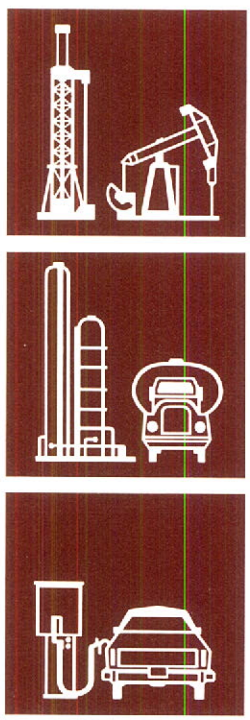
Total Petroleum (North America) Ltd. 1981 Annual Report

TOTAL

Corporate Profile



Total Petroleum (North America) Ltd. is active in exploration and production in Canada and the U.S., and refining and marketing in the Mid-continent U.S.

A strong land position and long life reserves are the foundation of TOTAL's Canadian operations. Exploration and production in the U.S. commenced in the early 1970's. Reserves and production have been growing steadily.

Through expansion and acquisitions, refining capacity has increased to 150,000 barrels per day in three locations: Alma, Michigan; Arkansas City, Kansas; and Ardmore, Oklahoma. Two refineries have been upgraded to produce a high yield of light oils and the Ardmore refinery is in the process of being similarly upgraded.

Through company-owned service stations and independent distributors, TOTAL markets in 22 Mid-continent and Great Lakes states under the brand names TOTAL, BEST, APCO and VICKERS.

Reflecting TOTAL's expansion of activities in the Mid-continent, new executive headquarters were opened in Denver, Colorado in August of 1981 and management functions previously located in different cities are now concentrated in Denver.

Total Petroleum (North America) Ltd. shares are listed on the American, Toronto, Montreal and Pacific Coast stock exchanges. Compagnie Française des Pétroles of Paris, France, owns approximately 50% of the voting shares of Total Petroleum (North America) Ltd.

Highlights

		1981	1980
OPERATING	Crude oil production (barrels per day)	**9,866**	10,427
	Natural gas sales (thousands of cubic feet per day)	**50,038**	51,618
	Proved crude oil reserves (barrels)	**28,764,000**	30,731,000
	Proved gas reserves (thousands of cubic feet)	**312,904,000**	288,106,000
	Refinery input (barrels per day) (i)	**134,259**	129,655
	Refined product sales (barrels per day) (ii)	**140,369**	162,243

		1981	1980
FINANCIAL (U.S. Dollars)	Total revenue	**$2,380,538,000**	$1,604,537,000
	Net income (loss)	**(63,608,000)**	47,749,000
	Net income (loss) per share	**(4.12)**	2.30
	Funds provided by operations (iii)	**(6,269,000)**	110,681,000
	Capital expenditures (iv)	**109,121,000**	66,866,000
	Shareholders' equity	**280,720,000**	357,879,000
	Total assets	**1,098,417,000**	1,155,017,000

(i) Includes Ardmore, Oklahoma refinery's average daily input for three months of 1980.
(ii) Includes Vickers Division's average daily refined product sales for three months of 1980.
(iii) Net income plus income charges not affecting working capital in the year. Refer to Consolidated Statement of Changes in Financial Position for other sources and uses of funds.
(iv) Excludes acquisition of certain assets from Traverse Corporation and Vickers Petroleum Corporation.

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To Our Shareholders

After six years of sustained growth 1981 marked a severe setback for TOTAL. Changes in world petroleum markets, amplified by TOTAL's particular situation, caused this setback. We are reassessing our strategies, and making or planning necessary adjustments to our assets and operations that, we are confident, will restore satisfactory profitability when markets return to more normal conditions.

In financial terms, the year 1981 resulted in a deficit of funds provided by operations (cash flow) of ($6,269,000) versus a cash flow of $110,681,000 in 1980, and a net loss of ($63,608,000) versus net income of $47,749,000 in 1980.

These results were caused primarily by a drastic reduction in U.S. refining and marketing margins. Production cash flow from Canada, which had increased steadily over the years, declined 10% under the effects of the National Energy Program. Cash flow was also adversely affected by the interest costs associated with our 1980 acquisitions and with high inventories. On the positive side, production cash flow from the U.S. increased 37%.

The major factors which affected the petroleum industry in 1981 are well known.

Demand for petroleum products continued to decline below all forecasts. Consumption of all petroleum products in the U.S. declined 5.8% in 1981 versus 1980, and stood at 15% below the peak of 1978. Gasoline demand declined 4.2% versus 1980, and was 13% below the peak of 1978. Current indications are that the decline is continuing.

In the face of weak demand and high inventories, crude oil costs in the U.S. received two jolts at the beginning of 1981: another round of OPEC price increases and, on January 28, the sudden removal of U.S. price controls that were to be phased out by October 1. Product prices never caught up with crude oil costs, and to make matters worse, wide price disparities persisted between U.S. domestic crude oil, low priced Saudi oil, high priced African oil, and spot market crude oil of various kinds, until Saudi Arabia forced a reunification of OPEC prices in October. These disparities seriously affected the relative competitiveness of individual refiners.

These adverse developments occurred at a critical time in TOTAL's history. Confident of the long term potential and of our specific strengths, we had just expanded our marketing outlets and refining capacity by the Vickers acquisition. We faced a changing and difficult environment at the time we were integrating two companies and implementing a major corporate and geographical reorganization.

The effects of market changes on TOTAL, and the actions we took to deal with them, are highlighted in the Refining and Marketing section of this report. The most important action involved a shifting of crude oil supplies from foreign to domestic sources. This took almost a year to accomplish, because of prior commitments to foreign supplies that had proved very beneficial in prior years. Other actions included reducing inventories, improving upgrading capabilities at the refineries, and improving the efficiency of the retail network. Meanwhile, competitive pressures continued unabated, and the net result of our efforts was only to bring refining and marketing cash flow back from a negative $52 million in the first half year to a near break even position in the second half year.

TOTAL's capital expenditures in 1981 amounted to $109 million, versus $67 million in 1980. More than half, namely $58 million, was spent in exploration and development in the U.S. Our efforts of the past few years have resulted in a number of economically attractive drilling opportunities, enhanced by the decontrol of crude oil prices. We also continued to expand and upgrade our exploratory acreage.

In Canada, our capital program was slowed in the course of the year because of the uncertainties of the National Energy Program. We spent $26 million, primarily to maintain our prospective acreage. In the process we continued to significantly increase our shut-in gas reserves, most of which are in the Elmworth area.

Capital expenditures of $20 million in the refining and marketing area were devoted primarily to the upgrading of the Arkansas City and Ardmore refineries.

In spite of the drastic reduction of cash flow, we could maintain our capital program because of our financial flexibility, which was put to its most severe test in 1981.

After such a turbulent and frustrating year, it is appropriate to assess TOTAL's position for 1982 and beyond.

Our strategies of the past few years rested on these basic premises:

1. An outstanding land position, long-life proved reserves, and large potential gas reserves in Western Canada.

2. Expertise at operating and upgrading refineries, and managing gasoline retail networks.

3. A goal to become a larger producer of oil and gas in the U.S. through acquisitions and exploration.

In 1981, the first two premises were seriously shaken, for different reasons, with different future outlooks.

In Canada, the 1980 National Energy Program, confirmed in September of 1981, imposes economic ground rules that contrast starkly with the excellent geological potential of Canada, and indeed frustrate the development of this potential. More troubling than the economics, though, is the political content of the NEP which discriminates against "foreign" companies. We must reluctantly face reality, and consider all options available to maximize the value of Canadian assets to our shareholders. These may include the sale of all or part of our Canadian assets, or transactions to increase the degree of Canadian ownership of our Canadian operations. We have retained investment bankers to assist us in this effort. Meanwhile, we carefully control capital expenditures in order to maintain our assets while in no event spending more cash in Canada than we generate there.

Our second premise appeared shaken in 1981, because of the sudden change in the economics of refining and marketing. However, we remain confident about the long term outlook for this segment of our business, once the necessary adjustments have taken place within the industry and within our own operations. The sudden change in economics resulted from the conjunction of the return to an unregulated market with a sharp drop in demand caused by price-induced conservation and a weak economy. The complex logistics of the petroleum industry and the lead times of its capital investments are such that reactions cannot be as quick as changes in the environment such as occurred in 1981, and earlier in 1974.

It is generally accepted that demand for petroleum products will not grow appreciably in the coming decade. This means that crude oil production, inventories and prices will be adjusted downward to reflect the reduced demand level: this adjustment is already in progress.

This also means that the current operable refining capacity in the U.S. will remain in excess of demand. Market forces, and the industry's drive toward efficiency and competitiveness should cause the closing of additional refining capacity beyond the approximately 2 million barrels per day that were shut down in 1981. Once these capacity adjustments have taken place, the industry, as in the past, should return to a cycle of profitability for efficient operators.

This scenario assumes no major supply interruption caused by political events, which remains a constant threat.

In this adjustment process, each company will base its decisions on its particular circumstances. TOTAL has already achieved substantial progress in making its crude oil supplies more competitive and in reducing inventories. Our operations and assets enjoy a number of positive features in the current and prospective environment:

— Our retail network, concentrated in high volume urban areas, provides an assured outlet for a substantial share of our refinery production, at very low cost.

— The combined gasoline demand of our retail network and of our jobber network, spread over 22 states, remains higher than the maximum gasoline production of our refineries, even allowing for declining market demand.

— Our refineries already have a competitive yield structure, and we anticipate further progress in upgrading residual fuel oil into gasoline and distillates.

We will have to make some yet undetermined adjustments to our operations and our assets to meet future market conditions; but basically, our system of supply, refining and marketing, is sound, balanced, and well positioned to be competitive and to return to profitability once industry-wide adjustments have restored a proper balance between supply, demand, and capacities.

Our third premise, rather a goal, was to become a larger producer of oil and gas in the U.S. We have made significant progress towards this goal since the early 1970's. The economics of many prospects in the U.S. remain very attractive. Gas prices are assured of continued increases with or without accelerated decontrol. We have considerably enhanced our land position and staff capabilities over the last few years. We will continue to allocate a substantial share of our capital resources to U.S. oil and gas operations, and leverage our investments through participation of financial partners. Depending on our financial position and opportunities, we will continue to consider acquisitions of oil and gas reserves in the U.S.

As mentioned earlier, TOTAL's financial flexibility was put to a severe test in 1981. We entered the year with a high level of debt incurred for the Vickers acquisition. Because of the lack of cash flow, capital expenditures had to be financed primarily by an additional $79 million of long-term debt and a $49 million reduction of working capital. The increasing level of debt, combined with high interest rates, inflated interest expenses to $68 million, which contributed largely to our corporate cash flow deficit.

Our lines of credit, and our capacity to borrow on our oil and gas reserves, are in excess of anticipated needs in the worst scenarios; thus our financial flexibility remains substantial. However, reduction of interest expenses through reduction of debt is now a primary corporate objective. It will be pursued in several ways:

- First and foremost, by our efforts to restore operating cash flow, but this depends largely on market factors.
- Second, by controlling capital expenditures: the 1982 capital budget is directed towards the maintenance of assets and projects with a high expected rate of return. It currently stands at $88 million versus $109 million in 1981. It allows for the continuation of our exploration momentum in the U.S., leveraged by farm-outs or participation by outside investors. The 1982 capital program will remain flexible.
- Third, by further reducing inventories of crude oil and finished products.
- Fourth, the recently announced acquisition of Supron Energy Corporation by Allied Corporation and Continental Group, Inc., will generate $58 million of cash for TOTAL as our investment in Supron is liquidated.
- Fifth, a modification of our corporate structure in Canada might involve a cash resource for TOTAL.

TOTAL's financial flexibility allows the Company to pursue worthwhile economic objectives, while simultaneously working towards the financial objectives mentioned above.

After the storm of 1981, 1982 is likely to be a period of adjustment, in an environment that appears to be less erratic than in 1981, but equally challenging. Severe competitive conditions are expected to continue in the refining and marketing sector; however, we are steadily improving our control of operating factors to direct the process of our own adjustments. We will work diligently to find a satisfactory solution to our Canadian dilemma, and continue to enhance our U. S. exploration and production.

TOTAL will spare no efforts to improve its operations and assets, but some help from the market will be needed to return to satisfactory levels of cash flow.

Our efforts are, in effect, the efforts of all the employees of Total Petroleum. I am pleased to take this opportunity to express my appreciation for their professional dedication during the past year, in which they were simultaneously confronted with a major internal reorganization and a revolutionized business environment. I also express my confidence that they will live up to the challenge of the adjustments and the recovery, so that, in future years, we will again have the pleasure of reporting to our shareholders on the growth of their investment in TOTAL.

On behalf of the Board of Directors,

Philippe Dunoyer, President

Exploration and Production

TOTAL's combined U.S. and Canadian production cash flow increased 19% in 1981 versus 1980, to $74.2 million. U.S. production cash flow increased 37%, to $52.6 million, more than offsetting a 10% decline in Canadian production cash flow, to $21.6 million (U.S.). The decline in Canadian production cash flow was a reflection of the Canadian National Energy Program.

On an energy equivalent basis (6 MCF of gas = 1 barrel of oil), combined U.S. and Canadian reserves, net of production, increased 3% in 1981 to 80.9 million equivalent barrels, as a result of exploration and development drilling activities in the U.S. and Canada.

Exploration and production activities have been steadily increasing in the U.S. TOTAL's most significant areas of success were in the Montana/Dakotas region of the Williston Basin, the Niagaran reef trend in northern Michigan, and the Texas Gulf Coast onshore.

In Canada, activities in the Elmworth area of West Central Alberta added significantly to our gas reserves, while drilling at Red Earth extended a new oil play. However, because of the disappointing economics of the Canadian National Energy Program we have reduced our 1982 capital program in Canada.

Exploration and Development

UNITED STATES: During the eight years TOTAL has been engaged in exploration and development in the U.S., 1981 was our most active year. Considerable experience has been gained by our professional staff in major exploratory areas of the United States, such as the Williston Basin, the Michigan northern reef trend and the Gulf Coast. At the same time, our portfolio of undeveloped acreage has been consistently enlarged and upgraded.

In 1981, TOTAL's capital commitments for U.S. exploration and development increased to $58.1 million, more than twice the 1980 level, resulting in our participation in 160 wells.

Williston Basin - Our 1981 activities in the Williston Basin were concentrated in the Richland-Roosevelt/Sioux Pass area of Montana and the McGregor area of North Dakota. TOTAL participated in 47 wells with a 65% success ratio. The major objective is the oil-bearing Red River formation, with secondary objectives often being encountered at shallower levels. TOTAL's working interest averages about 41% in the Williston Basin.

In July, 1981, TOTAL purchased 16,000 undeveloped net acres in the West Nesson area of North Dakota from Depco, Inc. We will have an active exploration campaign on this acreage as well as a significant development program in the already successful McGregor area. In 1982, TOTAL will continue an active exploration and development program in the Williston Basin area.

Michigan - TOTAL participated in 24 wells in Michigan in 1981 of which 15 were farmed out. Twelve were successful oil wells, of which two at the Rotary Camp field were particularly significant, adding approximately 275,000 net barrels to our reserves. Several secondary recovery projects are currently underway or planned in Michigan.

Gulf Coast - In the Gulf Coast area TOTAL participated in 66 wells in 1981. One of the most significant results was a gas discovery in the lower Wilcox formation at the Rancho Solo prospect in Duval County, Texas. TOTAL's working interest in this discovery is 50%. During the present year, we plan to continue development at Rancho Solo where some additional exploratory drilling could also take place.

In 1981, two wells at the Kirkbride prospect in Hidalgo County, Texas added 2.3 billion cubic feet (BCF) to TOTAL's net U.S. gas reserves. Kirkbride now accounts for about 4.5 million cubic feet per day (MMCFD) of TOTAL's U.S. gas production. Two additional development wells are presently being drilled in the prospect.

Production from Block 755 in the Federal offshore Texas area, where TOTAL's working interest is 10%, is expected to go on stream in 1982. Other oil and gas discoveries were made on Blocks 555, 700 and 713 where TOTAL has working interests ranging from 1.5% to 10%.

In 1980, TOTAL acquired a 100% interest in 1,148 acres comprising the western portion of Dauphin Island in

One of TOTAL's gas wells in the Rancho Solo prospect in Duval County, Texas (far left) which accounts for several million cubic feet per day. TOTAL has working interests in portions of Dauphin Island (left) near Mobile Bay. The Germundson Rye 3-1 (below) an oil producer from the Nesson formation in the McGregor area of North Dakota in Williston Basin.

Mobile Bay, Alabama. Late in 1981, TOTAL contributed its 100% interest in the portion of the Island lying within offshore Block 90 in exchange for a 19-1/4% interest in all of Block 90. TOTAL retains its 100% interest in the acres of the Island lease lying outside Block 90. Negotiations are in progress with participants in adjacent blocks to drill a joint exploratory well.

During 1981, TOTAL added two additional blocks to its existing four blocks in the South Padre Island area in the Federal waters of offshore Texas.

CANADA: Last year's exploration and development efforts in Canada continued to be concentrated in the Elmworth region of Western Alberta. Capital expenditures in Canada were $25.9 million (U.S.), similar to 1980 expenditures and in excess of 1981 Canadian cash flow. Expenditures were primarily directed to the maintenance of prospective acreage and the delineation of undeveloped reserves. In the current year, TOTAL's Canadian capital program will be subject to similar limitations and will continue to stress the enhancement of existing assets.

Elmworth - In 1981, TOTAL drilled 17 wells in the Elmworth area with a 73% success ratio. This resulted in the addition of over 40 BCF to our proven gas reserves and over 17 BCF to probable reserves. By way of comparison, TOTAL's current annual gas production in Canada is about 7.6 BCF.

The oil discovery in the Wembley/Hythe area of Elmworth was successfully extended to the northwest with the completion of three additional oil wells. In addition, this extension proved up sizeable reserves of gas and condensate in the Doig formation which underlies the oil bearing Halfway formation.

Other areas - During 1981, TOTAL followed up on a 1980 oil discovery at Red Earth in North Central Alberta. Eight wells were drilled, of which four were completed as oil wells and two more are awaiting completion. We plan to drill two additional wells at Red Earth this year. The oil produced from these wells qualifies for the "new oil" price (i.e., "world price") under the National Energy Program.

At the heavy oil steam injection project in North Battleford, Saskatchewan, where TOTAL has a 33-1/3% interest, a second steam recovery plant was constructed in order to extend the experiment to an adjacent tract where sufficient reserves had been established.

TOTAL has farmed out parts of its interest and is being carried for its share of drilling commitments in both the Beaufort Sea and Labrador. In the Beaufort Sea, one well drilled in 1981 was dry and abandoned while a small quantity of oil was recovered in one of the Labrador wells.

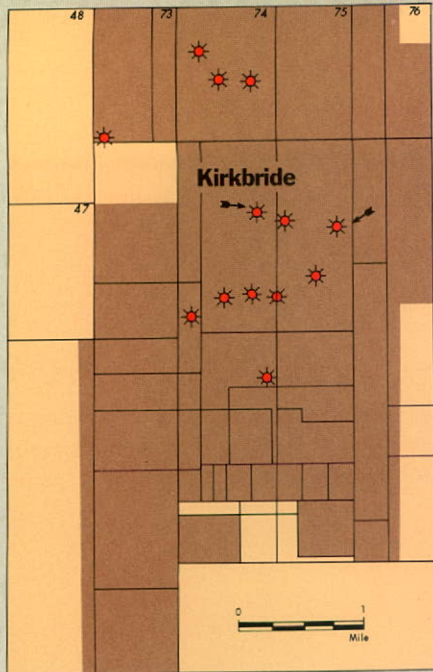
Reserves and Production

UNITED STATES: At year end, TOTAL's proved reserves in the U.S. amounted to 7.6 million barrels of oil and 59.8 BCF of gas. Additions to proved reserves during the year (on an energy equivalent basis) came within 2% of replacing production. The majority of additions to oil reserves occurred in the Williston Basin and in Michigan. Increased gas reserves were mainly attributable to activities in the Gulf Coast.

In 1981, TOTAL's daily average production amounted to 4,460 barrels of oil (4% lower than in 1980) and 29.2 million cubic feet of gas (2% lower). U.S. production cash flow increased 37% to $52.6 million, reflecting increased prices.

CANADA: Canadian oil reserves declined about 8% to 21.1 million barrels during 1981, as production exceeded new discoveries. Gas reserves, net of 1981 production, increased by 25.3 BCF, or 11%, to 253 BCF. On an energy equivalent basis Canadian oil and gas reserves increased 4%. The increase in gas reserves was mainly the result of drilling in the Elmworth area.

Our Canadian oil production declined about 7% in 1981 compared to 1980, while Canadian gas production declined about 5%. The oil production decline was mainly attributable to the production cutback ordered by the Province of Alberta during its negotiations with the Federal Govern-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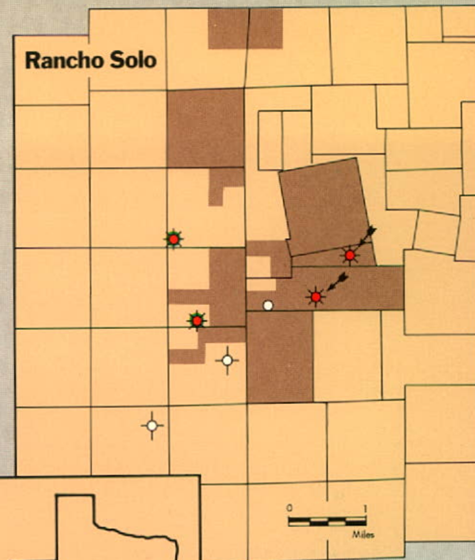
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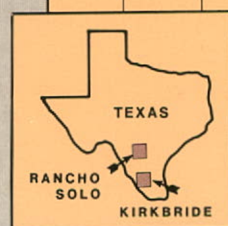
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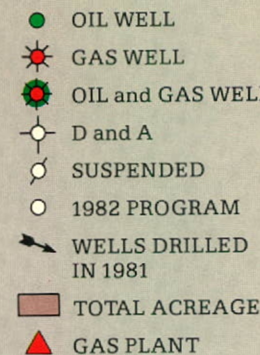
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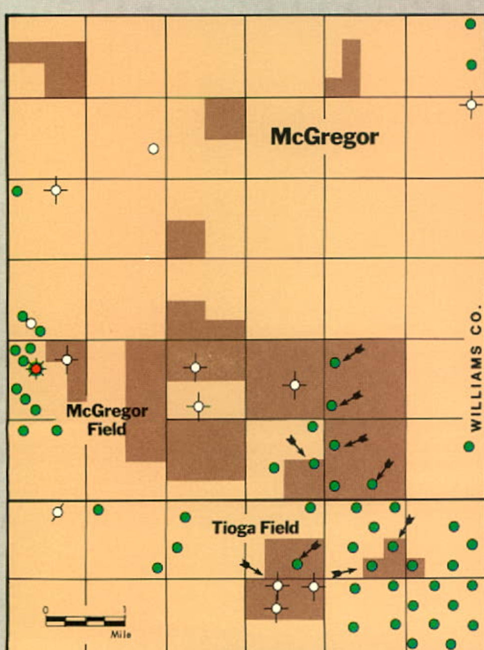
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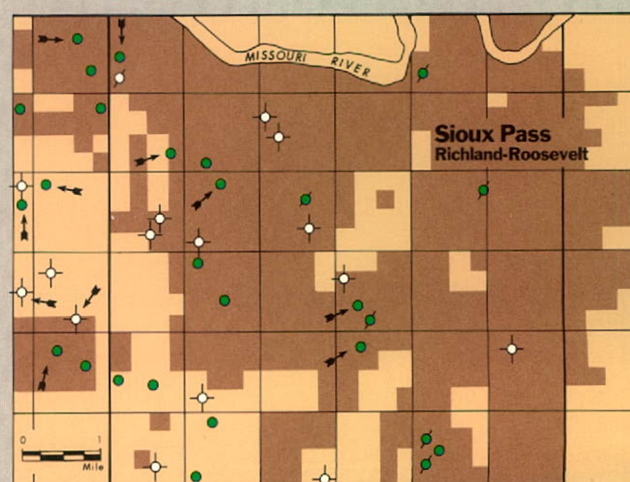
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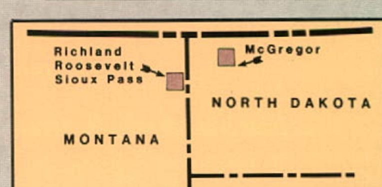
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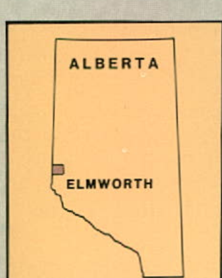
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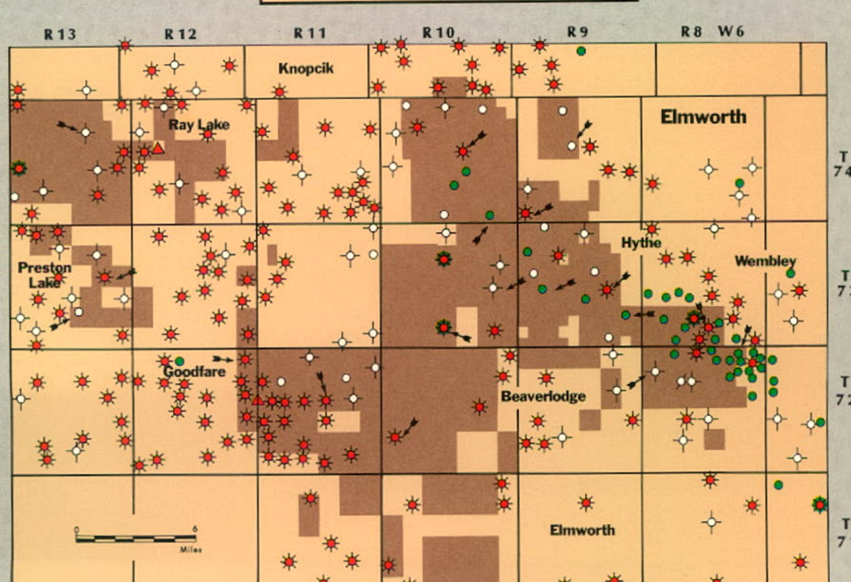
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ment over the National Energy Program. Gas production continued to be restricted due to a lack of market demand. It should be noted that at current production rates, TOTAL's year end 1981 Canadian gas reserves would last 33 years.

A contract for additional gas exports from the Elmworth region, currently under negotiation, could lead to a substantial increase in gas production by 1984.

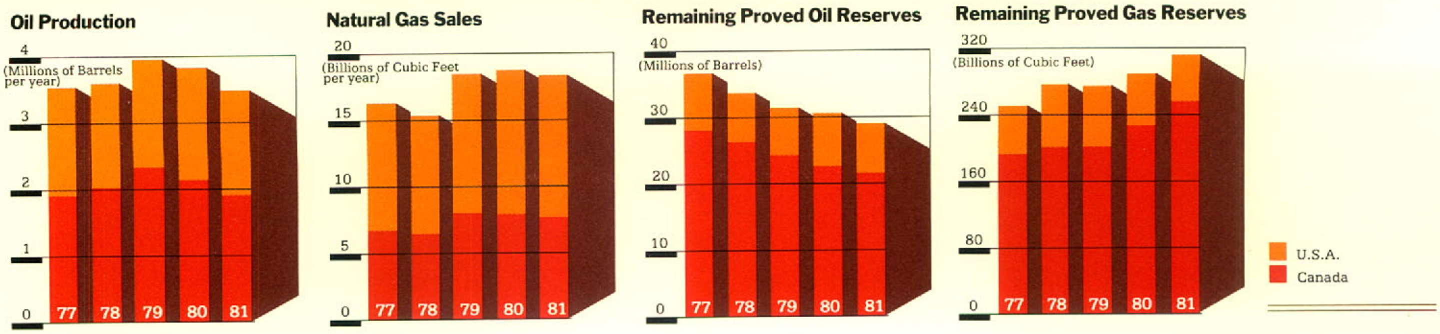
Outlook

In the United States, a free market for oil and phased decontrol of natural gas make exploration and production economically attractive. TOTAL can capitalize on a number of opportunities in 1982 through the follow-up of late 1981 discoveries and continued exploration, particularly on our expanded Williston Basin and Gulf Coast acreage.

In Canada, the National Energy Program has seriously reduced the incentives to explore, particularly for foreign controlled companies. As discussed in the President's letter, TOTAL is considering all options available to maximize the value of its Canadian assets to its shareholders. In the meantime, we will conduct a carefully controlled exploration and development program with two major objectives: maintain, and possibly enhance the value of our gas-prone acreage, particularly in the Elmworth region; develop new oil prospects which, even though of limited scope, are the only economically attractive ventures under the new pricing policies.

Drilling Activity

Exploratory Wells		1981		1980	
		Gross	Net	Gross	Net
CANADA	Oil	19	6.2	5	1.8
	Gas	28	10.2	30	7.5
	Dry/Suspended	34	10.4	35	8.1
		81	26.8	70	17.4
UNITED STATES	Oil	17	3.3	4	.6
	Gas	8	1.5	1	—
	Dry/Suspended	51	11.1	16	5.6
		76	15.9	21	6.2
Total Exploratory Wells		157	42.7	91	23.6
Development Wells					
CANADA	Oil	2	1	4	2.0
	Gas	—	—	3	.7
	Dry/Suspended	—	—	1	.7
		2	1	8	3.4
UNITED STATES	Oil	31	6.9	23	5.1
	Gas	24	2.2	18	2.2
	Dry/Suspended	29	5.5	14	4.0
		84	14.6	55	11.3
Total Development Wells		86	15.6	63	14.7
Total Wells		243	58.3	154	38.3



Consolidated Land Holdings at December 31, 1981

	Petroleum and Natural Gas Leases		Reservations, Permits and Licenses		Total	
	Gross	Net	Gross	Net	Gross	Net
British Columbia	641,516	201,110	5,199	529	646,715	201,639
Alberta	1,187,975	555,693	398,325	175,879	1,586,300	731,572
Saskatchewan	74,404	24,970	—	—	74,404	24,969
Ontario	43,366	21,683	—	—	43,366	21,683
Northwest Territories	82,111	54,972	663,436	110,738	745,548	165,710
Arctic	—	—	37,782	3,230	37,782	3,230
Labrador (Offshore)	—	—	16,459,420	345,648	16,459,420	345,648
CANADA	2,029,372	858,428	17,564,162	636,024	19,593,535	1,494,451
Michigan	431,107	229,771	—	—	431,107	229,771
Texas Onshore	347,000	95,000	—	—	347,000	95,000
Texas Offshore	80,000	47,000	—	—	80,000	47,000
Rocky Mountain Area	1,019,885	230,793	—	—	1,019,885	230,793
Other States	123,024	7,344	—	—	123,024	7,344
UNITED STATES	2,001,016	609,908	—	—	2,001,016	609,908
TOTAL	4,030,388	1,468,336	17,564,162	636,024	21,594,551	2,104,359

Production Statistics

Crude Oil Production	1981				1980			
(before royalties)	Bbls.	BPD	Revenue Per Bbl. (i)	Cash Flow Per Bbl. (ii)	Bbls.	BPD	Revenue Per Bbl. (i)	Cash Flow Per Bbl. (ii)
Canada	1,973,013	5,406	$15.69	$ 6.65	2,114,694	5,778	$13.47	$ 6.61
United States	1,627,788	4,460	$34.67	$19.31	1,701,489	4,649	$20.11	$11.72
TOTAL	3,600,801	9,866			3,816,183	10,427		

Natural Gas Sales	1981				1980			
(before royalties)	MCF	MCFPD	Revenue Per MCF (i)	Cash Flow Per MCF (ii)	MCF	MCFPD	Revenue Per MCF (i)	Cash Flow Per MCF (ii)
Canada	7,611,496	20,853	$ 2.34	$ 1.15	8,011,670	21,890	$ 2.32	$ 1.31
United States	10,652,349	29,185	$ 2.60	$ 2.20	10,880,607	29,728	$ 2.17	$ 1.36
TOTAL	18,263,845	50,038			18,892,277	51,618		

(i) Average revenue per barrel or MCF, before royalties, stated in U.S. dollars.
(ii) Revenue per barrel or MCF less royalties and operating costs.

Refining and Marketing

At the outset of 1981, TOTAL anticipated another good year for its refining and marketing operations. The sudden and sweeping changes that affected the entire U.S. refining industry resulted in the direct opposite. After four years of increasing profitability, refining and marketing operations sustained severe losses in 1981. Refining and marketing cash flow was a deficit of $58,463,000 compared to a positive $85,956,000 in 1980. Most of the cash flow deficit, namely $52,101,000, was incurred during the first half year; while during the second half year, the cash flow deficit was reduced to $6,362,000.

The year 1981 therefore became a period of adjustment with the goal of setting the stage to improve the Company's competitiveness in 1982.

Certain industry-wide factors contributed to the 1981 unfavorable results:

- Petroleum price and allocation regulations in the U.S. were abolished suddenly on January 28, 1981, whereas they had been scheduled to be phased out gradually by October 1.
- Another round of OPEC price increases occurred at the end of 1980.
- Refined products demand in the U.S. decreased sharply, reflecting price-induced conservation and an eroding economy.
- A high level of interest rates throughout 1981 increased the holding cost of inventories.
- Throughout 1981, large price disparities existed among various foreign crude oils, particularly high priced African crude oils and low priced Saudi Arabian crude oils.
- Domestic crude oil prices declined in the second quarter of 1981 but foreign crude prices were not adjusted to reflect world conditions until later in the year. This created price differentials as large as $6 per barrel between the delivered cost of domestic crude oil and certain foreign crude oils.
- For most of 1981, product prices were at levels that allowed profitability only if domestically priced crude oil was used in refining operations.

These were the principal industry-wide factors that had a negative impact on the U.S. refining and marketing industry. Their effect on each company within the industry differed, depending upon the company's position with respect to:

- Levels of crude oil and product inventories.
- The level, terms and duration of contractual foreign crude oil supplies versus domestic crude oil supplies.
- The level of refinery runs necessary to support contractual crude oil supplies, as opposed to the optimum runs related to reduced product demand and the need to reduce inventories.

Refining and Supply

At year end 1980, TOTAL's crude oil and refined product inventories were high relative to the product demand of 1981, in part due to the October 1980 acquisition of Vickers Petroleum with its inventories.

In late 1980, TOTAL made foreign crude oil supply commitments in the expectation that the level of refining operations in 1981, including the newly acquired Vickers operation, would match 1980 levels. Decreased demand for petroleum products and the necessity to reduce inventories resulted in optimum crude oil runs falling significantly below our committed levels of supply. While we were able to negotiate sizable reductions in foreign supplies during the second quarter, these obligations could not be entirely eliminated until year end. As the chart, Selected Crude Oil Prices (page 12) indicates, pressures of the market place gradually brought prices for crude oils of different sources into line; but in the meantime refiners such as TOTAL, still committed to sizable purchases of African crude oils at official prices, were at a severe disadvantage. Our domestic crude oil cost peaked at about $39 per barrel in April and dropped to about $35.50 by September, but foreign crude oil purchases did not allow our raw material costs to drop as fast as domestic crude oil prices.

As domestic crude oil prices declined $3/bbl. in the second quarter, product prices also declined by similar amounts. A corresponding decline in foreign crude oil costs did not occur until the fourth quarter. For TOTAL, and others with foreign supply commitments, this situation was the largest single factor contributing to the unsatisfactory refining and marketing results of 1981.

The vacuum tower of the crude unit at the Ardmore refinery (far left). TOTAL markets under the brand names of TOTAL, APCO, BEST and VICKERS. Nearly all Company stations are self-serve.

During 1981, we were successful in increasing our supplies of domestic crude oil and other domestic raw materials by about 50%. We can now supply approximately 70% of our full refinery capacity from domestic sources. We have eliminated all term obligations for the supply of offshore crude oil. This gives us considerable flexibility to adjust refinery runs to suit market fluctuations, and also allows flexibility to move in and out of the crude oil and product markets as profitable opportunities appear.

At year end crude oil inventories had been reduced near minimum working levels. Further reductions of both crude oil and product inventories will continue.

The operating performance of our three refineries in 1981 was mixed. The Alma refinery operated very efficiently and met its objectives. The newly acquired Ardmore, Oklahoma refinery progressed ahead of schedule in refining efficiency with light oil yields well above our initial projections. During the second quarter of 1982 we will start operating a new residual oil upgrading unit at the Ardmore refinery. This unit will further enhance our ability to convert low value residual products into gasoline and middle distillates.

The Arkansas City refinery encountered several mechanical problems throughout the year, which prevented the refinery from achieving its 1981 operating goals. We have been making progress in solving these problems and expect a more efficient operation in 1982.

The combined yield of light oils (gasoline, diesel fuel, and home heating oil) at TOTAL's refineries at year end 1981 was approximately 86%, up from 83% in the first quarter of 1981. Combined gasoline yield at year end was approximately 65%, versus approximately 59% during the first quarter. Our goal is to achieve a light products yield of 90% and a gasoline yield approaching 70%.

Despite the many problems that beset our refining and marketing operations during 1981, it was necessary for our staff to devote a considerable portion of its time and effort towards integrating Vickers Petroleum into TOTAL. By year end the two organizations had been successfully consolidated with resulting efficiencies and cost savings.

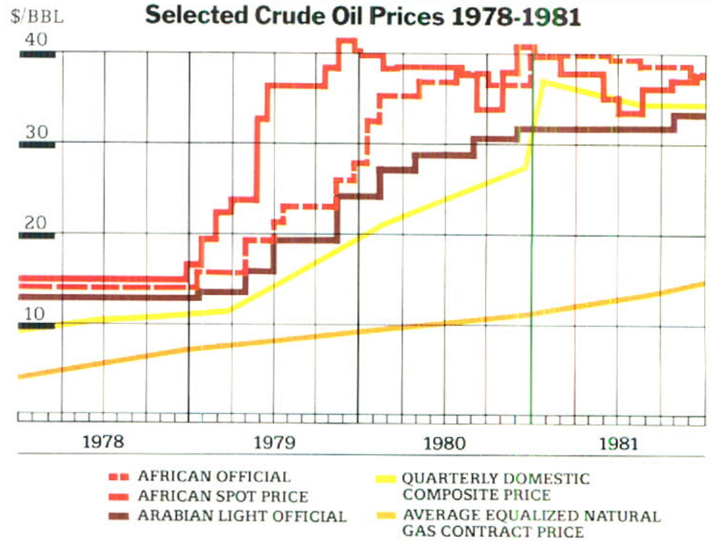
Marketing

Termination of petroleum price and allocation regulations in early 1981 had a significant impact on the marketing segment of our industry. After a slight increase immediately after decontrol, product prices eroded steadily due to the renewed competition stemming from free market forces and lower demand. The nationwide average wholesale price for regular gasoline was $0.985 per gallon on January 1, 1981; it peaked at $1.104 per gallon in March, 1981 and declined to $1.017 per gallon by February 24, 1982.

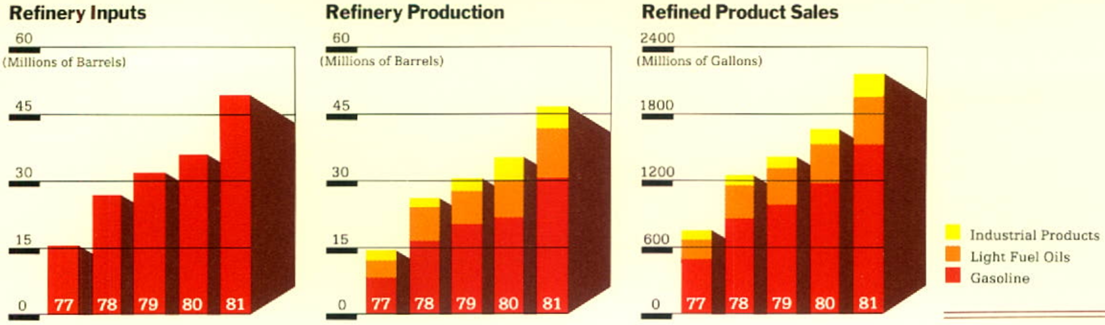
Gasoline demand in 1981 was down 4.2% from 1980 while middle distillate and residual fuel oil demand declined 4.6% and 19.9% respectively from 1980 levels.

Despite these adverse marketing conditions, TOTAL's retail operations generated cash flow in 1981 and we achieved a number of goals that strengthened our competitive position. Most important was the integration of

Selected Crude Oil Prices 1978-1981



Source: Petroleum Intelligence Weekly and The Petroleum Situation



Vickers retail and wholesale marketing into TOTAL with an overall improvement in operating efficiency and considerable savings in overhead.

TOTAL's retail operations now encompass a nineteen state area with 460 Company operated stations. This compares with 129 Company operated stations in two states prior to the Vickers acquisition. The large expansion of our retail network was a key factor in maintaining a high level of gasoline sales at the best possible prices under competitive conditions.

During 1981, TOTAL expanded sales of non-petroleum items such as cigarettes, soft drinks and snack items throughout the Vickers retail network. Our goal is to offer these items at all Company service stations by mid 1982. Non-petroleum items have already made a significant contribution to our retail profitability and we expect additional profits in the current year.

Nearly all of TOTAL's Company operated stations are self-service. Self-service is the fastest growing segment of retail marketing and is currently estimated to account for about two-thirds of all U.S. gasoline sales.

Last year, significant overhead savings were achieved through consolidation of various retail offices, as well as the consolidation of our credit card operations at a single credit card center located in Alma, Michigan. During 1982, we expect additional savings to result from the elimination of most Company operated warehouses.

Although TOTAL's retail sales through Company operated stations now exceed 50% of all our gasoline sales, we continue to maintain strong relationships with our branded jobbers. In Michigan and Ohio, jobbers use the TOTAL brand name while in the Mid-continent area all jobbers are under the APCO brand name. Sales volumes through this important channel decreased last year as a result of reduced demand and competitive conditions, but TOTAL has been able to reduce the volume loss with the additions of new jobbers.

Consumers' demands are constantly changing and TOTAL's marketing operations continue to evolve with such changes. For example, all of our Company operated retail stations now offer high octane gasoline. In 1982, we also intend to increase the availability of diesel fuel at Company stations.

Outlook

The demand for petroleum products is not expected to grow appreciably in the 1980's. Because of improved efficiency of new vehicles, reduced demand for gasoline seems assured for several years at least. Demand for other petroleum products may also decline as users substitute alternate fuels. In addition, the low level of economic activity has an impact on the use of petroleum products.

In 1981, the industry began to make adjustments to this changing environment and more adjustments will be required in the current year and beyond. Refinery closings and lower utilization rates indicate that such adjustments are under way.

TOTAL is in a far better position to deal with this competitive environment than it was a year ago. Nonrecurring costs attributable to the Vickers integration are behind us; crude oil supplies are competitive and flexible; inventories are at a level that will allow us to react quickly to potentially profitable opportunities; our refineries already have a competitive yield structure and we anticipate further progress in upgrading residual fuel into light oils and improving our saleable yields as well; and our retail network is highly efficient and becoming more so while providing an assured outlet for a significant portion of our refinery production.

Refining and marketing continues to be a cyclical business. We are currently in a period of low margins, reflecting highly competitive conditions. As adjustments take place in the market and within the industry, we should experience a return to a period of higher margins. Meanwhile, the actions we have taken in 1981, and continue to take, will make us more competitive and enable us to return to satisfactory levels of cash flow when market conditions improve.

Financial Section

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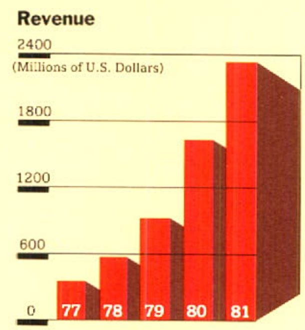

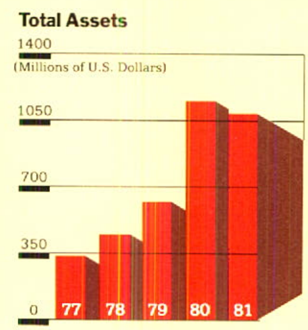

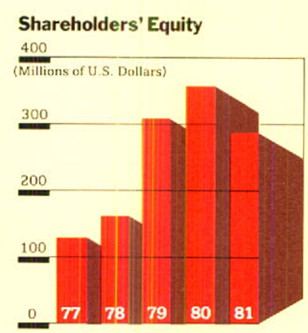

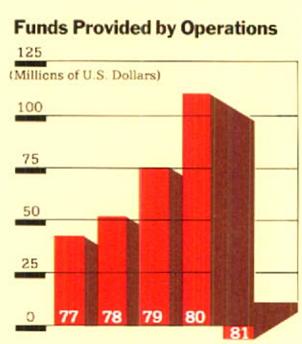

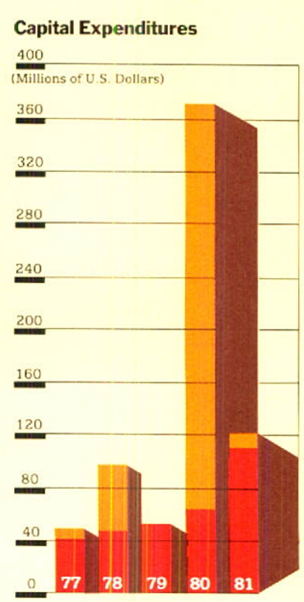

Selected Five-Year Data

		1981	1980	1979	1978	1977
FINANCIAL (in thousands of U.S. dollars, except per share amounts)	Revenues	**$2,380,538**	$1,604,537	$910,505	$572,310	$349,469
	Net income (loss)	**(63,608)**	47,749	29,871	14,416	12,964
	Net income (loss) per share	**(4.12)**	2.30	1.82	.98	1.01
	Dividends per common share (Can. $)	**.48**	.44	.29	.15	.05
	Funds provided by operations	**(6,269)**	110,681	75,029	51,579	42,357
	Capital expenditures	**109,121**	66,866	54,262	50,246	40,998
	Acquisition expenditures	**11,890**	306,407	—	48,025	9,850
	Total assets	**1,098,417**	1,155,017	624,262	440,554	346,690
	Long-term debt	**357,559**	278,060	68,542	109,868	134,807
	Shareholders' equity	**280,720**	357,879	306,565	163,476	129,017
	Ratio of debt to debt plus equity	**56%**	44%	18%	40%	51%
OPERATING Exploration and Production	Crude oil and condensate (thousands of barrels) —					
	Canada					
	Proved reserves at year-end	**21,137**	22,864	24,786	26,708	28,176
	Production during year	**1,973**	2,115	2,336	2,020	1,929
	United States					
	Proved reserves at year-end	**7,628**	7,867	7,022	7,240	8,614
	Production during year	**1,628**	1,701	1,641	1,578	1,628
	Natural gas (millions of cubic feet) —					
	Canada					
	Proved reserves at year-end	**253,063**	227,726	215,809	213,937	190,389
	Sales during year	**7,612**	8,012	8,062	6,800	6,876
	United States					
	Proved reserves at year-end	**59,841**	60,380	59,092	62,066	59,860
	Sales during year	**10,652**	10,880	10,328	8,505	9,319
	Gross land holdings (thousands of acres) —					
	Canada	**19,594**	25,261	25,235	28,626	32,092
	United States	**2,001**	1,972	2,124	2,401	2,641
	Net land holdings (thousands of acres) —					
	Canada	**1,494**	2,413	2,427	2,774	2,972
	United States	**610**	584	658	633	728
Refining and Marketing	Refinery input (thousands of barrels)	**49,005**	35,652	31,829	26,873	15,317
	Manufactured gasoline (thousands of barrels)	**30,417**	21,818	20,402	16,573	8,074
	Refined product sales (thousands of barrels)	**51,234**	39,560	33,378	29,525	17,884
	Gasoline sales (thousands of barrels)	**36,311**	27,815	22,967	20,088	11,407

Financial Review

Management Discussion and Analysis

The following discussion includes a brief description of significant factors affecting the Company's operations, its liquidity and financial resources. The financial statements and the table of Selected Five-Year Data provide financial and operating information for the past five years and should be read in conjunction with this discussion.

Results of Operations

The Company has two operating divisions — exploration and production in Canada and the United States (U.S.), and refining and marketing in the U.S. The Statement of Information by Industry Segment and Geographic Area (the Statement) presents revenues, funds provided by operations and operating profit with details for amounts directly attributable to the divisions. Certain administrative expenses and amounts included in other revenue, net are incurred at the corporate level and, accordingly, are not allocated to the divisions. Interest and income tax expense (benefit) are also not allocated.

Exploration and Production

Funds provided by operations of the exploration and production division have increased in each of the five years presented in the Statement. Higher sales prices have been the principal reason for the trend of rising funds. The following table presents an analysis of the increase in funds provided during each year presented compared to the prior year (in thousands of U.S. dollars):

	1981			1980			1979		
	Canada	U.S.	Total	Canada	U.S.	Total	Canada	U.S.	Total
Increased sales revenues (net of royalties) due to:									
Sales quantities	$(1,565)	$ (135)	$(1,700)	$(1,495)	$ 3,442	$ 1,947	$3,494	$ 669	$4,163
Sales prices	(784)	30,496	29,712	6,127	16,032	22,159	987	3,611	4,598
Other income	148	—	148	(30)	(210)	(240)	451	165	616
	(2,201)	30,361	28,160	4,602	19,264	23,866	4,932	4,445	9,377
Increased operating and administrative expenses	(179)	(16,106)	(16,285)	(745)	(2,288)	(3,033)	(927)	(1,357)	(2,284)
Total increase in funds provided	$(2,380)	$14,255	$11,875	$ 3,857	$16,976	$20,833	$4,005	$3,088	$7,093

In the U.S., sales quantities increased in 1980 as the result of the acquisition of producing properties from Traverse Corporation in January, 1980. Increased sales prices contributed to the increase in funds provided in each year presented. The "phased decontrol" in 1980 and complete decontrol in 1981 of crude oil prices resulted in very significant increases in funds due to sales prices. To a lesser extent, natural gas prices increased in accordance with provisions of the Natural Gas Policy Act. During the latter part of 1981 and into early 1982 the industry witnessed decreasing crude oil prices. This decrease has a favorable effect on the Company as crude oil costs incurred by the refining and marketing division decrease dollar for dollar while the revenues net of windfall profit tax from crude oil production decrease less than fifty cents on the dollar as the majority of the Company's crude oil production is taxed at the Tier I rate of 70%.

The large increase in operating and administrative expenses in 1981 was primarily due to increased windfall profit tax expense based on crude oil prices which were entirely decontrolled on January 28, 1981. In 1980 the tax was in effect for only ten months and applied to partially decontrolled crude oil prices. Windfall profit tax expense was $14.3 million in 1981 and $3.8 million in 1980.

In Canada, the National Energy Program (NEP) continues to have a negative impact on the oil and gas industry. During 1981, sales quantities decreased as the province of Alberta decreased allowable crude oil production to express displeasure with the Federal Government's NEP as proposed in 1980. Crude oil production increased in 1979 due to Western Canadian crude oil replacing crude oil imports in Eastern Canada and subsequently decreased in 1980 as an increased crude oil supply reduced the flow of western crude oil to the east. Even though the Company has abundant natural gas production capacity in Canada, market conditions held natural gas sales at a similar level each year.

A higher export price for natural gas was the principal reason for increased funds in 1980. A slight decrease occurred in 1981 as a result of the 8% Petroleum and Natural Gas Revenue Tax (PGRT), a provision of the NEP that is calculated on gross revenues less lifting costs. The PGRT, which is applied to the entire sales price of oil and gas, offset the increased revenues resulting from the price increases allowed by the Federal Government.

On September 1, 1981 an agreement was reached between Alberta and the Federal Government modifying the NEP as originally proposed. Crude oil prices are scheduled to increase at a faster rate in approaching world prices but unfortunately most of the increased revenues are confiscated by way of taxation by the provincial and federal governments. Provincial royalties, the PGRT, which has been increased to an effective rate of 12%, and a new tax, the Incremental Oil Revenue Tax, absorb most of the increased revenue resulting from the September, 1981 agreement. The producer is left with very little to reinvest in exploration and development activities.

Overall, the Company anticipates an increase in Canadian production that, along with projected U.S. natural gas price increases, will offset the effect of reduced U.S. crude oil prices and leave total 1982 funds provided at a level similar to 1981.

Depreciation and depletion attributable to the exploration and production segment increased in 1980 and again in 1981. This expense increases as costs to find and develop mineral reserves increase. The Summary of Exploration, Development and Production Activities provides additional information relative to costs incurred, production volumes and recorded depletion expense.

Refining and Marketing

The trend of increasing funds provided by the Company's refining and marketing division suffered a setback in 1981. This segment of our business, which had increased funds provided by operations from $12.6 million in 1976 to $86 million in 1980, experienced a funds deficit of $58.5 million in 1981.

The following table provides an anaylsis of the increase or decrease in funds provided by the refining and marketing division during each year presented compared to the prior year (in thousands of U.S. dollars):

	1981	1980	1979
Increase (decrease) in revenues:			
Sales related to acquired assets increased due to —			
Sales quantities	$ 600,965	$161,707	$ —
Sales prices	140,245	110,941	—
	741,210	272,648	—
Other sales increased (decreased) due to —			
Sales quantities	(143,567)	(9,987)	62,000
Sales prices	160,636	396,354	269,677
Increase (decrease) in other income	(2,011)	1,207	473
	756,268	660,222	332,150
Increased cost of purchased crude oil, products and merchandise due to:			
Purchase quantities	(328,455)	(146,168)	(46,211)
Purchase prices	(432,863)	(434,478)	(236,540)
	(761,318)	(580,646)	(282,751)
Increased operating, marketing and administrative expenses:			
Related to acquired assets	(101,000)	(19,242)	—
Other	(38,369)	(32,438)	(21,431)
	(139,369)	(51,680)	(21,431)
Total increase (decrease) in funds provided	$(144,419)	$ 27,896	$ 27,968

The table shows that the dramatic increases in 1981 revenues, materials costs and expenses resulted from the acquisition of Vickers Petroleum in late 1980. More importantly, the table provides the basic explanation of the 1981 setback — materials costs increased more than revenues during the year with the result that all increased expenses were a reduction of funds provided.

The industry's markets for crude oil and for finished petroleum products operated in opposite directions throughout most of the year. Faced with high inventory levels, demand below all forecasts and increased competition in an environment freed of governmental controls, product prices moved downward throughout most of the year. On the other hand, crude oil price declines, which came only in the latter part of the year, never caught up with declining product prices. This caused drastic reductions in refinery margins throughout the entire industry.

TOTAL's particular situation was further aggravated by foreign crude oil supply commitments which were at considerably higher prices than available domestic or spot market crude oils. These foreign crude oil supply obligations, which had served the Company well in the past, were negotiated downward during the year but could not be entirely eliminated until year-end.

These adverse market conditions occurred just as the Company was in the process of integrating the Vickers' assets and implementing a major corporate relocation. The internal change added complexity to dealing with the dramatic changes that were occurring in the marketplace. Despite these less than desirable conditions, considerable progress was made in coping with the adverse market conditions and improving the efficiency of the refining and marketing assets. Crude oil supplies were shifted from foreign to domestic sources. By year-end, the combined yield of higher-value light products (gasoline and fuel oils) at our refineries had been increased from 83 percent early in the year to approximately 86 percent. Combined gasoline yield was increased to approximately 65 percent from 59 percent. Progress continued on the $15 million upgrading program at the Ardmore, Oklahoma refinery which will further improve combined refinery yields when completed in mid-1982. The marketing organization completed the integration of the Vickers retail and wholesale marketing into TOTAL which has resulted in improved efficiency and considerable savings in overhead costs. These actions helped to reduce the funds deficit during the last half of 1981 and placed the refining and marketing division in a better position to begin 1982.

At this time, it is not possible to predict 1982 refining and marketing results. Since the start of 1982, demand for petroleum products has continued to slide and product prices have continued their downward plunge. On the positive side though, crude oil price declines have accelerated and adjustments are being made throughout the industry to reduce refining capacity.

Operating, marketing and administrative expenses in 1981 nearly doubled from 1980. As indicated in the table, $101 million of the increase relates to the assets acquired from Vickers — principally the Ardmore, Oklahoma refinery and approximately 350 company-operated service stations. These assets were operated by the Company for a full year in 1981 versus only three months of 1980. Depreciation expense for refining and marketing assets in 1981 increased $11.5 million from 1980, principally because of depreciation for a full year on the acquired assets.

General

Interest expense increased significantly in 1980 and 1981. The 1980 increase was due to the financing for the Vickers Petroleum acquisition and for additional working capital requirements. Approximately 75% of the 1981 increase relates to long-term borrowings and was caused by the financing for Vickers which was included in 1980 operations for three months and in 1981 for the entire year. The remainder of the 1981 interest expense increase resulted from higher short-term borrowings.

Income tax expense (benefit) tends to vary directly with net income (loss) before income taxes. The effective rate is increased in loss periods and decreased during income periods by investment and other tax credits. The effective tax rates in 1980 and 1979 in both the United States and Canada were at a similar level. The current year loss before income taxes resulted in the 1981 benefit for income taxes.

Financial Resources and Liquidity

As can be observed from the five years presented in the Consolidated Financial Statements, the Company has grown significantly in recent years. To a large degree this growth came from acquisitions which were primarily financed by new equity and long-term debt. The Company's strategy has been to borrow to finance acquisitions, raise new equity when market conditions are favorable in order to restore flexibility to the balance sheet, and devote cash flow to normal operations. This strategy can be illustrated with events of 1979 and 1980. In 1979, $117 million was raised from the sale of 2.8 million Preferred shares. Ninety-five million dollars of the proceeds was placed in short-term investments to be held for acquisitions, while the remaining proceeds were used to prepay long-term debt. The $95 million of short-term investments plus $16 million of equity raised from exercise of warrants, and $216 million of additional long-term borrowings were used to finance capital expenditures for acquisitions of $306 million in 1980.

In 1981, external financial sources were needed to finance the majority of the Company's normal capital expenditures because of the large decrease in cash flow. Working capital reductions supported operations and other financial requirements. The working capital reduction includes increased short-term bank debt of $93 million. Even though cash flow from operations continues to suffer from the drastically reduced refining and marketing margins, external financing may not be required in 1982. Projections for 1982 include the following major cash items (in thousands of U.S. dollars):

Liquidation of investment in Supron Energy Corporation	$ 58,000
Refund of taxes receivable	40,000
Capital expenditures, net	(85,000)
Scheduled repayment of long-term debt	(24,000)
	$(11,000)

Providing that cash flow from operations (excluding the gain on the Supron investment) exceeds about $11 million plus an amount to cover dividends, the indebtedness at December 31, 1981 could be reduced during 1982. In addition, the Company may sell certain of its properties in 1982. The amount of such transactions, if any, cannot be predicted at this time.

The Company's short-term liquidity is much stronger than the

December 31, 1981 elements of working capital indicate. The approximate replacement cost of inventories at December 31, 1981 is $290 million or nearly $150 million in excess of the LIFO cost amounts reflected in working capital in the Consolidated Financial Statements. In addition, committed and uncommitted bank lines for short-term borrowings aggregated approximately $212 million against which the Company has drawn $98 million at December 31, 1981. Subject to new financing arrangements, the Company expects the availability of these lines to continue.

Financing on a long-term basis remains available to the Company. The Company's oil and gas properties are unencumbered at the end of 1981 and could be utilized to support significant new debt.

Market Information and Dividends

Principal markets for the Company's common shares (TPN) are the Toronto Stock Exchange in Canada and the American Stock Exchange in the United States. There were approximately 6,200 holders of record of the Company's common shares on March 5, 1982.

The high and low sales prices of the common shares and the dividend paid during each quarterly period were as follows:

		1981				1980			
		1	2	3	4	1	2	3	4
Toronto Stock Exchange	High	24⅛	22⅜	25¼	20⅞	36½	31	30½	32¼
(Can. $)	Low	21¼	19⅜	11⅞	16⅝	20	23	26	24¼
American Stock Exchange	High	23⅝	21⅛	21	17⅝	31⅞	27	25⅝	27⅝
(U.S. $)	Low	17¾	16	10⅜	11	16¼	21⅝	22¼	22½
Dividend per share (Can. $)		.12	.12	.12	.12	.08	.12	.12	.12

The Canadian government imposes no limitations on rights of United States persons holding equity shares in the Company. The Canada-United States reciprocal tax convention states that the withholding tax rate on dividends paid to U.S. shareholders shall not exceed 15%. The Company has been withholding on such dividends at a 15% rate since the last quarter of 1981 pending the passage of a proposed amendment to the Income Tax Act Canada which would eliminate the 5% reduction allowed for corporations having a specified degree of Canadian ownership. Previously, withholding on dividends was at the reduced 10% rate.

Quarterly Results

The following summarizes certain quarterly financial information for 1981 and 1980 (in thousands of U.S. dollars except per share amounts):

	Quarter Ended				
1981	March 31	June 30	September 30	December 31	Total
Revenue	$603,115	$539,084	$583,401	$654,938	$2,380,538
Contribution to profit*	(26,890)	(19,876)	1,215	(10,563)	(56,114)
Income tax benefit	(21,270)	(14,030)	(9,900)	(15,050)	(60,250)
Net loss	(17,832)	(21,578)	(9,531)	(14,667)	(63,608)
Net loss per share	(1.14)	(1.36)	(.66)	(.96)	(4.12)
1980					
Revenue	$314,589	$326,531	$313,548	$649,869	$1,604,537
Contribution to profit*	18,805	38,655	27,937	20,036	105,433
Provision for income taxes	7,300	16,500	10,800	500	35,100
Net income	8,071	18,291	14,261	7,126	47,749
Net income per share	.38	.89	.69	.33	2.30

*Income (loss) before interest charges and provision for income taxes.

Net loss for the fourth quarter of 1981 includes approximately $2 million of expense related to an increase in the depletion rate from that applied in earlier quarters and other adjustments. The fourth quarter of 1980 included income of approximately $4 million because of a downward revision in the income tax rate and other adjustments.

Consolidated Balance Sheet

Total Petroleum (North America) Ltd. and Subsidiaries

(Thousands of U.S. dollars)

	December 31	1981	1980
ASSETS	Cash	$ 10,784	$ 22,930
	Short-term investments	30,839	34,696
	Accounts and notes receivable	189,773	298,148
	Taxes receivable	40,000	—
	Inventories of purchased crude oil and products	125,868	136,343
	Inventories of merchandise, materials and supplies	15,625	13,503
	Prepaid expenses and other	4,536	7,555
	Total current assets	417,425	513,175
	Other assets	10,505	4,932
	Property, plant and equipment, net ("full cost" method)	670,487	636,910
		$1,098,417	$1,155,017
LIABILITIES	Accounts payable (Note 10)	$ 216,844	$ 348,033
	Notes payable	98,000	5,000
	Accrued taxes	29,843	72,127
	Other accrued liabilities	35,520	21,123
	Current portion of long-term debt	24,561	5,375
	Total current liabilities	404,768	451,658
	Long-term debt	357,559	278,060
DEFERRED CREDIT	Deferred income taxes	55,370	67,420
SHAREHOLDERS' EQUITY	Capital Stock		
	Preferred shares	116,599	116,602
	Common shares	30,743	30,675
	Contributed surplus	92,213	92,213
	Retained earnings	41,165	118,389
		280,720	357,879
		$1,098,417	$1,155,017

See Notes to Consolidated Financial Statements

Approved on Behalf of the Board:

L. J. Richards
Director

Director

Consolidated Statement of Changes in Financial Position

Total Petroleum (North America) Ltd. and Subsidiaries (Thousands of U.S. dollars)

		1981	1980	1979	1978	1977
FUNDS PROVIDED BY OPERATIONS	Net income (loss)	$(63,608)	$ 47,749	$ 29,871	$ 14,416	$ 12,964
	Income charges (credits) not affecting working capital in the year:					
	Depreciation and depletion	68,574	47,932	31,358	30,063	21,693
	Deferred income taxes and other	(11,235)	15,000	13,800	7,100	7,700
		(6,269)	110,681	75,029	51,579	42,357
FUNDS USED FOR	Capital expenditures	121,011	373,273	54,262	98,271	50,848
	Short-term investments held for acquisitions	—	—	94,500	—	40,000
	Reduction of long-term borrowings	31,250	7,020	41,326	40,755	46,632
	Dividends	13,616	12,719	3,818	2,306	1,320
	Increase (decrease) in working capital	(48,860)	46,087	438	499	5,889
	Other	5,622	(149)	3,854	1,773	321
		122,639	438,950	198,198	143,604	145,010
DEFICIT		$128,908	$328,269	$123,169	$ 92,025	$102,653
DEFICIT FINANCED BY	Property sales	$ 18,860	$ 947	$ 6,133	$ 2,576	$ 2,415
	Additional long-term borrowings	109,983	216,538	—	26,340	100,009
	Liquidation of short-term investments	—	94,500	—	40,000	—
	Issuance of equity securities, net of conversions	65	16,284	117,036	23,109	229
		$128,908	$328,269	$123,169	$ 92,025	$102,653
INCREASE (DECREASE) IN WORKING CAPITAL	Cash and short-term investments	$ (16,003)	$ 43,003	$ 4,450	$ (6,385)	$ 7,223
	Accounts, taxes and notes receivable	(68,375)	171,138	64,528	34,402	4,830
	Inventories	(8,353)	85,255	479	41,975	2,833
	Prepaid expenses and other	(3,019)	1,614	2,126	(2,649)	501
	Accounts and notes payable and other accrued liabilities	23,792	(212,679)	(62,223)	(57,881)	(6,317)
	Accrued taxes	42,284	(57,229)	(9,612)	(1,279)	345
	Current portion of long-term debt	(19,186)	14,985	690	(7,684)	(3,526)
		$ (48,860)	$ 46,087	$ 438	$ 499	$ 5,889

See Notes to Consolidated Financial Statements

Consolidated Statement of Income (Loss) and Retained Earnings

Total Petroleum (North America) Ltd. and Subsidiaries

(Thousands of U.S. dollars except per share amounts)

		1981	1980	1979	1978	1977
REVENUE	Net sales of refined products	$2,271,802	$1,513,524	$854,509	$522,832	$306,135
	Net sales of crude oil and natural gas	105,412	77,399	53,294	44,533	41,146
	Other, net	3,324	13,614	2,702	4,945	2,188
		2,380,538	1,604,537	910,505	572,310	349,469
EXPENSES	Purchased crude oil, products and merchandise (Note 10)	2,043,203	1,281,885	701,239	418,488	240,338
	Operating	231,494	120,001	81,671	61,243	36,801
	Marketing and administrative	93,381	49,286	30,902	27,078	22,281
	Depreciation and depletion	68,574	47,932	31,358	30,063	21,693
	Interest	67,744	22,584	13,564	14,322	7,392
	Income taxes	(60,250)	35,100	21,900	6,700	8,000
		2,444,146	1,556,788	880,634	557,894	336,505
NET INCOME (LOSS)		(63,608)	47,749	29,871	14,416	12,964
RETAINED EARNINGS	Retained earnings at beginning of year	118,389	83,359	57,306	45,196	33,552
	Dividends:					
	Preferred shares	(6,863)	(6,880)	—	(606)	(845)
	Common shares	(6,753)	(5,839)	(3,818)	(1,700)	(475)
	Retained earnings at end of year	$ 41,165	$ 118,389	$ 83,359	$ 57,306	$ 45,196

PER SHARE	Net income (loss)	$(4.12)	$2.30	$1.82	$.98	$1.01
	Dividends:					
	Series A Preferred shares	—	—	—	$.525	$ .70
	Convertible Preferred shares (Can. $)	$ 2.88	$2.88	—	—	—
	Common shares (Can. $)	$ .48	$ .44	$ .29	$.15	$ .05

See Notes to Consolidated Financial Statements

Statement of Information by Industry Segment and Geographic Area

Total Petroleum (North America) Ltd. and Subsidiaries

(Thousands of U.S. dollars)

		1981	1980	1979	1978	1977
REVENUE	Exploration and production					
	Canada	$ **25,827**	$ 28,028	$ 23,426	$ 18,494	$ 16,507
	U.S.	**80,355**	49,994	30,730	26,285	25,023
	Refining and marketing — U.S.	**2,273,379**	1,517,111	856,889	524,739	306,698
	Unallocated	**977**	9,404	(540)	2,792	1,241
		$2,380,538	$1,604,537	$910,505	$572,310	$349,469
FUNDS PROVIDED BY OPERATIONS	Exploration and production					
	Canada	$ **21,592**	$ 23,972	$ 20,115	$ 16,110	$ 14,289
	U.S.	**52,621**	38,366	21,390	18,302	18,441
	Refining and marketing — U.S.	**(58,463)**	85,956	58,060	30,092	17,613
	Unallocated					
	Other income	**977**	9,404	2,459	2,792	1,241
	Interest expense	**(66,929)**	(22,584)	(13,564)	(14,322)	(7,392)
	Income taxes	**48,200**	(20,100)	(11,100)	400	(300)
	Administrative	**(4,267)**	(4,333)	(2,331)	(1,795)	(1,535)
		$ **(6,269)**	$ 110,681	$ 75,029	$ 51,579	$ 42,357
OPERATING PROFIT	Exploration and production					
	Canada	$ **13,960**	$ 16,819	$ 13,128	$ 10,645	$ 10,319
	U.S.	**17,427**	11,801	4,301	(138)	3,990
	Refining and marketing — U.S.	**(84,211)**	71,742	50,778	23,934	14,341
	Unallocated expenses, net	**(71,034)**	(17,513)	(16,436)	(13,325)	(7,686)
		$ **(123,858)**	$ 82,849	$ 51,771	$ 21,116	$ 20,964
CAPITAL EXPENDITURES	Exploration and production					
	Canada	$ **25,984**	$ 23,185	$ 20,484	$ 18,700	$ 11,885
	U.S.	**58,128**	24,237	16,629	23,540	15,870
	Refining and marketing — U.S.					
	Refining	**15,783**	11,882	12,650	4,144	11,140
	Supply and transportation	**3,035**	3,264	1,932	1,404	1,024
	Marketing	**1,529**	1,997	1,591	1,740	684
	Administrative	**4,662**	2,301	976	718	395
		109,121	66,866	54,262	50,246	40,998
	Acquisitions	**11,890**	306,407	—	48,025	9,850
		$ **121,011**	$ 373,273	$ 54,262	$ 98,271	$ 50,848
DEPRECIATION AND DEPLETION EXPENSE	Exploration and production					
	Canada	$ **7,632**	$ 7,153	$ 6,987	$ 5,465	$ 3,970
	U.S.	**35,194**	26,565	17,089	18,440	14,451
	Refining and marketing — U.S.	**25,748**	14,214	7,282	6,158	3,272
		$ **68,574**	$ 47,932	$ 31,358	$ 30,063	$ 21,693
ASSETS AT DECEMBER 31	Exploration and production					
	Canada	$ **145,907**	$ 132,614	$115,636	$105,339	$ 91,743
	U.S.	**170,123**	139,470	97,383	96,933	93,141
	Refining and marketing — U.S.	**700,764**	825,307	302,120	228,109	105,248
	Unallocated	**81,623**	57,626	109,123	10,173	56,558
		$1,098,417	$1,155,017	$624,262	$440,554	$346,690

See Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

1. Accounting Policies

The significant accounting policies followed by the Company and its subsidiaries are presented here to assist the reader in reviewing the financial information contained herein. The Company's accounting policies are based on generally accepted accounting principles in the United States. Any material differences between those principles and the principles recommended by the Canadian Institute of Chartered Accountants are disclosed in the financial statements or the notes thereto.

Principles of Consolidation

The consolidated financial statements include the accounts of all subsidiaries.

Business Segments (Classes of Business)

The Board of Directors has determined that the Company's operations can be divided into two business segments and such determination is recorded in the minutes of a meeting of the Board. Exploration and Production includes the exploration for, and development and production of, petroleum and natural gas reserves. Refining and Marketing includes the refining of crude oil and the distribution and marketing of refined products. Other income (principally financial) and expenses incurred at the corporate level, including income taxes, are not allocated to the segments. Unallocated assets are cash, short-term investments and taxes receivable.

Foreign Currency Translation

The Company presents the consolidated financial statements in United States dollars because the majority of the transactions and the major portion of the working capital and long-term debt of the consolidated companies are in that currency. Canadian assets and liabilities representing cash and amounts owing to or by the Company are translated at the rate of exchange in effect at the end of the period. Other assets (such as inventories and property, plant and equipment) and deferred income taxes are translated at historical rates. Operating results for the period are translated at the monthly average rate of exchange during the year; depreciation and depletion included in operating results are translated at historical rates. Currency translation gains and losses, which are not material, are included in net income (loss).

Inventories

Inventories are valued at the lower of cost or net realizable value. Cost of inventories of crude oil and refined products is determined by the last-in, first-out method. Cost of other inventories is determined by the first-in, first-out method with respect to merchandise and by the average cost method for materials and supplies. The replacement cost of inventories at December 31, 1981 and 1980 was approximately $290,500,000 and $265,000,000 respectively.

Property, Plant and Equipment

Property, plant and equipment is carried at cost.

The Company follows the "full cost" method of accounting for its exploration and production activities. All costs of exploring for and developing oil and gas reserves are capitalized and charged to operations over the life of estimated future production (proved reserves) on the unit-of-production method. Proceeds from disposals are applied against such cost.

Depreciation is provided using the straight-line method based on estimated useful lives.

Income Taxes

The Company's subsidiaries located in the United States file a consolidated tax return in that country while the parent company files a tax return in Canada for the Canadian operations.

The Company does not provide for taxes which would be payable upon transfer of undistributed earnings of subsidiaries because management believes that either such earnings will not be transferred in the foreseeable future or no tax expense would be incurred because of available credits or deductions. At December 31, 1981, undistributed earnings of subsidiaries amounted to $13,188,000.

Investment tax credits are applied as a reduction of income tax expense in the period realized.

Other

Excise taxes collected from customers are excluded from the Consolidated Statement of Income (Loss) and Retained Earnings.

Sales of purchased crude oil are deducted from the related purchases in the Consolidated Statement of Income (Loss) and Retained Earnings.

2. Acquisitions

On October 2, 1980, the Company acquired all of the outstanding capital stock of Vickers Petroleum Corporation, a wholly owned subsidiary of Esmark, Inc. Immediately upon acquisition, Vickers Petroleum Corporation was liquidated into a wholly owned subsidiary of the Company. The underlying assets acquired included a refinery in Oklahoma and related pipeline facilities and service station properties located in the United States Mid-continent area. The cost of the acquired assets, as measured by payments to the seller plus liabilities assumed and certain income tax liabilities incurred upon liquidation of Vickers, were attributed to current assets based on fair value with the remainder being attributed to property, plant and equipment. This allocation resulted in working capital of approximately $60,000,000 and cost of properties aggregating $276,211,000. The cost of properties includes $11,890,000 added in 1981 representing settlement of all disputed items. Financing for the acquisition was provided by proceeds from borrowings under revolving bank credits (see Note 4), liquidation of short-term investments and working capital.

In 1981, the Company disposed of a portion of its interest in petroleum and natural gas properties acquired in 1977. This disposal resulted from the Foreign Investment Review Agency's refusal to allow the acquisition on the grounds that it was not likely to be of significant benefit to Canada. The interest was sold for more than the proportionate cost of the properties, with the gain being credited to the cost of property, plant and equipment.

3. Property, Plant and Equipment

Property, plant and equipment is as follows (in thousands):

	1981	1980
Exploration and production	$426,824	$357,874
Refining	274,924	249,147
Marketing	117,274	130,062
Supply and transportation	60,440	42,338
Other	12,511	16,661
	891,973	796,082
Accumulated depreciation and depletion	221,486	159,172
	$670,487	$636,910

4. Debt

The following summarizes the consolidated long-term debt (in thousands):

	1981	1980
Notes payable:		
Due 1982, interest 8½%	$ 20,000	$ 20,000
Due 1983, interest 8⅝%	20,000	20,000
Due in five annual installments beginning May 1, 1982, interest 8%	16,000	—
Revolving credits	270,000	210,000
Guaranteed 14¾% Subordinated Notes due October 1, 1986	40,000	—
Guaranteed 11½% Sinking Fund Debentures due December 31, 1990 (subordinated)	10,320	10,625
Production Payment	—	10,660
Other secured debt at 5½% to 10½%	13,545	12,150
Less: unamortized discount	(7,745)	—
	382,120	283,435
Current maturities	24,561	5,375
	$357,559	$278,060

In connection with the acquisition of Vickers Petroleum Corporation in 1980, the Company entered into revolving credit agreements with ten banks. The agreements provide for maximum aggregate borrowings of $270,000,000 at rates based on domestic or Eurodollar short-term market rates. Prior to December 31, 1983 the Company may borrow any amount desired from time to time up to the maximum. Any borrowings outstanding on January 1, 1984 are payable in equal semi-annual installments beginning on June 30, 1984 with the final payment due on December 31, 1988.

On September 17, 1981, a subsidiary of the Company issued $40,000,000 of 14¾% Subordinated Guaranteed Notes (Notes) with detachable warrants to purchase 1,840,000 shares of Supron Energy Corporation common stock at $30.75 per share. The Notes are guaranteed as to payment of principal and interest (on a subordinated basis) by the Company. The warrants must be exercised no later than October 1, 1982. The Notes were issued at a discount which is being amortized over the period the Notes are outstanding, resulting in an effective interest rate of 19¼%.

The Guaranteed 11½% Sinking Fund Debentures are payable by a subsidiary and guaranteed as to payment of principal and interest (on a subordinated basis) by the Company. The sinking fund provisions require annual payments of $1,740,000 from December, 1981 through December, 1988 with the remaining balance due on December 31, 1990. In 1979, the Company elected to redeem $1,740,000 of the debentures effective January 1, 1980. Because of this redemption and repurchases in market transactions, sinking fund payments were not required in 1981 and may be omitted in 1982, 1983 and 1984. Annual payments of approximately $1,740,000 in 1985 through 1988 will be required with the remaining balance payable in 1990.

In satisfaction of all disputed items relating to the acquisition of Vickers Petroleum Corporation, the Company issued a $16,000,000 note payable to Esmark, Inc. The note is due in five annual installments of $3,200,000 each commencing on May 1, 1982. The note was recorded at a discount which is being amortized over the period of the note resulting in an effective interest rate of 16%.

The purchaser of the production payment outstanding at December 31, 1980 received 65% of the revenues net of royalties from specified properties. Payments were applied to interest at 0.85% above Canadian prime and to reduction of the primary sum. During September, 1981 payment of the remaining primary sum was made.

Interest expense on long-term borrowings was:

1981 - $53,232,000	1978 - $12,930,000
1980 - $18,641,000	1977 - $ 7,024,000
1979 - $12,288,000	

Minimum annual maturities of long-term debt for the next five years are as follows:

1982 - $24,561,000	1985 - $59,794,000
1983 - $24,070,000	1986 - $99,454,000
1984 - $57,999,000	

At December 31, 1981 the Company or its subsidiaries had unused commitments from various banks for future borrowings aggregating $54,500,000, all of which would be on a short-term basis. Borrowings under such agreements would be at the prime interest rate or at margins of ¼% to ½% over money market rates. Commitment fees on the unused available credits range from ¼% to ½%. All of the commitments for short-term borrowings may be withdrawn annually.

5. Income Taxes

Income (loss) before income taxes and the provision for income tax expense (benefit) included in the Consolidated Statement of Income (Loss) and Retained Earnings are as follows (in thousands):

	1981	1980	1979	1978	1977
Income (loss) before income taxes:					
U.S.	$(140,193)	$61,202	$42,230	$13,398	$12,255
Canadian	16,335	21,647	9,541	7,718	8,709
	$(123,858)	$82,849	$51,771	$21,116	$20,964
Current tax provision payable (refundable):					
U.S.	$ (43,500)	$20,200	$ 3,850	$ 250	$ —
Canadian	2,300	3,400	(850)	(650)	300
Deferred tax provision:					
U.S.	(25,000)	5,600	13,700	4,450	5,015
Canadian	5,950	5,900	5,200	2,650	2,685
	$ (60,250)	$35,100	$21,900	$ 6,700	$ 8,000

Substantially all of the Canadian deferred tax provision results from the deduction of exploration and development expenditures on various bases which generally have the effect of permitting such deduction to be made for tax purposes in advance of the related deduction from income for book purposes. At December 31, 1981, the Company had the following approximate deductions and credits available to reduce Canadian tax payments which would otherwise be required in future years:

Property expenditures	$ 9,200,000
Development expenditures	$ 9,400,000
Capital cost allowance	$ 4,500,000
Depletion allowance	$24,600,000

The currently refundable U.S. tax provision reflects the U.S. taxes previously paid that may be recovered under prescribed loss carryback rules. The remainder of the 1981 loss applicable to the U.S. (approximately $59,700,000) plus certain tax credits (approximately $10,300,000) will be carried forward to reduce U.S. taxes which would otherwise be payable. The future cash benefit of these carryforwards is recorded in the U.S. deferred tax provision.

Upon utilization, the benefits of these carryforwards will be credited to the deferred income taxes in the balance sheet except for approximately $5,900,000 related to Canadian depletion which will be credited to income. The U.S. deferred tax provision consists of timing differences related to the following (in thousands):

	1981	1980	1979	1978	1977
Exploration and development costs	$ 4,500	$1,400	$ 2,200	$ 750	$1,415
Utilization of tax loss carryforward	(27,500)	—	—	2,100	3,900
Revenue recognition differences	(6,400)	(2,500)	7,300	1,600	—
Depreciation expense	7,900	6,800	1,900	2,000	—
Allocation of purchase price of acquired assets	—	—	—	(2,000)	—
Investment tax credits	(10,300)	1,100	3,900	(1,100)	(1,000)
Other	6,800	(1,200)	(1,600)	1,100	700
	$(25,000)	$5,600	$13,700	$4,450	$5,015

Prior to 1981, investment tax credits are applied as a reduction of the tax expense, thereby reducing the expense to an amount below the statutory tax rate. Credits and special allowances in Canada similarly reduce taxes otherwise payable. Royalty and other payments to governments are not deductible for Canadian federal income tax purposes. In 1981, investment tax credits increased the tax benefit to an amount above the statutory tax rate.

Income tax expense (benefit) is at rates other than the statutory U.S. income tax rate as follows (in thousands):

	1981	1980	1979	1978	1977
Income (loss) before income taxes	$(123,858)	$82,849	$51,771	$21,116	$20,964
Statutory U.S. rate	46%	46%	46%	48%	48%
Tax provision at statutory rate	(56,975)	38,111	23,815	10,136	10,063
Differences:					
Canadian taxes at rates higher (lower) than U.S. rates	1,732	120	(40)	(1,306)	(393)
State income taxes and other	(1,617)	(106)	400	50	130
Investment and other tax credits	(2,390)	(2,225)	(1,475)	(1,380)	(1,000)
Amortization of additional tax basis on properties distributed as a dividend by a subsidiary	(1,000)	(800)	(800)	(800)	(800)
	$ (60,250)	$35,100	$21,900	$ 6,700	$ 8,000

6. Capital Stock

The Company's authorized capital at December 31, 1981 consists of 12,800,000 Preferred shares and 10,000,000 Second Preferred shares without nominal or par value, issuable in series, and an unlimited number of Common shares without nominal or par value. 2,800,000 of the authorized Preferred shares, 2,798,590 of which are outstanding at December 31, 1981, are designated as $2.88 Cumulative Redeemable Convertible Preferred shares ("Convertible Preferred shares").

Changes in issued capital stock and contributed surplus are as follows (in thousands of dollars):

	Preferred Shares		Common Shares		
	Number of Shares	Amount	Number of Shares	Amount	Contributed Surplus
Balance January 1, 1979	—	$ —	15,400,953	$14,244	$91,926
Sales of Convertible Preferred shares, net of expenses	2,800,000	116,665	—	—	—
Adjustments to 1978 Preferred share conversion	—	—	264	—	3
Exercise of stock options and warrants	—	—	42,611	84	284
Balance December 31, 1979	2,800,000	116,665	15,443,828	14,328	92,213
Exercise of stock options and warrants	—	—	1,639,545	16,292	—
Adjustments to 1979 sale of Convertible Preferred shares	—	(8)	—	—	—
Conversion of Convertible Preferred shares into Common shares	(1,310)	(55)	1,873	55	—
Balance December 31, 1980	2,798,690	116,602	17,085,246	30,675	92,213
Exercise of stock options and warrants	—	—	7,789	68	—
Redemption of Convertible Preferred shares	(100)	(3)	—	—	—
Balance December 31, 1981	2,798,590	$116,599	17,093,035	$30,743	$92,213

The holders of the Convertible Preferred shares are entitled to receive fixed cumulative preferential cash dividends, if and when declared by the Board of Directors, at an annual rate of $2.88 (Can.) per share payable quarterly. The Convertible Preferred shares are convertible into Common shares at any time at the option of the holder at a conversion rate of 1.43 Common shares for each Convertible Preferred share. These shares may be redeemed by the Company (but only under certain conditions prior to December 20, 1983) at specified prices declining from a high of $52.40 (Can.) per share to a low of $50.00 (Can.) per share after December 20, 1989.

Warrants to purchase 1,588,445 Common shares at $10.00 (U.S.) per share were exercised in late 1980 prior to their December 31, 1980 expiration. Warrants to purchase 40,587 Common shares had not been exercised by that date resulting in adjustments in 1981.

On April 29, 1981, the shareholders approved a resolution of the Board of Directors extending the term of the 1975 Stock Option Plan for Employees to November 30, 1990 and increasing the shares authorized for granting of options from 400,000 to 900,000 Common shares. Options to purchase 360,150 of the Company's Common shares at prices ranging from $9.49 to $22.75 (Can.) were outstanding at December 31, 1981 under this plan, 188,650 of which were exercisable. This includes options to purchase 314,850 Common shares granted in December 1981 that can be exercised (subject to shareholder approval) at the rate of 40% in the year granted and 20% in each of the three years following the year granted. The options previously granted may be exercised at any time within five years of the date of the grant. No charges are made to income in connection with the option plan.

7. Net Income (Loss) Per Share

The computation of net income (loss) per share in the Consolidated Statement of Income (Loss) and Retained Earnings is based on the weighted average shares outstanding during the year. Prior to 1981, average shares include outstanding Common shares, Common shares that would be issued assuming conversion of all Preferred shares and the incremental shares that would be issued assuming all dilutive options and warrants outstanding during the year were exercised at the beginning of the year and the proceeds were used to purchase treasury shares. In 1981, shares other than outstanding Common shares were anti-dilutive and, therefore, not considered in average shares outstanding. The net loss in 1981 plus dividends paid on Preferred shares was used in computing the loss per share amount.

Under Canadian practice, basic net income per share is calculated based on the net income available to Common shares (net income less dividends on Preferred shares) and the weighted average number of Common shares outstanding. The calculation of fully diluted net income per share is based on net income increased by net earnings which would be realized from investment of proceeds received on exercise of warrants and options, divided by the Common shares outstanding including the shares reserved for conversion of Preferred shares and exercise of warrants and options. Basic and fully diluted net loss per share are calculated based on the net loss available to Common shares (net loss plus dividends on Preferred shares) and the weighted average number of Common shares outstanding. Net income (loss) per share pursuant to Canadian practice is as follows:

	1981	1980	1979	1978	1977
Basic	$(4.12)	$2.63	$1.94	$1.07	$1.16
Fully diluted	$(4.12)	$2.32	$1.81	$ .94	$ .93

8. Pension Plans

The Company and its subsidiaries have several separate pension plans covering substantially all of their employees. The total pension expense for all plans, which includes amortization of prior service costs over 30 years, was: 1981 - $2,960,000, 1980 - $1,635,000, 1979 - $2,089,000, 1978 - $1,945,000 and 1977 - $1,526,000. The information pertaining to 1981 includes amounts relating to Vickers Petroleum Corporation pension plans assumed by the Company. The Company funds at least the pension expense described above.

At January 1, 1981, the net assets available for benefits (U.S. pension plans) were $30,220,000 which exceeded the actuarial present value of accumulated plan benefits of $22,330,000 (vested - $18,680,000 plus non-vested - $3,650,000).

The future rate of return assumed in determining the actuarial present value of vested and non-vested accumulated plan benefits is 7% per annum, compounded annually. Net assets are stated at market values.

9. Quarterly Results

Unaudited information for the individual quarters of 1981 and 1980 is presented on page 19.

10. Related Party Transactions

The Company purchased crude oil at contract prices from Total International Limited, a wholly owned subsidiary of Compagnie Française des Pétroles (CFP), a French corporation which owns approximately 50% of the voting shares of the Company. The contracts were for one-year periods ending each December 31, with purchase prices based upon the posted prices of certain African producing countries. The contracts were not renewed in 1982.

The aggregate of such purchases was $385,000,000 in 1981, $451,400,000 in 1980, $192,600,000 in 1979, $53,600,000 in 1978 and $33,800,000 in 1977. Accounts payable at December 31, 1980 include $36,900,000 (none in 1981) related to the purchases described above.

11. Contingencies

Effective January 28, 1981, substantially all crude oil and refined petroleum products were exempted from price and allocation controls administered by the Department of Energy (DOE). Nevertheless, the Company continues to be subject to the possibility of alleged violations of the regulations as interpreted by the DOE for the control period.

On March 17, 1980, the Company received a Notice of Probable Violation concerning certain processing agreements. The NOPV does not state any monetary claim against the Company. On September 26, 1980, the Company received a NOPV alleging that the Company had improperly calculated allowable finished product selling prices. The Company believes that it has settled all civil claims and disputes with the DOE and during 1980 provided for all anticipated losses.

Various issues between the DOE and certain other companies may result in retroactive refunds or increases in the prices of crude oil purchased in periods prior to decontrol. The future impact on the Company will depend on the outcome of litigation and on the provisions to be established by the DOE in connection with implementation of decontrol.

On April 1, 1978, the Company acquired a refinery and certain related U.S. assets from Apco Oil Corporation. Since the closing date, the Company and Apco have been unable to agree upon the purchase price for the inventories and accounts receivable. The Company has also asserted claims against Apco based upon the allegations, among others, that Apco has breached certain covenants and warranties. The amounts at controversy in the litigation add to approximately $10 million, which amounts the Company withheld from payments to Apco. Any additional payments would be added to the cost of the refinery and other facilities.

The Company believes that the liabilities, if any, that it might incur upon the resolution of all unresolved issues will not be materially important in relation to the Company's financial position.

12. Exploration and Production Activities

See Summary of Exploration, Development and Production Activities on Page 32 for audited information.

13. Subsequent Event — Short-term Investments

The amount of short-term investments represents the cost of such investment. Substantially all of the 1981 amount represents 1,866,000 shares of Supron Energy Corporation common stock. Approximately 1,505,000 of these shares were sold pursuant to a tender offer during the first quarter of 1982. The Company received $56,000,000 for these shares and the warrants which were exercised by other holders. The Company's gain on this first step of the merger transaction was $23,000,000.

Report of Management

The financial statements and all information in this report are the responsibility of management. The financial statements have been prepared in conformity with generally accepted accounting principles appropriate in the circumstances and, therefore, include amounts that are based on informed judgements and management's estimates. Other financial information in the report is consistent with that in the financial statements.

Management depends upon the Company's system of internal controls in meeting its responsibilities for reliable financial statements. This system provides reasonable assurance that assets are safeguarded and that transactions are properly recorded and executed in accordance with management's authorization. There are limits inherent in all systems of internal accounting control based on the recognition that the cost of such system should not exceed the benefits to be derived. The Company believes its system provides this appropriate balance.

The Company's independent accountants, Price Waterhouse, have examined the financial statements as described in their report included herein. Their role is to render an independent professional opinion on management's financial statements to the extent required by generally accepted auditing standards.

The Audit Committee of the Board of Directors, which includes a majority of directors who are not employees of the Company, is responsible for reviewing the accounting principles and practices employed by the Company and reviewing the Company's annual financial statements prior to their issuance. The Audit Committee meets periodically with the independent accountants and management to review the work of each and ensure that each is properly discharging its responsibilities. The independent accountants are entitled to call a meeting of the Committee and are invited to discuss any matters they deem appropriate, with or without management being present.

Report of Independent Accountants

To the Shareholders of
Total Petroleum (North America) Ltd.

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of income (loss) and retained earnings and of changes in financial position present fairly the financial position of Total Petroleum (North America) Ltd. and its subsidiaries at December 31, 1981 and 1980, and the results of their operations and the changes in their financial position for each of the five years in the period ended December 31, 1981, in conformity with generally accepted accounting principles consistently applied. Our examinations of these statements were made in accordance with generally accepted auditing standards and accordingly included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

PRICE WATERHOUSE

Denver, Colorado
February 5, 1982, except for Note 13 as to which the date is March 15, 1982.

Summary of Exploration, Development and Production Activities

Capitalized Costs and Net Revenues (Audited)

The information below provides additional details concerning the Company's oil and gas exploration and production activities from 1979 through 1981. The capitalized cost at the end of the year categorizes the gross cost of exploration and production properties. The cost of proved properties includes all costs for which evaluation has been completed. Unproved properties includes lease acquisition costs for properties not yet proved or abandoned plus the cost of wells drilling at the end of the year. Net revenues from oil and gas production are revenues less royalties, production expenses and windfall profit tax.

		(Thousands of U.S. dollars) Canada	U.S.	Total
Capitalized cost at December 31:	1981 - Proved properties	$144,320	$234,107	$378,427
	Unproved properties	15,661	32,736	48,397
		$159,981	$266,843	$426,824
	1980 - Proved properties	$117,914	$174,618	$292,532
	Unproved properties	31,017	34,325	65,342
		$148,931	$208,943	$357,874
	1979 - Proved properties	$ 96,129	$122,245	$218,374
	Unproved properties	29,617	20,711	50,328
		$125,746	$142,956	$268,702
Accumulated depletion at December 31:	1981	$ 27,733	$116,695	$144,428
	1980	$ 24,311	$ 81,501	$105,812
	1979	$ 17,198	$ 54,996	$ 72,194
Net revenues from oil and gas production:	1981	$ 21,903	$ 54,616	$ 76,519
	1980	$ 24,193	$ 40,305	$ 64,498
	1979	$ 20,205	$ 23,457	$ 43,662

Costs Incurred (Audited)

Property acquisition costs are those costs incurred to purchase, lease or otherwise acquire property and includes the purchase of proved properties of $30,053,000 in 1980. Exploration costs include costs of identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and carrying costs of undeveloped properties. Development costs are incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. Production or lifting costs include severance taxes and costs to operate and maintain wells and related equipment.

		(Thousands of U.S. dollars) Canada	U.S.	Total
Costs incurred in the year for:	1981 - Property acquisition	$ 3,257	$ 13,511	$ 16,768
	Exploration	17,997	23,874	41,871
	Development	4,730	20,743	25,473
	Total capitalized	$ 25,984	$ 58,128	$ 84,112
	Production (lifting)	$ 3,154	$ 11,490	$ 14,644
	1980 - Property acquisition	$ 3,387	$ 46,315	$ 49,702
	Exploration	14,028	10,919	24,947
	Development	5,770	9,089	14,859
	Total capitalized	$ 23,185	$ 66,323	$ 89,508
	Production (lifting)	$ 3,212	$ 9,689	$ 12,901
	1979 - Property acquisition	$ 3,871	$ 2,930	$ 6,801
	Exploration	9,010	7,555	16,565
	Development	7,603	6,144	13,747
	Total capitalized	$ 20,484	$ 16,629	$ 37,113
	Production (lifting)	$ 2,568	$ 7,064	$ 9,632

As indicated in Note 1, depletion is charged over the life of estimated future production on the unit-of-production method. Under this method the depletion rate per equivalent barrel is computed by dividing proved reserves into the accumulated undepleted cost of exploration and production properties and estimated future development cost. The rate per barrel is then multiplied by the equivalent barrels of sales during the year to determine the charge to expense. Natural gas reserves and sales are measured in cubic feet and then converted to equivalent barrels of crude oil based on relative energy content (six thousand cubic feet of gas equals one equivalent barrel).

		(Thousands of U.S. dollars) Canada	U.S.	Total
Depletion expense charged:				
	1981	$ 7,502	$ 35,194	$ 42,696
	1980	$ 7,153	$ 26,565	$ 33,718
	1979	$ 6,987	$ 17,089	$ 24,076
Depletion expense per equivalent barrel:	1981	$ 2.31	$ 8.83	
	1980	$ 2.07	$ 7.56	
	1979	$ 1.90	$ 5.33	

Reserve Quantities

The following table presents the estimated quantities of proved oil and gas reserves at December 31, 1978, 1979, 1980 and 1981 and details for changes in such quantities during 1979 through 1981. These estimates do not include any amounts for probable or possible reserves. Natural gas liquids are combined with crude oil quantities. The reserve quantities are before deduction for royalties. Oil quantities are expressed in millions of barrels. Gas volumes are stated in billions of cubic feet.

	Canada		U.S.		Total	
	Oil	Gas	Oil	Gas	Oil	Gas
Proved developed and undeveloped reserves -						
Reserves at December 31, 1978	26.71	213.94	7.24	62.07	33.95	276.01
Increase (decrease) in 1979 due to:						
Revisions of previous estimates	(.34)	(2.12)	.85	.84	.51	(1.28)
Extensions and discoveries	.76	12.05	.46	3.51	1.22	15.56
Production	(2.34)	(8.06)	(1.64)	(10.33)	(3.98)	(18.39)
Purchases of reserves in place	—	—	.11	3.00	.11	3.00
Reserves at December 31, 1979	24.79	215.81	7.02	59.09	31.81	274.90
Increase (decrease) in 1980 due to:						
Revisions of previous estimates	(.39)	1.26	.60	1.29	.21	2.55
Extensions and discoveries	.58	18.65	.34	5.30	.92	23.95
Production	(2.11)	(8.01)	(1.70)	(10.88)	(3.81)	(18.89)
Purchases of reserves in place	—	—	1.60	5.60	1.60	5.60
Reserves at December 31, 1980	22.87	227.71	7.86	60.40	30.73	288.11
Increase (decrease) in 1981 due to:						
Revisions of previous estimates	.38	(4.81)	.40	(.45)	.78	(5.26)
Extensions and discoveries	1.10	42.33	1.00	10.54	2.10	52.87
Production	(1.97)	(7.61)	(1.63)	(10.65)	(3.60)	(18.26)
Sales of reserves in place	(1.25)	(4.56)	—	—	(1.25)	(4.56)
Reserves at December 31, 1981	21.13	253.06	7.63	59.84	28.76	312.90
Proved developed reserves included above at -						
December 31, 1978	26.71	213.94	6.88	61.94	33.59	275.88
December 31, 1979	24.79	215.81	6.71	58.97	31.50	274.78
December 31, 1980	22.87	227.71	7.43	60.07	30.30	287.78
December 31, 1981	21.13	253.06	7.37	59.45	28.50	312.51

Proved reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions; i.e., prices and costs as of the date the estimate is made. The Company believes that its estimates are based on reasonable judgements and interpretations of available information, although it is possible that the ultimate recovery of hydrocarbons from the proved reserves will be significantly different from the quantities reported herein.

Future Net Revenues from Proved Reserves

The amounts for estimated future net revenues from proved reserves are based on prices and costs in effect at the end of 1981 which are assumed to continue for all future periods except for price escalation provisions in sales contracts. Deduction was made for royalties, severance taxes, lifting costs, windfall profits tax and future development expenditures that will be required to produce the estimated reserves. No consideration was given to income taxes nor any possible reduction in windfall profits tax as a result of application of the net income limitation on "windfall profit."

Provisions of the Canadian National Energy Program, as modified in the September 1, 1981 agreement with Alberta, were considered in determining future net revenues. The 16% Petroleum and Gas Revenue Tax levied on gross operating revenues less lifting costs has the effect of reducing total future net revenues from proved reserves in Canada approximately $112,000,000 before discount ($46,600,000 after discount). The Incremental Oil Revenue Tax, levied upon the increased "old oil" sales price allowed producers in the September 1 agreement, results in a further reduction of future net revenues in the amount of $20,900,000 before discount ($8,700,000 after discount). The value of the Company's Canadian oil and gas reserves has not been significantly increased as a result of the National Energy Program. The net revenue amounts related to Canadian reserves were translated to U.S. dollars at the exchange rate in effect at the end of the year.

Future net revenues at December 31, 1981 are estimated to be realized as follows (in millions):

	Canada	U.S.	Total
1982	$ 24.2	$ 42.9	$67.1
1983	25.5	30.7	56.2
1984	23.1	22.3	45.4
1985 and beyond	356.5	100.6	457.1
	$429.3	$196.5	$625.8

Present value (discounted at 10%) of estimated future net revenues at December 31 (in millions):

	Canada	U.S.	Total
1981	$179	$139	$318
1980	$166	$138	$304
1979	$140	$103	$243

Summary of Oil and Gas Activities

The Summary presents the results of oil and gas exploration and production activities on the basis of evaluation of discoveries, adjusted for the effects of revisions to prior year estimates and other items. Conventional financial statements measure operating profit as oil and gas revenues reduced by production expenses, depletion charges, and overhead and administrative expenses attributable to current year activities. Under Reserve Recognition Accounting (RRA) the results of oil and gas activities before taxes (the conceptual equivalent of operating profit) includes the change in present value of estimated future net revenues, thereby recognizing the economic significance of discoveries, the effects of changing prices on previously discovered reserves and accretion of value as cash flows are realized. Depletion charges are replaced by direct charges of costs evaluated during the year.

The amounts under net present value of proved reserves are calculated under procedures prescribed by the Securities and Exchange Commission (SEC) as described under "Future Net Revenues from Proved Reserves" above.

Funds Flow represents the actual costs incurred and actual net revenues received during the current year. Proceeds from sales of proved reserves are also included.

Deferred Costs adjust the Funds Flow to defer current year costs not yet evaluated and to charge previously deferred costs which were evaluated during the current year. Gains and losses resulting from purchases of proved reserves are deferred and subsequently recognized in accordance with the SEC guidelines.

Net Present Value of Proved Reserves includes the following:

- Discoveries and extensions - present value of future revenues, before deduction of future development and production costs, from proved reserves added during the current year.
- Revisions: Changes in prices - effect of change in prices on present value of reserves proved in prior years. In 1981, a decrease in U.S crude oil prices was offset by increasing gas prices.
- Revisions: Other - includes changes to reserve quantities proved in prior years, timing of production and changes in the translation rate for Canadian reserves.
- Interest Factor - represents the addition of value caused by accretion of discount and is calculated on estimated future revenues net of future development and production costs.

Provision for Income Taxes - the provision per the Funds Flow column is based upon income realized and deductions and credits allowable in the current year assuming no limitation on their utilization. The provision attributable to the Results of Oil and Gas Activities includes, in addition to the current taxes, the taxes which may become payable in future years (calculated at tax rates in effect at the end of the year) less the amount similarly calculated as of the beginning of the year.

Summary of Oil and Gas Activities on the Basis of Reserve Recognition Accounting

(in thousands)

Year ended December 31	1981				1980	1979
	Funds Flow	Deferred Costs	Net Present Value of Proved Reserves	Results of Oil and Gas Activities		
Additions to estimated proved reserves:						
Discoveries and extensions			$ 60,527	$ 60,527	$ 27,380	$ 21,629
Revisions to estimates of reserves proved in prior years-						
Changes in prices			7,216	7,216	56,199	54,042
Other			20,234	20.234	1,108	4,962
Interest factor			28,117	28,117	28,711	22,075
			116,094	116,094	113,398	102,708
Costs incurred/evaluated:						
Property acquisition (excluding purchases of proved reserves)	$(16,768)	$ 6,994	—	(9,774)	(4,985)	(5,168)
Exploration	(41,871)	4,095	—	(37,776)	(24,977)	(15,843)
Development	(25,473)	2,932	—	(22,541)	(12,794)	(13,393)
Present value of estimated future development and production costs related to -						
Discoveries and extensions	—	—	(11,829)	(11,829)	(4,765)	(3,778)
Changes in prior year estimates	—	—	(2,422)	(2,422)	(6,961)	(21,311)
Net revenues from sales of oil and gas	76,519	—	(76,519)	—	—	—
Overhead and administrative expenses	(2,306)	—	—	(2,306)	(2,161)	(2,157)
Purchases of proved reserves	—	(615)	—	(615)	(1,620)	353
Sales of proved reserves	10,818	—	(10,818)	—	—	—
Subtotal	919	13,406	14,506	28,831	55,135	41,411
Income tax provision (benefit)	(60)			18,700	28,900	19,500
Net change or amount	$ 979			$ 10,131	$ 26,235	$ 21,911
Balance, beginning of year		42,603	303,157			
Balance, end of year		$ 56,009	$317,663			

Financial Data Adjusted for Changing Prices

The financial statements included in this report are prepared on the basis of historical costs. The conventional accounting model reports the actual number of dollars received or expended without regard to changes in the purchasing power of the currency or changes in the cost of goods consumed. Depreciation and depletion charges are deducted from revenues in the calculation of net income even though the dollars expended to acquire properties in prior years had a different value, in terms of general purchasing power, than the value of revenues received in the current year. This mixing of transactions from various periods in which the dollars have differing values distorts the conventional measures of financial performance.

The accompanying schedules present the estimated effects of changing prices on certain financial information. Prices of specific goods and services change for many reasons in addition to the changes caused by the general decline in the value of the dollar. Any attempt to reflect the effects of changing prices on financial information involves the use of assumptions, approximations and estimates. Therefore, the resulting information should be regarded as an estimate of the effect of inflation, not a precise measure.

The constant dollar data adjusts the historical cost financial information to dollars having common units of measurement by use of an index which measures inflation. This price index, the Consumer Price Index for All Urban Consumers, measures the changes in the purchasing power of the dollars as such changes affect U.S. consumers as a group. The results of the approach do not purport to represent appraised value, replacement cost or any other measure of the current value of the underlying assets. The historical information was translated into average 1981 dollars.

The current cost disclosure measures the impact of changes in specific prices of inventories and property, plant, and equipment from the dates they were originally purchased to the present.

Property, Plant and Equipment

Property, plant and equipment (PPE) — computed by grouping related assets together and applying specific indices to historical costs. The costs related to exploration and production activities, approximately 40% of the PPE balance, are estimates of the amounts that would be required had past drilling and development costs been incurred at today's prices. The results do not represent the current cost of finding or purchasing a similar quantity of oil and gas reserves.

During 1981, indices most commonly used in the petroleum industry were applied to the remaining PPE, mainly consisting of refining and marketing assets, to compute a current cost which had previously been derived using fair market values. Prior year amounts have been changed to reflect the use of indices. The resulting current cost of PPE was less than that previously disclosed in 1980, due to a lower value assigned to the refineries. The current cost of PPE at December 31, 1980 computed using specific indices would have been $822,078,000 rather than $959,053,000 previously reported. The amounts of depreciation, depletion and amortization were similarly adjusted. No changes in estimated lives or computational methods as used in the historical financial statements were made in computing these amounts.

Inventory

The current cost of inventory was primarily determined from current market prices. The cost of purchased crude oil, products and merchandise did not change from historical amounts as predominantly all inventories and purchases are accounted for under the LIFO method of inventory valuation in the historical financial statements. The LIFO method charges the most recent purchases to operations and, as a result, such charges approximate current cost.

Statement of Income (Loss) from Continuing Operations Adjusted for Changing Prices

(in thousands)

Year ended December 31, 1981	As Reported in the Primary Statements	Adjusted for General Inflation (Constant Dollar)	Adjusted for Changes in Specific Prices (Current Cost)
Revenue	$2,380,538	$2,380,538	$2,380,538
Expenses:			
Purchased crude oil, products and merchandise	2,043,203	2,045,864	2,043,203
Operating	231,494	231,494	231,494
Marketing and administrative	93,381	93,381	93,381
Depreciation and depletion	68,574	86,745	89,191
Interest	67,744	67,744	67,744
Income taxes	(60,250)	(60,250)	(60,250)
	2,444,146	2,464,978	2,464,763
Loss from continuing operations	$ (83,608)	$ (84,440)	$ (84,225)
Loss per share	$ (4.12)	$ (5.34)	$ (5.32)
Increase in current cost valuation of inventory and property, plant and equipment held during the year			$ 71,976
Effect of increase in general price level			107,256
Excess of increase in general price level over increase in specific prices			$ 35,280
Current cost at December 31, 1981:			
Inventory			$ 290,497
Property, plant and equipment, net			$ 873,188

Five-Year Comparison of Selected Supplementary Financial Data Adjusted for Changing Prices

(in thousands of average 1981 dollars)

	1981	1980	1979	1978	1977
Revenue	$2,380,538	$1,770,972	$1,140,853	$797,836	$524,492
Income (loss) from continuing operations:					
Constant dollar	$ (84,440)	$ 32,390	$ 24,858	—	—
Current cost	$ (84,225)	$ 26,251	$ 20,482	—	—
Income (loss) from continuing operations per Common share:					
Constant dollar	$ (5.34)	$ 1.48	$ 1.52	—	—
Current cost	$ (5.32)	$ 1.11	$ 1.24	—	—
Net assets at year-end:					
Constant dollar	$ 505,965	$ 591,370	$ 522,592	—	—
Current cost	$ 640,208	$ 734,417	$ 573,197	—	—
Gain from decline in purchasing power of net amounts owed	$ 41,775	$ 21,479	$ 28,405	—	—
Excess of increase in specific prices over (under) increase in general price level	$ (35,280)	$ 99,225	—	—	—
Cash dividends declared per Common share	$ .40	$ .41	$ .31	$ .19	$ .07
Market price per Common share at year-end	$ 13.79	$ 23.85	$ 28.91	$ 20.31	$ 15.19
Average consumer price index	$ 272.40	$ 246.80	$ 217.40	$ 195.40	$ 181.50

Directors and Officers

Directors

Pierre Capoulade
Senior Vice President,
Compagnie Française des Pétroles,
Paris, France

Martin E. Citrin
Partner, J.A. Citrin Sons Co.,
Birmingham, Michigan

Louis Deny
Executive Vice President and Deputy Chairman,
Compagnie Française des Pétroles,
Paris, France

Philippe Dunoyer
President and Chief Executive Officer,
Denver, Colorado

Joseph-Camille Genton
Senior Vice President,
Compagnie Française des Pétroles,
Paris, France

Pierre Germes
Senior Vice President,
Compagnie Française des Pétroles,
Paris, France

Alexander D. Hamilton
Chairman and Chief Executive Officer,
Domtar Inc.,
Montreal, Quebec

Vernon L. Horte
President, V.L. Horte Associates Limited,
Calgary, Alberta

Linden J. Richards
Consultant,
Tucson, Arizona

David L. Torrey
Vice Chairman and Director,
Pitfield Mackay Ross Limited,
Montreal, Quebec

William G. Tucker
Property Investment Consultant,
Victoria, British Columbia

Principal Officers

Linden J. Richards
Chairman of the Board,
Tucson, Arizona

Philippe Dunoyer
President and Chief Executive Officer,
Denver, Colorado

Paul H. Gutknecht
Executive Vice President-Finance and Legal,
Denver, Colorado

Peter Affeld
Vice President-Corporate Development,
Denver, Colorado

Kenneth R. Buckler
Vice President-Marketing,
Denver, Colorado

Robert R. Dean
Vice President-Manufacturing,
Supply and Transportation
Denver, Colorado

Gilbert M. Kiggins
Vice President,
New York, New York

Philippe Magnier
Vice President-Exploration and Production,
Denver, Colorado

Robert A. Wall
Vice President, Secretary and
General Manager-Canadian Division,
Calgary, Alberta

William F. Kellock
Vice President Operations-
Canadian Division,
Calgary, Alberta

Donald F. West
Vice President Exploration-
Canadian Division,
Calgary, Alberta

Richard E. Dana
Treasurer,
Denver, Colorado

Ross S. Marzolf
Controller,
Denver, Colorado

Corporate Information

Registrars

National Trust Company, Limited
Calgary, Regina, Winnipeg,
Toronto, Vancouver and
Montreal, Canada

Morgan Guaranty Trust Company
of New York
New York, New York

Transfer Agents

National Trust Company, Limited
Calgary, Regina, Winnipeg,
Toronto, Vancouver and
Montreal, Canada

Morgan Guaranty Trust Company
of New York,
New York, New York

Auditors

Price Waterhouse
Denver, Colorado

Exchange Listings

Toronto Stock Exchange
Montreal Stock Exchange
American Stock Exchange
Pacific Stock Exchange

Form 10-K

Copies of the Company's annual report to the Securities and Exchange Commission on Form 10-K are available without charge upon request to the Shareholder Relations Department of the Company at P.O. Box 500, Denver, Colorado 80201, U.S.A.

Annual Meeting

Shareholders are cordially invited to attend TOTAL's Annual Meeting to be held this year at the Calgary Convention Centre, 120 9th Avenue, S.E., Calgary, Alberta on Wednesday, May 12, 1982 at 11:00 a.m.

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Investor Relations

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Refineries

Alma, Michigan
Arkansas City, Kansas
Ardmore, Oklahoma

Calgary
DENVER
Kansas City
Oklahoma City
Houston
Memphis
Alma
Milwaukee
Detroit
New York City
AREAS OF MARKETING
AREAS OF EXPLORATION
PRINCIPAL OFFICES
REFINERIES

TOTAL

Total Petroleum (North America) Ltd.
ONE DENVER PLACE, SUITE 2201
999 18TH STREET, DENVER, COLORADO 80202