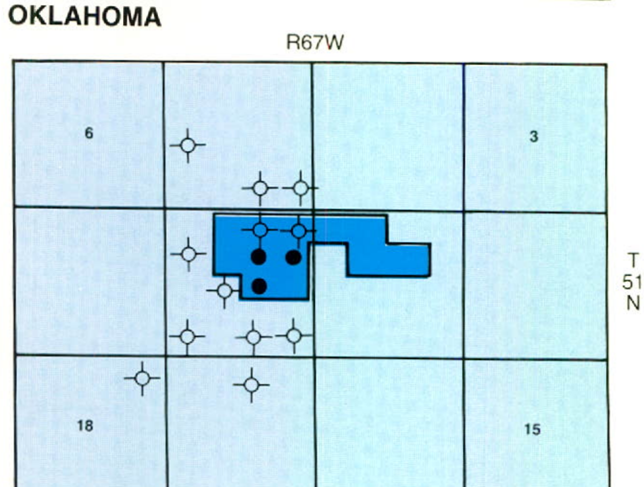



**OKLAHOMA**

## Wyoming

Seven wells were drilled in the Powder River Basin of Wyoming resulting in two oil wells and five dry holes. The Federal #8-4 well was completed and has delineated the Art Creek Field as a three well pool with gross proven and probable initial reserves of 620,000 barrels of oil. The Company's net interests in the field range from 12.5 to 16.67 percent.

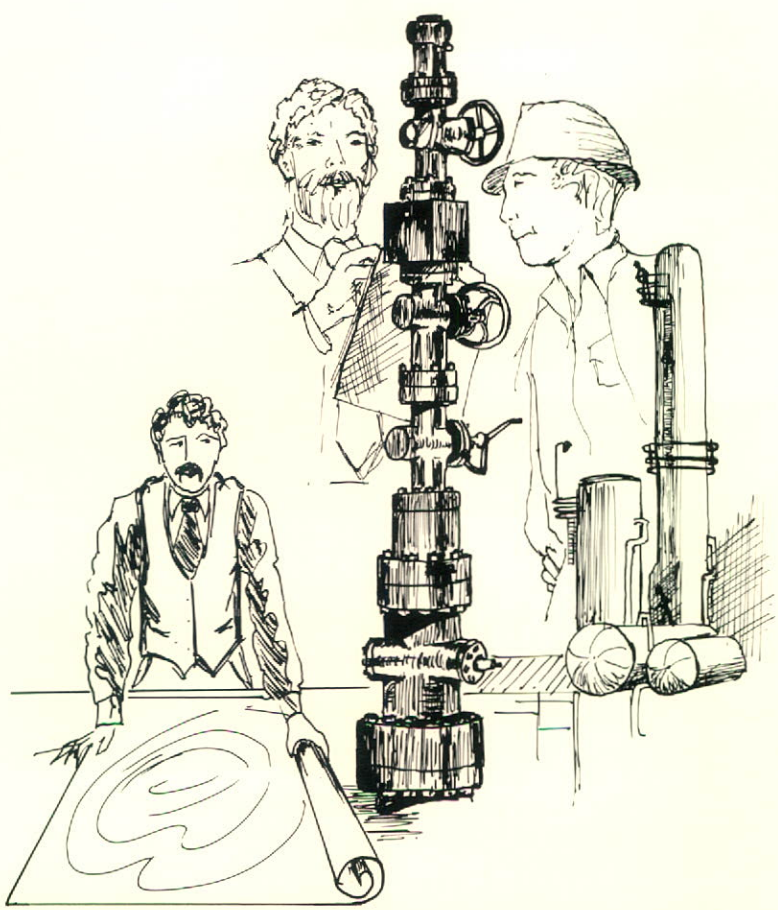
Daily production from the three producing wells is 235 BOPD after recovery of 116,800 barrels of primary reserves. The Anderson #22-1 well was also completed as a 19 percent working interest oil well.




**WYOMING**

## LAND HOLDINGS
at May 31, 1982

| | Developed | | Undeveloped | |
|---|---|---|---|---|
| | Gross | Net | Gross | Net |
| **CANADA** | | | | |
| Alberta | 117,570 | 53,547 | 121,640 | 48,921 |
| British Columbia | 1,340 | 318 | 24,371 | 7,915 |
| Total — Canada | 118,910 | 53,865 | 146,011 | 56,836 |
| **UNITED STATES** | | | | |
| Montana | 560 | 48 | 16,222 | 5,804 |
| Wyoming | 160 | 24 | 1,608 | 413 |
| Oklahoma | 3,780 | 1,256 | 4,652 | 1,046 |
| New Mexico | 320 | 69 | 320 | 32 |
| Texas: | | | | |
| East Texas | 7,330 | 3,571 | 5,688 | 3,964 |
| Other | 879 | 451 | 47,601 | 21,058 |
| Total — United States | 13,029 | 5,419 | 76,091 | 32,317 |
| TOTAL | 131,939 | 59,284 | 222,102 | 89,153 |



# Production

A total of 7.38 BCF of gas was produced during the year, 93 percent in Canada, 7 percent in the U.S. Production of crude oil and natural gas liquids totalled 136,775 barrels, 46 percent in Canada and 54 percent in the U.S. Natural gas production averaged 20.21 MMCF/D, an increase of 12 percent over last year and oil production increased by 17 percent to 375 BOPD.

Dynex was successful in increasing gas sales through a short term gas sales contract which will be continued into the coming year. TransCanada PipeLines Ltd., our major gas purchaser, has extended its voluntary market allocation progam until November 1982, which provides for a minimum reduction of 20 percent in its take-or-pay requirements. Dynex is currently assessing TransCanada's proposal, to be effective from November 1, 1982, which provides for the producers to accept a lump sum payment for previously incurred take-or-pay gas, and reduces TransCanada PipeLine's take-or-pay obligation to 60 percent from 90 percent.

We expect that the National Energy Board Omnibus Three Phase Hearing on Canadian supply and exportable surpluses of natural gas will result in favourable ruling by year end which will allow for additional exports. Any significant increase in approved exports could have a positive impact on operating results for the Company.

The increase in oil production is completely attributable to the U.S. drilling program. Although prices have dropped from record highs of $36 to the $32 level, all oil production has a ready market.

## FIVE YEAR OPERATIONS SUMMARY

| | 1982 | 1981 | 1980 | 1979 | 1978 |
|---|---|---|---|---|---|
| **GROSS PRODUCTS SALES** | | | | | |
| Natural Gas — MMCFD | | | | | |
| Canada/U.S.A. | 20.21 | 18.05 | 16.01 | 14.28 | 14.34 |
| Crude Oil — BOPD | | | | | |
| Canada/U.S.A. | 374.7 | 320.0 | 132.0 | 72.0 | 1.0 |
| **AVERAGE SALE PRICE** | | | | | |
| Natural Gas $/MCF | 2.588 | 2.427 | 2.056 | 1.535 | 1.405 |
| Crude Oil $/Bbl. | 31.15 | 26.52 | 14.04 | 12.68 | 10.85 |
| **PROVEN RESERVES — after royalties** | | | | | |
| Natural Gas — BCF | 103 | 104 | 81 | 74 | 48 |
| Crude Oil — Bbls. x 1000 | 1314 | 1494 | 950 | 830 | 77 |
| **LAND HOLDINGS** | | | | | |
| Canada | | | | | |
| — Gross Acres | 264,921 | 239,900 | 210,101 | 117,155 | 77,839 |
| — Net Acres | 110,701 | 108,100 | 96,197 | 57,156 | 42,154 |
| United States | | | | | |
| — Gross Acres | 89,120 | 112,300 | 128,066 | — | — |
| — Net Acres | 37,736 | 51,000 | 58,267 | — | — |
| Other — Gross Acres | — | 63,000 | — | — | — |
| — Net Acres | — | 6,300 | — | — | — |
| Total — Gross Acres | 354,041 | 415,200 | 338,167 | 117,155 | 77,839 |
| — Net Acres | 148,437 | 165,400 | 154,464 | 57,156 | 42,154 |
| **WELLS DRILLED** | | | | | |
| Gas | 9 | 47 | 48 | 33 | 68 |
| Oil | 11 | 30 | 19 | 1 | 3 |
| Dry | 8 | 19 | 11 | 8 | 3 |
| Total | 28 | 96 | 78 | 42 | 74 |

# Reserves

The following table of reserves summarizes and compares the volumes of oil and gas and the present worth values assigned for the current and previous fiscal years ended May 31. All reserves and values are determined by independent petroleum engineers based on their studies of performance characteristics and volumetric determination of reservoirs.

Although there were no significant changes in net oil and gas reserves from those reported a year ago, the present worth of these reserves at a 15 percent discount factor showed a very significant increase of 20.6 percent to $178,200,000. All of the increase occurred in Canada and is mainly due to two factors: a significant reduction in the royalty schedule by the Province of Alberta for low productivity gas wells and the Federal-Provincial agreement of September 1981. Approximately 96 percent of the Company's reserves are situated in Alberta and an estimated 90 percent of all its producing wells qualify for the royalty reduction of up to a maximum of a 44.5 percent reduction from previous rates.

## CORPORATE RESERVES

| | Gross | | Net | | Present Worth $MM at 15% | |
|---|---|---|---|---|---|---|
| | 1982 | 1981 | 1982 | 1981 | 1982 | 1981 |
| **NATURAL GAS (BCF)** | | | | | | |
| **Proven** | | | | | | |
| Alberta | 248.3 | 268.8 | 95.4 | 93.1 | $137.8 | 93.5 |
| British Columbia | 5.6 | 5.7 | 1.3 | 1.3 | 1.2 | 1.2 |
| Texas | 3.6 | 3.1 | 1.1 | 1.3 | 3.1 | 5.4 |
| Oklahoma | 7.9 | 10.3 | 1.2 | 1.2 | 2.7 | — |
| Others — New Mexico | 1.4 | 1.7 | 0.2 | 0.3 | 0.2 | 0.2 |
| TOTAL PROVEN | 266.8 | 289.6 | 99.2 | 97.2 | 145.0 | 100.3 |
| **Probable Additional** | | | | | | |
| Alberta | 8.8 | 9.7 | 1.6 | 2.0 | 3.4 | 2.3 |
| Texas | 4.7 | 7.6 | 1.9 | 4.3 | 6.5 | 18.3 |
| Oklahoma | 1.0 | 3.2 | 0.4 | 0.6 | 0.6 | — |
| TOTAL PROBABLE | 14.5 | 20.5 | 3.9 | 6.9 | 10.5 | 20.6 |
| TOTAL GAS | 281.3 | 310.1 | 103.1 | 104.1 | 155.5 | 120.9 |
| **CRUDE OIL AND NATURAL GAS LIQUIDS (BBLS x 1000)** | | | | | | |
| **Proven** | | | | | | |
| Alberta | 6,480.2 | 5,674.4 | 681.4 | 795.0 | 12.2 | 12.8 |
| Texas | 197.5 | 146.4 | 36.6 | 40.3 | 1.4 | 0.5 |
| Oklahoma | 565.1 | 824.3 | 102.8 | 123.8 | 2.1 | 5.7 |
| Wyoming | 199.2 | 336.3 | 23.8 | 39.5 | 0.5 | 0.9 |
| Others | 92.7 | 132.8 | 0.7 | 22.0 | — | 0.8 |
| TOTAL PROVEN | 7,534.7 | 7,114.2 | 845.3 | 1,020.6 | 16.2 | 20.7 |
| **Probable Additional** | | | | | | |
| Alberta | 2,267.3 | 2,089.9 | 403.2 | 424.4 | 6.0 | 5.9 |
| Texas | 30.9 | 32.5 | 10.7 | 18.4 | — | — |
| Oklahoma | 41.8 | 203.6 | 17.7 | 30.7 | — | 0.4 |
| Wyoming | 296.3 | — | 37.4 | — | 0.5 | — |
| TOTAL PROBABLE | 2,636.3 | 2,326.0 | 469.0 | 473.5 | 6.5 | 6.3 |
| TOTAL OIL | 10,171.0 | 9,440.2 | 1,314.3 | 1,494.1 | 22.7 | 27.0 |
| TOTAL PRESENT WORTH | | | | | $178.2 | 147.9 |

Gross reserves are the total reserves for projects in which the Company has a working interest. The net reserve values are net to the Company's working interest after deduction of royalties and allowance for the production taken during the year.

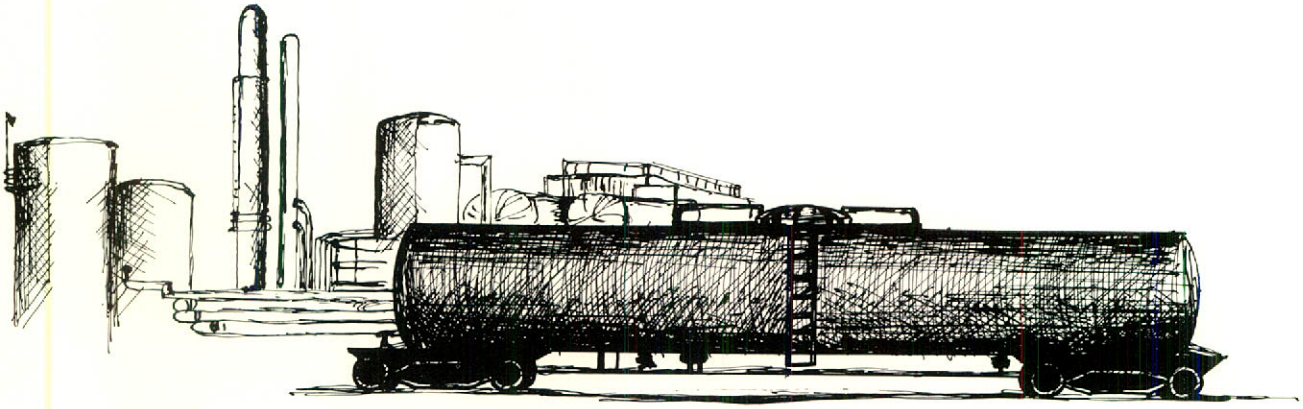
# Marketing Division

The Marketing Division has just completed a year in which revenues increased by approximately 26 percent, but gross profits declined considerably.

This decrease can be attributed to several factors. The extremely cold winter in most of North America should have brought record sales to the industry, but these markets never materialized due to the poor economy. The present recession has had a devastating effect on profits in the propane and butane markets and has caused the U.S. markets to act in an irregular fashion with falling prices in periods of high heating demand. Some losses were incurred on disposition of inventory, due to the unusual price behaviour during the winter. The petrochemical industry, historically a very heavy user of both propane and butane for feedstock purposes, required lower volumes than anticipated. As a result of reduced markets most plants operated at far below maximum capacity. Dynex encountered high net tank car costs during this year, due to the high cost of retrofitting safety equipment and low utilization in poor markets.

Outlook for a market recovery in the next year is very dependent on the economic recovery of both Canada and the U.S.A.

| SALES (Bbls) | 1982 | 1981 |
|---|---|---|
| Volume (Bbls) ....... | 808,000 | 648,216 |
| Value ($) ............ | 20,922,000 | 16,591,000 |



# Drilling Division

DOLPHIN DRILLING enjoyed an activity level of 67 percent of available rig time during the fiscal year despite the effects of the National Energy Program, high interest rates and the collapse of the equity market all of which reduced available funds for our customers. Dolphin has maintained an excellent reputation in the industry and has developed a large clientele of Canadian independent companies who were able to maintain drilling activity until March, 1982. Comparing the drilling industry's activity between 1982 and 1981 shows a 19 percent decline in drilling rig utilization to 50 percent. At year end utilization was only 28 percent with 131 of 463 available rigs working.

Dolphin drilled a total of 231 wells during the fiscal year with a total of 580,458 feet or an average of 2,512 feet per well. Gross revenue decreased 5.8 percent to $7,230,000 from $7,678,000 for the prior year. Gross margin after deducting direct contract costs decreased from 52 percent in 1981 to 36 percent in 1982 resulting in a 73 percent reduction in segmented operating profit to $273,000 from $1,009,000 recorded last year.

The prospects for the coming year are not favorable with low utilization expected to continue. In addition, intensive competition will reduce margins. Alberta's recently announced extension of certain drilling grants to development wells and exploratory wells should cause some revival of the drilling industry during the next fiscal year.

Dolphin has retained the core of its drilling staff, whose continued superior performance remains one of its most valued assets.


*Dolphin rig #4*

# Financial Review

For the fiscal year ended May 31, 1982, the Company had a loss before unusual item and extraordinary item of $4,817,000 ($0.32 per share) compared to earnings of $553,000 ($0.04 per share) reported in fiscal 1981. After an unusual item of $1,361,000 related to the write-down of its gas processing plant in the United States, the net loss before extraordinary item amounted to $6,178,000 ($0.42 per share). An extraordinary gain of $243,000 on the sale of Dalco Petroleum Corporation shares, reduced the net loss for fiscal 1982 to $5,935,000 ($0.40 per share). There were no unusual or extraordinary items in fiscal 1981.

## Revenue

Operating revenue for 1982 was $40.9 million, an increase of 15.2 percent over the $35.5 million reported in 1981.

As summarized in the accompanying table of Comparative Results by Operating Segments, all segments except the drilling division showed an improvement in operating revenue.

Revenue from oil and gas operations were $12.7 million in 1982, an improvement of 13.7 percent from the $11.2 million reported in 1981. The major improvement occurred in the United States where higher production volumes, despite lower prices, increased revenue by 75.8 percent to $3.4 million in fiscal 1982. In Canada, where increased gas production and higher oil prices more than offset a decline in gas prices and oil production, revenue increased to $9.4 million versus $9.3 million last year.

Marketing revenue increased 26.1 percent to $20.9 million compared to $16.6 million last year, an overall improvement of $4.3 million. Canada contributed $3.6 million to the increase in revenue with the remaining $700,000 increase occurring in the United States. Higher volumes, and to a lesser extent, higher average product prices accounted for the change.

Despite a continuing high level of drilling activity and an increase in total footage drilled in 1982, revenue from contract drilling decreased $448,000 to $7.2 million, a decline of 5.8 percent from the $7.7 million reported in 1981. Depressed prices arising from competitive market conditions created by the low activity levels for the drilling industry in general, accounts for the decline.

Interest and other revenue decreased marginally to $618,000 from the $681,000 reported a year earlier.

## Expenses

Operating cost of sales increased $6.5 million to $29.9 million in 1982, an increase of 27.8 percent. Increased costs were experienced by all divisions.

Operating cost of sales for the oil and gas division were $3.1 million in 1982 versus $1.9 million in 1981. Of the $1.2 million increase, approximately $900,000 was associated with the U.S. operation where increased volumes for both oil and gas were the largest single contributing factor. In Canada, higher volumes of gas production and increased lifting costs for oil production resulted in a 21.4 percent increase in operating cost of sales.

Total cost of sales for the marketing division experienced a $5 million increase to $20.6 million from the $15.6 million recorded in 1981. Operating cost of sales in Canada increased $4 million to $15.5 million in 1982. Higher sales volumes, and to a lesser extent, increased net tank car rentals, accounts for the change. In the United States, the $1 million increase in operating cost of sales to $5.1 million in 1982, reflects higher operating costs associated with the Cashion gas processing plant.

The drilling division had a 5.4 percent increase in operating costs to $6.2 million in 1982. Although drilling costs per foot actually decreased during the year, higher activity levels both in footage drilled and the number of operating days resulted in costs increasing by $320,000 over that reported last year.

Interest expense for 1982 amounted to $11.9 million compared to $5.9 million in 1981, an increase of $6

## COMPARATIVE RESULTS BY OPERATING SEGMENTS

(thousands of dollars)

| | Canada | | United States | | Total | |
|---|---|---|---|---|---|---|
| | 1982 | 1981 | 1982 | 1981 | 1982 | 1981 |
| **Operating Revenue** | | | | | | |
| Oil and gas | $ 9,375 | 9,290 | 3,360 | 1,911 | 12,735 | 11,201 |
| Marketing | 16,025 | 12,413 | 4,897 | 4,178 | 20,922 | 16,591 |
| Drilling | 7,230 | 7,678 | — | — | 7,230 | 7,678 |
| | $32,630 | 29,381 | 8,257 | 6,089 | 40,887 | 35,470 |
| **Operating Cost of Sales** | | | | | | |
| Oil and gas | $ 1,625 | 1,338 | 1,439 | 520 | 3,064 | 1,858 |
| Marketing | 15,489 | 11,518 | 5,155 | 4,136 | 20,644 | 15,654 |
| Drilling | 6,235 | 5,915 | — | — | 6,235 | 5,915 |
| | $23,349 | 18,771 | 6,594 | 4,656 | 29,943 | 23,427 |

million. Average long-term debt outstanding which amounted to $61.2 million in 1982 versus $34.9 million last year resulted in additional interest charges of $4.5 million. An increase in the average effective rate of interest to 19.4 percent from 16.9 percent associated with rising interest rates in the summer of 1981 accounted for the remaining $1.5 million.

Depletion, depreciation and amortization increased $114,000 to $4 million in 1982. Higher production volumes in Canada and the United States which more than offset a lower depletion and depreciation rate per equivalent unit of production accounted for the change.

Taxes were a credit of $2.1 million in 1982 compared to a credit of $356,000 in 1981. An increase in the effective rate of PGRT from 8 percent to 12 percent effective January 1, 1982 and a full year's provision for PGRT in fiscal 1982 resulted in petroleum and gas revenue tax increasing to $969,000. Deferred income taxes were a credit of $956,000 in 1982 versus a provision of $176,000 in 1981. The credit is the result of the loss experienced by the Company in the current year. The Alberta Royalty Tax Credit increased $1.3 million to $2.1 million in 1982 as a result of an increase in the credit to 75 percent of Alberta Crown royalties paid from 25 percent, effective September 1, 1981.

## Changes in Financial Position

During the year, the Company had a cash flow deficiency of $2.1 million ($0.14 per share) versus cash flow of $4.3 million ($0.29) per share in 1981, a decrease of $6.4 million. Long-term debt, after repayments of $1.3 million, increased $11.4 million in the current fiscal year. Capital expenditures in fiscal 1982 amounted to $13 million compared to $35.8 million the previous year, an overall reduction in capital spending of $22.7 million. Despite the setbacks of 1982, the Company was able to maintain a favourable working capital position of $2.2 million at year end.

## Financial Outlook

At May 31, 1982 the Company had total capital employed of $76.4 million of which $62.8 million is comprised of long-term debt. The Company is aggressively pursuing alternatives to minimize its present overleveraged position, and as part of that ongoing program has the following to report:

— an agreement in principle has been reached to dispose of the Company's unprofitable gas processing plant located in Oklahoma for a cash consideration of $2.7 million (U.S.). While the terms of the agreement for sale, which is conditional, are yet to be finalized, closing is expected to take place in October this year and;

— the Company is currently assessing a new proposal put forth by TransCanada PipeLines to accept a lump sum payment for previously incurred take-or-pay gas and to reduce the future take-or-pay obligation of TransCanada to 60 percent from the current 90 percent. An acceptance of the proposal would provide the Company with approximately $4.7 million in cash by the end of calendar 1982.

It is the Company's intention to apply these funds towards the reduction of long-term debt to the maximum extent possible.

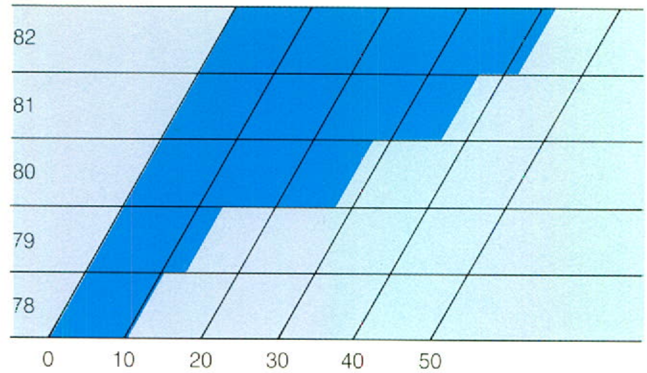
Further recent developments which have a positive impact to the Company include the Alberta Oil and Gas Activity Program and the National Energy Program: Update 1982.

On April 13, the Alberta government announced a royalty reduction effective April 1, 1982 on low productivity gas wells. In addition, the Alberta Royalty Tax Credit program was changed, with retroactive effect to September 1, 1981, and to be applicable to the end of 1983, to reimburse oil and gas producers to the extent of 75 percent of royalties paid to the Alberta Crown up to a maximum credit of $4 million. The National Energy Program: Update 1982 had several important changes. The petroleum and gas revenue tax (PGRT) was reduced to an effective rate of 11 percent from 12 percent for a one year period commencing May 31, 1982. In addition, a yearly PGRT exemption of $250,000 was implemented. A one year suspension of the Incremental Oil Revenue Tax (IORT) was also announced as was an acceleration of the price of old oil discovered after 1973 and before January 1981 to 75 percent of the current world price, effective July 1, 1982.

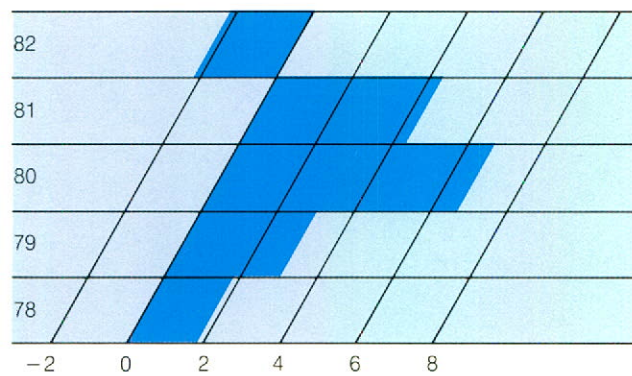
The Company anticipates additional annual cash flow of approximately $2,000,000 from these measures.

As indicated elsewhere in the report, the Company has received approval from the Board of Directors to change its year end to December 31. In the upcoming seven month fiscal period, the Company anticipates a dramatic improvement in both earnings and cash flow. Further improvements are expected in 1983.

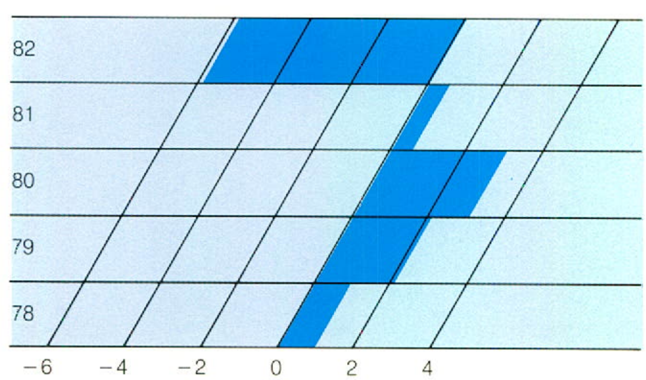
**Gross Revenue**
Millions of Dollars




**Cash Flow**
Millions of Dollars




**Net Earnings**
Millions of Dollars



DYNEX
Petroleum Ltd.

# Five Year Financial Summary

| | 1982 | 1981 (restated) | 1980 (restated) | 1979 | 1978 (3) (unaudited) |
|---|---|---|---|---|---|
| **Revenue** | | | | | |
| Oil and gas | $12,735,000 | 11,201,000 | 7,203,000 | 4,356,000 | 4,508,000 |
| Marketing | 20,922,000 | 16,591,000 | 13,628,000 | 4,003,000 | 4,183,000 |
| Drilling | 7,230,000 | 7,678,000 | 6,024,000 | 3,278,000 | 1,155,000 |
| Operating revenue | 40,887,000 | 35,470,000 | 26,855,000 | 11,637,000 | 9,846,000 |
| Other | 618,000 | 681,000 | 720,000 | 1,108,000 | 191,000 |
| | 41,505,000 | 36,151,000 | 27,575,000 | 12,745,000 | 10,037,000 |
| **Costs, expenses and taxes** | | | | | |
| Operating cost of sales | 29,943,000 | 23,427,000 | 16,798,000 | 6,062,000 | 5,801,000 |
| General and administrative | 2,904,000 | 2,820,000 | 2,238,000 | 1,656,000 | 1,425,000 |
| Interest | 11,873,000 | 5,914,000 | 2,387,000 | 1,369,000 | 794,000 |
| Depletion, depreciation and amortization | 4,000,000 | 3,886,000 | 2,067,000 | 1,115,000 | 771,000 |
| Loss (gain) on foreign exchange | (304,000) | (93,000) | (10,000) | 40,000 | 9,000 |
| Unusual item | 1,361,000 | — | — | — | — |
| Taxes | (2,094,000) | (356,000) | 1,057,000 | 463,000 | 289,000 |
| | 47,683,000 | 35,598,000 | 24,537,000 | 10,705,000 | 9,089,000 |
| Earnings (loss) before extraordinary item | (6,178,000) | 553,000 | 3,038,000 | 2,040,000 | 948,000 |
| Extraordinary item | 243,000 | — | — | — | — |
| **Net earnings (loss)** | $ (5,935,000) | 553,000 | 3,038,000 | 2,040,000 | 948,000 |
| **Earnings (loss) per share** | | | | | |
| Before extraordinary item | $(0.42) | 0.04 | 0.23 | 0.16 | |
| After extraordinary item | $(0.40) | 0.04 | 0.23 | 0.16 | |
| **Funds provided by (applied to) operations** | $ (2,104,000) | 4,278,000 | 6,643,000 | 2,916,000 | 1,826,000 |
| **Capital employed** | | | | | |
| Working capital | $ 2,151,000 | 4,486,000 | 490,000 | 896,000 | 2,071,000 |
| Property, plant and equipment | 70,217,000 | 66,256,000 | 34,228,000 | 14,461,000 | 8,904,000 |
| Other | 4,063,000 | 969,000 | 1,029,000 | 3,150,000 | 220,000 |
| | $76,431,000 | 71,711,000 | 35,747,000 | 18,507,000 | 11,195,000 |
| **Capital employed comprised of** | | | | | |
| Long-term debt | $62,789,000 | 51,434,000 | 16,693,000 | 12,358,000 | 8,270,000 |
| Deferred revenue | $ 4,949,000 | 4,576,000 | 3,667,000 | 2,908,000 | 2,785,000 |
| Deferred income taxes | $ 2,765,000 | 3,640,000 | 3,464,000 | 2,065,000 | 977,000 |
| Shareholders' equity (deficiency) | $ 5,928,000 | 12,061,000 | 11,923,000 | 1,176,000 | (837,000) |
| **Common shares outstanding** (1) | 14,780,000 | 14,780,000 | 14,700,000 | 10,000,000 | |
| **Capital expenditures** | | | | | |
| Acquisitions and land retention | $ 1,617,000 | 7,255,000 | 8,484,000 | 2,332,000 | |
| Geological and geophysical | 1,407,000 | 1,354,000 | 630,000 | — | |
| Drilling and equipping | 9,188,000 | 24,914,000 | 7,208,000 | 1,753,000 | |
| Cost of finding and developing reserves | 12,212,000 | 33,523,000 | 16,322,000 | 4,085,000 | 1,682,000 |
| Other | 840,000 | 2,246,000 | 5,376,000 | 2,129,000 | 568,000 |
| | $13,052,000 | 35,769,000 | 21,698,000 | 6,214,000 | 2,250,000 |

(1) Restated to reflect stock dividends declared May 29, 1981 on the basis of one dividend share for every common share issued.

(2) Certain figures for prior years have been reclassified to conform with the financial statement presentation adopted for 1982.

(3) Incomplete information is available for 1978 due to a change in year end.

# Consolidated Statement of Earnings and Retained Earnings

| | Year Ended May 31 1982 | 1981 (restated) |
|---|---|---|
| **Revenue** | | |
| Operating | $40,887,000 | 35,470,000 |
| Interest and other | 618,000 | 681,000 |
| | 41,505,000 | 36,151,000 |
| **Expense** | | |
| Operating cost of sales | 29,943,000 | 23,427,000 |
| General and administrative | 2,904,000 | 2,820,000 |
| Interest on long-term debt | 11,873,000 | 5,914,000 |
| Depletion | 2,592,000 | 2,407,000 |
| Depreciation and amortization | 1,408,000 | 1,479,000 |
| Gain on foreign exchange | (304,000) | (93,000) |
| | 48,416,000 | 35,954,000 |
| Earnings (loss) before unusual item, taxes and extraordinary item | (6,911,000) | 197,000 |
| **Unusual item** (Note 16) | | |
| Provision for write-down of gas processing plant | 1,361,000 | — |
| Earnings (loss) before taxes and extraordinary item | (8,272,000) | 197,000 |
| **Taxes** (Note 7) | | |
| Petroleum and gas revenue tax | 969,000 | 335,000 |
| Incremental oil revenue tax | 30,000 | — |
| Alberta royalty tax credit | (2,137,000) | (867,000) |
| Deferred income taxes | (956,000) | 176,000 |
| | (2,094,000) | (356,000) |
| Earnings (loss) before extraordinary item | (6,178,000) | 553,000 |
| **Extraordinary item** | | |
| Gain on sale of Dalco Petroleum Corporation shares, net of income tax of $81,000 | 243,000 | — |
| Net earnings (loss) | (5,935,000) | 553,000 |
| Retained earnings, beginning of year, as restated (Note 5) | 4,765,000 | 4,212,000 |
| Retained earnings (deficit), end of year | $(1,170,000) | 4,765,000 |
| **Earnings (loss) per share (based on weighted average number of shares outstanding)** | | |
| Earnings (loss) before extraordinary item | $(0.42) | 0.04 |
| Net earnings (loss) | $(0.40) | 0.04 |

See accompanying notes to consolidated financial statements.

# Consolidated Balance Sheet

| | May 31 1982 | May 31 1981 (restated) |
|---|---|---|
| **ASSETS** | | |
| Current assets | | |
| Cash and short term deposits | $ 2,508,000 | 688,000 |
| Accounts receivable | 10,276,000 | 13,940,000 |
| Inventories | 506,000 | 944,000 |
| Prepaid expenses and other assets | 63,000 | 132,000 |
| Total current assets | 13,353,000 | 15,704,000 |
| Investment in affiliated company, at cost | — | 50,000 |
| Asset held for resale (Note 16) | 3,333,000 | — |
| Property, plant and equipment (Note 3) | 81,944,000 | 74,861,000 |
| Less accumulated depreciation and depletion | 11,727,000 | 8,605,000 |
| | 70,217,000 | 66,256,000 |
| Other assets (Note 4) | 730,000 | 919,000 |
| | $87,633,000 | 82,929,000 |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| Current liabilities | | |
| Accounts payable and accrued liabilities | $ 8,725,000 | 10,012,000 |
| Bank loan | 1,877,000 | 601,000 |
| Current portion of long-term debt | 600,000 | 605,000 |
| Total current liabilities | 11,202,000 | 11,218,000 |
| Long-term debt (Note 8) | 62,789,000 | 51,434,000 |
| Deferred revenue (Note 6) | 4,949,000 | 4,576,000 |
| Deferred income taxes | 2,765,000 | 3,640,000 |
| Shareholders' equity | | |
| Share capital (Note 9) | 9,822,000 | 9,822,000 |
| Retained earnings (deficit) | (1,170,000) | 4,765,000 |
| Receivables from employees in respect of share purchase plans (Note 10) | (2,724,000) | (2,526,000) |
| | 5,928,000 | 12,061,000 |
| Commitments and contingencies (Notes 11 and 12) | | |
| | $87,633,000 | 82,929,000 |

On behalf of the Board

LONNIE M. DUNN
Director

DEREK WHITTLE
Director

See accompanying notes to consolidated financial statements.

# Consolidated Statement of Changes in Financial Position

| | Year Ended May 31 1982 | 1981 (restated) |
|---|---|---|
| **Working capital derived from** | | |
| Operations | | |
| Earnings before extraordinary items | $ — | 553,000 |
| Depreciation, depletion and amortization | — | 3,886,000 |
| Deferred income taxes | — | 176,000 |
| Deferred revenue — product exchange | — | (337,000) |
| Funds provided from operations | — | 4,278,000 |
| Increase in long-term debt | 12,702,000 | 36,174,000 |
| Deferred natural gas revenue | 704,000 | 1,246,000 |
| Proceeds on sale of Dalco Petroleum Corporation shares | 374,000 | — |
| Proceeds on sale of property, plant and equipment | 520,000 | — |
| Proceeds on issuance of common shares | — | 400,000 |
| | 14,300,000 | 42,098,000 |
| **Working capital applied to** | | |
| Operations | | |
| Loss before extraordinary item | 6,178,000 | — |
| Depletion, depreciation and amortization | (4,000,000) | — |
| Provision for write-down of gas processing plant | (1,361,000) | — |
| Deferred income taxes | 956,000 | — |
| Deferred revenue — product exchange | 331,000 | — |
| Funds applied to operations | 2,104,000 | — |
| Additions to property, plant and equipment | 13,052,000 | 35,769,000 |
| Repayment of long-term debt | 1,347,000 | 1,433,000 |
| Other | 132,000 | 900,000 |
| | 16,635,000 | 38,102,000 |
| **Working capital** | | |
| Increase (decrease) in working capital | (2,335,000) | 3,996,000 |
| Working capital, beginning of year | 4,486,000 | 490,000 |
| Working capital, end of year | $ 2,151,000 | 4,486,000 |

See accompanying notes to consolidated financial statements.

# Auditors' Report

To The Shareholders
Dynex Petroleum Ltd.

We have examined the consolidated balance sheet of Dynex Petroleum Ltd. as at May 31, 1982 and the consolidated statements of earnings and retained earnings and changes in financial position for the year then ended. Our examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these financial statements present fairly the financial position of the Company as at May 31, 1982 and the results of its operations and the changes in its financial position for the year then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

Calgary, Canada
August 24, 1982

Peat, Marwick, Mitchell & Co.
Chartered Accountants

# Notes to Consolidated Financial Statements

Year ended May 31, 1982

1. Change of Name

On April 15, 1982, the name of the Company was changed from Dalco Petroleum Ltd. to Dynex Petroleum Ltd.

2. Significant Accounting Policies

(a) Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly-owned U.S. subsidiary, Dynex Energy Inc. (formerly Dalco Petroleum U.S., Ltd.). Approximately 66 percent of all issued and outstanding shares of the Company are owned by Dalco Petroleum Corporation.

(b) Foreign Currency Translation

Foreign currency balances included in the consolidated financial statements have been translated to Canadian dollars on the following basis:

Current assets and liabilities — at the year end rate of exchange.

Other assets and liabilities — at exchange rate in effect at the date of transaction.

Revenue and expense — at the average rate of exchange for the period except depletion, depreciation and amortization which are translated on the same basis as the related assets.

The resultant gains or losses are included in the statement of earnings and retained earnings.

(c) Oil and Gas Operations

The Company follows the full cost method of accounting for petroleum and natural gas properties and related expenditures, under which all costs related to the exploration and development of petroleum and natural gas reserves are capitalized into one North American cost centre. Such costs include those related to lease acquisitions and retention, geological and geophysical activities including overhead related to exploration and the costs of drilling productive and non-productive wells.

Depletion of petroleum and natural gas properties and depreciation of production equipment are calculated on the unit-of-production method based upon estimated net proven developed reserves as determined by independent engineers.

Other equipment is depreciated as follows:

| | |
|---|---|
| Automotive | 30% declining balance |
| Furniture and fixtures | 20% declining balance |
| Leasehold improvements | 20% declining balance |
| Drilling rigs and equipment | 10-30% declining balance |
| Gas processing plant (U.S.A.) | 15 years straight line |

Substantially all of the Company's petroleum and natural gas exploration and production activities are conducted jointly with others and accordingly these financial statements reflect only the Company's proportionate interest in such activities.

(d) Inventories

Inventories of Liquefied Petroleum Gas products and materials and supplies are stated at the lower of average cost and current replacement costs.

(e) Liquefied Petroleum Gas (LPG) Operations

Revenue and costs related to the sale, purchase or trading in LPG products are recognized at the time of passage of title, as specified in the related agreements. Passage of title generally takes place upon completion of a particular product move.

(f) Deferred Natural Gas Revenue

Deferred natural gas revenue represents amounts received pursuant to "take-or-pay" natural gas contracts. These amounts have been deferred pending recovery through future gas deliveries or until the expiration of the applicable contracts.

(g) Investment Tax Credits

Income tax expense is reduced by the flow through of allowable investment tax credits.

(h) Basis of Presentation

Dynex Petroleum Ltd. is the result of a statutory amalgamation of M-P Petroleum Ltd. (M-P), Aldis Petroleum Ltd. (Aldis), D & D Drilling Ltd.(D & D), and Yarmouth Petroleum Ltd. (Yarmouth), on May 31, 1979.

Certain of the following Notes to Consolidated Financial Statements may refer to specific predecessor corporations where the distinction is deemed to be of significance in its disclosure.

(i) Comparative Figures

Certain of the 1981 comparative figures have been reclassified to conform with the financial statement presentation adopted for 1982.

3. Property, Plant and Equipment

| | 1982 | | 1981 | |
|---|---|---|---|---|
| | Assets At Cost | Accumulated Depreciation and Depletion | Assets At Cost | Accumulated Depreciation and Depletion |
| Oil and gas interests including exploration and development costs thereon | $64,226,000 | 7,710,000 | 55,300,000 | 5,118,000 |
| Production equipment and related facilities | 11,400,000 | 1,835,000 | 8,635,000 | 1,503,000 |
| Gas processing plant | — | — | 5,072,000 | 393,000 |
| Drilling rigs and equipment | 5,678,000 | 1,880,000 | 5,378,000 | 1,397,000 |
| Other | 640,000 | 302,000 | 476,000 | 194,000 |
| | 17,718,000 | 4,017,000 | 19,561,000 | 3,487,000 |
| | $81,944,000 | 11,727,000 | 74,861,000 | 8,605,000 |

4. Other Assets

| | 1982 | 1981 |
|---|---|---|
| Prepaid income taxes (Note 12) | $607,000 | 607,000 |
| Advances to employees | — | 72,000 |
| Underground storage rights, net of amortization | — | 117,000 |
| Investment, at cost (no quoted market value) | 76,000 | 76,000 |
| Other | 47,000 | 47,000 |
| | $730,000 | 919,000 |

5. Restatement of Prior Periods

Retained earnings has been restated as follows:

| | 1982 | 1981 |
|---|---|---|
| Retained earnings, beginning of year, as previously reported | $4,945,000 | 4,392,000 |
| Adjustment of prior years' income taxes | (180,000) | (180,000) |
| Retained earnings, beginning of year, as restated | $4,765,000 | 4,212,000 |

During 1982, the Company, on advice of tax counsel, recognized as payable an amount of $180,000 being that portion of an assessment by Revenue Canada for failure to pay non-resident withholding taxes. The amount relates to the years 1975 - 1977 and the balance of retained earnings at June 1, 1980 has been adjusted accordingly.

6. Deferred Revenue

| | 1982 | 1981 |
|---|---|---|
| Deferred Natural Gas Revenue | $3,347,000 | 2,643,000 |
| Deferred Revenue — Product Exchange | 1,602,000 | 1,933,000 |
| | $4,949,000 | 4,576,000 |

(a) Deferred Natural Gas Revenue

This represents amounts received for annual contracted gas volumes not taken by gas purchasers. During the year $704,000 (1981 — $1,246,000) was received from purchasers for contracted volumes not taken.

(b) Deferred Revenue — Product Exchange

| | 1982 | 1981 |
|---|---|---|
| Reduction in product exchange liability | $6,116,000 | 6,116,000 |
| Loss on underground storage construction contract | (1,044,000) | (1,044,000) |
| Overriding royalties — Odessa | (303,000) | (303,000) |
| Payment received under royalty agreement | 200,000 | 200,000 |
| Write-down of Dalco Petroleum, Inc. account (1976) | (1,857,000) | (1,857,000) |
| | 3,112,000 | 3,112,000 |
| Amortization | 1,510,000 | 1,179,000 |
| | $1,602,000 | 1,933,000 |

In 1974 and 1975 a series of transactions were entered into with the El Paso Company (El Paso) and others, which transactions are accounted for as related transactions. Specifically, these transactions are:

(i) Three LPG product exchange agreements between El Paso and M-P Petroleum Ltd. (M-P);

(ii) The sale to Odessa Natural Corporation (Odessa), a subsidiary of El Paso, of an 18 percent gross overriding royalty on a property owned by M-P; and

(iii) The purchase by M-P from El Paso of its 50 percent interest in an underground storage project.

Product received under the LPG product exchange agreements referred to above was sold to an associated company, Dalco Petroleum Inc. An amount of $1,857,000 relating to the product exchange agreements was receivable and included in the related transactions.

On September 9, 1976, pursuant to the LPG product exchange agreements, El Paso presented an invoice to the American Bank of Odessa for $2,525,000 and subsequently received the escrowed funds, including interest. A mutual termination agreement relieved M-P of its obligation to return product thus extinguishing the liability for product payable of $6,116,000.

The resultant gain on this transaction ($6,116,000) has been reduced by deferred charges on the El Paso transactions and the resulting deferred revenue ($3,112,000) is being amortized to income in amounts proportionate to royalty payments made under the Odessa agreement.

## 7. Taxes

Total taxes amounted to a recovery of $2,094,000 in 1982 (1981 — $356,000). The total is different from the expected amount computed by applying the combined expected Canadian federal and provincial tax rates to earnings (loss) before taxes and extraordinary item. The reason for these differences are as follows:

| | 1982 | 1981 |
|---|---|---|
| Computed tax expense | $(3,888,000) | 93,000 |
| Add (deduct): | | |
| Disallowed payments to Crown, net of provincial rebates and credits | (504,000) | 696,000 |
| Loss of subsidiary | 2,222,000 | 62,000 |
| Petroleum and gas revenue tax | 969,000 | 335,000 |
| Resource allowance on resource profits | (1,357,000) | (1,142,000) |
| Depletion allowance on production income | — | (413,000) |
| Other | 464,000 | 13,000 |
| | $(2,094,000) | (356,000) |

At May 31, 1982, the Company had available non-capital loss carry forwards of $7,400,000 (1981 — $130,000), capital loss carry forwards of $326,000 (1981 — $326,000) and investment tax credit carry-forwards of $1,150,000 (1981 — $1,062,000).

## 8. Long-Term Debt

The long-term debt of the Company is comprised of the following loans and contracts:

| | 1982 | 1981 |
|---|---|---|
| Demand bank loan, bearing interest at prime plus ½% with repayment in multiples of $100,000 at the option of the Company, until June 1, 1983 followed by monthly payments over a term of up to 5½ years. The bank loan is secured by a registered assignment of certain oil and gas properties under Section 177 of the Bank Act and a general assignment of book debts | $36,700,000 | 42,400,000 |
| Demand bank loan in the amount of U.S. $300,000, bearing interest at U.S. base rate plus ½% with repayment in multiples of $100,000 at the option of the Company, until June 1, 1983 followed by monthly payments over a term of up to 5½ years. The bank loan is secured by a registered assignment of certain oil and gas properties under Section 177 of the Bank Act and a general assignment of book debts | 370,000 | — |
| Demand bank loan in the amount of U.S. $20,000,000 (1981 — U.S. $5,000,000), bearing interest at U.S. prime plus 1% with repayment in multiples of $100,000 at the option of the Company, until June 1, 1983 followed by monthly payments over a term of up to 5½ years. The bank loan is secured by a registered assignment of the Company's interest in hydrocarbons, equipment, accounts, contract rights, and other properties in the United States. The loan is also guaranteed by Dalco Petroleum Corporation and is secured by 4,000,000 common shares of Dynex Petroleum Ltd. | 24,039,000 | 6,012,000 |
| Finance contract, bearing interest at prime plus 1%, with a minimum of 10%, repayable in monthly instalments of $50,000 together with interest until February, 1986. A debenture has been issued providing the finance company with a first specific charge on all drilling equipment, together with a floating charge on all other assets including the security of hydrocarbon reserves subject only to chartered bank security | 2,200,000 | 2,850,000 |
| Convertible debentures | — | 684,000 |
| Other | 80,000 | 93,000 |
| | 63,389,000 | 52,039,000 |
| Less current portion | 600,000 | 605,000 |
| | $62,789,000 | 51,434,000 |

During the year, the January 22, 1980 and the December 3, 1980 convertible debentures totalling $684,000 were redeemed by the Company at cost.

## 9. Share Capital

The authorized and issued share capital of the Company is as follows:

| | Authorized | | Issued | |
|---|---|---|---|---|
| | 1982 | 1981 | 1982 | 1981 |
| First Preference preferred shares of a nominal value or par value of $10 each | 10,000,000 | 10,000,000 | — | — |
| Second Preference preferred shares of a nominal or par value of $1 each | 144 | 144 | 144 | 144 |
| Common shares without nominal or par value | 100,000,000 | 100,000,000 | 10,139,999 | 7,810,000 |
| Convertible Class "B" shares without nominal or par value (Non-voting) | 100,000,000 | 100,000,000 | 4,640,001 | 6,970,000 |

The Second Preference preferred shares are only issuable to the directors of the Company and shall only be transferable with the prior written consent of the Company among and between the directors of the Company. The registered holders of the Second Preference preferred shares are entitled to 1,000 votes for each of these shares held.

The Convertible Class "B" shares are fully participating and rank equally with the common shares of the Company but have no voting privileges attached. These shares are convertible into common shares of the Company on a one-for-one basis. Dalco Petroleum Corporation, which is currently the registered holder of all issued Convertible Class "B" shares may convert only such number of Class "B" shares to common shares, such that after the conversion Dalco Petroleum Corporation shall be the registered owner of less than 50 percent of the issued outstanding common shares of the Company.

## 10. Employee Share Purchase Plan

The Company provided an interest-free five year advance on behalf of the employees to The Royal Trust Company (the "Trustee"), in 1981. During the year no shares (1,400 shares in 1981) were released with the cumulative number of shares at May 31, 1982 held in trust for the employees in this series totalling 448,800 shares with advances to the employees of $2,126,000. These shares are held by the Trustee and were to be released to the employee purchaser subject to repayment of the proportionate amount of the term loan in amounts up to 20 percent annually on each anniversary of the Plan until December, 1985 at which time the employee loans relating to the Plan mature and become payable.

During the year the Company, with the approval of the employees in the Plan, amended the Plan to temporarily discontinue the 20 percent annual "earning process". The Plan provides that to the extent the shares are not "earned" by the employees in the Plan, the Company is required to purchase the shares from the Trustee at the original share purchase price when the Plan was originated.

In addition, the Trustee was authorized to purchase 80,000 Treasury shares at $5 per share. The $400,000 interest-free advances are repayable not later than November 30, 1986. The Plan requires the Company to purchase the shares at the purchase price of $5 if the participants are no longer employees of the Company at December 1, 1985.

During the year, the Company authorized the Trustee to purchase 50,900 shares on the open market at an aggregate cost of $198,400. These shares have not been allocated to employees at May 31, 1982.

As a result of the amendment to the "earning process" and the requirement of the Plan that the Company purchase shares from the Trustee under certain circumstances, the receivables from employees in respect of the share purchase plan in the amount of $2,526,000 and the unallocated shares in the amount of $198,000 have been reclassified as a reduction of shareholders' equity. In the event that the employees do not pay for shares which have been "earned" and the Company is required to purchase shares which have not been "earned", the share capital account will be charged with the average stated value of share capital of the Company purchased shares in the amount of $486,000 and the remainder will be charged to retained earnings.

11. Commitments

The Company is committed under a lease for its Canadian office premises until February, 1985. The annual rental approximates $104,000. The Company is committed under lease for its U.S. office premises until June, 1986. The annual rental approximates $37,000 (U.S.).

The Company entered into lease agreements for the rental of LPG tank cars. The annual rental is approximately $230,000 and the lease agreements expire between April, 1988 and February, 1990.

The Company has also entered into a lease agreement for the rental of a gas compressor in Canada. The annual rental is approximately $88,000 and the lease agreement expires October, 1985.

12. Contingencies

The Company is contingently liable as a guarantor for advances to an associated company in the amount of $2,500,000 (U.S.).

Revenue Canada, Taxation has reviewed certain transactions entered into by a predecessor company during the years 1974 to 1976 (El Paso transactions) and as a result of such review, has assessed additional income taxes. On the advice of its tax counsel the Company had paid assessments in the amount of $607,000, including interest of $108,000. Concurrently, the Company has filed Notices of Objection and a Request for Competent Authority Consideration with Revenue Canada relative to certain of the items reassessed. The Company has provided income taxes relating to certain of these reassessed transactions.

In addition and related to the above transactions, Revenue Canada has reassessed for the years 1977-1979 in the amount of $772,000 (excluding interest). The Company has also been assessed a non-resident withholding tax of $442,000 including interest and penalty by Revenue Canada for failure to withhold monies from payments made to Dalco Petroleum Corporation in 1975-77. On advice from tax counsel, the Company has recorded $180,000 of the non-resident assessment. A Bank Letter of Guarantee has been obtained and provided to Revenue Canada for the non-resident withholding tax.

The Company has filed Notices of Objection to certain of these assessments.

If the current reassessments are upheld, the Company would be required to provide for additional income taxes, however, since the ultimate resolution of the assessments is not determinable, no additional provision has been included in the consolidated financial statements. If the Company is not successful in its appeal, the additional income taxes will be charged to earnings in the respective periods in which the transactions occurred.

The Company is a defendant in a lawsuit alleging conspiracy and wrongful diversion of corporate opportunity which lawsuit was originally filed in 1977 in the United States District Court of Kansas. The Company, however, was dismissed from the action after judgment in the amount of U.S. $4.7 million was delivered against the Company's co-defendants. All parties to the action have, in a timely fashion, filed appeals from all aspects of the trial judgment including the dismissal of the Company; the Company's co-defendants have posted security in an amount in excess of the trial judgments.

The Court's dismissal of the Company has substantially reduced the probability that the Company may ever be required to make any expenditure in the lawsuit. In addition, Dalco Petroleum Corporation has agreed to indemnify the Company from any liability arising out of the legal proceedings described above.

## 13. Segmented Information (thousands of dollars)

The operations of the Company are divided into three business segments. Oil and gas include the exploration for, and the development and production of petroleum and natural gas reserves. Marketing includes the purchase and resale of LPG products on the spot market and the resale of natural gas purchased and processed for the extraction of LPGs. The drilling operations involve the activities of four drilling rigs in Canada.

The segmented operating profit for 1981 has been restated to include general and administrative expenses directly allocable to the various operating segments. Identifiable assets attributable to the operating segments has similarly been restated to include all assets including those related to property, plant and equipment.

Export sales to customers outside Canada were $5,426,000 (1981 — $9,555,000).

| | Oil and Gas | | Marketing | | Drilling | Other | | Consolidated |
|---|---|---|---|---|---|---|---|---|
| | Canada | U.S. | Canada | U.S. | Canada | Canada | U.S. | |
| **Industry and Geographic — 1982** | | | | | | | | |
| Revenue earned from outside the enterprise | $ 9,375 | 3,360 | 16,025 | 4,897 | 7,230 | 417 | 201 | 41,505 |
| Segmented operating profit | $ 5,045 | 1,441 | 105 | (619) | 273 | 417 | 201 | 6,863 |
| General corporate expenses | | | | | | | | 2,205 |
| Interest expense | | | | | | | | 11,873 |
| Gain on foreign exchange | | | | | | | | (304) |
| Unusual item | | | | | | | | 1,361 |
| Extraordinary item | | | | | | | | (243) |
| Taxes | | | | | | | | (2,094) |
| | | | | | | | | 12,798 |
| Net earnings (loss) | | | | | | | | $ (5,935) |
| Identifiable assets | $33,411 | 43,537 | 1,532 | 3,333 | 4,688 | 1,020 | 112 | 87,633 |
| Capital expenditures | $ 2,673 | 9,580 | — | 376 | 350 | 41 | 32 | 13,052 |
| Depletion, depreciation and amortization | $ 2,474 | 450 | 117 | 362 | 483 | 77 | 37 | 4,000 |
| **Industry and Geographic — 1981** | | | | | | | | |
| Revenue earned from outside the enterprise | $ 9,290 | 1,911 | 12,413 | 4,178 | 7,678 | 647 | 34 | 36,151 |
| Segmented operating profit | $ 5,119 | 954 | 442 | (295) | 1,009 | 589 | 25 | 7,843 |
| General corporate expenses | | | | | | | | 1,825 |
| Interest expense | | | | | | | | 5,914 |
| Gain on foreign exchange | | | | | | | | (93) |
| Taxes | | | | | | | | (356) |
| | | | | | | | | 7,290 |
| Net earnings | | | | | | | | $ 553 |
| Identifiable assets | $33,487 | 36,382 | 1,227 | 5,664 | 4,786 | 1,358 | 25 | 82,929 |
| Capital expenditures | $ 9,448 | 24,205 | — | 1,397 | 664 | 55 | — | 35,769 |
| Depletion, depreciation and amortization | $ 2,622 | 244 | 144 | 336 | 473 | 58 | 9 | 3,886 |

14. Related Party Transactions

None of the Directors or Officers of the Company or any shareholder of the Company, and no associate or afiliate of any of them, has any material interest in any transaction which has materially affected or will materially affect the Company, other than the following, or as otherwise disclosed in the Notes to Consolidated Financial Statements:

(a) Pursuant to an agreement dated June 1, 1978 Windermere Petroleum Ltd. ("Windermere") has the right to participate for up to 5 percent of the Company's interest on a working interest basis in any prospect. Conversely, the Company has the right to participate for up to 95 percent on a working interest basis in any prospect acquired by Windermere. Mr. W. R. Sharp, the President and controlling shareholder of Windermere, is the President and a Director of the Company.

Leprechaun Agencies Ltd. ("Leprechaun") has the right to participate in certain prospects entered into by the Company. Leprechaun supplies the services of Mr. M. L. Dea, a Director and Executive Vice-President of the Company.

Wild Bull Petroleum Ltd. ("Wild Bull") has the right to participate in certain prospects entered into by the Company. Mr. R. D. Weir, Vice-President Production of the Company, is the President of Wild Bull.

The above companies have participated in certain lease acquisitions and exploration activities of the Company. Their participation is conducted under joint venture agreements similar to unrelated industry partners.

Amounts owing from Windermere, Leprechaun, and Wild Bull in the amount of $617,000 (1981 — $693,000) have been included in accounts receivable.

(b) Pursuant to a management contract dated October 25, 1979, the Company is required to pay for all actual costs of Dalco Petroleum Corporation incurred in rendering management services to the Company up to a maximum of $200,000 per annum. In addition, the Company has agreed to reimburse Dalco Petroleum Corporation for aircraft expenses which the Company may charter from time to time. The aggregate of these amounts totalling $230,000 (1981 — $295,000) were charged to general and administrative expense.

(c) The Company retains Dalco Services, Inc. for the operation of a gas plant in Kingfisher County, Oklahoma. During the year management fees in the amount of $252,000 (1981 — $153,000) were charged to earnings.

(d) At May 31, 1982, Dalco Petroleum Corporation owed the Company $973,000 (1981 — $705,000) while the Company owed $621,000 (1981 — $40,000) to various subsidiaries of Dalco Petroleum Corporation. The net receivable has been classified as accounts receivable on the balance sheet.

15. Remuneration of Directors and Officers

The aggregate remuneration paid or payable to directors and senior officers (as defined by the Companies Act, Alberta, which term includes the five highest paid employees of the Company) during the year amounted to $845,000 (1981 — $762,000).

16. Subsequent Event

Subsequent to May 31, 1982, the Company reached an agreement in principle to sell its gas processing plant located in the United States. The plant has been written down to its estimated proceeds of disposition and has been reclassified as asset held for resale on the balance sheet. Proceeds of disposition totalling approximately $2,700,000 (U.S.) will be applied to reduce long-term debt.

# Corporate Information

## DIRECTORS

†Lonnie M. Dunn — Chairman
President and Chairman of the Board
Dunoco Corporation

†*F. M. Parsons — Vice Chairman
President
Dalco Petroleum Corporation

J. Athol Brown
President
Brown's Purchasing Enterprises Ltd.

Murray L. Dea
Executive Vice-President
Dynex Petroleum Ltd.

*John W. Ohanian, Jr.
Executive Vice-President and Treasurer
Dunoco Corporation

*George W. Oughtred
Chairman of the Board
Commercial Oil & Gas Ltd.

†Wayne R. Sharp
President
Dynex Petroleum Ltd.

Arthur R. Smith
President
Lavalin Services Inc.
(Western Region)

*Louis Waters
Chairman of the Board
Fannin Bank, Houston

*Derek Whittle
Co-Chairman
The MerBanco Group

†Member of Executive Committee
*Member of Audit Committee

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(303) 393-1400

## OFFICERS

Wayne R. Sharp
President

Murray L. Dea
Executive Vice-President

Deane G. H. Ross
Vice-President U.S. Operations

Robert D. Weir
Vice-President Canadian Operations

Robert A. Wall
Vice-President Finance

Richard E. Cheetham
Vice-President Land

Lorraine Lawrence
Corporate Secretary

## SOLICITORS

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T2P 3A6

## AUDITORS

Peat, Marwick, Mitchell & Co.
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Calgary, Alberta
T2P 2W2

## TRANSFER AGENTS

Royal Trust Corporation of Canada
in Calgary, Toronto and Montreal

## STOCK LISTING

Toronto Stock Exchange
Alberta Stock Exchange
Montreal Stock Exchange
(Symbol — DPL)

## PRINCIPAL BANKERS

Bank of Montreal
Calgary, Alberta

United Bank of Denver
Denver, Colorado



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