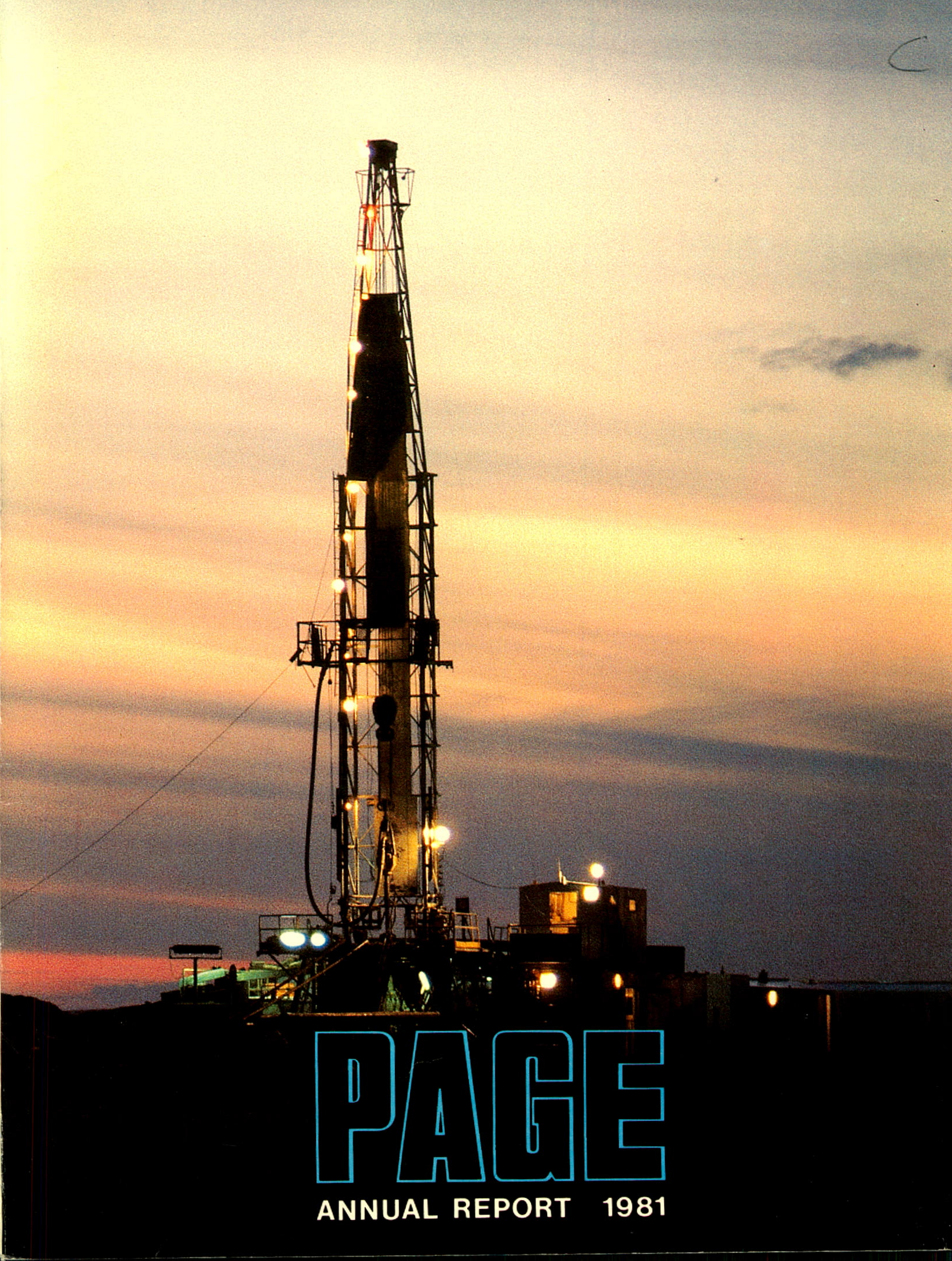


PAGE

ANNUAL REPORT 1981

PAGE PETROLEUM LTD.

Incorporated in Alberta, Canada

CORPORATE PROFILE

Page Petroleum Ltd. was formed by amalgamation in Alberta on August 13, 1971. The Company has continued and expanded the operations of its predecessor companies, acquiring oil and gas reserves through exploration, development and purchase. Page has traditionally operated in Western Canada, although in 1973 the Company expanded its operations into the United States. The Company's principal reserves and production are located in Western Canada, Utah and Texas. Page has been listed on the Toronto and American Stock Exchanges since 1971 and 1979, respectively.

As of February 28, 1982, Page's 3,606,750 outstanding common shares were held by 2,170 registered shareholders. At February 28, 1982 Page shares were held 85% in the U.S. and 15% in Canada. Institutions, primarily in the U.S., owned 18% of the shares.

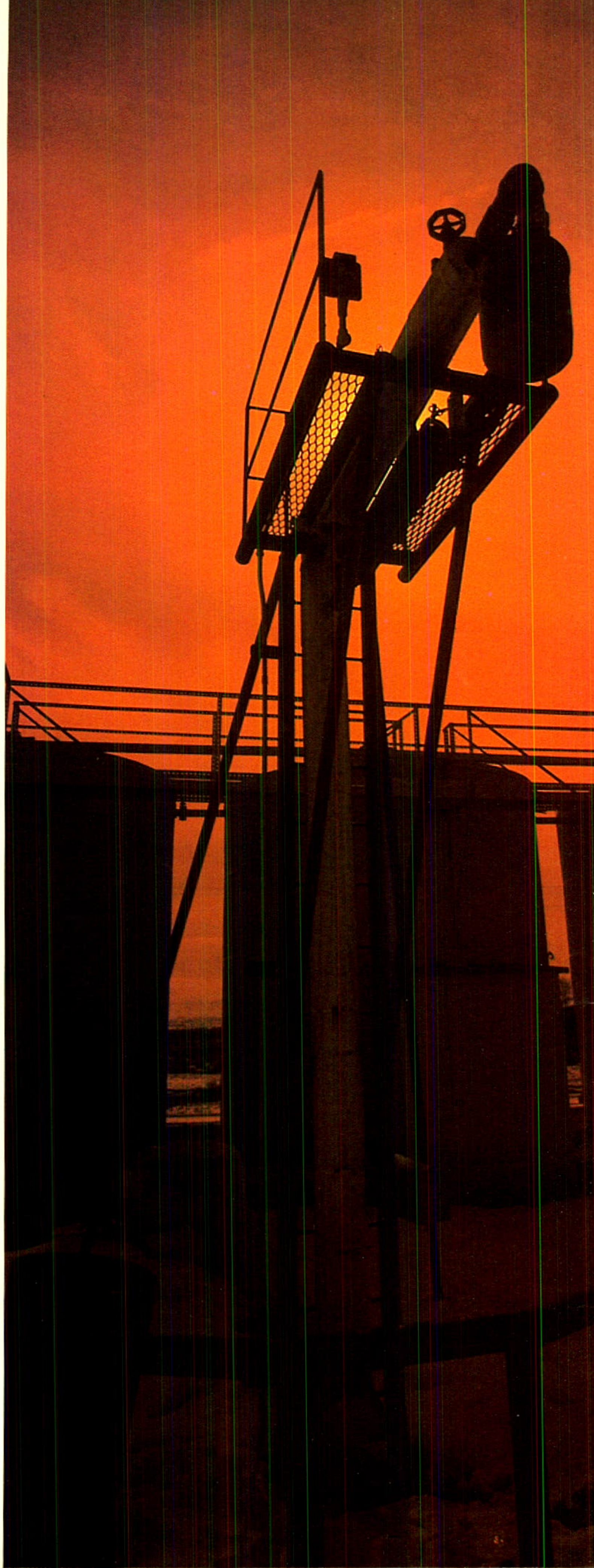
COVER

The cover picture was taken in August of 1981, during the drilling of Page Atlee Buffalo 8-13-24-8W4. This southeastern Alberta well resulted in a Colony natural gas discovery. The rig pictured is owned one-third by Page Petroleum Ltd. Photography courtesy of A.C. Stirrett, a Page geologist.

CONTENTS

METRIC (SI) CONVERSION TABLE

To Convert From	To	Multiply by
Acre (ac)	hectare (ha)	0.404 69
Foot (ft)	metre (m)	0.304 80
Mile (mi)	kilometre (km)	1.609 00
Barrel (bbl)	cubic metre (m^3)	0.158 91
Thousand Cubic Feet (mcf)	cubic metre (m^3)	28.173 99



FINANCIAL AND OPERATING HIGHLIGHTS

(Unless otherwise indicated, all dollar amounts in this report are expressed in thousands of Canadian dollars).

	1981	1980	Increase (Decrease) Per Cent
FINANCIAL			
Gross income	$ 31,148	$ 22,505	38.4
Sales of oil and gas	$ 29,482	$ 21,926	34.5
Investment and other income	$ 1,666	$ 579	187.7
Total expenses	$ 37,632	$ 21,716	73.3
Income (loss) from continued operations	$ (5,717)	$ 616	—
(Loss) from discontinued operations	$ (1,022)	$ (1,775)	(42.4)
Net (loss)	$ (6,739)	$ (1,159)	481.4
Preferred dividends	—	$ 140	—
Net (loss) applicable to common shares	$ (6,739)	$ (1,299)	418.8
Per common share	$ (1.89)	$ (.37)	410.8
Funds generated from operations	$ 2,146	$ 6,905	(68.9)
Additions to property plant and equipment	$ 86,736	$ 36,749	136.0
Working capital (deficiency)	$ (19,575)	$ (1,089)	—
Long-term debt	$ 126,915	$ 62,282	103.8
Shareholders' equity	$ 14,300	$ 20,127	(29.0)
Common shares outstanding	3,594,250	3,492,750	2.9
Number of shareholders	2,243	2,589	(13.4)
OPERATIONS			
LAND HOLDINGS			
Gross acres	115,199,573	5,233,365	2101.3
Net acres	2,039,517	1,271,185	60.4
DRILLING ACTIVITY			
Gross wells drilled	156.0	147.0	6.1
Net wells drilled	103.7	126.0	(17.7)
Net wells productive	97.5	116.4	(16.2)
Net wells dry	6.2	9.6	(35.4)
PRODUCTION – gross (before royalties)			
Crude oil and liquids – barrels	1,342,798	1,219,408	10.1
Per day	3,679	3,341	10.1
Natural gas – mcf	1,813,010	1,006,357	80.2
Per day	4,967	2,757	80.2
Reserves – gross proven			
Crude oil – barrels	25,296,000	22,018,000	14.9
Natural gas – mcf	54,351,000	18,393,000	195.5

RANGE OF MARKET PRICES ON COMMON SHARES:

	Year	1st Quarter High	1st Quarter Low	2nd Quarter High	2nd Quarter Low	3rd Quarter High	3rd Quarter Low	4th Quarter High	4th Quarter Low	Annual Share Volume
Toronto Stock Exchange	1980	35.25	16.00	28.25	19.50	30.75	25.50	32.75	23.50	1,527,620
	1981	27.50	19.00	29.00	19.50	26.50	12.50	19.50	14.50	529,687
American Stock Exchange (U.S. dollars)	1980	31.62	12.00	24.75	16.00	26.87	20.87	28.37	19.37	7,657,000
	1981	23.62	16.00	24.62	16.25	21.75	10.87	16.50	12.50	2,865,600

PRESIDENT'S REPORT

Net oil and gas revenues for the year ended December 31, 1981, were $29,482,000, a 35% increase from $21,926,000 in 1980. Funds generated from operations amounted to $2,146,000 compared to $6,905,000 the previous year. A net loss of $5,717,000 from continuing operations, combined with a $1,022,000 loss from discontinued operations, resulted in a net loss applicable to common shares of $6,739,000 ($1.89 per share). This compares to earnings from continuing operations and a loss from discontinued operations of $616,000 and $1,775,000, respectively, for 1980. The 1980 loss applicable to common shares was $1,299,000 (37¢ per share).

The Company greatly increased its bank borrowings in 1981 to fund capital expenditures of $86,736,000. This resulted in interest costs totalling $13,800,000, or 150% more than the $5,513,000 expended in 1980. This increase accounted for all of Page's earnings loss and greatly reduced the Company's cash flow. Unexpected high interest rates, averaging 16.6% for the year, were a material factor. Total capital expenditures for Texas Panhandle development drilling and pipeline construction amounted to $28,875,000. Lease purchases in the U.S. and Canada totalled $30.6 million. These expenditures will greatly enhance the Company's growth in future years but contributed little to cash flow in 1981.

At year end, the Company's proved net oil reserves totalled 19.9 million barrels, an increase of 11% from 17.9 million barrels at December 31, 1980. Proved net gas reserves were 38 billion cubic feet, up 150% from 15.2 billion cubic feet the previous year.

Page participated in a total of 156 wells (103.7 net) during the year. Of these, 64 were 3,200 foot oil and casinghead gas wells drilled on the Whittenburg lease in the Panhandle Field of Hutchinson County, Texas. Plans call for a total of 99 wells to be completed on this lease by May 1, 1982. The Whittenburg lease will be placed on production early in the second quarter following completion of a 17.6 mile casinghead gas line. At that time, production to Page's account from this lease is expected to be 12 million feet of gas and 1,200 barrels of oil and gas liquids per day. Page's operating revenues from the Panhandle Field are expected to exceed $21 million in 1982, against a total capital cost of approximately $47 million. Revenues from this field are projected to be slightly higher in 1983.

DIRECTORS OF PAGE PETROLEUM LTD.
Clockwise from upper left: Fred Hemming, C.D. Gould, Brian G. McCombe, Lawton L. Clark, Harry A. Irving and Alex S. Cathcart.

In line with much of the industry, Page's 1982 budget for exploration and development will be reduced considerably from the previous year. The Company will spend much less for leases and more effort will be made to obtain industry partners to share in the costs. The 1982 budget calls for capital expenditures of $46 million, divided 67% for development and 33% for exploration. Approximately 74% of the budgeted funds are allocated to the U.S.

In mid-1981 Page announced its intention to sell its Canadian properties. This decision was largely motivated by "Canadianization" policies of the National Energy Program, as outlined in October of 1980. The bids that were received were not satisfactory and, following the announcement of a long awaited pricing agreement between Saskatchewan and the Federal Government, Page decided to withdraw its properties from the market. As a result of the new pricing agreement Page's future cash flow from its large reserves in the Dodsland Field of Saskatchewan will be greatly increased. As of

January 1, 1982, Page's proven reserves in this field were estimated to be 12 million barrels, with future undiscounted net revenues of $872 million. Using a 15% discount factor, the value of these reserves has increased from $82.4 million to $118.8 million. The increase is due chiefly to greatly reduced royalty rates on wells producing less than 20 barrels per day. Wells drilled after January, 1981, will qualify for a new oil price that is designed to follow world oil prices. On 12 wells drilled in 1981, and as many as 60 scheduled to be drilled in 1982, Page will net $25-$31 per barrel. This is after deduction of all royalties, wellhead taxes and estimated operating costs. This does not provide for Federal Income Tax; however, because of large tax losses Page should not be in a taxable position for some years.

The Company continues to make substantial progress in most areas of our business. We are pleased with the steady rate of growth of revenues and reserves as evidenced by the five year statistical summary and graphs found on the following two pages. This growth pattern seems assured for at least the next few years, with oil and gas revenues in 1982 expected to increase by approximately 60%. However, because of our very aggressive drilling and land acquisition program, we have incurred substantial indebtedness. This, together with high interest rates, has resulted in negative earnings and a barely positive cash flow in 1981. Your Management's number one priority is to reduce indebtedness and to restore profitability. As discussed in the Company's third quarter report, we are considering the sale of certain assets in the U.S. and Canada that, together, could amount to as much as $50 million. The Company has taken steps to substantially reduce general and administrative expenses. In early April, Page's administrative payroll expense was reduced by approximately 32% through employee terminations and salary decreases. This action, together with other overhead reductions, will achieve savings of approximately $2 million per year from earlier projections. The staff reductions were made most reluctantly, but were deemed necessary, given the uncertain outlook for oil pricing and the probability of continued high interest rates.

As this is written, the future of world oil prices has attracted considerable attention and many gloomy predictions. Whether these predictions have any merit can only be determined by time. Barring the unexpected, approximately one-half of Page's production in 1982 and 1983 should not be affected by decreases in world oil prices. This is due to Page's increasing natural gas revenues, accounting for an estimated one-quarter of expected 1982 revenues, and the fact that most of the Company's Canadian oil production receives regulated prices well below world levels.

We look forward to the future and believe that Page will be a stronger and more profitable Company at the end of 1982.

Lawton L. Clark

April 12, 1982 President

Page Petroleum Ltd. was honored by having its 1980 Annual Report judged First in the Junior Oil Companies Division of the Oilweek Magazine Annual Report Awards Program. The plaque, shown above, was presented to Page in October, 1981.

PAGE PETROLEUM LTD.

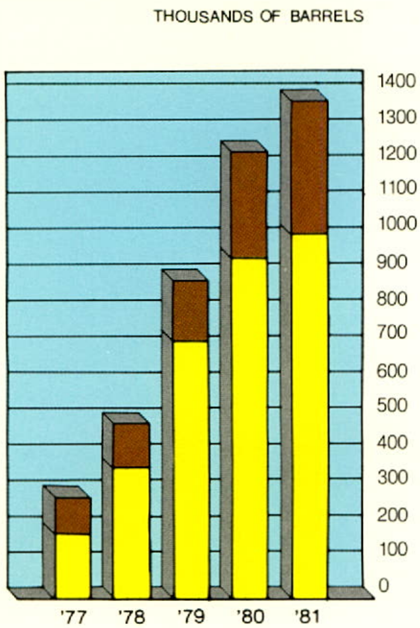
FIVE YEAR STATISTICAL SUMMARY

	1981	1980	1979	1978 (Restated)	1977 (Restated)
FINANCIAL					
INCOME					
Oil and gas sales	$ 39,474	$ 27,909	$ 15,235	$ 6,682	$ 2,914
Royalties paid	9,992	5,983	3,629	1,752	996
Net oil and gas sales	29,482	21,926	11,606	4,930	1,918
Interest and other income	1,007	579	68	130	99
Well servicing revenue	659	—	—	—	—
GROSS INCOME	31,148	22,505	11,674	5,060	2,017
Production expense	8,164	5,797	3,429	1,340	469
General and administrative	4,005	2,613	1,413	537	276
Federal production taxes	2,977	1,122	—	—	—
Interest expense	13,800	5,513	2,355	709	370
Well servicing	533	—	—	—	—
Depreciation depletion and amortization	8,153	6,671	3,869	1,444	517
Loss from discontinued operations	1,022	1,775	406	8	—
Current income taxes	(451)	(195)	(178)	(145)	(147)
Deferred income taxes	(316)	368	413	368	235
NET EARNINGS (LOSS)	(6,739)	(1,159)	(33)	799	297
Preferred dividends	—	140	445	183	—
Net earnings (loss) applicable to common shares	(6,739)	(1,299)	(478)	616	297
Per common share	(1.89)	(0.37)	(0.18)	0.30	0.17
FUNDS GENERATED FROM OPERATIONS	2,146	6,905	4,533	2,669	1,049
BALANCE SHEET					
Working capital (deficiency)	(19,575)	(1,089)	(744)	114	668
Investments and advances	4,895	6,560	3,620	—	—
Property and equipment	154,402	75,444	45,074	18,880	8,998
Other assets	2,993	3,284	1,539	1,581	65
CAPITAL EMPLOYED	142,715	84,199	49,489	20,575	9,731
Deduct: Long-term debt	126,915	62,282	26,645	10,182	5,547
Deferred income taxes	1,474	1,790	1,422	1,009	641
Minority interest	26	—	—	—	—
Shareholders' equity	14,300	20,127	21,422	9,384	3,543
Common shares outstanding	3,594,250	3,492,750	2,960,868	2,065,418	1,999,252
CAPITAL EXPENDITURES					
Exploration and development (net)	85,332	35,979	27,859	10,059	2,870
Well servicing	—	—	1,300	666	—
Other	1,404	770	1,097	663	59
	86,736	36,749	30,256	11,358	2,929
OPERATIONS					
LAND HOLDINGS (working interest)					
Gross acreage held (in thousands)	115,200	5,233	1,537	882	1,627
North America — net	1,011	829	360	89	111
International — net	1,028	442	—	24	43
TOTAL NET ACREAGE	2,039	1,271	360	113	154
DRILLING ACTIVITY					
Gross wells drilled	156.0	147.0	146.0	113.0	53.0
Net wells drilled	103.7	126.0	117.3	92.6	42.6
Productive	97.5	116.4	111.1	87.5	42.3
Dry	6.2	9.6	6.2	5.1	0.3
PRODUCTION — gross (before royalties)					
Crude oil and liquids - barrels	1,343,000	1,219,000	862,000	468,000	266,000
Average daily, barrels	3,679	3,341	2,361	1,282	730
Natural gas - mcf	1,813,000	1,006,000	1,071,000	607,000	195,000
Average daily, mcf	4,967	2,757	2,934	1,664	534
GROSS RESERVES - proven					
Crude oil - thousand barrels	25,296	22,018	16,074	10,146	5,720
Natural gas - mmcf	54,351	18,393	15,393	10,773	6,776

OPERATING TRENDS

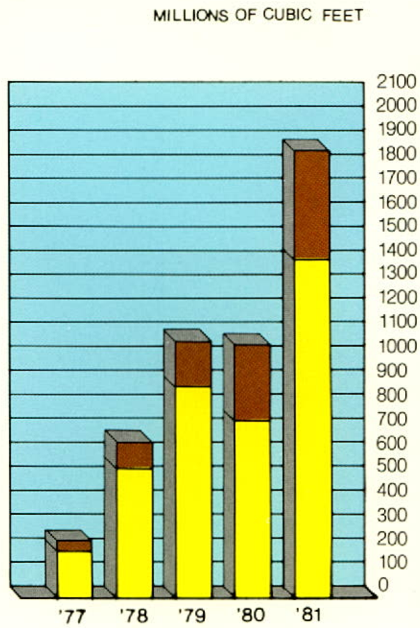
OIL PRODUCTION

GROSS
NET



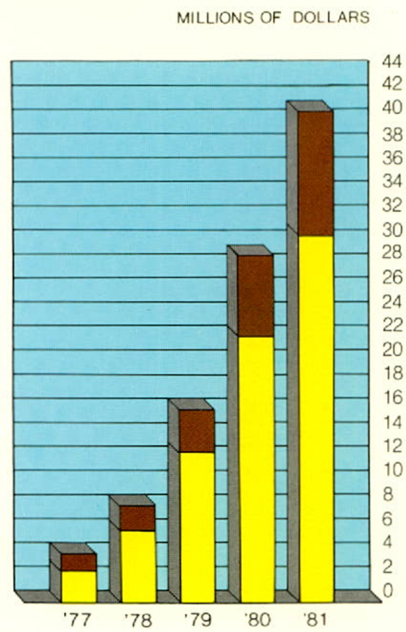
NATURAL GAS PRODUCTION

GROSS
NET



GROSS AND NET OIL AND GAS REVENUES

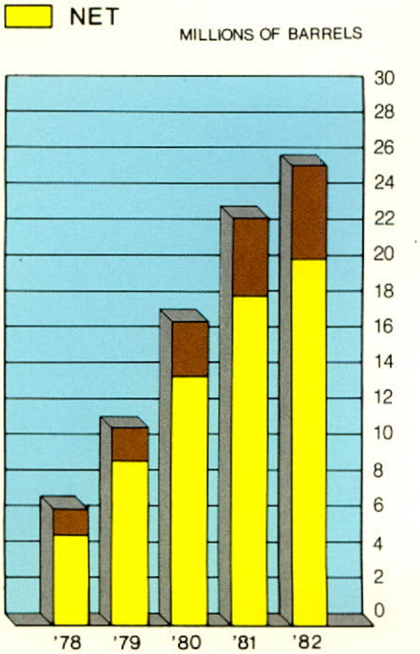
GROSS
NET



OIL RESERVES

Proven as of January 1.

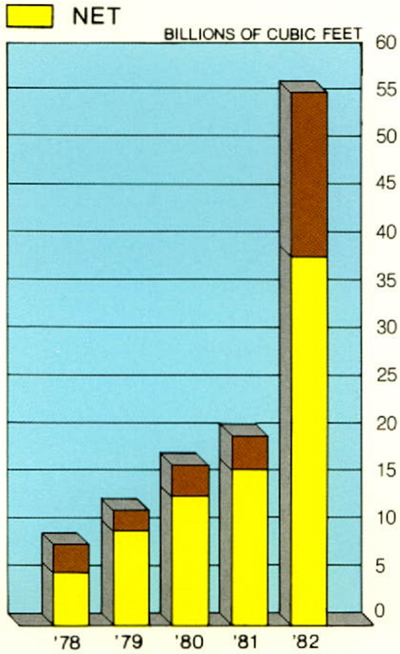
GROSS
NET



NATURAL GAS RESERVES

Proven as of January 1.

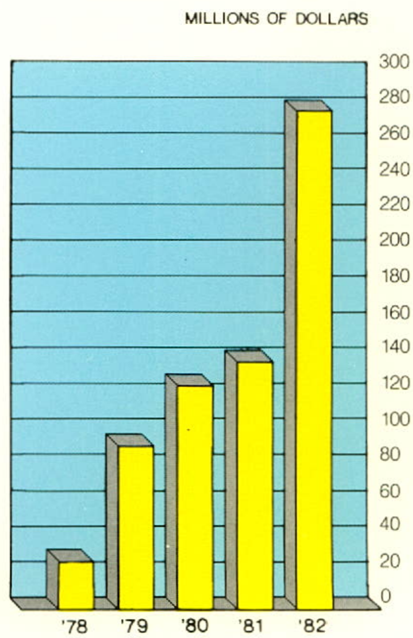
GROSS
NET



TOTAL PROVEN NET OIL AND GAS CASH FLOW

Proven as of January 1.

DISCOUNTED @ 15%



PRODUCTION AND RESERVES

Page's gross oil and gas production, before royalties, reached all time highs during 1981 with oil production averaging 3,679 barrels per day and gas production 4,967 Mcf per day. The average oil production was up moderately from the 1980 average of 3,341 barrels per day, while the average gas production increased significantly from 2,757 Mcf per day in 1980.

Independent engineering firms in the United States and Canada have estimated Page's proven net oil reserves at December 31, 1981, to be 19,863,000 barrels. This represents an 11% increase over the 17,883,000 barrels estimated at December 31, 1980. Proven net gas reserves increased 150% to 38 billion cubic feet from 15.2 billion cubic feet. Most of the reserve increase resulted from a 77-well development program in the Panhandle Field of Hutchinson County, Texas. The future undiscounted cash flow from these proven reserves, as calculated by independent engineering firms in Canada and the United States, is $1.14 billion compared to $397 million a year ago. Using a 15% discount factor, the cash flow was determined to have a present worth of $279 million compared to $134 million at the end of 1980. These values are net after deduction of estimated royalties, operating costs, and future capital expenditures. In Canada, the Petroleum and Gas Revenue Tax (PGRT) and the Incremental Oil Revenue Tax (IORT) have also been deducted from the oil property evaluations. In the United States, the oil property evaluations take into account the deregulated price of crude oil less the appropriate Windfall Profit Tax. Much of the large increase in estimated future revenues is due to the Saskatchewan and Canadian Federal Government pricing agreement of October 26, 1981. The terms of this agreement included an increase in the wellhead price of oil, a reduction in provincial royalties, and a reduction in federal wellhead taxes. These changes particularly effect the economics of Page's 328 wells in the Dodsland field and greatly enhance the economics of the future development of up to 350 additional wells.

Proven reserves are defined by the consultants as the crude oil, natural gas, and natural gas liquids, which upon analysis of geological and engineering data, appear with reasonable certainty to be recoverable in the future from known oil and gas reserves under presently anticipated economic and operating conditions.

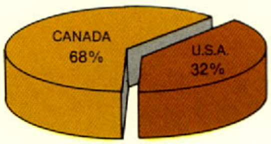
In 1981, Page obtained approximately 80% of its total net oil and gas revenues from two fields: the Dodsland Field in Saskatchewan with net sales of $9,343,055 (32%) and the Altamont-Bluebell Field in Utah with net sales of $14,174,841 (48%). It is worth noting that for the first time in the Company's history, net oil and gas revenues from the United States ($16,777,700, or 57% of the Company total) were greater than that from Canada ($12,704,400, or 43% of the Company total). It is anticipated that approximately 70% of Page's 1982 revenues will be from the U.S.

PROVEN RESERVES

	JANUARY 1, 1982		JANUARY 1, 1981	
	Gross	Net	Gross	Net
	(thousands of barrels)		(thousands of barrels)	
OIL				
Alberta	2,069	1,357	2,120	1,405
Saskatchewan	14,617	13,505	16,511	13,717
Nebraska	25	20	—	—
Oklahoma	3	2	—	—
Texas	4,976	2,453	166	132
Utah	3,606	2,526	3,221	2,629
Total Oil	25,296	19,863	22,018	17,883
	(millions of cubic feet)		(millions of cubic feet)	
GAS				
Alberta	7,355	5,765	6,191	4,986
Saskatchewan	2,379	2,020	2,370	2,304
New York	110	96	—	—
Oklahoma	179	152	179	152
Texas	37,307	24,765	4,953	3,872
Utah	7,021	5,244	4,700	3,839
Total Gas	54,351	38,042	18,393	15,153

NET OIL AND GAS RESERVES (PROVED) BY COUNTRY

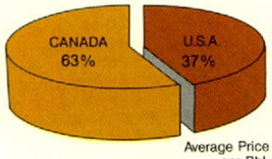
At December 31, 1981 (Equivalent Bbls.)



Canada	15,795,000
United States	7,328,000
Total	23,123,000

PRODUCTION OF OIL AND GAS - 1981

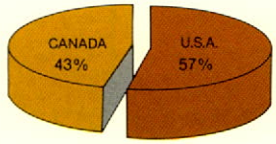
Expressed in Barrels



		Average Price per Bbl.
Canada	942,000	18.86
United States	552,000	39.84
Total	1,494,000	26.61

NET OIL AND GAS REVENUES - 1981 BY COUNTRY

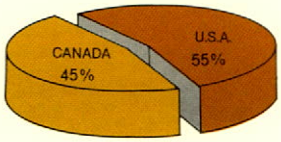
Canadian Dollars



Canada	12,704,000
United States	16,778,000
Total	29,482,000

TOTAL FUTURE NET OIL AND GAS CASH FLOW

Discounted @ 15%



Canada	125,721,000
United States	153,307,000
Total	279,028,000

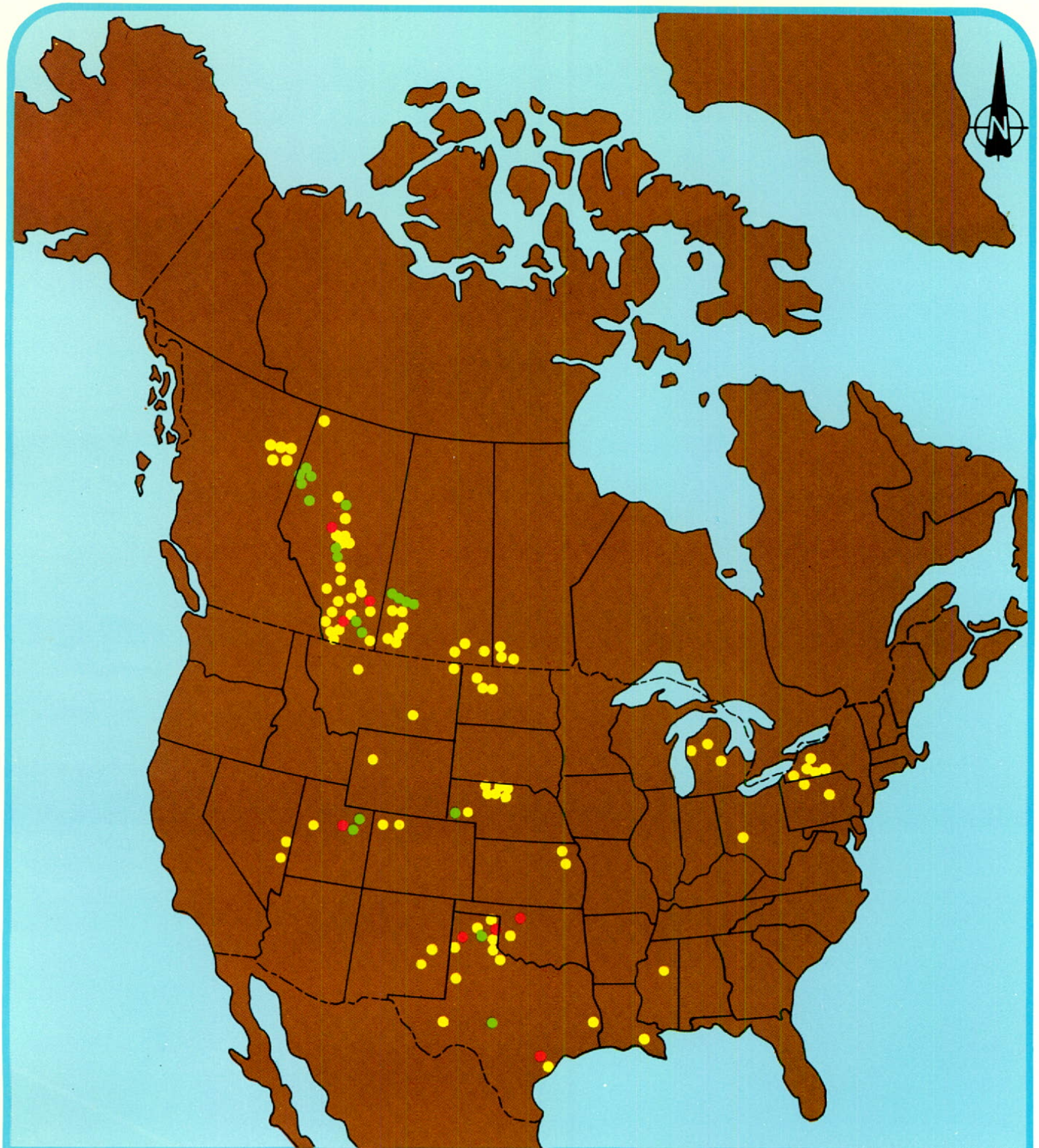
LAND HOLDINGS

At January 1, 1982

	DEVELOPED ACREAGE		UNDEVELOPED ACREAGE	
	Gross Acres	Net Acres	Gross Acres	Net Acres
CANADA				
Alberta	18,399	6,428	107,274	69,476
British Columbia	—	—	8,542	1,549
Manitoba	—	—	8,060	3,351
Saskatchewan	18,573	16,221	35,674	28,214
Arctic	—	—	341,242	29,484
Total	36,972	22,649	500,792	132,074
UNITED STATES				
Alaska	—	—	2,560	320
Alabama	—	—	200	67
Colorado	—	—	16,029	601
Kansas	—	—	259,508	122,191
Michigan	40	40	175,983	93,217
Mississippi	—	—	53,348	17,783
Montana	—	—	52,637	35,915
Nebraska	80	60	1,051,658	168,193
Nevada	—	—	83,144	83,144
New Mexico	—	—	26,874	12,765
New York	80	16	70,147	14,029
North Dakota	—	—	131,070	16,384
Ohio	—	—	22,847	22,847
Oklahoma	1,440	403	1,560	314
Pennsylvania	—	—	46,904	38,863
Texas	20,609	3,845	78,095	30,725
Utah	16,640	10,816	183,454	183,454
Wyoming	—	—	23,000	575
Total	38,889	15,180	2,279,018	841,387
INTERNATIONAL				
Australia	—	—	109,926,182	442,498*
Egypt	—	—	2,116,000	520,900
Italy	—	—	157,440	52,475
Tunisia	—	—	119,000	11,900
U.K. North Sea	—	—	25,280	455
Total	—	—	112,343,902	1,028,228
Total	75,861	37,829	115,123,712	2,001,689

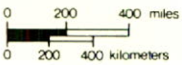
The above table excludes varying royalty interests in 13,595 gross acres.

**This represents Page's 33⅓ % ownership in Springwest-Page Petroleums N.L.*



NORTH AMERICA AREAS OF ACTIVITY

- Exploration areas
- Oil production
- Gas production



EXPLORATION AND DEVELOPMENT

Page's expenditures for development and exploration in Canada and the United States during 1981 totalled \$85.3 million. The expenditures were 96% in the U.S. and 4% in Canada. Development drilling accounted for 51% of the funds spent while exploration costs, including land and seismic, were 49% of the total. A total of 156 (104 net) wells were drilled, of which 117 were development and 39 exploratory. This drilling resulted in 123 oil wells (94 net), 10 gas wells (3.4 net) and 23 dry holes (6.2). The expenditures included \$30.6 million for land acquisitions and \$2.6 million for geophysical work.

Page's major development program was in the old Panhandle Field of Hutchinson County, Texas, where a total of 77 development oil and casinghead gas wells were drilled. The usual large development program in the Dodsland Field of Saskatchewan was cut back to a total of 12 wells, from 100 the year before. This was due to the negative impact of the Canadian Energy Policy announced in October, 1980. Recent concessions to industry from the Federal and Saskatchewan Governments have greatly improved the economics of drilling in Saskatchewan.

A total of \$46 million has been budgeted for exploration and development in 1982. Of this, 74% is to be spent in the U.S., 18% for Canada and 8% International.

CANADA

During 1981, a much reduced exploration and development program was carried out in Canada because of the negative impact of the National Energy Policy of October, 1980. In addition to 12 development wells drilled in the Dodsland Field, the Company participated in six exploratory wells in Alberta and Saskatchewan. The exploratory drilling

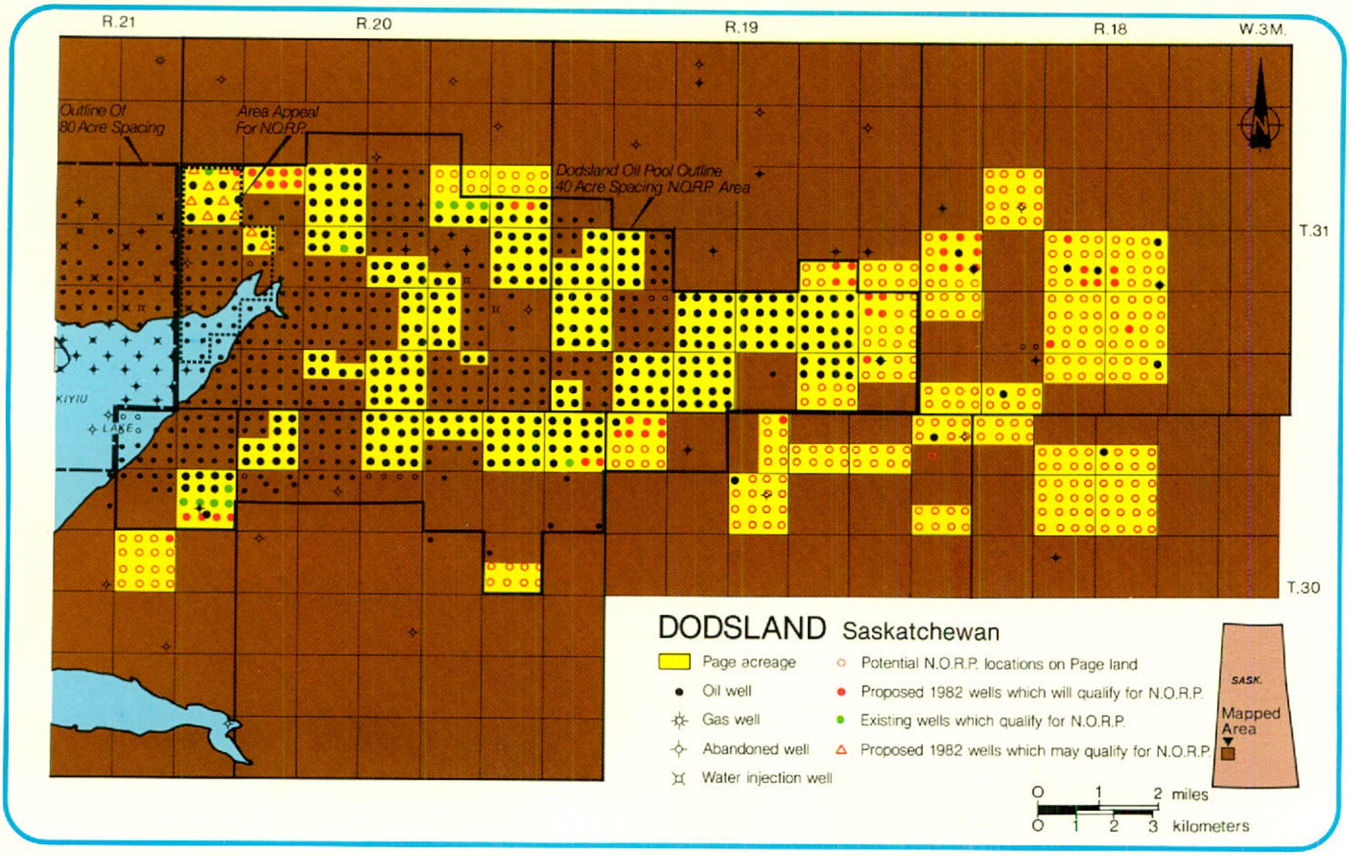
resulted in two oil wells, two gas wells, and two dry holes.

The Saskatchewan-Federal Government pricing agreement announced in November, 1981, and the new Saskatchewan royalty schedule announced in February, 1982, have, in combination, dramatically enhanced the netbacks at the wellhead and, therefore, the value of Page's oil reserves in the Dodsland field. Page now plans to reinstate its development program in this field and may drill as many as 60 development oil wells at Dodsland in 1982.

Page, as a U.S. controlled Company, is not eligible for certain Canadian exploratory incentive credits, which puts Page at a competitive disadvantage with Canadian controlled companies. However, in view of the large potential for oil and gas in Western Canada, and with the recently improved industry economics, the Company intends to maintain a viable exploration program. Page will continue its recent policy of seeking industry partners to drill wells at little or no cost to Page. The drilling of four exploratory wells at Antler River, Saskatchewan in 1981 at no cost to Page, and the drilling of two exploratory wells at Shekilie, Alberta, in the first quarter of 1982, at reduced cost to Page, are positive results of this approach.

DRILLING STATISTICS - 1981

	OIL		GAS		DRY		TOTAL		SUCCESS RATIO	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
EXPLORATION										
Canada	3.0	0.75	2.0	2.0	2.0	0.42	7.0	3.14	71.4%	86.6%
United States	4.0	1.36	8.0	1.4	20.0	4.79	32.0	7.55	37.5%	36.6%
Subtotal	7.0	2.11	10.0	3.4	22.0	5.21	39.0	10.69	43.6%	51.3%
DEVELOPMENT										
Canada	14.0	13.33	0	0	0	0	14.0	13.33	100%	100%
United States	102.0	78.66	0	0	1.0	1.0	103.0	79.66	99.0%	98.7%
Subtotal	116.0	91.99	0	0	1.0	1.0	117.0	92.99	99.1%	98.9%
Total	123.0	94.10	10.0	3.4	23.0	6.21	156.0	103.68	85.3%	94.0%



SASKATCHEWAN

Dodsland

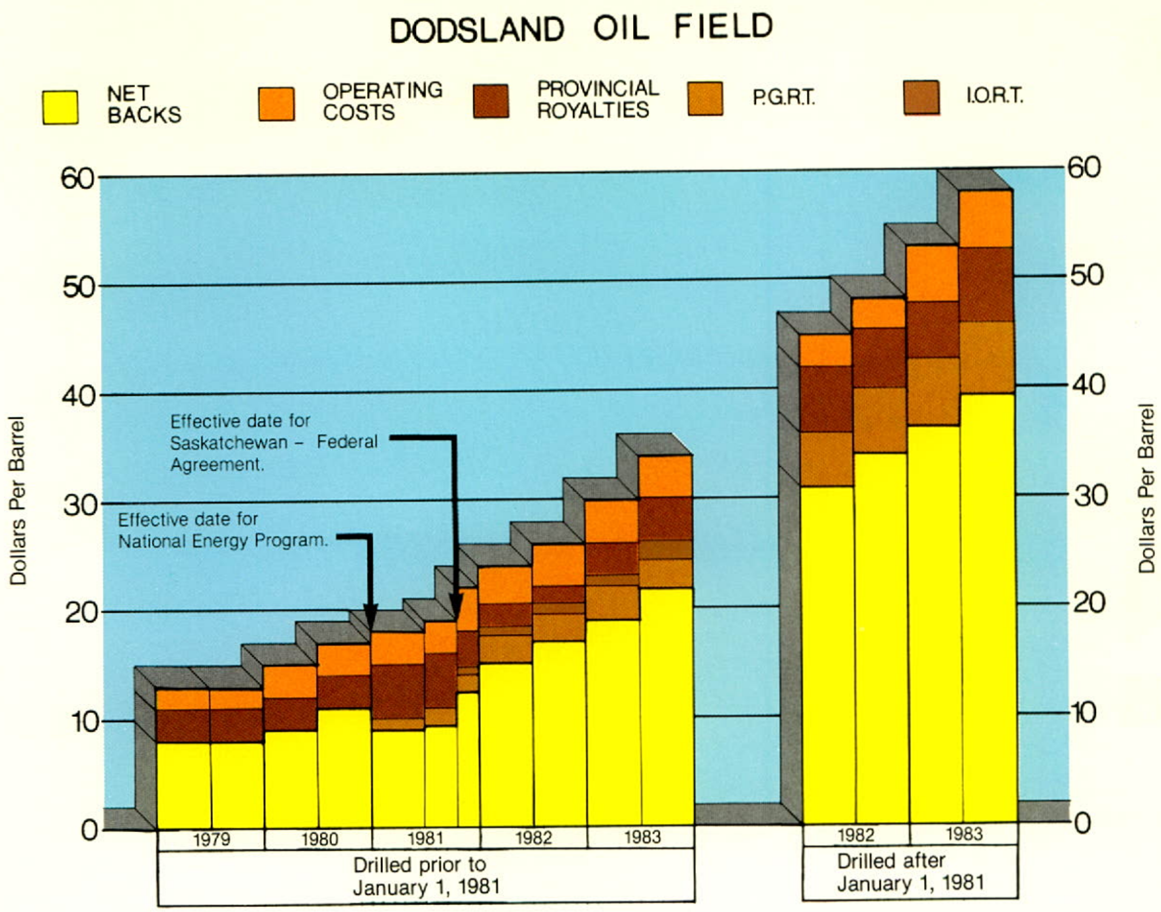
Page operates 328 producing oil wells (319 net) in the Dodsland Field of west-central Saskatchewan. The Company's land holdings at December 31, 1981, totalled 25,234 net acres of leases and mineral titles. At the March 9, 1982, Saskatchewan land sale an additional 1,760 net acres of leases were acquired at a cost of $454,113.

The oil pricing and revenue sharing agreement between the Federal and Saskatchewan governments, in combination with the new Saskatchewan royalty schedule, have significantly improved the value of Page's Dodsland oil reserves and undeveloped acreage. During 1981, the netback per barrel to the Company after provincial royalty, operating costs, and wellhead taxes, from an average Dodsland well (6 BOPD) was $9.53. During the first six months of 1982 the netback increases to approximately $15.20 per barrel and in the second half of 1982 it will be $16.76 per barrel. New wells, (wells drilled after January 1, 1981) will receive the "New Oil Reference Price" ("NORP") which is scheduled to closely approximate world oil prices. At present, Page has 12 oil wells which qualify for NORP. Based on the NORP price schedule, the netback at the wellhead from a barrel of oil from an average "new" Dodsland well during the first half of 1982 is forecast to be $31.02 per barrel. This netback was achieved during January and February of 1982; however, weakening world oil prices will likely lower this during the remainder of 1982. A more realistic netback for 1982 is expected to be $25 - $28 per barrel, a very substantial increase in value in comparison to that from existing older wells.

Page has scheduled the drilling of 60 development wells this year, commencing in June. In addition to the wells in the 1982 drilling program, the Company will have approximately 290 remaining locations, all qualifying for the new oil price.

At January 1, 1982, the discounted present worth (at 15%) of the net proven Dodsland oil reserves was $118.8 million compared to $82.4 million on January 1, 1981. The discounted present worth (at 15%) of combined net proven and probable reserves increased from $100.2 million on January 1, 1981 to $156.9 million on January 1, 1982. These figures demonstrate the overall effect of the increased return at the wellhead under the new pricing and royalty schedules.

The Dodsland field produces light (34° API) gravity crude from the Viking sand at a depth of 2,200 feet. During 1981, production averaged 1,761 barrels of oil per day resulting in a net revenue to Page of $9.3 million, or 32% of the Company total. The new increase in net income per barrel ensures that this field will continue to be a major source of revenue for Page for many years.



Effects on pricing and Net Backs at Wellhead of Saskatchewan - Federal Agreement and National Energy Program on a typical Dodsland oil well.

Buffalo Coulee

Page Petroleum Ltd. operates 21 oil wells, a water injection plant, 7 injection wells and 8 shut-in oil wells in the main Buffalo Coulee field. This field has historically been very difficult to produce economically because of serious sand problems and the low oil gravity; however, since initiating a secondary recovery waterflood scheme in February of 1981, a gradual improvement has been recorded. During the past six months there has been excellent flood response with a marked reduction in gas-oil ratios, improved productivity and reduced problems due to sand. Company production is currently averaging 140 barrels of oil per day.

Page also proposes to carry out an experimental, one well, CO_2 "Huff and Puff" project. An engineering consultant's study indicates this pool should be an ideal candidate for a CO_2 flood. Laboratory tests show the 13.5 API gravity oil has a viscosity of over 750 Centipoise at a formation temperature of 78°F. When saturated with CO_2 the viscosity is reduced to 30 Centipoise resulting in a great improvement in the mobility of oil. A pilot test may be carried out in the latter half of 1982.

Shaunavon Trend

The Company purchased five leases, totalling 1,760 acres, in southwestern Saskatchewan at the March 9, 1982, Provincial land sale, for bonuses totalling $274,106. The addition of these leases raises Page's holdings on the oil-prolific Jurassic Shaunavon Trend to 5,200 acres. Medium gravity oil is produced along this trend from an average depth of 4,600 feet. Each of the five recently purchased leases is directly offset by a producing oil well. The cumulative oil production from these wells, to date, ranges from 75,000 barrels to 325,000 barrels each. The Company is now preparing a farmout package whereby Industry will be invited to earn an interest in the leases by drilling wells at no cost to Page.

ALBERTA

Shekilie

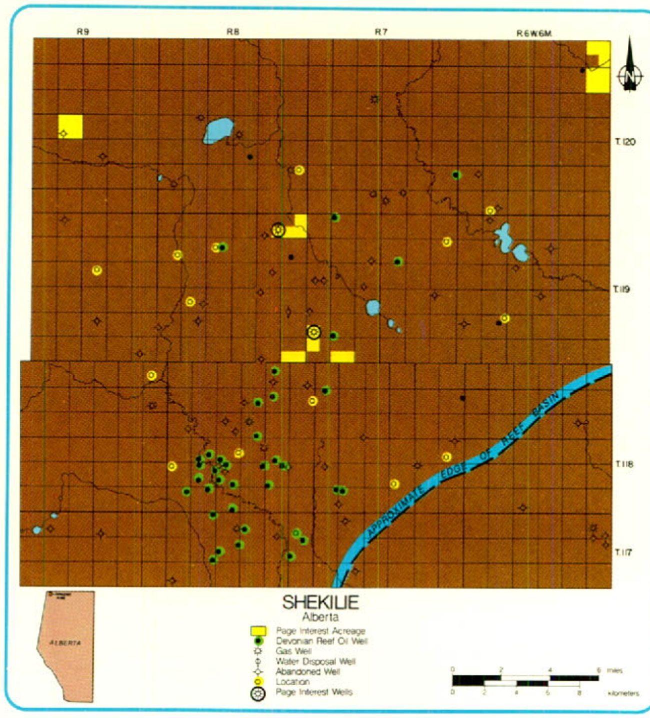
Page is currently active in the Shekilie Reef Basin located in the northwestern corner of Alberta. This basin is highly prospective for oil in middle Devonian Keg River pinnacle reefs with present production per well averaging nearly 200 barrels per day. Thirty-six separate reefs have been discovered to date and sixteen wells are currently drilling. Currently one of the most active oil plays in Alberta, the Shekilie area has commanded prices of over $6,000 per acre at recent land sales.

Page is participating in two wells in Shekilie, one of which, Strand et al Amigo 8-35-119-8W6, is an indicated triple zone gas discovery. Log interpretations indicate gas pays of 121 feet in the Keg River Reef, 20 feet in the Zama member, and 43 feet in the Sulphur Point. Drillstem tests of the Sulphur Point and Keg River flowed gas at rates of 3.7 and 3.9 million cubic feet of gas per day, respectively. The Company has a 20 percent interest in this well. This is one of only three gas-bearing reefs in the area and will be much less economic than a similar oil-bearing reef. No gas market is available at the present time. The Page et al Amigo 3-7-119-7W6 well (Page 23%) encountered 36 feet of gas pay in the Sulphur Point and penetrated the Keg River Reef in a flank position. A total of 95 feet of reef was penetrated and oil stained samples were recovered from the uppermost 80 feet. This well will be whipstocked next winter in an attempt to penetrate the top of the reef.

In addition to these wells, Page recently completed 27 miles of detail seismic over four other potential leads. Once the drilling activity has been completed, Page will have working interests ranging from 18 - 23% in 3,040 lease acres.

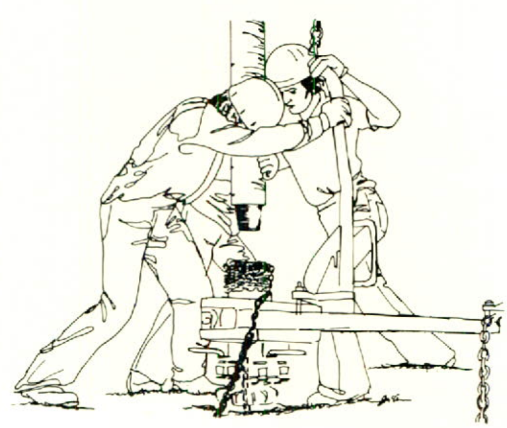
Atlee Buffalo

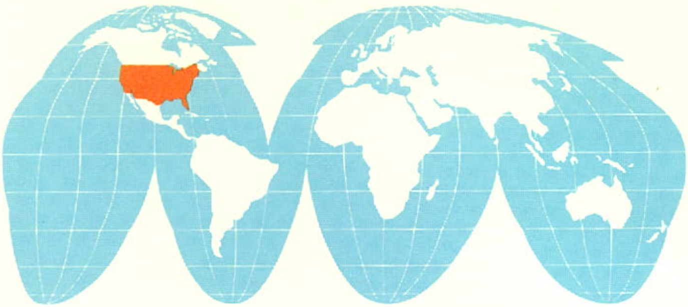
Page Petroleum Ltd. holds a 100% working interest in 19 sections (12,160 acres) at Atlee Buffalo in south-eastern Alberta. Two exploratory gas discoveries were drilled in 1982, raising the number of shut-in gas wells on the property to five. Gas reserves have been established in the Colony, Viking, Second White Specks and Milk River sands, ranging in depth from 1,100 to 3,000 feet. A gas contract with Pan Alberta provides for delivery of 7.8 million cubic feet of gas per day. Page may be able to commence marketing its gas reserves on this acreage by late 1983.



Canal Creek

The Company, as part of its regional 1980 seismic program, surveyed approximately 65 miles of seismic in the Canal Creek area of southeast Alberta. A prospective structural anomaly was delineated, and Page subsequently purchased a 3,040 acre Petroleum and Natural Gas License, for a bonus of $162,101 at the March 11, 1981, Alberta Land Sale. Page used Alberta Exploration Incentive Credits instead of cash to make this acquisition. It is planned to farm out an interest in this acreage for the drilling of a 5,800 foot Cambrian test.





UNITED STATES

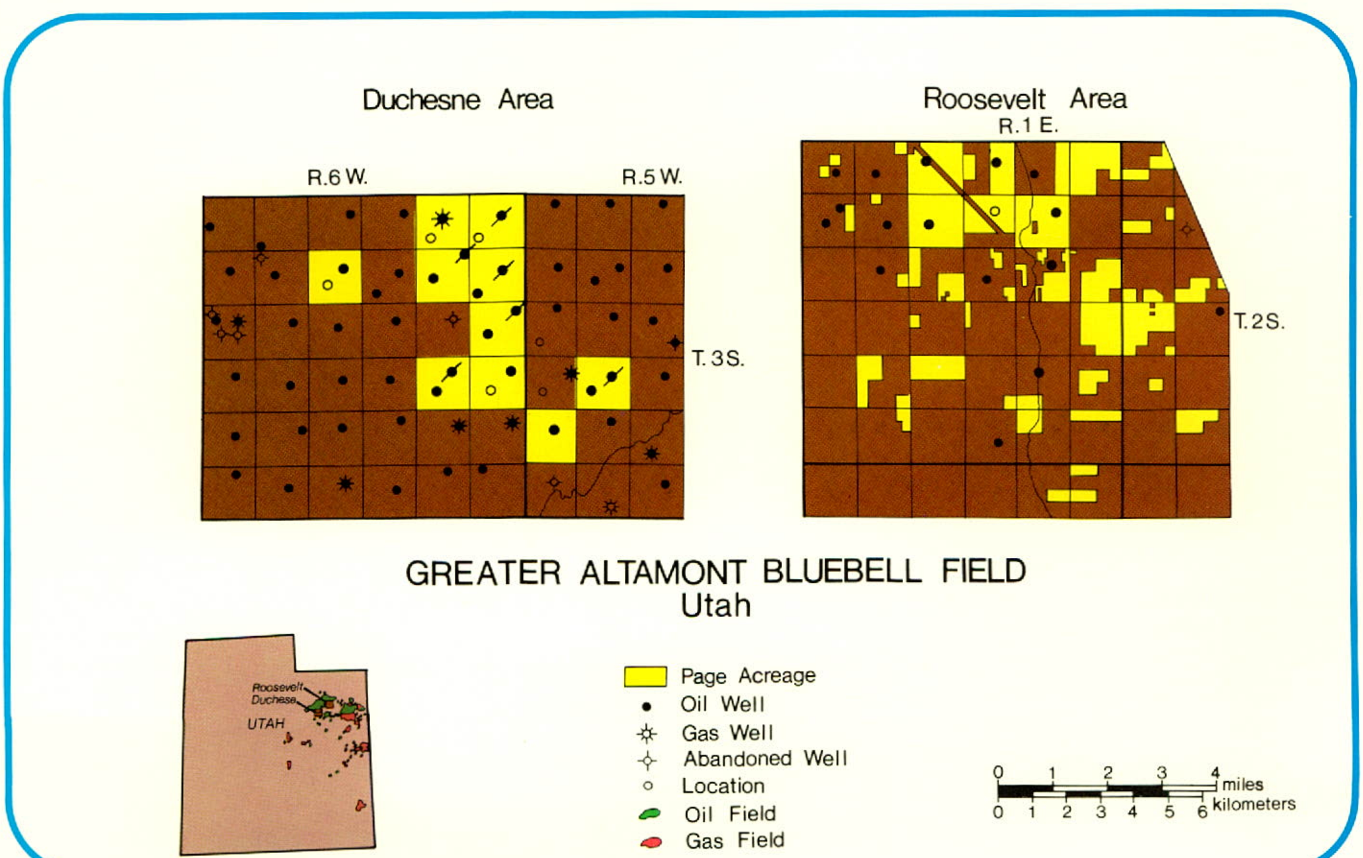
Page continues to expand its oil and gas exploration and development activities in the United States. Page Petroleum Inc., Page's wholly owned subsidiary, participated in 135 wells (87.2 net) resulting in 114 (81.4 net) oil and/or gas wells and 21 (5.8 net) dry holes. An aggressive land acquisition program also continued in 1981. At December 31, 1981, Page's U.S. land holdings had increased to 2,306,289 gross acres (860,396 net) from 1,814,459 gross acres (689,801 net).

During 1981, significant additional land acquisitions were made in the Michigan Basin, the Williston Basin in North Dakota, the Black Warrior Basin in Alabama, the Abo trend in New Mexico, and the Austin Chalk trend in Texas. Page now has land holdings in 18 states.

UTAH

Altamont-Bluebell Field

At year-end, Page owned interests in 30 wells (19.2 net) in the Altamont-Bluebell Field of Duchesne and Uintah Counties, Utah. Page drilled four development wells in 1981, three in the Duchesne area and one in the Roosevelt area. Three of the wells were drilled following the resolution of lease title problems with the Bureau of Indian Affairs. One of these wells, the 2-11C6 (Page 100%), was completed at year end and in early January was tested at flow rates up to 1,300 barrels of oil and 1.2 million cubic feet of gas per day. At March 15, the well was producing at an average rate of 525 barrels of oil and 800 thousand cubic feet of gas per day. Two wells operated by Exxon, the Ute Tribal A-1 (Page 11.9%), and the



Ute Tribal B-1 (Page 23%), were both awaiting completion at year's end. One of Page's older wells in the Roosevelt area, the Earl Gardner B-1, was recompleted in the lower Green River interval and is producing 70 barrels of oil per day. While most of Page's production is from the deeper Wasatch formation, it is likely that the lower Green River production can be expanded fairly substantially over the next two or three years.

Page's net production in 1981 from the Altamont-Bluebell Field was 317,116 net barrels of oil and 635 million cubic feet of gas. The waxy crude produced in this field has a very high pour-point and requires downhole heat and heated tank batteries. Although this increases operating costs, Page has, through careful production practices, made this a highly profitable operation. After deduction of all operating costs (averaging $6.70 per barrel) these properties netted Page $13.8 million, being 84% of total U.S. operating revenues and 47% of the total Company revenues. Page owned 16,000 net acres of leases in this area at year-end.

TEXAS

Panhandle Field

The Company took part in a large development drilling program during 1981 on its properties in the giant Panhandle Field northeast of Amarillo. A total of 77 wells (70.4 net to Page) were drilled on three principal leases. Page's initial working interests in the wells range from 40% to 100%. The wells produce oil and casinghead gas from the White Dolomite and Moore County Lime from approximately 3,100 - 3,300 feet. A substantial portion of the leases were drilled forty to fifty years ago, with most of the wells subsequently plugged and abandoned during the 1950's. Infill drilling, using modern fracing and completion techniques, has resulted in economic wells at today's prices.

At year end, Page's share of production from the three leases was approximately 193 net barrels of oil and 1.4 million cubic feet of gas per day. The Whittenburg lease, on which the Company held a 100% interest in 64 wells at year end, is effectively shut-in awaiting the completion of a 17.6 mile casinghead gas line. Initial throughput will commence approximately April 1, 1982, with the line expected to be fully operational in June. At this point, Page's net production from this lease is expected to be approximately 1,200 barrels of oil and gas liquids and 12 million cubic feet of casinghead gas per day. This will result in monthly revenues to Page of approximately $1.8 million (U.S.). The final completed costs for the Whittenburg development drilling and pipeline will be approximately $31 million (U.S.).

Viking

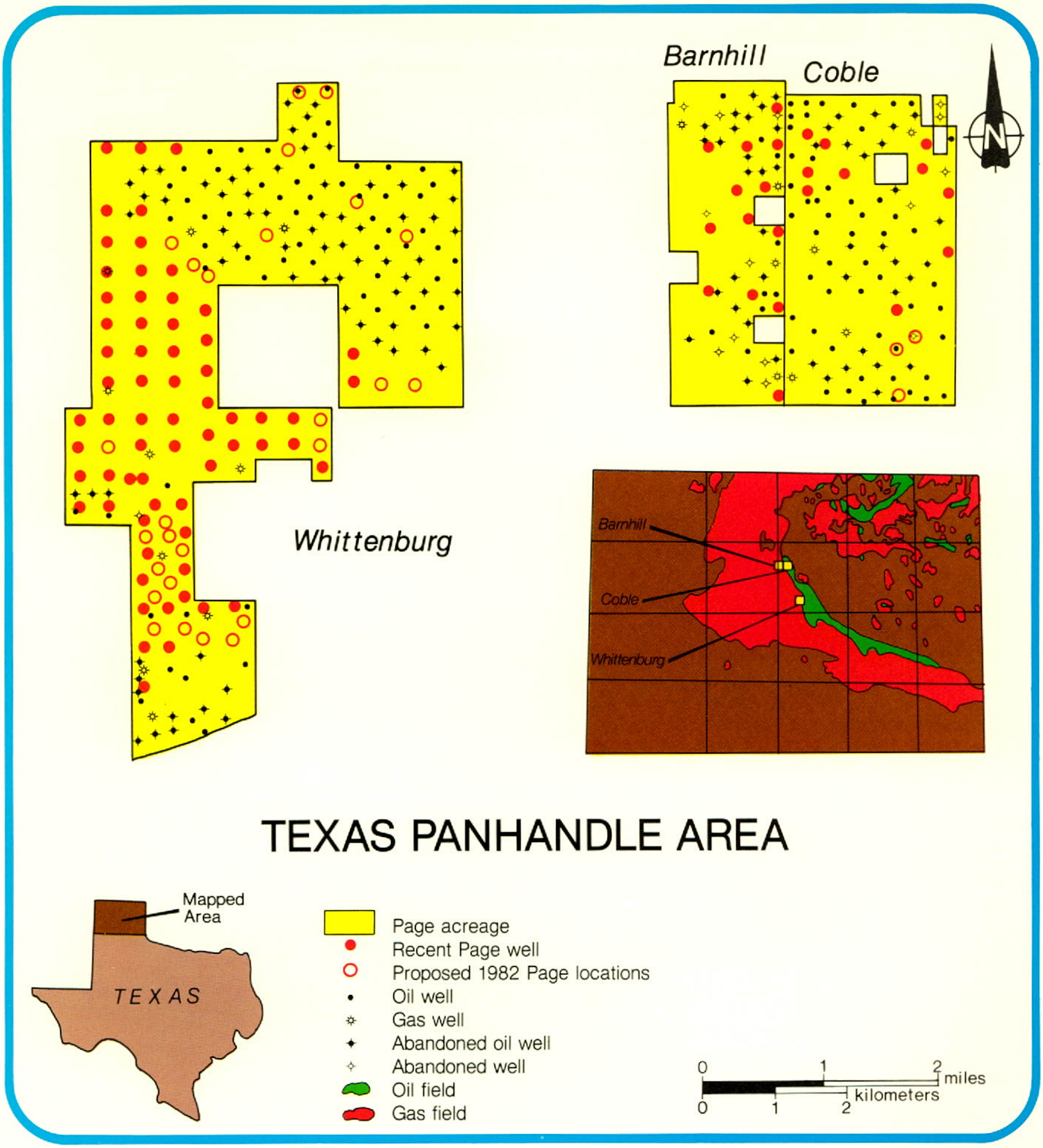
Page participated in two 15,200 foot Upper Morrow wells in this southeast Hemphill County, Texas field in 1981. Although both wells are presently awaiting completion, their electric logs appear to compare favorably with other Upper Morrow wells in this field. Similar wells are producing between 4 to 7 million cubic feet of gas per day. Page owns working interests of 9.35% in the L.L. Jones #1-16 and 25% in the Aitkenhead #1-259. Another well, Aitkenhead #2-20 (Page 25%) is currently drilling. The company anticipates drilling a further development well (Page 17.5%) during the third quarter of 1982.

Broaddus

Page has acquired leases and options on approximately 26,423 acres of leases (5,945 net to Page) in the Austin Chalk trend of San Augustine County. Following an initial seismic program, the Company participated in three Austin Chalk wells. Two were unsuccessful; the third was completed for a potential of 101 barrels of oil and 700 Mcf of gas per day. Page and partners propose to drill additional wells on the joint acreage and may also benefit from increasing industry activity in the area. Phillips Petroleum and partners have announced their intention to spend approximately $100 million on exploration in the general vicinity of our leases.

Gomez Field

A well drilled in 1980, the Tom Marsh Gomez-Eaton #1 (Page 25%), in Pecos County, Texas, was plugged back to the Fusselman at 19,253 feet after encountering severe down-hole problems in the Ellenburger below 22,000 feet. The well is currently producing from the Fusselman at less than one-half million cubic feet of gas per day. Since well logs indicated that the Ellenburger should be productive at this location, it was decided to drill a second well. This well (Page 18.75%) commenced drilling in May of 1981, and, once again, severe mechanical problems prevented a successful completion in the Ellenburger. Total depth was 22,276 feet, approximately 475 feet into the Ellenburger formation. The well has been temporarily abandoned, pending a final decision on future action. Side-track drilling out of the casing at approximately 10,500 feet is a remote possibility.



The partners might again elect to drill a new hole or may decide to farm out the lease to another operator. The Ellenburger is the main producing zone in the Gomez Field, which has estimated recoverable reserves in excess of 10 trillion cubic feet. It was felt that 15 billion cubic feet of gas could reasonably be expected at the Marsh Gomez-Eaton location. Even with well costs of $6 - $8 million, the expected reserves, at prices of more than $5 per Mcf, make the drilling economics very attractive.

PENNSYLVANIA

Page Petroleum owns 36,853 acres of leases in Lycoming County, Pennsylvania, located along the northern portion of the Appalachian Overthrust Belt.

A 60-mile program has indicated three very strong overthrust leads. Page is now conducting an infill leasing program and, through additional seismic, will attempt to better define the three potential prospects. Primary reservoir objectives in this area are the Lower Devonian Oriskany, the Silurian Tuscarora, and the Ordovician Trenton-Black River Group. Page will attempt to farm out this block for the drilling of two 8,000 foot Oriskany wells and a 15,000 foot Ordovician test. Texaco has commenced the drilling of a 19,500 foot Pre-Cambrian test in the northern portion of Clinton County, approximately 28 miles due west of Page's acreage block.

NEW YORK-NORTHERN PENNSYLVANIA

Page Petroleum is a 20% working interest partner in a group that currently holds 80,198 acres of leases in New York and northern Pennsylvania. The group drilled a 3,998 foot lower Silurian Medina sand gas well, and completed it for 650 thousand cubic feet of gas per day. This well, the Rettig #1, is located on a 1,200 acre block of leases in Chautauqua County, New York. It has now been successfully offset by a well that has a potential, on calculated open flow test, of five million cubic feet per day. The partners plan to drill up to ten additional wells, depending upon the assurance of a gas market. The Federal Energy Regulatory Commission has designated the Medina as a tight gas sand for Chautauqua and Cattaraugus Counties in New York. The tight sand gas price is in excess of $5.00 per Mcf.

The group will consolidate its acreage position through further leasing. Plans also call for the purchase of approximately 76 miles of available seismic data and conducting an additional 100 miles of seismic. The 100 miles of new seismic will include detail work on existing anomalies. It is anticipated that at least four exploratory wells will be drilled by the end of 1982.

NEW MEXICO

Page holds a 47.5% working interest in 26,314 acres (12,499 net) in the Abo gas trend of east-central New Mexico. The Company has committed to participate in the drilling of six test wells ranging in depth from 3,800 - 5,100 feet. The main objective is gas production from the Abo sand formation. Secondary objectives are gas from the Wolfcamp, the upper Pennsylvanian, and possibly the Granite Wash. Portions of the prospect acreage qualify for the tight gas sand price, which has a current ceiling of $4.92 per Mcf. Three of the obligation wells have now been plugged and abandoned and a fourth is drilling.

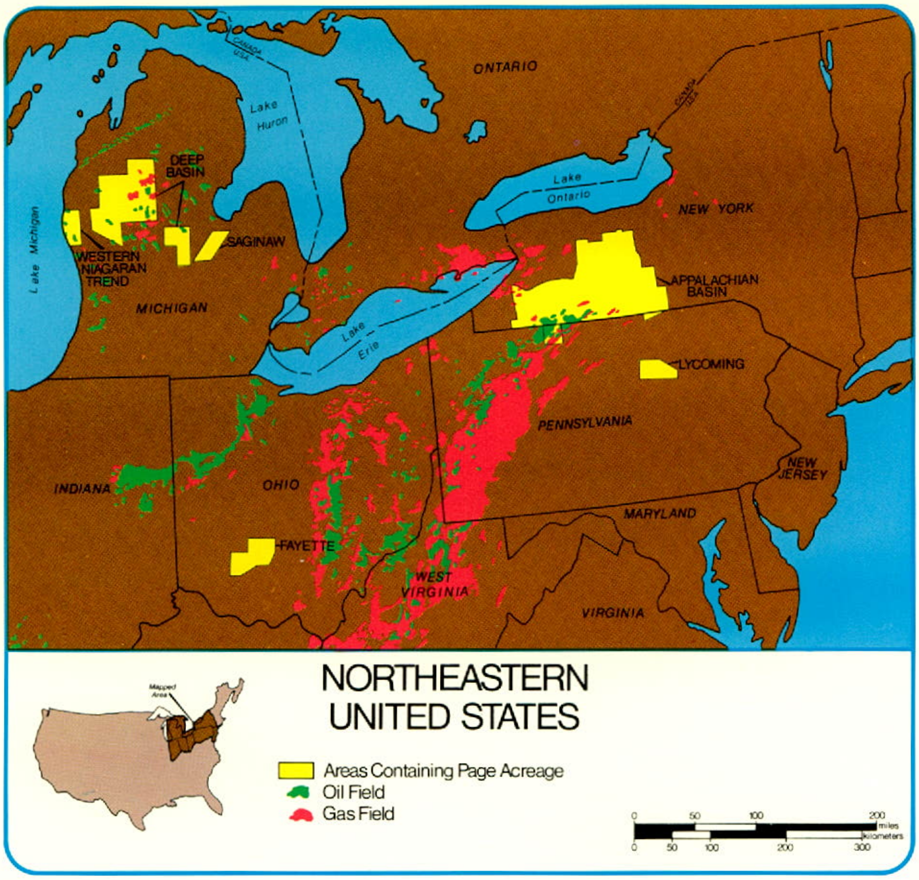
OHIO

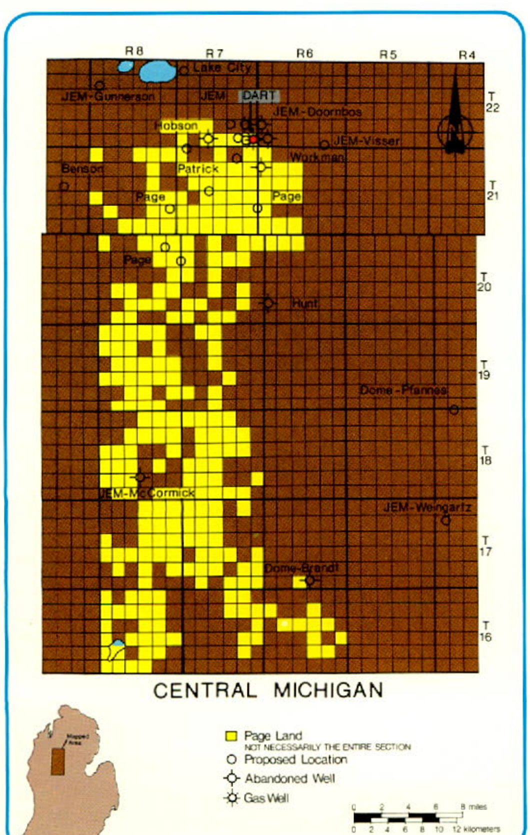
Page owns 22,847 net acres of leases in Clinton and Fayette Counties in south central Ohio. During the spring of 1981, Page conducted 27 miles of seismic in order to better define surface and subsurface geological leads. The two seismic lines indicate an anomaly located at the boundary of two distinctly different basement complexes. The primary reservoir objectives would be carbonate rocks of the Ordovician Trenton-Black River group and the Cambro-Ordovician Trempealeau group. Page will attempt to farm out this prospect for a commitment to drill a Cambrian test to an approximate depth of 4,000 feet.

MICHIGAN

Page acquired its first leases in Michigan in 1979 and now owns a very substantial land position in the state. Company holdings of 176,000 acres (95,000 net) include 62,000 net acres purchased from KEP Resources in April of 1981, at a cost of $12 million (U.S.). The KEP leases are located in the central portion of the Michigan Basin, principally in Missaukee, Osceola and Clare Counties. A massive leasing boom in this area was touched off by the completion of a deep gas discovery in southern Missaukee County. The well has estimated recoverable reserves of 60 billion cubic feet of gas in the Prairie du Chien (Lower Ordovician) from intervals between 10,548 - 10,700 feet. Following the discovery, several other deep wells were drilled without success. It is now obvious that wells in the deep basin must be located on carefully detailed seismic anomalies. Page's first drilling venture in the deep Michigan Basin was plugged and abandoned, at total depth of 11,153 feet. Page and partners subsequently conducted an extensive seismic program and have located a number of drillable prospects.

Page may participate in 12 - 15 wells in Michigan during 1982. These include at least two 3,800 foot Niagaran reef tests in Oceana County and up to eight Dundee-Detroit River tests at depths of approximately 4,000 feet. It is likely that three to four wells to test the Prairie du Chien will be drilled on, or offsetting, Company leases.

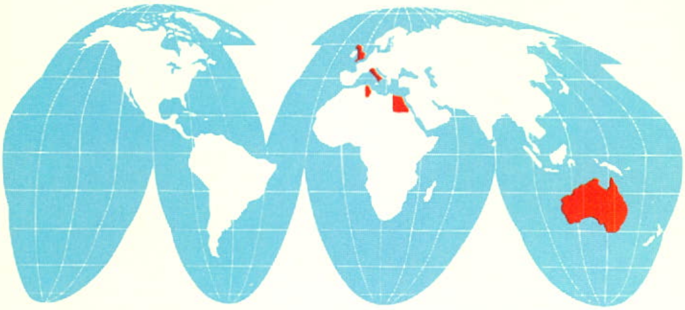




NORTH DAKOTA

In early 1981, Page acquired a 25% working interest in 130,000 acres underlying the Garrison Reservoir in Dunn, McLean, Mercer and Mountrail Counties, North Dakota. The purchase price was $1,250,000 in cash and 55,000 shares of Page common stock. The acreage is part of a 220,000 acre block which is subject to a five year, $25 million exploration agreement between Columbia Gas Corporation and Page et al. Columbia is initially committed to conduct a minimum 1,000 mile seismic program at an estimated cost of $3 million. Columbia has the option to increase its exploration expenditures, including drilling, to a total of $10 million by the end of 1983. A further option provides for Columbia to expend an additional $15 million in exploration drilling during the remaining two years of the program. If the entire program is completed, Columbia will earn a 50% interest in the acreage and Page's interest will then be reduced to 12½%.

Columbia Gas has conducted 400 miles of marine seismic work, the quality of which appears to be excellent. Preliminary interpretations indicate a number of possible drillable anomalies. The remaining seismic work is expected to be completed by late 1982 which may allow commencement of one or more exploratory wells by year-end.



INTERNATIONAL

During 1981, Page expanded its involvement outside of North America in the Mediterranean region and in Australia. Exploration programs were initiated in Tunisia and Italy, and a partly owned Australian subsidiary, Springwest-Page Petroleums N.L., opened an exploration office in Brisbane, Queensland.

EGYPT

The concession agreements covering the Sheiba onshore concession (1.3 million acres) and the Ras El Hekma offshore concession (800,000 acres) were ratified by the Egyptian Parliament and signed by the President of Egypt on December 29, 1981. The original group holding the Sheiba concession has been restructured. This came about through the addition of two financially and technically strong oil companies and the deletion of several smaller companies. Page now owns a 9% interest in this concession. The new group will commence a large seismic program in the latter half of 1982. A major oil discovery is reported to have been made by Shell in a wildcat well located 10 miles south of the Sheiba concession. International news services have stated that the well has tested up to 6,000 barrels of light gravity oil per day from a depth of 11,500 feet. In addition to this, the Egyptian General Petroleum Corporation has made a gas-condensate discovery 25 miles south of the Sheiba concession. This well flow-tested 5.7 million cubic feet of gas and 356 barrels of condensate per day from two pay zones between 5,600 and 6,500 feet. Initial reserve estimates are 400 billion cubic feet of gas and 15 million barrels of condensate.

A $1 million seismic program is scheduled for 1982 on the Ras El Hekma offshore concession. Negotiations are currently underway to strengthen this group in a similar fashion to the Sheiba group. At present, Page holds a 50% interest in this concession.

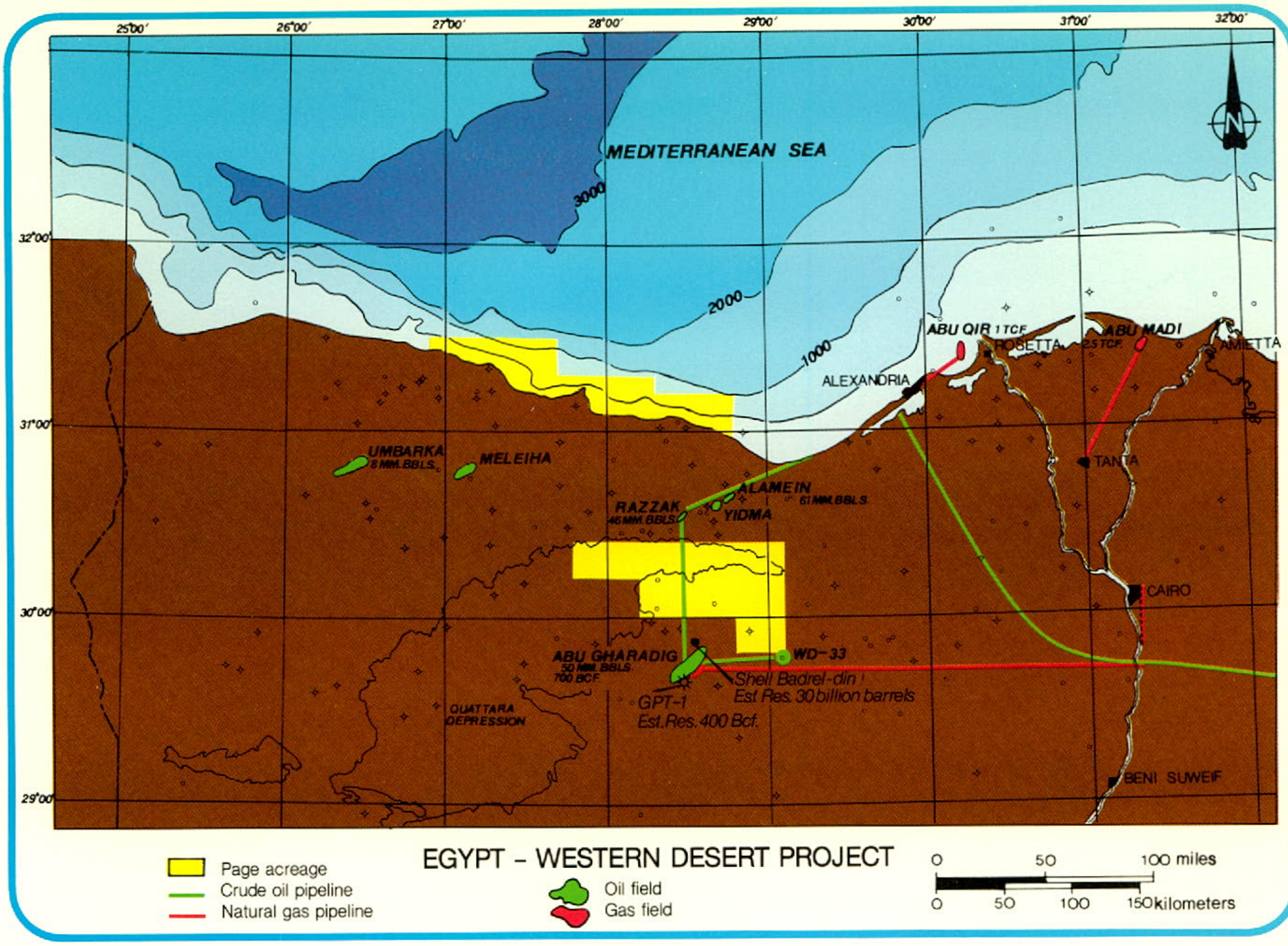
AUSTRALIA

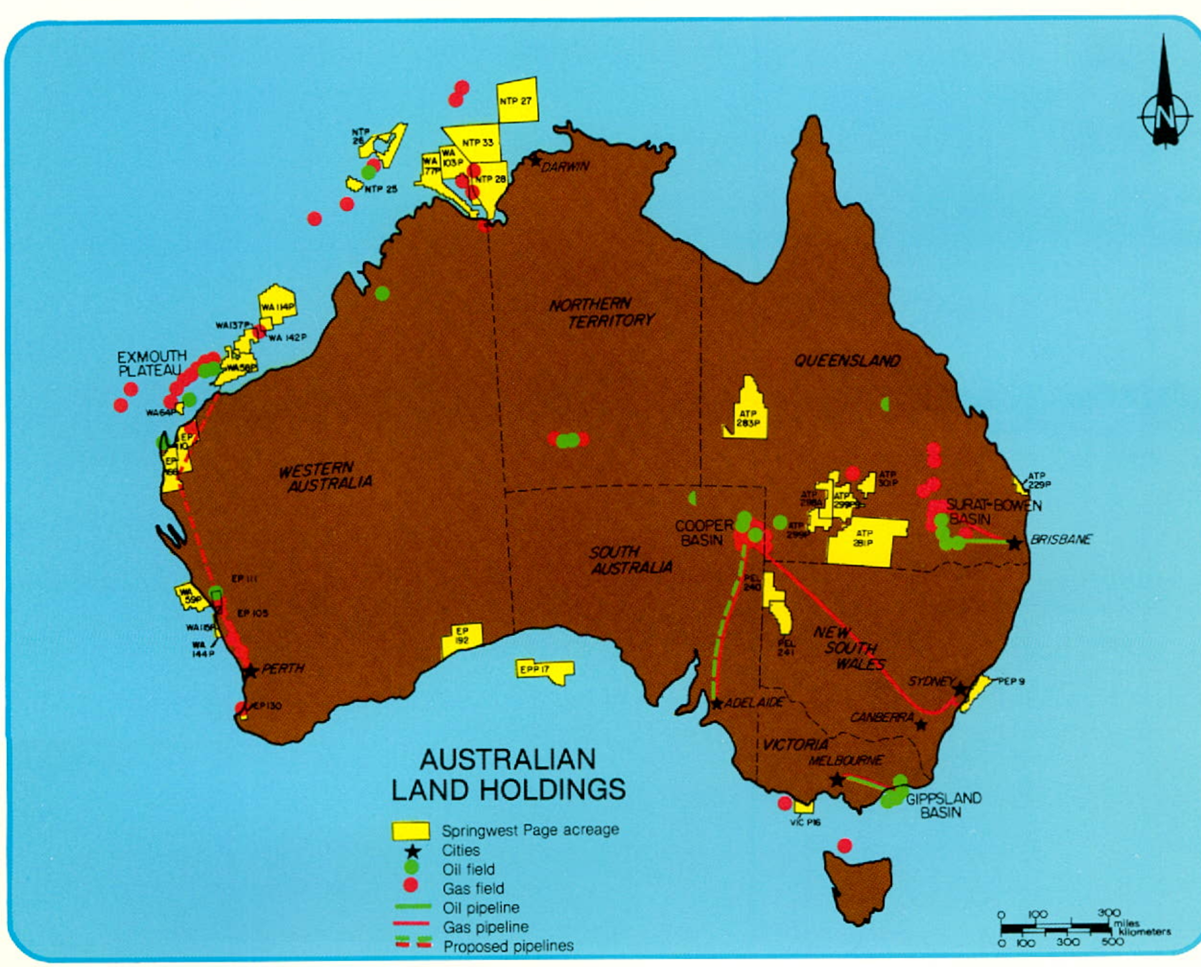
Currently the scene of a renewed exploration effort by Industry, Australia represents Page's most active international area of interest. In 1980, Page Petroleum Ltd., along with two other Canadian oil companies, formed an Australian exploration company, Springwest-Page Petroleums N.L. Page subsequently agreed to purchase one of the original partner's interest, increasing its ownership from 33⅓% to 66⅔%. Springwest-Page now has an exploration office located in Brisbane, Australia, headed by John G. Stout as General Manager. The Company is the owner of a 7,500-foot capacity drilling rig. This rig is operated in Australia by a Canadian contractor and has been drilling continuously since it arrived in the Surat Basin in Queensland in October, 1981.

Springwest-Page is involved in the exploration of 33 permits covering 109,926,182 acres. By investing $5.4 million during 1982 and 1983 the Company will earn 1.3 million net acres, 60% of which are located offshore. Several of the permits contain existing gas fields under which Springwest-Page has estimated gas reserves of 150 billion cubic feet. Seven wells have been drilled to date, resulting in five gas wells and two dry holes. Four of the gas wells are delineation wells in the shallow Tubridgi field located in the Carnarvan Sub Basin onshore Western Australia. This field produces gas from the Lower Cretaceous - Upper Triassic from depths ranging from 2,000 - 2,500 feet. A gas contract is currently being negotiated and five additional development wells are planned for 1982. Springwest-Page has a 0.166% interest in the 3.9 million acre permit containing the Tubridgi field.

Another gas discovery, Petrel #3, was a successful six-mile step-out to the Petrel field in the Bonaparte Gulf, offshore Northern Territory. This well tested 22.7 million cubic feet of gas per day from the Upper Permian at depths to 15,000 feet and has significantly enlarged the proven area of the Petrel structure. Estimates made prior to the drilling of Petrel #3 had indicated that the Petrel structure contained 5.2 trillion cubic feet of gas. Springwest-Page has a 0.833% interest in the 6.3 million acre permit containing the Petrel structure. Two wells are now drilling, one of which is offshore and offsetting the Barrow Island oil field. Five additional wells are scheduled for 1982, including tests of high potential prospects in the Exmouth Plateau area, Australia's most active offshore play.

Page has budgeted $2.9 million for its share of Australian exploration in 1982. This may be reduced substantially if we accomplish a private sale of additional equity in Springwest-Page. Our long-term plans are to take the Company public in Australia when market conditions permit.


EGYPT - WESTERN DESERT PROJECT
MEDITERRANEAN SEA
3000
2000
1000
ABU QIR 1 TCF
ROSETTA
ABU MADI 2.5 TCF
AMIETTA
ALEXANDRIA
TANTA
CAIRO
BENI SUWEIF
UMBARKA 8 MM.BBLS.
MELEIHA
ALAMEIN 61 MM.BBLS.
RAZZAK 46 MM.BBLS.
YIDMA
ABU GHARADIG 50 MM.BBLS. 700 BCF
WD-33
Shell Badrel-din
Est Res. 30 billion barrels
GPT-1
Est.Res. 400 Bcf.
QUATTARA DEPRESSION
25°00′
26°00′
27°00′
28°00′
29°00′
30°00′
31°00′
32°00′
29°00′
Page acreage
Crude oil pipeline
Natural gas pipeline
Oil field
Gas field
0 50 100 miles
0 50 100 150 kilometers


AUSTRALIAN LAND HOLDINGS
NTP 27
NTP 26
NTP 33
NTP 25
NTP 28
WA 77P
WA 103P
DARWIN
NORTHERN TERRITORY
QUEENSLAND
WESTERN AUSTRALIA
SOUTH AUSTRALIA
NEW SOUTH WALES
VICTORIA
EXMOUTH PLATEAU
WA 114P
WA137P
WA 142 P
WA 58P
WA64P
ATP 283P
ATP 229P
ATP 281P
COOPER BASIN
SURAT-BOWEN BASIN
BRISBANE
PEL 240
PEL 241
EP 111
EP 105
WA 59P
WA 144 P
PERTH
EP 130
EP 192
EPP 17
ADELAIDE
SYDNEY
PEP 9
CANBERRA
MELBOURNE
GIPPSLAND BASIN
VIC P16
Springwest Page acreage
Cities
Oil field
Gas field
Oil pipeline
Gas pipeline
Proposed pipelines
0 100 300 miles
0 100 300 500 kilometers

FINANCIAL REVIEW

(All dollar amounts in Canadian dollars, unless otherwise indicated)

MANAGEMENT'S DISCUSSION AND ANALYSIS OF OPERATIONS AND FINANCIAL POSITION

The discussion and analysis of operations and financial position has been presented with respect to the years ended December 31, 1981 and 1980. The reading of the following should be done with reference to the Consolidated Financial Statements which appear in this Annual Report immediately following the Financial Review.

1981 Compared with 1980

Operations

Oil and gas revenue, net of royalties, increased 34% to $29,482,000 from $21,926,000 in 1980. In spite of increased revenues the 1981 loss applicable to common shares was $6,739,000 ($1.89 per common share) compared to the 1980 loss of $1,299,000 (37¢ per common share) and funds generated by operations decreased to $2,146,000 (60¢ per common share) from $6,905,000 ($1.98 per common share) in 1980.

Provisions for losses from discontinued operations were $1,022,000 in 1981. These arose from the disposition of the Habco companies required under a Foreign Investment Review Agency ruling and the $836,000 write off of assets in Gathering and Service Company Ltd. due to reduced oil and gas reserve estimates. For the most part this loss from discontinued operations was not caused by the 1980 decision to dispose of well servicing and manufacturing operations.

Substantially increased borrowings combined with increased interest rates resulted in the 1981 interest expense being 150% greater than 1980 levels. This $8,287,000 increase is the most significant factor in financial operating results achieved in 1981.

Financial Position

Capital expenditures of $86,736,000 in 1981 represents a 136% increase over the 1980 level of $36,749,000. These expenditures were financed almost in total by increased borrowings of $64,633,000 and increased working capital deficiency of $18,486,000.

The working capital deficiency at December 31, 1981 included $10,900,000 payable in 1982 for the purchase of leases in the state of Michigan. This deficit together with planned capital spending of $45.7 million in 1982 will be financed with 1982 cash flow from operations, additional long-term debt drawn from negotiated bank line-of-credit and sales of selected producing and non-producing properties.

The Company has included, as supplementary information in the financial statements, data based on Reserve Recognition Accounting and Changing Price Level Accounting in compliance with the requirements of the Securities and Exchange Commission. The Company cautions that this information, although reported in compliance with established rules, may be of limited usefulness in analyzing the results of operations or the financial position of the Company.

1980 Compared with 1979

The Company incurred an overall net loss of $1,159,000 in 1980 compared to $33,000 in 1979. This was caused by a $1,775,000 loss incurred by businesses that are being discontinued. These businesses had an operating loss of $800,000 for the year and a provision had been allowed for losses on disposition of $975,000.

The net loss applicable to common shares totalled $1,299,000 or 37¢ per common share. This compares with the net loss applicable to common shares in 1979 of $478,000 or 18¢ per common share. Earnings from continuing operations after income taxes were $616,000, an increase of 65%.

Higher interest costs experienced during 1980 coupled with the large borrowings made to finance the capital expenditures resulted in a 134% increase in interest expense. Interest on long-term debt is the only item other than losses on discontinued operations that increased disproportionately to revenue in 1980.

Funds generated from operations totalled $6,905,000, an increase of 52% over the $4,533,000 in 1979. Capital expenditures increased 21% to $36,749,000 in 1980 from $30,256,000 in 1979.

On April 29, 1980, the Company completed the sale in the United States of $25,000,000 (U.S.) aggregate principal amount of 10% Convertible Subordinated Debentures due 2000. The debentures are convertible into common shares at any time at the option of the debenture holders at a price of $20 (U.S.) per share. The proceeds to the Company amounted to $24,087,000 (U.S.).

At December 31, 1980, The Company had 3,492,750 common shares outstanding and a reserve for a further 1,250,000 common shares for conversion of the 10% Convertible Subordinated Debentures.

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CONSOLIDATED STATEMENTS OF EARNINGS

Years ended DECEMBER 31, 1981, 1980 and 1979

(Thousands of Canadian dollars, except share data)

	1981	1980	1979
INCOME			
Oil and gas sales, net of royalties	$ 29,482	$ 21,926	$ 11,606
Investment and other income	1,007	579	68
Well servicing revenues	659	—	—
	31,148	22,505	11,674
EXPENSES			
Production	8,164	5,797	3,429
Well servicing	507	—	—
Federal production taxes	2,977	1,122	—
General and administrative	4,005	2,613	1,413
Interest on long-term debt	13,800	5,513	2,355
Depreciation, depletion and amortization	7,778	6,379	3,778
Amortization of deferred financing charges	375	292	91
Minority interest	26	—	—
	37,632	21,716	11,066
Earnings (loss) from continuing operations before income taxes	(6,484)	789	608
PROVISION FOR (RECOVERY OF) INCOME TAXES			
Current	(451)	(195)	(178)
Deferred	(316)	368	413
	(767)	173	235
Earnings (loss) from continuing operations	(5,717)	616	373
(LOSS) FROM DISCONTINUED OPERATIONS (Note 2)			
(Loss) from operations of discontinued businesses (net of applicable income taxes of $54 in 1980)	—	(800)	(406)
Provision for (loss) on disposal of discontinued businesses (net of applicable income taxes of $50 in 1980)	(1,022)	(975)	—
	(1,022)	(1,775)	(406)
NET (LOSS)	(6,739)	(1,159)	(33)
Preferred dividends	—	140	445
Net (loss) applicable to common shares	$ (6,739)	$ (1,299)	$ (478)
Earnings (loss) from continuing operations per common share (basic and fully diluted)	$ (1.60)	$ 0.18	$ (0.03)
Net (loss) per common share (basic and fully diluted)	$ (1.89)	$ (0.37)	$ (0.18)
Weighted average number of common shares outstanding	3,562,131	3,479,848	2,724,250

The accompanying notes are an integral part of these consolidated financial statements.

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CONSOLIDATED BALANCE SHEETS

DECEMBER 31, 1981, 1980 and 1979

(Thousands of Canadian dollars)

ASSETS

	1981	1980	1979
CURRENT ASSETS			
Cash	$ 1,385	$ 204	$ 373
Accounts receivable (Note 5)	9,928	7,392	4,721
Provincial royalty tax credit	452	255	201
Inventories – at cost	3,033	1,469	1,089
Prepaid expenses	89	73	31
	14,887	9,393	6,415
INVESTMENTS AND ADVANCES (Note 2)	4,895	6,560	3,620
PROPERTY, PLANT AND EQUIPMENT – at cost (including oil and gas properties accounted for by the full cost method of accounting) (Notes 3 and 5)	175,413	88,564	52,172
Less: Accumulated depreciation, depletion and amortization	21,011	13,120	7,098
	154,402	75,444	45,074
OTHER ASSETS (Note 4)	2,993	3,284	1,539
	$177,177	$94,681	$56,648

APPROVED ON BEHALF OF THE BOARD

Lawton L. Clark DIRECTOR

[signature] DIRECTOR

The accompanying notes are an integral part of these consolidated financial statements.

LIABILITIES

	1981	1980	1979
CURRENT LIABILITIES			
Outstanding cheques	$ 4,479	$ 2,088	$ —
Accounts payable and accrued liabilities	29,682	8,165	5,799
Current maturities of long-term debt (Note 5)	301	229	1,360
	34,462	10,482	7,159
LONG-TERM DEBT (Note 5)	126,915	62,282	26,645
DEFERRED INCOME TAXES	1,474	1,790	1,422
MINORITY INTEREST	26	—	—
COMMITMENTS AND CONTINGENCIES (Note 6)			
SHAREHOLDERS' EQUITY			
Share capital (Notes 7 and 8)			
Authorized			
10,000,000 Preferred Shares with a par value of $10			
20,000,000 Common Shares without par value			
Issued and Outstanding			
7% Cumulative Redeemable Convertible Preferred Shares Series B	—	—	9,687
Common Shares	21,365	20,453	10,755
	21,365	20,453	20,442
Contributed surplus	250	250	250
Capital redemption reserve fund (Note 7)	204	204	47
Retained earnings (deficit)	(7,519)	(780)	683
	14,300	20,127	21,422
	$177,177	$94,681	$56,648

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CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Years ended DECEMBER 31, 1981, 1980 and 1979

(Thousands of Canadian dollars, except share data)

	Preferred Shares		Common Shares		Contributed	Capital Redemption Reserve	Retained Earnings
	Series A	Series B	Shares	Amount	Surplus	Fund	(Deficit)
Balances, December 31, 1978	$ 5,000	$ —	2,065,418	$ 2,924	$250	$ —	$ 1,210
Issue of 1,000,000 7% Cumulative Redeemable Convertible Preferred Shares	—	10,000	—	—	—	—	—
Conversion of preferred shares							
Series A	(4,953)	—	717,396	4,949	—	—	—
Series B	—	(313)	16,554	313	—	—	—
Redemption of preferred shares	(47)	—	—	—	—	47	(49)
Acquisition of Habco Sales Ltd.	—	—	130,000	2,457	—	—	—
Exercise of employee stock options	—	—	31,500	112	—	—	—
Net (loss)	—	—	—	—	—	—	(33)
Dividends on preferred shares	—	—	—	—	—	—	(445)
Balances, December 31, 1979	—	9,687	2,960,868	10,755	250	47	683
Conversion of preferred shares	—	(9,530)	504,283	9,530	—	—	—
Redemption of preferred shares	—	(157)	—	—	—	157	(164)
Exercise of employee stock options	—	—	27,599	168	—	—	—
Net (loss)	—	—	—	—	—	—	(1,159)
Dividends on preferred shares	—	—	—	—	—	—	(140)
Balances, December 31, 1980	—	—	3,492,750	20,453	250	204	(780)
Lease acquisition	—	—	55,000	808	—	—	—
Exercise of employee stock options	—	—	11,500	104	—	—	—
Common shares granted under Employee Incentive Share Purchase Plan (Note 8)	—	—	35,000	—	—	—	—
Net (loss)	—	—	—	—	—	—	(6,739)
Balances, December 31, 1981	$ —	$ —	3,594,250	$21,365	$250	$204	$(7,519)

The accompanying notes are an integral part of these consolidated financial statements.

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CONSOLIDATED STATEMENTS OF CHANGES IN FINANCIAL POSITION

Years ended DECEMBER 31, 1981, 1980 and 1979

(Thousands of Canadian dollars)

	1981	1980	1979
SOURCES OF FUNDS			
Earnings (loss) from continuing operations	$ (5,717)	$ 616	$ 373
(Loss) from discontinued operations	(1,022)	(1,775)	(406)
Charges to earnings not involving funds:			
Minority interest	26	—	—
Provision for loss on disposal or discontinuance	1,022	1,025	—
Depreciation, depletion and amortization	8,153	6,671	4,153
Deferred income taxes	(316)	368	413
Funds generated from operations	2,146	6,905	4,533
Proceeds from issuance of common shares	912	168	2,569
Proceeds from issuance of preferred shares	—	—	10,000
Increase in long-term debt	115,634	50,755	28,126
Proceeds from sale of affiliated companies	3,042	—	—
	121,734	57,828	45,228
USES OF FUNDS			
Investment in and advances to unconsolidated and affiliated companies	2,399	3,965	3,620
Dividends on preferred shares	—	140	445
Redemption of preferred shares	—	164	53
Net additions to property, plant and equipment	86,736	36,749	30,256
Additions to other assets	84	2,037	49
Repayment and current maturities of long-term debt	51,001	15,118	11,663
	140,220	58,173	46,086
(Decrease) in working capital	(18,486)	(345)	(858)
Working capital (deficiency), beginning of year	(1,089)	(744)	114
Working capital (deficiency), end of year	$ (19,575)	$ (1,089)	$ (744)
WORKING CAPITAL CHANGES			
Increase (decrease) in current assets			
Cash	$ 1,181	$ (169)	$ 373
Accounts receivable	2,536	2,671	3,171
Note receivable	—	—	(960)
Provincial royalty tax credit	197	54	30
Inventories	1,564	380	863
Prepaid expenses	16	42	(36)
	5,494	2,978	3,441
Increase (decrease) in current liabilities			
Outstanding cheques	2,391	2,088	(1,564)
Accounts payable and accrued liabilities	21,517	2,366	5,261
Current maturities of long-term debt	72	(1,131)	602
	23,980	3,323	4,299
(Decrease) in working capital	$ (18,486)	$ (345)	$ (858)

The accompanying notes are an integral part of these consolidated financial statements.

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CONSOLIDATED STATEMENTS OF INCOME TAXES

Years ended DECEMBER 31, 1981, 1980 and 1979

(Thousands of Canadian dollars)

	1981	1980	1979
Computation of Income Taxes – The total provision for (recovery of) income taxes differs from the amount which would be computed by applying the statutory Federal income tax rates to book earnings (loss) before income taxes. The reasons for this difference are as follows:			
Book earnings (loss) from continuing operations before provision for income taxes	$(6,484)	$ 789	$ 608
Computed "expected" tax (recovery) expense	$(3,127)	$ 379	$ 280
Tax effect of royalties and other payments to governments which are disallowed as deductions for Canadian federal income tax	2,596	1,413	953
Rebates by provincial governments related to payments disallowed for Canadian federal income tax	(452)	(255)	(234)
Depletion allowance on oil and gas production income	—	(62)	(62)
Federal resource allowance	(1,241)	(995)	(575)
Tax losses not booked due to a lack of virtual certainty of recovery	1,516	—	—
Provincial income taxes less federal abatements	5	(17)	16
Other	(64)	(290)	(143)
Actual tax (recovery) expense – current & deferred	$ (767)	$ 173	$ 235
Federal tax rate	48%	48%	46%
Actual tax expense as a percentage of pre-tax (loss) earnings	12%	22%	39%
An analysis of actual tax (recovery) expense follows:			
Canada	$ 33	$ (281)	$ (29)
United States	(800)	454	264
	$ (767)	$ 173	$ 235
Deferred Income Taxes – Result from timing differences in the recognition of expenses for tax and accounting purposes. The source of these differences and tax effect of each are as follows:			
Difference between income tax depreciation and amount provided for depreciation in the accounts	$ (762)	$ 453	$ 273
Difference between exploration and development expenditures claimed for income tax purposes and amount provided for depletion in the accounts	446	(85)	140
	$ (316)	$ 368	$ 413

The accompanying notes are an integral part of these consolidated financial statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Tabular amounts in thousands of Canadian dollars, except share data)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Principles of Consolidation

The consolidated financial statements include the accounts of the Company's wholly owned subsidiaries Page Petroleum Inc. and Page Petroleum (U.K.) Limited, and its controlling interest in R.D.R. Well Servicing Ltd. Investments in Springwest-Page Petroleums N.L. and Pirate Drilling Ltd. are accounted for by the equity method. Investment in Habco Sales Ltd. and affiliated companies are accounted for on the basis described in Note 2. In 1982 the Company acquired additional interests in Springwest-Page Petroleums N.L. and it will be consolidated in 1982.

(b) Full Cost Method of Accounting

The Company and its subsidiaries follow the full cost method of accounting for oil and gas operations whereby all costs of exploring for and developing oil and gas reserves are capitalized and charged against earnings as set out in Note 1(c). Such costs include land acquisition costs, geological and geophysical expense, carrying charges of non-producing property, costs of drilling both productive and non-productive wells and overhead expense related to exploration activities. The costs are accumulated in cost centers as follows:

(i) Canada
(ii) United States
(iii) The United Kingdom

Costs associated with a purchase of leases in Michigan have been excluded from the U.S. cost center for depletion purposes in 1981. The capitalized acquisition costs excluded from the cost center as being associated with the purchase were $15,100,000 and include $388,000 of capitalized interest expense.

Proceeds on disposal of properties are ordinarily deducted from accumulated costs without recognition of gain or loss. Any gain or loss realized on the disposition of a major property would be recognized in the statement of earnings.

(c) Depletion

The costs accumulated in the Canadian and U.S. cost centers, together with estimated future capital costs associated with developing proved reserves, are depleted using the future revenue method based upon estimated future cash flows net of royalties to be derived from total proved reserves as determined by independent engineers.

Costs associated with United Kingdom cost center are amortized in line with the terms of the leases.

The imposition of the National Energy Program in Canada in 1980 and the Federal/Provincial Energy Pricing and Taxation agreements during 1981 led to the decision to adopt the revenue depletion method. In prior years the unit of production method based upon proved reserves was used. This accounting policy was changed on a prospective basis as information prior to 1979 is not available. The application of this method has resulted in a reduction of depletion and depreciation expense of $1,194,000 for 1981. If this method had been applied in 1980 and 1979 a reduction of $862,000 and $432,000 respectively in depletion expense would have occurred.

(d) Depreciation

Depreciation of production equipment in the U.S. and Canada is provided using the revenue method. Depreciation of sundry equipment is computed on the diminishing balance method at rates varying from 20% to 30%. Well servicing equipment is depreciated on a straight line basis over an estimated 84 month service life.

(e) Maintenance and Repairs

Maintenance and repairs are charged to earnings when incurred and major renewals and betterments which extend the serviceable life of the properties are capitalized.

(f) Joint Venture Accounting

Substantially all of the Company's exploration and production activities are conducted jointly with others and accordingly the accounts reflect only the Company's proportionate interest in such activities.

(g) Limited Partnerships

The Company is involved in certain limited partnerships for the purpose of exploring for and producing oil and gas. The Company's investment in these limited partnerships is reflected on a proportionate consolidation basis.

(h) Deferred Financing Costs

Costs incurred in connection with issuance of capital stock and long-term debt are deferred and amortized using the straight line method over seven years from the date of the respective issues.

(i) Foreign Currency Translation

Current assets and current liabilities of foreign subsidiaries are translated to Canadian dollars using the exchange rates in effect at the dates of the balance sheets. Other assets and liabilities are translated at the rates in effect at the date the original transactions took place. Revenue and expense items are translated using average rates of exchange prevailing throughout the year. The aggregate exchange gains or losses included in net earnings in each of the years ended December 31, 1981, 1980 and 1979 were not significant.

The method of translating long-term debt differs from the method generally accepted in the U.S. If translated into Canadian dollars at year end rates of exchange, long-term debt at December 31, 1981 would increase by $120,000. The long-term debt at December 31, 1980 would increase by $610,000 and the difference at December 31, 1979 was not significant.

(j) Income Taxes

The Company follows interperiod tax allocation with respect to timing differences in the recognition of revenues and expenses for tax and accounting purposes. It is not expected that the cash outlay for income taxes will exceed income tax expense in any of the next three years. Reference is made to the Consolidated Statements of Income Taxes for the components of and additional information relating to income taxes.

(k) Interest Costs

Interest is charged against earnings with the exception of $388,000 capitalized in 1981 as being applicable to the cost of acquiring leases specifically excluded from the U.S. full cost pool [See Note 1(b)].

(l) Earnings per Common Share

Earnings per Common Share have been computed in accordance with Canadian generally accepted accounting principles by dividing the net earnings applicable to common shares (after deducting cumulative dividends on preferred shares in 1980 and 1979) by the weighted average number of common shares outstanding during the years. In determining the weighted average number of shares, no consideration has been given to the number of common shares issuable on the exercise of employee stock options. In determining such aggregate, the common shares issued on conversion of securities convertible into common shares were considered to be outstanding from the date of the last dividend or interest payment date.

Earnings per common share, assuming full dilution, was determined on the assumption that all employee stock options were exercised and all securities convertible into common shares were converted at the beginning of each year (or the time of issuance, if later). The earnings were adjusted to give effect to an assumed after-tax amount attributable to the proceeds which would have been received on the exercise of employee stock options and the after-tax effect of interest savings on convertible debt securities.

If earnings per share were calculated on the basis of United States generally accepted accounting principles, the difference from those calculated as described above would not be material.

2. INVESTMENTS AND ADVANCES

During 1981 the Company disposed of, or discontinued, all its well servicing and manufacturing businesses except R.D.R. Well Servicing Ltd. The consent applied for in 1980 by the Company under the Foreign Investment Review Act in connection with the acquisition of Habco Sales Ltd. and affiliated companies was not granted and the results of operations of these companies have not been included in the accompanying financial statements. These companies are being voluntarily liquidated in the first quarter of 1982. The petroleum and natural gas properties of Habco and its affiliates are being disposed of and other assets wound up into the Company. The combined loss and provision for losses relating to these disposals and voluntary liquidations in the amount of $1,022,000 have been charged to earnings during 1981.

As of December 31, 1981 the Company has investments in and advances to Habco Sales Ltd. and affiliated companies of $3,907,000 and to Springwest-Page Petroleums N.L. of $988,000.

3. PROPERTY, PLANT AND EQUIPMENT

The amounts at which property, plant and equipment are stated do not purport to represent present or future realizable values. The following is a breakdown of the costs of property, plant and equipment and accumulated depreciation, depletion and amortization by major classification:

	Assets at Cost	Accumulated Depreciation, Depletion and Amortization	Net Investment
December 31, 1981			
Petroleum and natural gas leases and rights, including exploration, development and production equipment costs thereon			
Canada	$ 54,083	$ 7,390	$ 46,693
United States	117,780	12,122	105,658
United Kingdom	244	233	11
	172,107	19,745	152,362
Other	3,306	1,266	2,040
	$175,413	$21,011	$154,402
December 31, 1980			
Petroleum and natural gas leases and rights, including exploration, development and production equipment costs thereon			
Canada	$ 50,504	$ 5,545	$ 44,959
United States	36,035	6,378	29,657
United Kingdom	236	226	10
	86,775	12,149	74,626
Other	1,789	971	818
	$ 88,564	$13,120	$ 75,444
December 31, 1979			
Petroleum and natural gas leases and rights, including exploration, development and production equipment costs thereon			
Canada	$ 29,345	$ 3,643	$ 25,702
United States	18,789	2,425	16,364
United Kingdom	231	223	8
	48,365	6,291	42,074
Other	3,807	807	3,000
	$ 52,172	$ 7,098	$ 45,074

4. OTHER ASSETS

	December 31 1981	1980	1979
Prepayments, drilling deposits and miscellaneous assets	$ 564	$ 466	$ 137
Real estate held for resale	587	601	601
Unamortized deferred financing costs	1,842	2,217	801
	$ 2,993	$ 3,284	$ 1,539

The deferred financing costs were incurred in connection with the issue of the Company's 7% Cumulative Redeemable Convertible Preferred Shares and 10% Convertible Subordinated Debentures.

5. LONG-TERM DEBT

	December 31 1981	1980	1979
Page Petroleum Ltd.			
Canadian Bank Production Loan, evidenced by promissory notes, at the bank's prime lending rate	$ 7,203	$ 7,625	$20,150
Mortgage loan, due 1982	236	240	243
10% Convertible Subordinated Debentures ($25,000 U.S.)	29,730	29,730	—
Obligation under capital lease	54	—	—
Page Petroleum Inc.			
U.S. Bank Production Loan, evidenced by promissory notes – at the bank's prime rate plus ¼ % ($49,401 U.S.)	58,900	24,114	4,094
– at LIBOR priced rate plus 5/8% ($25,000 U.S.)	29,812	—	—
6% Note payable ($585 U.S.)	688	702	798
9½ % Notes payable	—	—	799
Other	593	100	1,921
	127,216	62,511	28,005
Less current minimum maturities	301	229	1,360
	$126,915	$62,282	$26,645

The Bank Production Loans are secured by a general assignment of accounts receivable and certain oil and gas properties. Current maturities of long-term debt during the next five years are not significant.

The 10% Convertible Subordinated Debentures are unsecured subordinated obligations of the Company, maturing April 1, 2000. The debentures are convertible into 1,250,000 common shares at $20 (U.S.) per share, subject to adjustment under certain conditions and to prior redemption. The debentures are redeemable:

(i) At any time, at the Company's option, at 109.47% prior to April 1, 1982 and at declining prices thereafter and,

(ii) Commencing April 1, 1991, at their principal amount through operation of a sinking fund, in an annual amount of not less than 10% nor more than 20% of the debentures outstanding on March 31, 1990.

6. COMMITMENTS AND CONTINGENCIES

The Company has guaranteed bank and other indebtedness of Springwest-Page Petroleums N.L. to a maximum amount of $3,898,000.

The Company has guaranteed bank and other indebtedness of R.D.R. Well Servicing Ltd. to a maximum of $650,000.

The Company has extended a letter of credit of $266,000 as a commitment guarantee on an Egyptian exploration concession.

Reference is made to Note 9 for commitments under leases.

7. PREFERRED SHARES

During 1980, 953,276 of the Series B Preferred Shares were converted into 504,283 common shares and the remainder were redeemed at $10.50 per share.

During 1979, 495,285 of the Series A Preferred Shares were converted into 717,396 common shares and the remainder were redeemed at $10.50 per share. Also, 31,300 of the Series B Preferred Shares were converted into 16,554 common shares.

In accordance with the provisions of The Alberta Companies Act, amounts of $157,000 and $47,000, equal to the par value of the shares redeemed, were transferred from retained earnings to the capital redemption reserve fund.

8. COMMON SHARES

(a) Shares Reserved for Conversion of 10% Convertible Subordinated Debentures

There were 1,250,000 common shares reserved at December 31, 1981 for issuance upon the possible conversion of the $25,000,000 (U.S.) 10% Convertible Subordinated Debentures (see Note 5).

(b) Options to Purchase Common Shares

There were 198,735 common shares reserved at December 31, 1981 for issuance upon the exercise, to 1986, of employee stock options at prices ranging from $8.21 to $28.35 per share.

The stock options have been granted from time to time to certain employees at a price equal to 90% of the fair market value of the common shares on the date of grant. Options granted are for a term of five years from the date of grant and are exercisable, on a cumulative basis, as to one-third of the option shares in each of the second, third and fourth years after the date of the grant. As a result the options have become, or will become, exercisable without restriction in varying amounts at varying dates and by July 8, 1984 all of the options outstanding on December 31, 1981 will have become exercisable in full.

In 1982 the Board of Directors approved a revision to all existing employee stock options priced in excess of $15.00. These options would be rescinded and new options granted at an exercise price of $11.70 (90% of the February 10, 1982 fair market value). All other terms of the existing option agreements would remain unchanged.

During 1981, 1980 and 1979 options for 11,500, 27,599 and 31,500 common shares, respectively, were exercised at prices from $4.21 to $9.79, $2.59 to $14.85 and $2.59 to $6.08 per common share, respectively.

(c) Employee Incentive Share Purchase Plan

During 1981 35,000 common shares were issued to certain employees at prices ranging from $15.07 to $19.80 per share. At December 31, 1981 there were an additional 12,500 common shares issuable under executed agreements with employees at $15.18 per share.

The right to purchase the common shares has been granted at 90% of their fair market value on the date of the grant. The shares granted are issued to the designated employee in return for a non-interest bearing, non-recourse note payable to the Company. Employees have the right to repay the loans on a cumulative basis in amounts of one-third of the principal amount in each of the second, third and fourth years after the date of the grant. At the time of payment a proportionate number of the shares issued will be released from trust to the employee. All agreements are issued with a 5-year term. Failure to pay a note or other termination of an agreement will result in the issued shares being placed in an escrow account for future reassignment by the Company.

The shares issued under this plan have been included in common shares outstanding. However, recognition will be given in the accounts to the increase in share capital when partial or full payment of the related notes is made.

9. LEASE COMMITMENTS

The Company has certain lease obligations covering rental of office space. The minimum rental commitments under all leases are as follows:

Year Ending December 31, 1982	$ 434
1983	1,597
1984	1,597
1985	1,478
1986	1,346
Five Years Ending December 31, 1991	5,815
	$12,267

10. BUSINESS SEGMENTS

The Company's operations consist of oil and gas exploration and production, and well servicing.

The following table sets forth for the years indicated the revenue, production income, net of lifting costs, operating profit and identifiable assets attributable to the geographic regions in which the Company has reserves and production and conducts its well servicing operation.

	Year Ended December 31		
	1981	1980	1979
Revenue			
Canada	$ 13,363	$11,140	$ 6,828
United States	16,778	10,786	4,778
	$ 30,141	$21,926	$11,606
Production Income, Net of Lifting Costs			
Canada	$ 8,789	$ 7,423	$ 4,666
United States	12,681	8,706	3,511
	$ 21,470	$16,129	$ 8,177
Operating Profit			
Canada	$ 5,659	$ 5,471	$ 3,025
United States	4,688	3,600	1,679
	$ 10,347	$ 9,071	$ 4,704
Identifiable Assets			
Canada	$ 48,051	$44,959	$25,702
United States	106,340	29,657	16,364
	$154,391	$74,616	$42,066

11. SECURITIES AND EXCHANGE COMMISSION REPORTING REQUIREMENTS

Costs Incurred and Capitalized Costs Related to Oil and Gas Producing Activities

The following table sets forth (i) costs incurred in oil and gas producing activities (whether charged to expense or capitalized) and (ii) the aggregate capitalized costs relating to oil and gas producing activities and the aggregate amount of related depreciation, depletion and amortization. Capitalized costs of unproven properties are not significant and are being depleted as disclosed in Note 1(c), except for those Michigan properties discussed in Note 1(b):

	Year Ended December 31, 1981			Year Ended December 31, 1980			Year Ended December 31, 1979		
	Total	Canada	United States	Total	Canada	United States	Total	Canada	United States
Capitalized costs incurred:									
Property acquisition costs (unproved)	$ 29,669	$ 836	$ 28,833	$ 3,456	$ 1,042	$ 2,414	$ 4,693	$ 2,608	$ 2,085
Acquisition of proved properties	—	—	—	180	180	—	5,162	1,531	3,631
Exploration costs	10,612	1,540	9,072	18,648	9,789	8,859	3,505	2,304	1,201
Development costs	45,043	1,203	43,840	16,121	10,148	5,973	14,499	7,717	6,782
Total	$ 85,324	$ 3,579	$ 81,745	$38,405	$21,159	$17,246	$27,859	$14,160	$13,699
Costs charged to expense:									
Production (lifting) costs	$ 8,164	$ 4,067	$ 4,097	$ 5,797	$ 3,715	$ 2,082	$ 3,429	$ 2,074	$ 1,355
Depreciation, depletion and amortization expense	$ 7,357	$ 1,612	$ 5,745	$ 6,067	$ 2,130	$ 3,937	$ 3,473	$ 1,729	$ 1,744
Capitalized costs:									
Costs of properties being amortized	$171,863	$54,083	$117,780	$86,539	$50,504	$36,035	$48,134	$29,345	$18,789
Accumulated depreciation, depletion and amortization	$ 19,512	$ 7,390	$ 12,122	$11,923	$ 5,545	$ 6,378	$ 6,068	$ 3,643	$ 2,425

Regulation S-X, Article 4-10(k)(5) to (8) includes requirements for disclosure of unaudited information regarding estimated quantities of proved oil and gas reserves, projections of estimated future net revenues from production of proved reserves and the estimated present value of these future net revenues, and a summary of oil and gas producing activities prepared on the basis of Reserve Recognition Accounting. This information is disclosed as supplemental information.

12. REMUNERATION OF DIRECTORS AND OFFICERS

The total remuneration paid to directors and officers of the Company amounted to $514,000 (1980 - $367,000, 1979 - $327,000).

AUDITOR'S REPORT

To the Shareholders of Page Petroleum Ltd.:

We have examined the consolidated balance sheets of Page Petroleum Ltd. (an Alberta company) and subsidiaries as of December 31, 1981, 1980 and 1979, and the related consolidated statements of earnings, shareholders' equity, changes in financial position and income taxes for the three years then ended. Our examinations were made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, the accompanying consolidated financial statements present fairly the financial position of Page Petroleum Ltd. and subsidiaries as of December 31, 1981, 1980 and 1979, and the results of their operations and the changes in their financial position for the years then ended, in accordance with generally accepted accounting principles which, except for the change in 1981 (with which we concur) to the revenue depletion method as described in Note 1 to the accompanying consolidated financial statements, were applied on a consistent basis.

Calgary, Canada
March 19, 1982

ARTHUR ANDERSEN & CO.
Chartered Accountants

SUPPLEMENTARY INFORMATION - UNAUDITED

(Thousands of Canadian dollars)

A. RESERVE RECOGNITION ACCOUNTING ("RRA")

The following information is provided to comply with the oil and gas producing activity disclosure requirements of the United States Securities and Exchange Commission ("SEC").

ESTIMATED QUANTITIES OF PROVED RESERVES

Estimated quantities of proved developed and proved undeveloped reserves of crude oil (including condensate and natural gas liquids) and natural gas for the past three years ending December 31, 1981, 1980 and 1979 are disclosed in the following tables. As prescribed by the SEC, these quantities are presented net after royalty and form the basis for the calculations included in the following section on Reserve Recognition Accounting. Reserve quantities have been calculated in accordance with SEC definitions as follows:

(1) Proved reserves – estimated quantities of reserves which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

(2) Proved developed reserves – reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

(3) Proved undeveloped reserves – reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required.

Table 1 displays the Company's net proved reserves including proved developed producing, proved developed non-producing and proved undeveloped reserves. Table 2 presents the net proved developed reserves. Data for both tables is based on estimates by independent petroleum engineers in accordance with guidelines set out by the SEC. Table 3 sets out the estimated future net revenues to be derived from producing the estimated net proved reserves. Pricing and timing assumptions are the same as under the RRA cash flow determinations presented in this section.

Table 1 - Changes in Quantities of Proved Reserves

	Total		Canada		U.S.A.	
	Oil (thousands of bbls)	Gas (Mmcf)	Oil (thousands of bbls)	Gas (Mmcf)	Oil (thousands of bbls)	Gas (Mmcf)
Balance, December 31, 1978	8,804	8,552	8,779	4,759	25	3,793
Revisions to previous estimates	(1,019)	812	(1,023)	833	4	(21)
New field discoveries & extensions	4,410	711	3,865	—	545	711
Purchases of reserves	2,065	2,837	278	—	1,787	2,837
Production	(666)	(821)	(534)	(84)	(132)	(737)
Sales of reserves	(219)	—	(219)	—	—	—
Balance, December 31, 1979	13,375	12,091	11,146	5,508	2,229	6,583
Revisions to previous estimates	(622)	(2,663)	(32)	481	(590)	(3,144)
New field discoveries and extensions	6,068	6,466	4,662	1,457	1,406	5,009
Purchases of reserves	—	—	—	—	—	—
Production	(913)	(703)	(654)	(156)	(259)	(547)
Sales of reserves	(25)	(38)	—	—	(25)	(38)
Balance, December 31, 1980	17,883	15,153	15,122	7,290	2,761	7,863
Revisions to previous estimates	263	5,875	(87)	(931)	350	6,806
New field discoveries & extensions	2,725	16,860	628	1,205	2,097	15,655
Purchases of reserves	—	—	—	—	—	—
Production	(977)	(1,359)	(637)	(339)	(340)	(1,020)
Sales of reserves	—	—	—	—	—	—
Balance, December 31, 1981	19,894	36,529	15,026	7,225	4,868	29,304

Table 2 - Estimated Quantities of Net Proved Developed Reserves

	Total		Canada		U.S.A.	
	Oil (thousands of bbls)	Gas (Mmcf)	Oil (thousands of bbls)	Gas (Mmcf)	Oil (thousands of bbls)	Gas (Mmcf)
December 31, 1978	6,319	4,254	6,296	545	23	3,709
December 31, 1979	8,693	3,961	7,942	593	751	3,368
December 31, 1980	13,474	11,765	12,604	6,785	870	4,980
December 31, 1981	16,398	29,302	13,126	6,952	3,272	22,350

Table 3 - Estimated Future Net Revenue (Undiscounted)

	Proved Reserves			Proved Developed Reserves		
Year	Total	Canada	U.S.A.	Total	Canada	U.S.A.
1982	$ 31,962	$ 6,451	$ 25,511	$ 37,616	$ 9,502	$ 28,114
1983	37,973	10,001	27,972	28,095	10,067	18,028
1984	30,881	11,106	19,775	23,584	9,303	14,281
Remaining	342,218	233,381	108,837	240,360	179,645	60,715
Total	$443,034	$260,939	$182,095	$329,655	$208,517	$121,138

RESERVE RECOGNITION ACCOUNTING

Statement of Reserve Recognition Accounting Policies

Beginning in 1979, the SEC required that companies present unaudited financial information on the basis of RRA. The accounting policies set forth below have been followed in preparing the RRA presentations.

Under RRA, an asset is recognized and earnings are recorded when proved reserves are added through exploration, acquisition and development activities.

A dollar valuation (the "RRA valuation") of proved reserves is determined as follows:

(1) Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions.

(2) The estimated future production of proved reserves is priced on the basis of year-end prices except that future prices of gas are increased for fixed and determinable escalation provisions in contracts and that future prices of Canadian oil are increased in accordance with prices established by the Federal/Provincial Energy Pricing and Taxation Agreements up to the present world price level for new oil and 75% of the world price level for old oil.

(3) The resulting future gross revenue streams are reduced by estimated future costs to develop and to produce the proved reserves, based on year-end cost estimates.

(4) The resulting future net revenue streams are reduced to present value amounts by applying a 10 percent discount factor.

As acknowledged by the SEC, this valuation does not necessarily yield an accurate estimate of the fair market value of a company's oil and gas properties. An estimate of fair market value should also take into account, among other factors, the value of potential reserves not considered proved at present, a discount factor closer to present interest rates, and anticipated future prices of oil and gas including related development and production costs.

Subsequent revision to the RRA valuation of proved reserves are included in RRA earnings as they occur. The estimated impact of major factors affecting annual changes in proved reserves based on year-end RRA valuations were determined as described below:

(1) "New Field Discoveries and Extensions" represents proved reserves added from drilling exploratory and development wells.

(2) "Changes in Prices and Royalties of Oil and Gas, Net of Related Lifting Costs" represents the approximate effect of changes from one period to the next in the prices, royalties and lifting costs used in the RRA valuation calculation.

(3) "Interest Factor - Accretion of Discount" is computed by applying 10 percent to the RRA valuation as of the beginning of the year in recognition of the increase resulting from the impact of the passage of time on the discounted cash flow approach to the valuation of the proved reserves.

(4) "Other" includes the net effect of all changes affecting the RRA valuation not otherwise reported.

Exploration and Development Costs

The costs of acquiring unproved properties and drilling exploratory wells are deferred until the properties are evaluated and determined to be either productive or nonproductive, at which time they are charged to expense. Other exploration costs are charged to expense as incurred.

Estimated future costs to develop proved reserves are deducted in the RRA valuation of proved reserves. Subsequent revisions to estimated future development costs are included in revisions to reserves proved in prior years. Other development costs are charged to expense when related proved reserves are recognized.

Purchases and Sales of Proved Reserves

Differences, when not significant, between the consideration paid or received and the RRA valuation of proved reserves purchased or sold have been included in RRA operating results in the periods that the transactions occurred. In 1979, the purchase of proved reserves in Utah resulted in a significant excess of RRA valuation of proved reserves purchased over the purchase price paid. At December 31, 1979, the Company deferred $30,821 of such excess. The amount remaining to be amortized over the life of the reserves purchased is $23,333 at December 31, 1981.

Production and Funds Flow

Under RRA, because earnings are recognized when proved reserves are discovered and as the RRA valuation of proved reserves changes, no earnings are reported when oil and gas are produced. Consequently, RRA earnings may differ substantially from funds generated or required by current exploration, development and producing operations.

Income Taxes

The provision for income taxes has been calculated separately for Canada and the U.S.A. using the income tax rates as calculated after making provision for the tax base for oil and gas properties. Also, deductions for depletion as well as provisions for non-allowable royalties, Petroleum and Gas Revenue Tax ("PGRT") Incremental Oil Revenue Tax and other expenses have been taken into account.

Management's Discussion and Analysis

RRA seeks to reflect events relating to exploration and development as they occur; whereas under generally accepted accounting principles, the impact of such events are reported over future years. A number of years may lapse, however, between incurring costs and knowing the economic results of the expenditures. Information about reservoir characteristics may significantly change previous estimates of proved reserves and their valuation.

The discounted value of proved reserves has increased from $138,614 at December 31, 1980, to $209, 978 at December 31, 1981. This is due primarily to an extensive exploration and development drilling program in the U.S.A.

In the opinion of management, the estimated fair market value of the Company's oil and gas properties is substantially in excess of the RRA valuation of its proved reserves.

Table 4

SUMMARY OF OIL AND GAS PRODUCING ACTIVITIES

For the Years Ended December 31, 1981, 1980 and 1979
Prepared on the Basis of Reserve Recognition Accounting

	1981			1980	1979
	Total	Canada	U.S.A	Total	Total
Additions to Proved Reserves:					
New Field Discoveries and Extensions	$54,880	$ 4,995	$49,885	$52,354	$29,496
Revisions to Reserves Proved in Prior Years:					
Increases in Prices of oil and gas, net of related lifting costs	(944)	2,905	(3,849)	33,622	6,239
Interest Factor – accretion of discount	13,861	8,453	5,408	10,223	4,250
Impact of PGRT	3,502	3,502	—	(13,281)	—
Other	9,731	(7,541)	17,272	(43,601)	(15,155)
Total Revisions to Proved Reserves	26,150	7,319	18,831	(13,037)	(4,666)
Total Additions to Proved Reserves	81,030	12,314	68,716	39,317	24,830
Related Exploration and Development Costs	39,510	2,419	37,091	35,964	15,278
Additions to proved reserves in excess of related costs	41,520	9,895	31,625	3,353	9,552
Amortization of deferred excess of RRA Value of Proved Reserves over purchase price	3,543	—	3,543	3,945	1,606
RRA Income Before Income Taxes	45,063	9,895	35,168	7,298	11,158
Provision for Income Taxes	7,794	2,375	5,419	7,762	3,942
Income (Loss) from oil and gas producing activities on the basis of RRA (before other income and expenses)	$37,269	$ 7,520	$29,749	$ (464)	$ 7,216

Table 5

SUMMARY OF CHANGES IN THE PRESENT VALUE OF ESTIMATED FUTURE NET REVENUE FROM PROVED RESERVES

For the Years Ended December 31, 1981, 1980 and 1979
Prepared on the Basis of Reserve Recognition Accounting

	1981			1980	1979
	Total	Canada	U.S.A	Total	Total
Opening Balance	$138,614	$84,534	$ 54,080	$102,227	$ 42,510
Revisions to Reserves Proved in Prior Years including impact of PGRT	26,150	7,319	18,831	(13,037)	(4,666)
	164,764	91,853	72,911	89,190	37,844
New Field Discoveries & Extensions	54,880	4,995	49,885	52,353	29,496
Purchases of Proved Reserves	—	—	—	—	37,589
Current year development costs included in prior year estimate	8,675	2,244	6,431	12,692	5,605
Production, Net of Lifting Costs	(18,341)	(7,728)	(10,613)	(15,007)	(8,177)
Sale of Reserves	—	—	—	(614)	(130)
Closing Balance	$209,978	$91,364	$118,614	$138,614	$102,227

Present Value of Proved Developed Reserves

	Total	Canada	U.S.A.
December 31, 1979	$ 55,045	$38,575	$16,470
December 31, 1980	$ 95,843	$73,111	$22,732
December 31, 1981	$164,566	$79,925	$84,641

SUPPLEMENTARY INFORMATION - UNAUDITED

(Thousands of Canadian dollars)

B. IMPACT OF INFLATION AND CHANGING PRICES

The following information is provided in compliance with Financial Accounting Standards Board's Statements No. 33 and 39 dealing with information on the impact of changing prices on historical cost financial statements. The earnings and financial position of the Company, as reported in the primary financial statements, are based on historical costs and are not intended to reflect the financial impact of changing prices and general inflation.

"Constant Dollar Accounting" which adjusts for general inflation is used to restate historical dollar amounts into dollars of equivalent purchasing power. This is accomplished using the Consumer Price Index for all Urban Consumers (CPI) in restating relevant dollar amounts in "Average 1981 Dollars".

"Current Cost Accounting" adjusts for inflation recognized as applicable to specific cost groups and is used to restate the historical cost financial statements in dollars which reflect the current cost of replacing those specific assets.

The impact of these two inflation accounting methods on the income for 1981 of the Company is reflected in Table B-1 - Impact of Changing Prices. The effect of adjusting depreciation, depletion and amortization (D D & A) to reflect the increased cost of assets subject to D D & A accounts for the increased losses. Assets with a historical cost of $175,413 would have cost $198,109 using Constant Dollar Accounting and $203,680 using Current Cost Accounting. D D & A expense for 1981 would be $7,778, $8,784 and $9,031 under the three methods respectively.

Table B-1 also displays the unrealized gains resulting because our net monetary liabilities will be satisfied with dollars of lesser value. This purchasing power gain amounted to $7,975 for 1981. The holding gain reflects the increase in current costs of assets held throughout the year adjusted for the effect of general inflation. This holding gain has therefore resulted from the Company holding property, plant and equipment during 1981 which has increased in price faster than the CPI has increased during the year.

Table B-2 - Five Year Summary - Constant Dollars provides certain financial data stated in "Average 1981 Dollars".

The Constant Dollar and Current Cost methods are intended to provide only an approximation of the impact of inflation on the Company's reported income and financial position. Data provided in this discussion on the Impact of Price Changes does not attempt to apply a realistic valuation of the oil and gas reserves or the finding costs of those reserves. This deficiency in these accounting methods makes the data presented of limited usefulness in evaluating the results of the Company's 1981 activities.

Table B-1 - Impact of Changing Prices

(In thousands, except per share data)

	Historical Cost	Constant Dollar	Current Cost
(Loss) from continuing operations	$ (5,717)	$ (6,723)	$ (6,970)
- per share	$ (1.60)	$ (1.89)	$ (1.96)
Gain from declining value of amounts owed		$ 7,975	$ 7,975
Net assets at year-end	$14,300	$39,020	$ 38,127
Holding gain (increase in specific prices in excess of increases in general price level)			$ 4,424
Increase in specific prices of property, plant & equipment held during the year			$ 14,910
Current cost (net of D D & A) of property, plant and equipment			$179,283

Table B-2 - Five Year Summary - Constant (Average 1981) Dollars

	1981	1980	1979	1978	1977
Average CPI	272.4	246.8	217.4	195.4	181.5
Gross income (in thousands)	31,148	24,839	14,627	7,054	3,027
Market price per common share at year-end	$14.75	$30.08	$30.55	$12.55	$10.18

PAGE PETROLEUM LTD.

DIRECTORS

LAWTON L. CLARK
President, Page Petroleum Ltd.
Denver, Colorado

ALEX S. CATHCART
Senior Vice-President, Page Petroleum Ltd.
Calgary, Alberta

C.D. GOULD
Geological Consultant
Calgary, Alberta

FRED HEMMING
President, Bankton and Associates,
Management Consultants Ltd.
Calgary, Alberta

HARRY A. IRVING
President, Irving Industries
(Irving Wire Products Division) Ltd.
Calgary, Alberta

BRIAN G. McCOMBE
Barrister and Solicitor
McCombe and Company
Calgary, Alberta

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ALEX S. CATHCART, Senior Vice-President
LYLE F. WIDDIFIELD, Vice-President Finance
BRIAN G. McCOMBE, Secretary
WILLIAM R. HARRISON, Controller and Assistant Secretary

OFFICERS PAGE PETROLEUM INC.

LAWTON L. CLARK, President
ORIN C. CRANE, Executive Vice-President
LYLE F. WIDDIFIELD, Vice-President Finance
F.E. DIGERT, Vice-President Exploration
N.L. STENBUCK, Controller

Lawton L. Clark

Alex S. Cathcart

Lyle F. Widdifield

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AUDITORS

Arthur Andersen & Co.
Calgary, Alberta

LEGAL COUNSEL

McCombe & Company
Calgary, Alberta

BANKING

The Royal Bank of Canada
Calgary, Alberta

STOCK LISTINGS

The Toronto Stock Exchange
American Stock Exchange
Symbol "PGE"

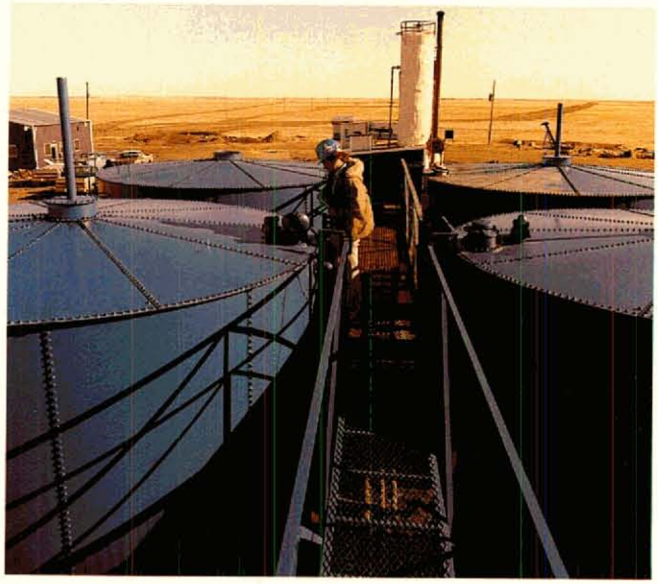
ACTIVE SUBSIDIARIES

Page Petroleum Inc.
Page Petroleum (U.K.) Limited
Habco Sales Ltd.
R.D.R. Well Servicing Ltd.
Springwest-Page Petroleums N.L.

MANAGEMENT REPORT

The Board of Directors has approved the information contained in this Annual Report. The accompanying financial statements have been prepared by management in conformity with those generally accepted accounting principles most appropriate for the nature of the Company's business.

All financial information contained in the Annual Report is consistent with the financial statements.



FORM 10-K

The Company's 1981 Annual Report on Form 10-K, filed with the Securities and Exchange Commission of the United States, is available to shareholders who request it by writing to Page Petroleum Ltd. at 11th Floor, Royal Bank Building, 335 - 8th Avenue S.W., Calgary, Alberta, Canada T2P 1C9.

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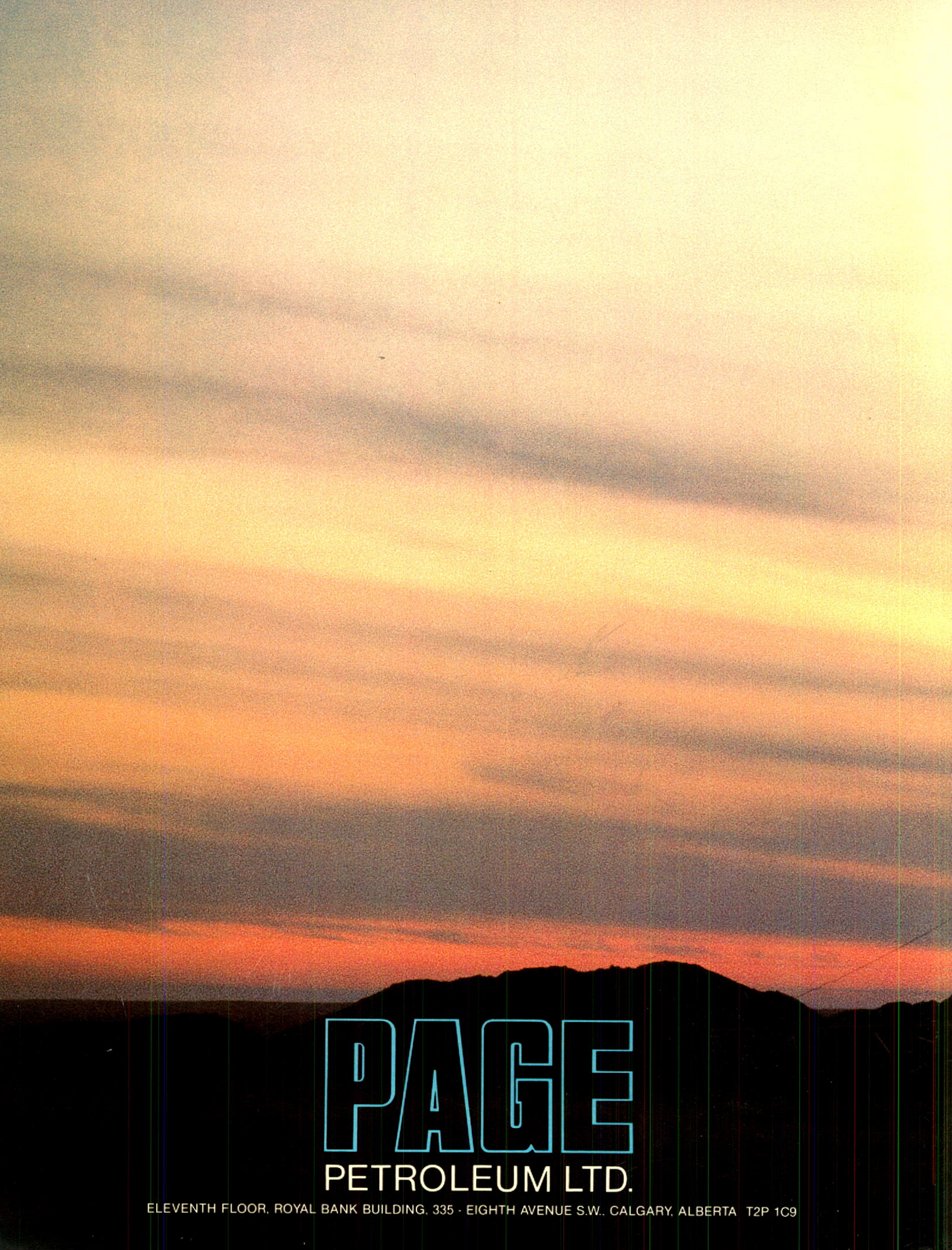

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