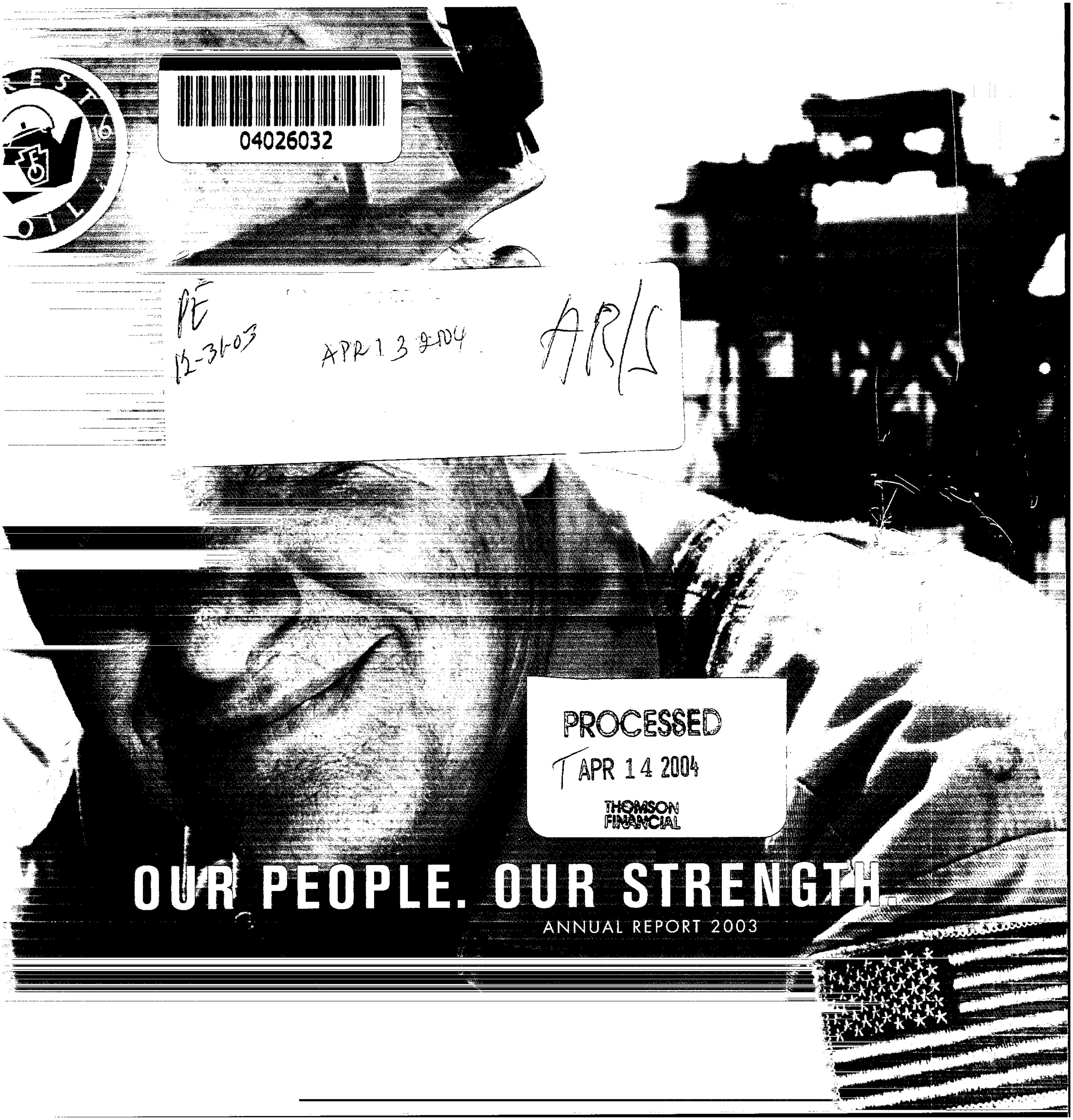


OUR PEOPLE. OUR STRENGTH.

ANNUAL REPORT 2003

Forest Oil Corporation and its subsidiaries are engaged in the acquisition, exploration, development and production of natural gas and crude oil primarily in North America. Headquartered in Denver, Colorado, the Company is among the largest independent oil and gas producers in North America.

OIL AND GAS TERMS

Many terms used in this Annual Report are unique to the oil and gas business. Listed below are several terms used in this Annual Report:

Bbls, MBbls, MMBbls, and Bbbls
Barrels, thousands, millions, and billions of barrels, respectively, of oil, condensate, or natural gas liquids.

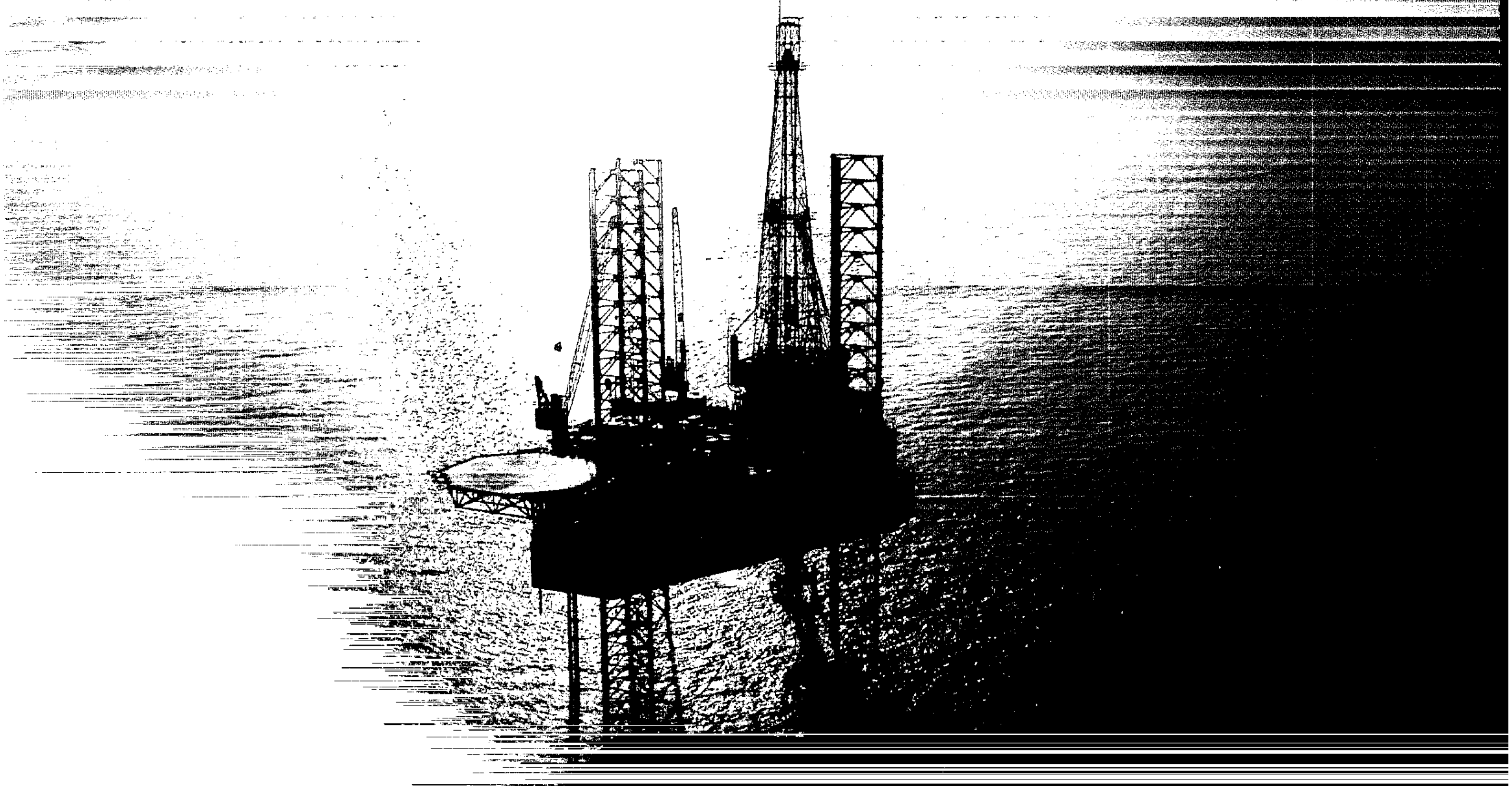
Mcf, MMcf, Bcf, and Tcf
Thousand, million, billion, and trillion cubic feet, respectively, of natural gas.

Mcfe, MMcfe, Bcfe, and Tcfe
Thousand, million, billion, and trillion cubic feet, respectively, of natural gas equivalents (1 barrel of oil = 6 Mcf of natural gas).

Front Cover: David E. Crothers, Pumper A, 11 years

CONTENTS

Forest Oil believes that if you have disciplined people, it will result in disciplined action, and disciplined action will produce predictable results.



CORPORATE STRATEGY

The people of Forest Oil are entrusted with the responsibility to grow the Company in 2004 according to the tenets of a 4-point strategy launched in the fall of 2003. First, we have strengthened our culture of cost discipline across all levels of the Company including a continued reduction in lease operating expenses, general and administrative expenses, and financing costs.

Second, we are aggressively pursuing acquisitions according to our long-term strategy for growth. A significant portion of capital was devoted to acquisitions in 2003, and this will continue in 2004. A separate section of this report outlines five significant acquisitions we closed in 2003.

Third, our investment focus has shifted away from frontier exploration toward low-risk exploitation of existing fields and proven acreage.

Fourth, Forest Oil aims to maintain liquidity to allow flexibility for acquisitions and is managing the debt portfolio to reduce refinancing risks and to minimize the cost of debt.

DEAR FELLOW SHAREHOLDERS:

The year 2003 will be remembered as a year of change for our Company, perhaps more so than at any other time in our 88-year history. Leadership changes and transitions occurred at all levels, resulting in five significant transactions and heightened well activity. Many of the year's highlights occurred in the latter part of 2003 as we, in effect, "squeezed" a year's work into several months. All of our employees worked very hard to create these accomplishments and to provide benefits to our shareholders. The pace of the change has exceeded our expectations.

FUTURE STRATEGY

We have two main goals going forward: to make money in all areas of the Company and to add value for our shareholders. We will have to work hard to establish credibility and change the Company's past poor performance.

To meet these goals, we will focus on drill bit activity, acquisitions, and cost reductions. Disciplined people taking disciplined action and making disciplined decisions will yield the desired results. We expect all areas of the Company to contribute; in our opinion, the purpose of an exploration program is production.

We strive to be the most efficient exploration and production company in our respective basins. Discipline, cost control, asset quality, innovation and timing are the key elements, achieved through the combined efforts of talented people who will ensure the successful execution of our strategy and operations. The photographs in this annual report are exclusively Forest employees. The names of our employees are listed on pages 18 and 19 in recognition of their contributions to the Company. We thank all of our employees and ask for your continued commitment to the well being of Forest Oil.

Sincerely,

Forrest E. Hoglund
Chairman of the Board

H. Craig Clark
President and Chief Executive Officer

2003 SUMMARY

- Changed leadership and reorganized departments.
- Announced a 4-point strategy in September, which is firmly in place and consistent throughout the organization.
- Maintained our discipline on cost control in operating expenses, corporate expenses and drilling costs.
- Reallocated capital and completed analyses of all business units, focusing on free cash flow and return on capital employed.
- Acquired oil and gas assets in the Gulf Coast and Permian Basin at the competitive price of $1.22/Mcfe (net of tax), which included 157,000 net undeveloped acres.
- Operated these major acquisitions immediately following the transactions, a first for the Company.
- Achieved exploration success in the Gulf of Mexico deep shelf and South Africa.
- Continued to leverage high-risk prospects throughout the Company, saving approximately $45 million of capital.
- Revised estimated proved reserves at year-end, which increased our depletion rate.
- Completed a successful equity offering.

SELECTED FINANCIAL DATA

On December 7, 2000, Forest Oil Corporation completed its merger with Forcenergy Inc. The merger was accounted for as a pooling of interests for accounting and financial reporting purposes. Under this method of accounting, the recorded assets and liabilities of Forest and Forcenergy were carried forward to the combined company at their recorded amounts on the date of the merger. Income and expense amounts reported for the combined company for 2000 include amounts attributable to the operations of both Forest and Forcenergy for the entire year. Forcenergy was merged into Forest on the date of the merger and, accordingly, all amounts attributable to periods after the merger represent the operations of the combined entities. The results of operations of Forcenergy prior to December 31, 1999, the effective date of its reorganization and fresh-start reporting, are not included in the financial statements of the combined company. Financial highlights and measurements presented herein have been prepared on this basis.

YEAR ENDED DECEMBER 31	2003	2002	2001	2000	1999
REVENUE AND EARNINGS (IN THOUSANDS EXCEPT PER SHARE AMOUNTS)					
Oil and Gas Sales	$ 655,193	471,740	714,852	623,624	189,895
Net Earnings	$ 88,351	21,276	103,743	130,608	19,043
Basic Earnings Per Share	$ 1.79	0.45	2.18	2.73	0.79
Diluted Earnings Per Share	$ 1.75	0.44	2.11	2.64	0.79
BALANCE SHEET DATA (IN THOUSANDS)					
Current Assets	$ 215,360	160,471	201,965	238,828	231,325
Total Assets	$ 2,683,548	1,924,681	1,796,369	1,752,378	1,474,689
Long-Term Debt	$ 929,971	767,219	594,178	622,234	686,153
Shareholders' Equity	$ 1,185,798	921,211	923,943	858,966	558,984
ESTIMATED PROVED RESERVES					
Natural Gas (MMcf)	808,068	813,394	828,549	844,058	825,623
Liquids (MBbls)	81,324	124,366	119,549	89,241	97,086
Total (Bcfe)	1,296	1,560	1,546	1,380	1,408
Proved-Developed (%)	75	63	61	73	76
STANDARDIZED MEASURE (IN MILLIONS)					
After-Tax Discounted Future Net Cash Flows Relating to Proved Reserves	$ 2,308	2,053	1,347	3,694	1,419
PRODUCTION					
Natural Gas (MMcf)	96,977	92,068	108,394	113,842	61,702
Liquids (MBbls)	8,701	8,657	10,600	11,427	4,397
Total (Bcfe)	149	144	172	182	88
DRILLING ACTIVITY (NET)					
Exploratory Wells – Productive	10.3	2.6	48.6	34.1	6.7
Exploratory Wells – Dry	6.4	5.8	7.3	9.7	4.1
Development Wells – Productive	35.7	26.5	6.1	8.9	5.1
Development Wells – Dry	5.9	3.0	1.3	—	—
TOTAL ACREAGE					
Gross Acres	22,578,097	23,259,867	22,575,018	29,486,206	62,050,698
Net Acres	14,101,404	14,603,671	15,701,110	19,662,094	34,513,178

FINANCIAL MEASUREMENTS

CAPITAL EXPENDITURES — Measures total investment in growth assets, including capitalized general and administrative expenses.

RESERVE ADDITIONS — The estimated amount of oil and gas added to proved reserves through acquisitions, exploration, and development activities, net of revisions.

THREE YEAR AVERAGE FINDING COSTS — Measures a company's historical cost of adding proved reserves through acquisitions, exploration and development activities averaged over a three year period.

PROVED RESERVES — Estimated quantities of oil and gas in the ground that have been demonstrated to be recoverable in future years from known reservoirs under existing economic and operating conditions.

RESERVE LIFE — At previous year's production rates, indicates how long it would take to produce all of a company's estimated proved reserves if no new reserves were added.

PROVED DEVELOPED — Proved developed oil and gas reserves as a percentage of total proved reserves. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

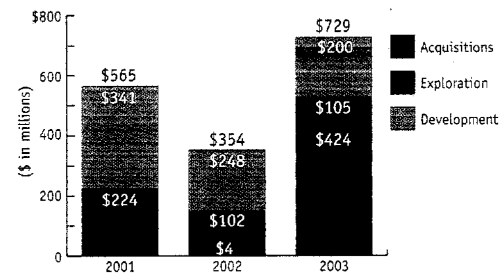
DEBT TO EBITDA — Ratio of a company's long-term debt to net earnings from continuing operations before income taxes, depreciation and depletion, impairments, and accretion.

EBITDA/INTEREST — Ratio of a company's net earnings from continuing operations before income taxes, depreciation and depletion, impairments and accretion, to interest payments.

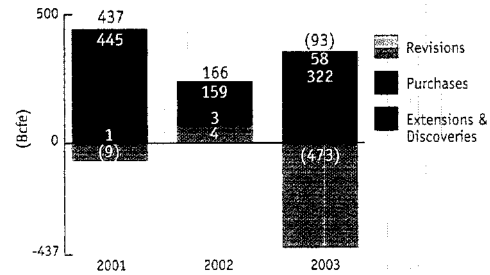
EBITDA — Net earnings from continuing operations before income taxes, depreciation and depletion, impairments and accretion.

CASH FLOW — Net cash provided by operating activities before changes in working capital.

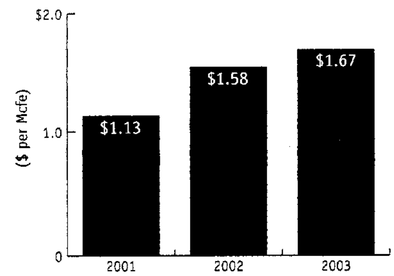
CAPITAL EXPENDITURES



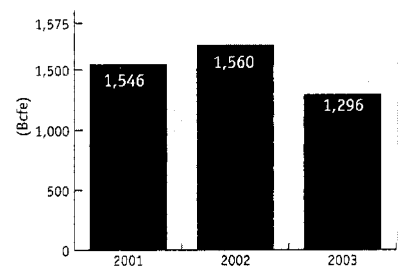
RESERVE ADDITIONS



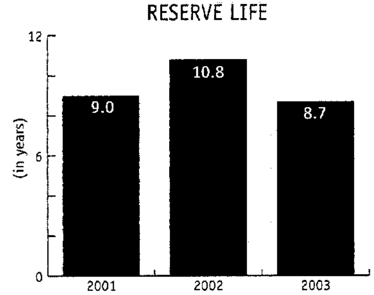
THREE YEAR AVG. FINDING COSTS



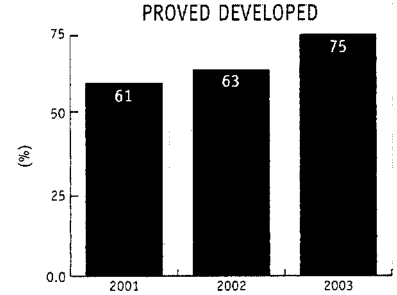
PROVED RESERVES



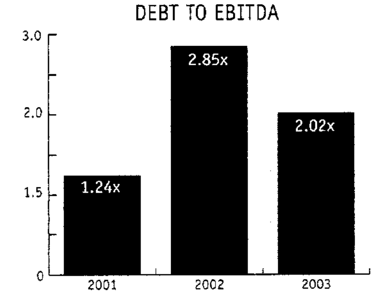
RESERVE LIFE



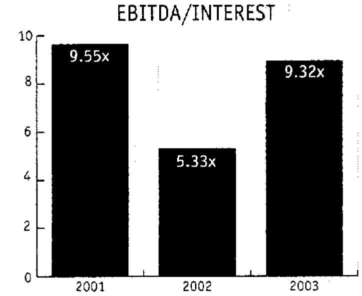
PROVED DEVELOPED



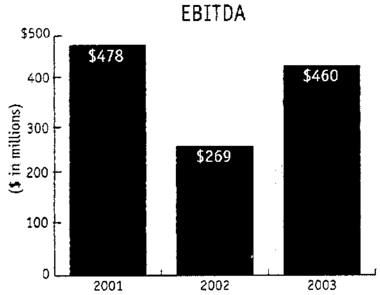
DEBT TO EBITDA



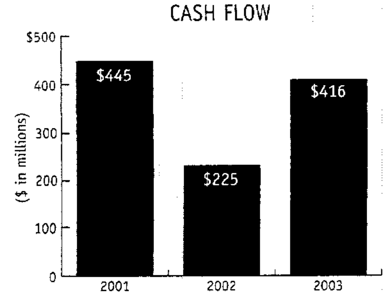
EBITDA/INTEREST



EBITDA



CASH FLOW



Dan A. Daigle, Production Foreman, 34 year

GULF COAST BUSINESS UNIT

Forest Oil merged its Onshore and Offshore Business Units in early 2003 to create the Gulf Coast Business Unit, a move designed to reduce costs and improve efficiencies. This Business Unit is the largest in the Company and "leads the way" in terms of free cash flow generation and return on capital employed. In line with our new strategy and corporate acquisitions initiative, Gulf Coast was the most active business unit in 2003, growing by over 30 percent. Its employees maintained their history of "bottom-line" commitment and goal orientation by setting record production levels, reducing lease operating costs and providing free cash flow in excess of $200 million, which funded their acquisition program.

2003 HIGHLIGHTS

- For the second consecutive year, Gulf Coast achieved reductions in both operating expenses and overhead costs while becoming increasingly efficient on a per unit basis.
- Total net acreage grew by over 75 percent and net undeveloped acreage by over 190 percent.
- The Vermilion 102 #1 well drilled in the first quarter of 2003 came on-line at 15 MMcf/d and 240 Bbls/d.
- In the Gulf of Mexico deep shelf, the South Timbalier 72 #21 well was drilled to a total depth of 19,025 feet and had first production only 90 days from spud at a rate of 2,000 Bbls/d and 1.2 MMcf/d. The West Cameron 112 #1 wildcat was subsequently drilled to 16,000 feet and recently tested 15 MMcf/d and 300 Bbls/d.
- Other Gulf of Mexico successes include Eugene Island 325, High Island 116 and High Island 53. The new facilities at Eugene Island 273 and West Cameron 112 discoveries will come on-line in 2004.
- Production from the Bonus Area in South Texas increased from 4 to 16 MMcf/d and the McAllen Ranch Field in Texas had its net production triple from 4 to 12 MMcf/d.
- Production increased in the Katy Field from 15 to 22 MMcf/d following a successful recompletion and deepening program. More work is planned for 2004 following the acquisition of 3-D seismic.

FUTURE STRATEGY

- The properties acquired in 2003 will be our primary focus for exploitation and development in 2004.
- Gulf Coast will concentrate on exploitation and low risk projects on the shelf in the Gulf and onshore, which provide a solid base for production, cash flow and future rig activity.
- We will further capitalize on enhanced margins from higher commodity prices and favorable relationships with service providers.
- Continued consolidation will add to our cost and operational efficiencies.

Stephen W. Rawlings, Production Manager, 3 year

WESTERN BUSINESS UNIT

The Western Business Unit, which operates some of Forest's most mature producing fields, is now the second largest Business Unit in the Company. A combination of increased capital allocation, increased operational capacity and targeted acquisitions has contributed to this growth. During 2003, activity in the Western Business Unit diversified beyond the Rocky Mountain gas program into the Mid-Continent and, more specifically, the Permian Basin. The Business Unit continues to yield an attractive return on capital employed and to generate free cash flow, which funded the Oxy-Permian acquisition in West Texas. The employees of the Western Business Unit, working in conjunction with the corporate functions, are credited with the smooth integration of the newly acquired properties in West Texas and New Mexico.

2003 HIGHLIGHTS

- The Western Business Unit grew its year-end estimated proved reserves by almost 23 percent and its year-end production by 19 percent. Our operated position in the Permian Basin grew significantly with the acquisition of producing fields from Oxy-Permian and a private Permian operator, in addition to taking over operations on seven fields where Forest owned a 70 percent working interest.

- The Western Business Unit had its most active drilling year ever with 33 gross wells drilled during 2003.

- The Apollo Field in Winkler County, Texas, grew from a divestiture candidate to the best producing field in the Business Unit, increasing from 1 to 16 MMcfe/d. Positive results were also achieved in the Vermejo Field where production increased from 6 to 9 MMcfe/d.

- Our Oxy-Permian acquisition was funded with free cash flow and provided over 150 percent reserve replacement in the Business Unit. Production has increased and operating costs are lower since the property was acquired in late 2003.

- Activity escalated in the Wild Rose area of Southwestern Wyoming to increase gas production and to take advantage of a cost efficient multi-rig, multi-well program. A total of 16 wells were drilled and completed in 2004.

- Our year-end net daily production and active rig count set all-time records for this region.

FUTURE STRATEGY

- Success in fields like Apollo and Vermejo has generated optimism for our existing property base as well as for the newly acquired properties. In 2004, we plan to exploit our acquisitions by installing long-awaited waterfloods while managing costs and margins.

- We expect the Western Business Unit to continue to be a free cash flow generator with additional enhancement acquisitions targeted throughout the Business Unit.

- Due to the maturity of the Western region basins, advanced technology will be of benefit in exploitation involving artificial lift, stimulations, workovers, recompletions, secondary recovery and development drilling.

- Our goal is to further consolidate operations in our current basins and to grow activity starting with our undeveloped acreage in the Rocky Mountains and Mid-Continent areas.

Ted Kramer, Production Manager, 3 yea

ALASKA BUSINESS UNIT

For the past several years, the primary focus of the Alaska Business Unit has been the exploration and development of the Redoubt Shoal field in the Cook Inlet. Disappointing results at Redoubt led us to redirect capital to other projects and other regions in 2003. Despite the Redoubt results, Alaska remains an excellent area for hydrocarbon exploration, asset exploitation, cost control and consolidation. In 2003, the Alaska Business Unit transitioned from an oil exploration program to an organization focused on all of its assets. We are committed to water injection implementation and enhancement as well as to natural gas opportunities. Our large acreage position should prove beneficial for future activity both offshore and onshore, and for oil and gas exploration.

2003 HIGHLIGHTS

- The Kustatan onshore facilities were completed on-time and became fully operational in 2003. The facilities utilize innovative designs to minimize air emissions and discharge while generating electricity for our own needs.
- Operating costs were lowered on a per unit basis, which caused the Alaska Business Unit to join the ranks of "cost cutters" across the Company.
- Following the completion of the Redoubt facilities, our capital expenditures were reduced by almost 60 percent from the previous year.
- The Alaska Business Unit had record production in 2003, exceeding the 2002 levels by five percent. Lower activity on our non-operated fields offset some of the production gains on operated properties.
- All operations were completed without a lost-time accident or major spill. Forest continues to work closely with local groups and regulatory agencies such as the United States Coast Guard and State of Alaska.

FUTURE STRATEGY

- Capital expenditures will be minimized in 2004 while focusing on secondary recovery and exploitation opportunities. The Business Unit is expected to become a free cash flow generator for the first time in 2004.
- Upon expiration of our long-term drilling rig contract for the Redoubt project, we installed a smaller, less expensive hydraulic rig to perform our remedial and rework activity cost-effectively.
- Although costs were lowered from the prior periods, this Business Unit still remains the highest cost area in the Company on a per unit basis, which means cost control on all fields will remain a priority, particularly the non-operated properties.
- We expect to take advantage of our large undeveloped acreage position to form partnerships while shifting our focus from offshore oil accumulations to onshore exploration opportunities. The expanding gas market in Southern Alaska is expected to benefit Forest in the near term.
- Multi-disciplinary teams will be assembled for all future exploration projects by incorporating company-wide resources and "importing" technology from other areas.

David M. Anderson, Plains Team Lead, 5 yea

CANADA BUSINESS UNIT

Our transition of the Canada Business Unit away from a high-risk, exploration dominated capital program to a more diversified portfolio with less inherent risk is nearly completed. Canada self-funded its capital program and generated free cash flow for the second consecutive year while managing to drill twice the number of gross wells in 2003 than it did in 2002. Even though the Canada Business Unit operates in an adverse weather environment, Canada continues to report some of the lowest operating costs in the Company. The transition process and recent results speak to the determination and flexibility of our employees in this Business Unit.

2003 HIGHLIGHTS

- We drilled 39 gross wells, reflecting high overall activity while concentrating more heavily in the Plains and Foothills areas.
- Production from our Narraway field reached a record level at 33 MMcfe/d, making it our best producing field in Canada. Our program was highlighted by the Narraway 3-24 and 11-23 wells, both of which had initial production rates of 14 MMcfe/d.
- Our Plains activity was highlighted by 15 wells drilled in the Kaybob, Herrington and Pembina areas. The shallow Kaybob development program increased our net production from 1 to 8 MMcf/d.
- Progress was made on the proposed pipelines serving the Mackenzie Delta and Mackenzie Valley areas where Forest has acreage and discoveries.
- Exited the gas marketing business with the sale of our Canadian subsidiary, Producers Marketing, Ltd.

FUTURE STRATEGY

- Generating free cash flow, improving return on capital employed and achieving greater cost efficiencies will continue as priorities in 2004.
- Local staff has been added to insure that acquisitions will play a greater role in the growth of the Canada Business Unit.
- Although our drilling program will diversify over time, the 2004 program will focus primarily on basins in the Plains and Foothills areas. These regions contribute most of Canada's net production and will therefore receive a more equitable distribution of manpower and capital expenditures.
- Exploration activity will focus on extending our Foothills success, particularly in the Narraway area, and developing the southern portion of the trend in the Waterton area. Additional 3-D seismic will be acquired.
- Our undeveloped acreage position in Canada, which approximates our position in the lower 48 states and Alaska combined, will provide opportunities for partnerships, leveraged drilling or exchanges.

Arthur P. Bills, Director-Business Development & Negotiations, 3 years

INTERNATIONAL BUSINESS UNIT

Consistent with our strategy to limit frontier exploration, the International Business Unit has narrowed its focus to two primary plays: offshore Africa (South Africa and Gabon) and basin-centered gas in Europe (Romania, Germany and Italy). We will continue to utilize our large undeveloped acreage position to leverage our exploration and reduce our capital exposure; we will also seek strategic partners for participation, trades or sales. The International Business Unit has been very successful in locating partners and extracting value from its assets. Their cooperation with our other Business Units has resulted in advantageous technology exchange, particularly in the area of drilling engineering.

2003 HIGHLIGHTS

- We drilled a total of four wells offshore Gabon and South Africa at no cost to Forest, retaining a 45 to 53 percent working interest, while our partners spent approximately $35 million during 2003.
- We established strategic partnerships with two companies in Germany.
- Our 4-well exploration program in South Africa yielded both exploration success and drilling cost reductions of over 40 percent.
- We signed an agreement with PetroSA for their equity participation in our gas prospects in South Africa and for future gas sales.
- We acquired 100 percent of Gabon concessions.

FUTURE STRATEGY

- Our biggest priority in 2004 is to return value to the corporation.
- Near-term drilling will focus on gas plays in Romania and Italy.
- We will continue to evaluate our large Gabon acreage position.
- Our focus in South Africa will be gas commercialization. Additional seismic interpretation will be done in both the shallow and deepwater acreage.

ACQUISITION STRATEGY

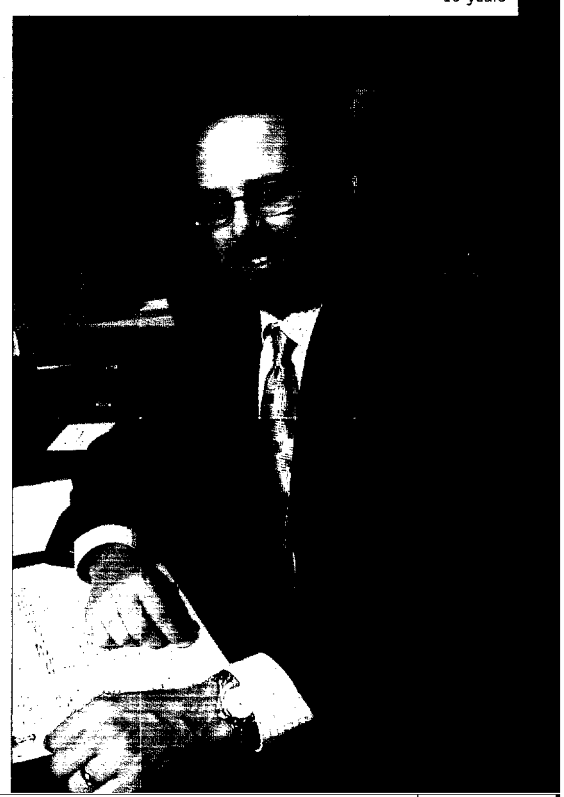
This year represents the first time the Company has devoted a separate section to Acquisition Strategy in our Annual Report. This decision reflects the critical role acquisitions played in the Company's growth this past year, and are expected to play in the years ahead. Acquisitions are a major component of our 4-point strategy and are viewed as one of the primary means of increasing the value of this Company for its employees and shareholders.

The corporate decision to aggressively pursue acquisition opportunities in 2003 led to five significant transactions in the last half of the year under the direction of our new acquisition team. The Company added properties with a total initial production of 110 MMcfe/d and estimated proved reserves of 322 Bcfe at a combined purchase price for the oil and gas properties of $391 million (net of tax). Included in these transactions was an additional 376,000 net acres, almost half of which are undeveloped.

Most notable among the 2003 purchases was an acquisition of Gulf Coast onshore and offshore properties for a purchase price of $219 million, closing on October 31, 2003. Pipeline assets, gas plants, an onshore separation facility, a farm-out option and a hedging "true-up" concept were included in the transaction. In total, these properties, at closing, provided an immediate 30 percent production growth and 24 percent reserve growth for the Gulf Coast Business Unit. At the time, this acquisition placed Forest Oil in the top ten of approximately 260 Gulf Coast operators, making us the third largest shelf acreage holder and sixth largest shelf producer.

Two separate 2003 transactions provided the Company 58,000 acres in the Permian Basin in West Texas and New Mexico, and two others increased our activity in the South Bonus and McAllen Ranch fields of South Texas. In every situation, we assumed immediate control of the acquired properties and expeditiously integrated their operations into our programs. In keeping with our 4-point strategy, Forest Oil will actively pursue acquisition opportunities in each Business Unit in 2004.

David H. Keyte, Executive Vice President and Chief Financial Officer, 16 years



OPERATIONAL FACT SHEET

GULF COAST

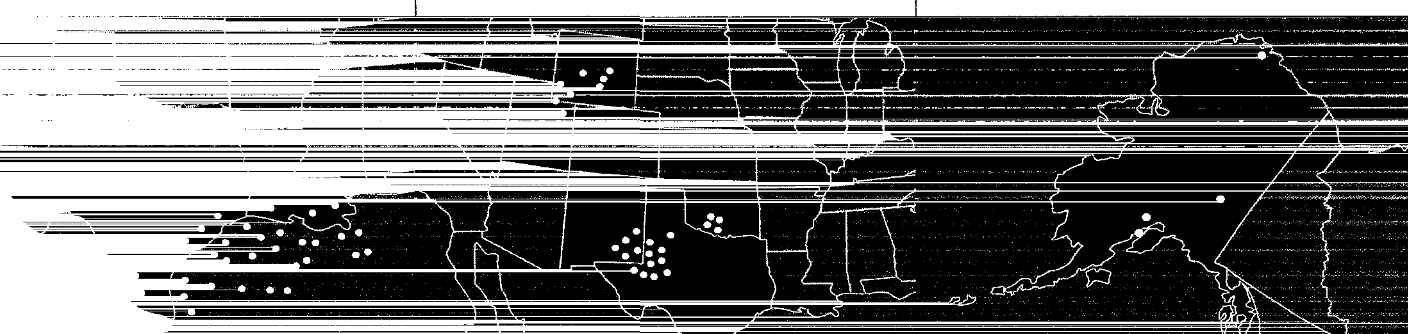
	2003	2002	2001
NET PRODUCTION			
Gas (Bcf)	69.2	62.8	82.6
Liquids (MMBbls)	3.0	3.0	4.4
ESTIMATED PROVED RESERVES			
Gas (Bcf)	473.2	434.5	467.9
Liquids (MMBbls)	23.5	25.8	26.1
DEVELOPED ACREAGE			
Gross	1,058,316	731,509	712,784
Net	482,651	337,766	367,225
UNDEVELOPED ACREAGE			
Gross	416,177	188,197	258,116
Net	306,648	104,130	175,101
GROSS WELL COUNT			
Gas	475	416	431
Oil	360	280	215
CAPITAL EXPENDITURES In thousands			
	$412,072	$115,256	$316,536

WESTERN

	2003	2002	2001
NET PRODUCTION			
Gas (Bcf)	15.2	15.8	14.7
Liquids (MMBbls)	1.2	1.2	1.4
ESTIMATED PROVED RESERVES			
Gas (Bcf)	206.7	217.8	195.2
Liquids (MMBbls)	30.3	16.6	17.1
DEVELOPED ACREAGE			
Gross	312,958	253,222	261,949
Net	98,636	63,837	51,570
UNDEVELOPED ACREAGE			
Gross	251,999	231,515	155,012
Net	114,926	118,687	91,424
GROSS WELL COUNT			
Gas	535	222	208
Oil	1,435	356	418
CAPITAL EXPENDITURES In thousands			
	$193,014	$37,578	$45,333

ALASKA

	2003	2002	2001
NET PRODUCTION			
Gas (Bcf)	-	-	-
Liquids (MMBbls)	3.5	3.3	3.4
ESTIMATED PROVED RESERVES			
Gas (Bcf)	10.3	26.1	5.6
Liquids (MMBbls)	20.2	75.1	67.8
DEVELOPED ACREAGE			
Gross	305,030	312,606	282,099
Net	37,379	26,708	13,686
UNDEVELOPED ACREAGE			
Gross	1,438,220	1,457,145	167,912
Net	1,208,798	1,243,753	161,529
GROSS WELL COUNT			
Gas	1	1	1
Oil	921	1,060	1,031
CAPITAL EXPENDITURES In thousands			
	$68,933	$163,836	$106,260



GULF COAST — 2003 HIGHLIGHTS

- Achieved organic production growth by spending just 39% of 2003 cash flow
- Reduced production expense by over 15% on a per unit basis
- Achieved 100% success rate in the deep shelf drilling program

GULF COAST — 2004 PLANS

- Focus on acquired properties for exploitation and development
- Continue with highly successful workover and recompletion programs
- Continue consolidation to further reduce costs and enhance operational efficiencies
- Concentrate exploration program on deep shelf inventory

WESTERN — 2003 HIGHLIGHTS

- Achieved record reserves and net daily production at year-end
- Created new "core" area in the Permian Basin
- Successfully integrated newly acquired properties in West Texas and New Mexico

WESTERN — 2004 PLANS

- Focus on acquired properties for exploitation and development
- Continue to focus on our new "core" area, the Permian Basin, for exploitation and consolidation efforts
- Increase activity on our undeveloped acreage in the Rocky Mountains

ALASKA — 2003 HIGHLIGHTS

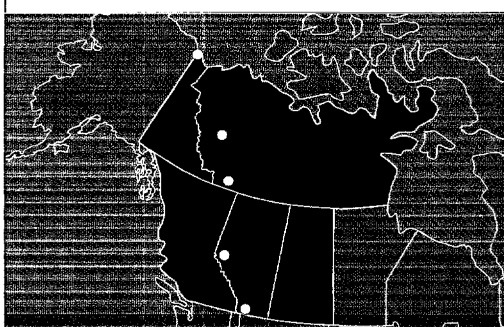
- Completed Kustatan onshore facilities on-time
- Reduced per-unit operating costs
- Reorganized business unit management

ALASKA — 2004 PLANS

- Focus on generating free cash flow
- Reduce costs in all fields
- Focus exploration program on shallow onshore gas

CANADA

	2003	2002	2001
NET PRODUCTION			
Gas (Bcf)	12.6	13.5	11.0
Liquids (MMBbls)	1.0	1.2	1.4
ESTIMATED PROVED RESERVES			
Gas (Bcf)	117.9	135.0	159.8
Liquids (MMBbls)	7.3	6.9	8.6
DEVELOPED ACREAGE			
Gross	209,189	210,475	262,387
Net	102,887	106,657	126,240
UNDEVELOPED ACREAGE			
Gross	1,419,937	1,238,150	1,637,479
Net	794,722	534,380	735,448
GROSS WELL COUNT			
Gas	231	215	209
Oil	346	332	270
CAPITAL EXPENDITURES In thousands			
	$46,518	$21,286	$63,193



2003 HIGHLIGHTS

- Achieved record production in our Narraway Field
- Implemented an exploitation program for our Plains area

2004 PLANS

- Continue to focus on generating free cash flow
- Drilling program designed to exploit and develop our Plains area
- Exploration program to focus on the Narraway and Waterton areas in the foothills
- Evaluation of acquisition opportunities

INTERNATIONAL

	2003	2002	2001
EUROPE: UNDEVELOPED ACREAGE			
Gross	5,770,549	5,961,546	6,161,778
Net	3,377,834	3,809,268	4,383,253
WEST AFRICA: UNDEVELOPED ACREAGE			
Gross	11,395,722	12,675,502	12,675,502
Net	7,576,923	8,258,485	9,595,634
CAPITAL EXPENDITURES In thousands			
	$8,211	$16,264	$33,339

2003 HIGHLIGHTS

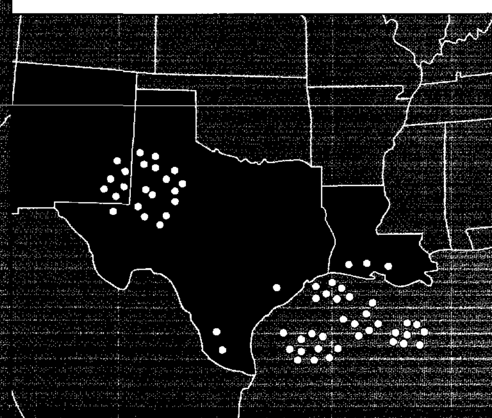
- Completed a successful drilling program in South Africa
- Participated in drilling expenditures of $35 million with a full carry

2004 PLANS

- Focus on gas commercialization in South Africa
- Farm-out prospects to bring value forward while limiting capital exposure

ACQUISITIONS

	2003	2002	2001
NET INITIAL PRODUCTION			
Gas (MMcfe/d)	68.0	0.6	0.4
Liquids (MBbls/d)	7.0	-	-
ESTIMATED PROVED RESERVES ACQUIRED			
Gas (Bcf)	162.1	2.2	0.9
Liquids (MMBbls)	26.6	0.1	0.1
DEVELOPED ACREAGE ACQUIRED			
Gross	375,776	70,066	-
Net	193,252	5,706	1,216
UNDEVELOPED ACREAGE ACQUIRED			
Gross	220,592	91	-
Net	172,155	1	-
ACQUISITION EXPENDITURES In thousands			
	$424,245	$3,925	$31



2003 HIGHLIGHTS

- Completed five significant transactions that added estimated proved reserves of 322 Bcfe for $1.22 per Mcfe
- Reorganized management of the acquisition effort

2004 PLANS

- Continued to focus on acquisition effort
- Areas of interest include Texas, Rocky Mountains, Gulf Coast and Canada

FOREST OIL TEAM
(AS OF MARCH 15, 2004)

Abshire, Carl E.
Accardo, Zachary L.
Accettura, Roccine H.
Ace, Linda S.
Agrawal, Bipin K.
Alderete, Alfred
Aldrich, Jeffrey B.
Alexander, Gregory
Alexander, Jane B.
Alfeld, Stephanie
Alpaugh, B K.
Amundsen, John D.
Anctil, Mark
Andersen, Craig L.
Anderson, Dave M.
Anderson, Gene W.
Andrus, Ted S.
Archer, Andrea R.
Arlington, James D.
Ash, John D.
Barkley, Sherry L.
Baumbach, Linda A.
Baxter, Robert E.
Beard, Charles R.
Beck, Jonathan F.
Becker, Sheree L.
Beery, Nancy J.
Beeson, Beverly A.
Bell, John D.
Bell, William P.
Berge, Timothy B.
Berkeland, Garth W.
Bernard, Stephanie A.
Bertinot, Sabra S.
Bertrand, Adam D.
Bills, Arthur P.
Blair, James M.
Bloom, William R.
Bobbett, Gregory C.

Boger, Cindy J.
Bolen, James R.
Booker, Colleen E.
Books, Aaron
Boubede, Rhonda A.
Boudreaux, John M.
Bourbonnais, Lise A.
Bravo, Alan E.
Brazeal, Danny D.
Bretz, Christine
Brice, Bradley W.
Brooks, Charles S.
Broussard, Garrett P.
Broussard, Janet R.
Bryan, Anderson L.
Buchanan, Russell W.
Budde, Roberta L.
Bush, Mark E.
Buur, Peter
Caple, John W.
Carriere, Michael
Carswell, James W.
Cart, Glenn J.
Cart, Jonathan C.
Cartwright, Jimmy G.
Casias, Melody A.
Casteel, Shane P.
Cavalier, Patrick J.
Chandler, Colleen M.
Charles, Shirley H.
Chatara, Katharine C.
Chatman, Maria T.
Christensen, Nicole Marie
Christiansen, Darrell
Clark, H. Craig
Clay, Floyd
Cochran, Mark D.
Cogley, Richard C.
Colby, Douglas D.

Colwell, Cecil N.
Compton, Ronald
Cook, Delbert W.
Cook, Shelley
Copeland, W D.
Cormier, Eugene L.
Cormier, Jack
Coutts, Heather M.
Couvillon, Terry M.
Crane, Douglas R.
Cranford, Daniel G.
Criger, Julie A.
Crosby, Ronald A.
Crothers, David E.
Culverhouse, Nancy K.
Daigle, Donald A.
Davis, James D.
Dawson, Julie A.
Day, Leonard J.
Dellva, Paul E.
Deriabina, Olga V.
Dern, Michael J.
Detrich, Janice K.
Dial, Thomas R.
Dicken, Elaine
Dillehay, Arthur C.
Dodge, Karen G.
Domingue, Jesse H.
Dorn, Forest D.
Dorn, Frederick M.
Doucet, Ronald J.
Douget, Randal K.
Dowell, Lorrie C.
Downey, Billy L.
Dunn, Patricia A.
Duplechin, Darrel J.
Durham, Nonya K.
Dusha, Paul J.
Dykstra, Tjeerd D.

Eichmann, Rolf
Ellington, Michael L.
Ellis, Marcia A.
Ellison, Jim E.
Enright, Christopher M.
Ewing, Kirk J.
Fagan, Rebecca L.
Farris, Marsha A.
Fawvor, James K.
Fenton, Karen
Ferdais, Ryan D.
Fischbach, Mitch G.
Fitzgerald, Carrie A.
Fletcher, Vernon
Folvag, Mary D.
Fontenot, James P.
Fontenot, Larry E.
Fountain, James A.
Friesell, Regina M.
Fruge, Paul C.
Gaddis, Bennie
Gallucci, Tina
Garcia, Emelda S.
Gareau, Carmen A.
Gill, John D.
Gill, Leslie R.
Girouard, Carlos J.
Girouard, Rachel K.
Glenn, Michael L.
Godes, Terry J.
Godfrey, Stephen J.
Gonzales, Gerald
Gonzales, Pascasio S.
Good, James R.
Good, Matthew R.
Goss, Peggy J.
Grant, Clay W.
Greer, Donald W.
Gremban-Hobson, Sheree L.

Grenn, R. M.
Grosswiler, Martha L.
Groundwater, Brian
Grover, Vickie
Guidry, Kevin G.
Gurule, Leonard C.
Guynn, Peter C.
Hall, David M.
Hanes, Marcia A.
Harford, Scott A.
Harpham, Stephen T.
Harrington, A. G.
Harris, Alison R.
Harris, Mary L.
Hatcher, Rick L.
Hawkins, Jennifer A.
Hea, Robert G.
Hebert, Darrell J.
Hebert, David P.
Hebert, Leon E.
Hebert, Michael S.
Heim, Corinne J.
Hendry, Cheryl L.
Henningsen, Gregory
Hess, Scott A.
Hetzel, Allan P.
Hoffmaster, Margaret A.
Hofmann, Tami L.
Holberton, Jim
Holmes, Bill
Hornung, Jackie L.
House, Edward J.
Hutchinson, John E.
Hutnik, Frank A.
Inman, Paula R.
Jackson, Janet M.
Jackson-Reardon, Emily E.
Jaynes, Earl F.
Jaynes, Evelyn L.

Jones, Donald G.
Jordan, Marty D.
Joseph, Erin K.
Kennedy, Michael N.
Kenny, Thomas E.
Keyte, David H.
Khwajazada, Shellene K.
Kidder, Jr. Raphael F.
Killingsworth, Robert B.
Kiloh, Kirk D.
King, Ty M.
Kirkland, Gregory L.
Kjelmyr, John P.
Klein, John P.
Knell, James W.
Knight, Rick E.
Kocourek, David J.
Kramer, Ted E.
Kranker, Steven A.
Kriser, Linda S.
Kriskovich, Diane R.
Kruk, Barbara A.
Kulick, Jeffrey C.
Kunz, Theodor J.
Ladner Sr., Phillip W.
Landry, Gil J.
Lavergne, Janet H.
Lawson, Linda S.
Lejeune, David C.
Lindsey, Charlotte A.
Linzell, Lynn M.
Little, Pamela
Longenbaugh, S. J.
Lopez, Carl J.
Louis, Roberta L.
Luszcz, Victor J.
Mahaffie, Deon K.
Major, Roger L.
Manderson, Neville J.

Maniscalco, James A.
Marano, Teresa J.
Marie, Lisa Q.
Marter, Cyrus D.
Martin, Cheryl A.
Martinez, Davyna J.
Massett, Tina Marie S.
Matsinger, Michael J.
Matthews, Ross
Maxwell, Joyce T.
Mayberry, Mark D.
McCartney, Michelle M.
McCauley, Mary K.
McClaren, Michael S.
McClurg, Caroline M.
McGee, Cullen P.
McIntyre, John F.
McKnight, Terrell M.
McNutt, Jerry L.
McPhee, Kenneth A.
Meany, Ronda A.
Meiklejohn, Douglas L.
Mello, Michael C.
Mercer, Vicki L.
Mericle, Kathy A.
Miley, Barry G.
Miller, Carol A.
Miller, Dennis W.
Miller, Donna R.
Miller, Russell D.
Mitchell, Gary C.
Mitchell, Jerry W.
Mitten, Elisabeth
Mizenko, Glen J.
Molis, Misty
Moore, David
Morrow, Norvin W.
Morton, Kimberly C.
Mote, Danny N.
Munoz, Raul R.
Munro, James G.
Murphy, Patricia A.
Murphy, Patrick
Murray, Michael R.
Myers, Billy R.
Neal, Daniel L.
Newstead, James E.
Newth, Sandra W.
Nguyen, Michael H.
Norman, James L.
Novotney, Maria E.
Nugent, Charles F.
Oakes, Chandler A.
O'Keefe, Timothy F.
Oliver, Donald L.
Olson, Judy M.
Olson, William A.
Ortiz, Julian C.
Ouellette, Donald P.
Packard, Robert W.
Palmerton, Margaret J.
Parks, Leigh R.
Paton, Roger L.
Paxton, Tom L.
Pearson, Bobby G.
Perrin, Kelly P.
Perry, William R.
Peterson, James B.
Petraske, Arthur K.
Picou, Phillip P.
Pochatko, Nancy S.
Poletto, Grazia
Polidore, John R.
Porter, John D.
Poscente, Clelia R.
Pottenger, Deborah S.
Poudyal, Mani R.
Pouncey, David A.
Pousson, James W.
Prahl, Cal A.
Price, Karen A.
Prout, Patrick L.
Quint, Thomas A.
Ragland, Ronald D.
Rahming, Marc B.
Rains, Russell R.
Randall, Greggory K.
Rankin, Dian
Rasey, Charles A.
Rawlings, Stephen W.
Reagan, Deborah J.
Redmond, Patrick J.
Reeve, Milton D.
Reeves, Jeffrey A.
Regan, Eugene L.
Reinhardt, Dallas
Reinhardt, Nancy M.
Richard, Francis P.
Richardson, Philip J.
Richter, Richard A.
Ritchie, Willliam
Roben, Linda A.
Roberts, Angelo
Roberts, John W.
Robertson, David
Robson, Polly A.
Rogers, Rickey
Rogge, Elizabeth A.
Rogowski, Christine M.
Ross, Nancy F.
Rost, Alda A.
Rothe, Lindy S.
Rust, Marilyn G.
SaBell, Dennis W.
Sabrier, Steven L.
Sadler, Jannine L.
Saiz, Ismael
Saltmarsh, Arthur C.
San Nicolas, Lynnette E.
Savoy, Timothy F.
Schamberger, Faith G.
Schelin, Richard W.
Schmidtberger, Travis L.
Schnake, Carl A.
Schuh, Julie M.
Scofield, Yvonne M.
Seal, Craig A.
Senn, Kathryn W.
Shiflett, Ned O.
Shockley, Catherine V.
Shorey, Barbara A.
Simar, John D.
Simmonds, Marc S.
Simmons, Alvin L.
Sipfle, Kenneth A.
Sirbin, Jane E.
Skelton, Debra A.
Skizinski, Meredith L.
Slade, Mark A.
Slechta, John J.
Small, Carolyn M.
Smith, Kenneth
Smith, Victor G.
Smith, Willie B.
Sniatynski, John A.
Sonnen, Joan C.
Sorensen, Richard A.
Spangler, Carl M.
Sparks, Royce G.
Srikijkarn, Kay G.
St. Peter, Andrea S.
Stahl, Lauretta E.
Stanczyk, Mark F.
Starr, Linda M.
Statham, Kenneth F.
Stecyk, Kenneth J.
Stenmark, Lizbeth J.
Stevenson, Christopher M.
Stiles, William
Stonecipher, Roy E.
Stoute, Anthony C.
Stoutes, Greg W.
Strachan, Greg
Strauss, Mary M.
Stupnyckyj, Oleh
Styron, Shannon O.
Sutton, Christopher R.
Sutton, Daryl E.
Sweet, Gregory L.
Sweetman, Sandy L.
Tarman, Barry L.
Tatarski, Anthony M.
Taylor, Barbara
Teff, John C.
Tew, Phyllis A.
Thibodeaux, Rodney T.
Thomas, Brett
Thomas, Kenneth J.
Thompson, Troy L.
Timmermeyer, Sandra L.
Toal, Jean T.
Todd, Debra A.
Todd, Thomas L.
Toudouze, Robert J.
Trahan, Daniel R.
Trahan, Vincent J.
Trees, Dorothy E.
Trujillo, Irene
Valero, Alberto
Varley, Renee S.
Vernon, Dana M.
Vickers, Noel R.
Villarreal, Robert D.
Vincent, Stacia W.
Vorwerk, John E.
Walgenbach, Barry A.
Walls, Anna V.
Warnick, Patricia L.
Washburn, Kim S.
Wellard, Charles
White, Michael R.
White, Ralph D.
Whitecotton, Marilyn M.
Wiesendanger, John C.
Wiggins, Thomas L.
Wilkinson, Carma L.
Williams, Cynthia L.
Williams, Kelleen
Williams, Terrill L.
Williford, Ernest L.
Wilson, Charles H.
Wilson, Newton W.
Winslow, Paul M.
Winter, Gary J.
Wohlgenant, Andro K.
Woodall, R. Scot
Woody, Darrell R.
Worden, Daniel B.
Wurtzbacher, Matthew A.
Ybarra, Rodolfo
Young, Cheryl D.
Young, Douglas W.
Zellitti, John
Zingle, Laura

EXECUTIVE AND OTHER OFFICERS

H. CRAIG CLARK, 47
President and Chief Executive Officer
Years of Service: 3

DAVID H. KEYTE, 47
Executive Vice President and
Chief Financial Officer
Years of Service: 16

FOREST D. DORN, 49
Senior Vice President - Corporate Services
Years of Service: 26

JAMES R. GOOD, 60
President - Canadian Forest Oil Ltd.
Years of Service: 8

LEONARD C. GURULE, 47
Senior Vice President - Alaska
Years of Service: 1

JAMES "BUD" W. KNELL, 53
Senior Vice President - Gulf Coast
Years of Service: 16

JOHN F. MCINTYRE III, 48
Senior Vice President - International
Years of Service: 5

NEWTON "TREY" W. WILSON III, 53
Senior Vice President - General Counsel
and Secretary
Years of Service: 3

MATTHEW A. WURTZBACHER, 41
Senior Vice President - Corporate Planning
and Development
Years of Service: 5

CECIL N. COLWELL, 53
Vice President - Worldwide Drilling
Years of Service: 15

RICK L. HATCHER, 40
Vice President and Chief Technology Officer
Years of Service: 12

JOAN C. SONNEN, 50
Vice President - Controller and Chief
Accounting Officer
Years of Service: 14

R. SCOT WOODALL, 42
Vice President - Western
Years of Service: 4

BOARD OF DIRECTORS

WILLIAM L. BRITTON*
Partner in the law firm of Bennet Jones, LLP. Director of Akita Drilling Ltd., and Vice Chairman and Lead Director of ATCO Ltd., and Canadian Utilities Limited. Director of ATCO Gas & Pipelines Ltd., Barking Power Ltd., Thames Power Ltd., Hanzell Vineyards, Ltd. and the Denver Broncos Football Club. Member of our Nominating and Corporate Governance Committee.

H. CRAIG CLARK
President and Chief Executive Officer and Director, Forest Oil Corporation. Member of our Executive Committee.

CORTLANDT S. DIETLER*
Chairman of the Board, TransMontaigne Inc., Director of Hallador Petroleum Company and Cimarex Energy Co. Chair of the Nominating and Corporate Governance Committee and Compensation Committee.

DOD A. FRASER*
President of Sackett Partners Incorporated. Former Managing Director and Group Executive of the global oil and gas group of Chase Securities, Inc., a subsidiary of The Chase Manhattan Bank. Former General Partner of Freres & Co. Chair of our Audit Committee and member of our Nominating and Corporate Governance Committee.

FORREST E. HOGLUND*
Chairman of the Board of Forest Oil Corporation. Chairman of the Board and Chief Executive Officer of Arctic Resources Company, Ltd. Former Chairman of the Board of EOG Resources Inc. Chair of our Executive Committee and member of our Compensation Committee.

JAMES H. LEE*
Managing General Partner, Lee, Hite & Wisda Ltd., a private oil and gas consulting firm. Director of Frontier Oil Corporation. Member of our Audit Committee and Executive Committee.

PATRICK R. MCDONALD*
Director and Founder of Nytis Exploration Company. Former President, Chief Executive Officer and Director of Carbon Energy Corporation, and Chairman, President, Chief Executive Officer and Founder of Interenergy Corporation. Member of our Audit Committee.

* Notes Independent Director. Our Board of Directors uses the independence standards adopted by the Securities and Exchange Commission and the New York Stock Exchange in making determinations of director independence.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2003

or

☐ **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period from to

Commission File Number: 1-13515

FOREST OIL CORPORATION

(Exact name of registrant as specified in its charter)

State of incorporation: **New York** I.R.S. Employer Identification No. **25-0484900**

1600 Broadway
Suite 2200
Denver, Colorado **80202**
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: **303-812-1400**
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on which Registered
Common Stock, Par Value $.10 Per Share	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
Title of Each Class
Warrants to purchase Common Stock, expiring February 15, 2005
Warrants to purchase Common Stock, expiring March 20, 2010

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is an accelerated filer. Yes ☒ No ☐

The aggregate market value of the voting stock held by non-affiliates as of June 30, 2003, the last business day of the registrant's most recently completed second fiscal quarter, was $1,023,721,464 (based on the closing price of such stock on the New York Stock Exchange Composite Tape).

There were 53,733,381 shares of the registrant's Common Stock, Par Value $.10 Per Share outstanding as of February 27, 2004.

Document incorporated by reference: Portions of the registrant's definitive proxy statement for the Forest Oil Corporation annual meeting of shareholders to be held on May 13, 2004, are incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

PART I

Throughout this Form 10-K, we make statements that may be deemed "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. See Item 1, Business—Forward-Looking Statements, below. Historical statements made herein are accurate only as of the date of filing this Form 10-K with the Securities and Exchange Commission and may be relied upon only as of that date.

In this report, quantities of oil or natural gas liquids are expressed in barrels (BBLS), thousands of barrels (MBBLS) or millions of barrels (MMBBLS). One barrel equals 42 U.S. gallons. Quantities of natural gas are expressed in thousands of cubic feet (MCF), millions of cubic feet (MMCF) or billions of cubic feet (BCF). Equivalent units are expressed in thousand cubic feet of gas equivalents (MCFE), million cubic feet of gas equivalents (MMCFE), or billion cubic feet of gas equivalents (BCFE). Liquids are converted to gas at one barrel of oil equaling six MCF of gas. The term liquids is used to describe oil, condensate and natural gas liquids (NGL). With respect to information relating to Forest's working interest in wells or acreage, "net" oil and gas wells or acreage is determined by multiplying gross wells or acreage by Forest's working interest therein.

Item 1. Business

The Company

Throughout this Form 10-K we use the terms "Forest", "Company", "we", "our" and "us" to refer to Forest Oil Corporation and its subsidiaries. Forest is an independent oil and gas company engaged in the acquisition, exploration, development and production of natural gas and liquids in North America and selected international locations. Forest was incorporated in New York in 1924, as the successor to a company formed in 1916, and has been a publicly held company since 1969. On December 31, 2003, we had 458 employees. Our common stock, par value $.10 per share, is traded on the New York Stock Exchange under the symbol "FST."

We operate from offices located in Denver, Colorado; Lafayette and Metairie, Louisiana; Anchorage, Alaska; and Calgary, Alberta, Canada. Our corporate headquarters is located at 1600 Broadway, Denver, Colorado, 80202, telephone 303.812.1400. Information about Forest, including the periodic and current reports that it files with the Securities and Exchange Commission, and all amendments thereto, are accessible, free of charge, on Forest's website, *www.forestoil.com*, as soon as reasonably practicable after filing with the SEC.

In 2003, we operated in five business units: the Gulf Coast, Western United States, Alaska, Canada and International. We conduct exploration and development activities in each of our North American core areas and in selected international locations. Our proved reserves and producing properties are all located in North America. At December 31, 2003, approximately 88% of our proved oil and gas reserves were in the United States and approximately 12% in Canada.

For information with respect to our reserves, see Item 2, Properties, of this Form 10-K. For financial information relating to our geographic and operational segments, see Note 12 of Notes to Consolidated Financial Statements of this Form 10-K.

Exploration and Production Activities

At December 31, 2003, we held interests in approximately 1,989 net oil and gas wells in the United States and Canada. During 2003, we drilled a total of 129 gross wells, 25 of which were injection wells. Of the remaining 104 wells, 23 were exploration and 81 were development. Our 2003 drilling program achieved an 82% success rate. During 2003, we sold 149 BCFE or an average of 409 MMCFE per day. Approximately 87% of our total production in 2003 was in the United States and approximately 13% in Canada.

Our operations conducted through our U.S. and Canadian business units are summarized below.

2003 Exploration and Production Activities in North America

Business Unit	Primary Areas	% Total Production	2003 Sales Volumes/Average Daily Volume	% Total Estimated Reserves At 12/31/03	Number of Wells Drilled in 2003/ Productive No. of Wells
Gulf Coast(1)	South Texas Louisiana Gulf Coast Offshore Gulf of Mexico	58%	87 BCFE/ 240 MMCFE	48%	25/19
Western United States	Oklahoma Utah Wyoming West Texas SE New Mexico	15%	22 BCFE/ 61 MMCFE	30%	33/26
Alaska(2)	Primarily Cook Inlet Area	14%	21 BCFE/ 57 MMCFE	10%	3/2
Canada	Alberta—Plains Region and Foothills British Columbia NW Territories	13%	19 BCFE/ 51 MMCFE	12%	39/37
		100%	149/409	100%	100/84

(1) Our Gulf Coast business unit was formed in the first quarter of 2003 by combining our Gulf of Mexico Offshore Region and our Gulf Coast Onshore Region to achieve greater efficiencies.

(2) During the fourth quarter of 2003, we recorded significant downward revisions of our estimated proved reserves, primarily in the Redoubt Shoal Field in the Cook Inlet, Alaska. See Item 2, Properties—Reserves, of this Form 10-K.

International Business Unit. Forest also evaluates oil and gas opportunities in countries outside North America. We currently hold concessions in South Africa, Gabon, Switzerland, Germany, Albania, Italy and Romania, as well as overriding royalty interests in certain other areas. Although we have had some successful wells in South Africa, to date Forest has not recorded any proved reserves related to its international concessions. The book value of these international interests at December 31, 2003 represents approximately 1% of our total assets.

During 2003, we entered into participation agreements in connection with our exploration activities in South Africa and Germany. Pursuant to these agreements, Forest receives partial cost reimbursements and is carried for drilling costs in exchange for a reduced interest in the concessions.

During 2003, the International business unit drilled three wells in South Africa, of which one was tested, and one well in Gabon which was not productive.

Sales and Markets

Oil and Gas Operations. Forest's U.S. production of natural gas is generally sold at the wellhead in the areas where it is produced or at nearby "pooling points". Our U.S. natural gas production is typically sold on a month to month basis in the spot market using published indices. The creditworthiness of various purchasers is an important consideration in choosing purchasers at a given delivery point. We believe that the loss of one or more of our current natural gas spot purchasers would not have a material adverse effect on Forest's business in the United States because any individual spot purchaser could be readily replaced by another spot purchaser who would pay approximately the same sales price. Sales to BP Energy Company and Occidental Petroleum Corporation, purchasers of natural gas in the Gulf Coast, represented approximately 10% each of our total revenue in 2003.

Natural gas production in Canada has been sold by Canadian Forest Oil Ltd. ("Canadian Forest") either through a netback pool (the "Canadian Netback Pool") administered by Producers Marketing, Ltd. (ProMark) on behalf of Canadian Forest, or through Canadian Forest's direct sales contracts or under spot contracts. In 2003, Canadian Forest sold approximately 71% of its natural gas production through the Canadian Netback Pool. As described below, on March 1, 2004, the assets of ProMark were sold to a third party.

Our U.S. production of oil and natural gas liquids is typically sold under short-term contracts at prices based upon posted field prices. Canadian oil and natural gas liquids are typically sold under short-term contracts at prices based upon posted prices at Alberta pipeline and processing hubs, netted back to the field. Except in Alaska, our liquids production is generally sold at the wellhead. Our Alaskan oil production, which represented approximately 14% of our total 2003 production, is currently being sold at the terminal to one local refiner, Tesoro Alaska Petroleum Company and its affiliate. The oil is transported to a terminal by a pipeline company that is 40% owned by Forest. The primary term of our contract with this refiner expires on December 31, 2004, but will be renewed automatically from year to year thereafter unless terminated by either party upon written notice 60 days prior to expiration. Sales to this purchaser represented 15% of our total revenue in 2003.

We enter into energy swaps and collars to hedge the price of a portion of our spot market volumes against price fluctuations.

Canadian Netback Pool Sales. The Canadian Netback Pool, which was formerly administered by ProMark, matches major end users with providers of gas supply through firm transportation arrangements, and uses a netback pricing mechanism to establish the average, or "blended," wellhead price paid to producers. Under this netback arrangement, producers receive the blended well head price less related transportation and other direct costs. The administrator charges a marketing fee to the pool participant producers for marketing and administering the gas supply pool.

The Canadian Netback Pool gas sales in 2003 averaged 69 MMCF per day, of which Canadian Forest supplied approximately 29 MMCF per day or 42%. Approximately 22% of the volumes sold in the Canadian Netback Pool in 2003 were sold at fixed prices. The remainder of the volumes sold were priced in a variety of ways, including prices based on published indices. The weighted average price realized by Canadian Forest for volumes sold through the Canadian Netback Pool in 2003 was $4.51 CDN per MCF, compared to an average price of $5.31 CDN per MCF for volumes sold through other channels.

On March 1, 2004, we sold the gas marketing business of ProMark to Cinergy Canada, Inc. (Cinergy). Immediately prior to the closing, ProMark was amalgamated with Canadian Forest. Following the closing, all employees of ProMark became employees of Cinergy. Under the terms of a contract administration agreement, Cinergy will administer the Canadian Netback Pool. In addition, the parties entered into a separate agreement under which Cinergy will purchase all of Canadian Forest's natural gas that is not otherwise subject to existing contracts for a period of five years. Canadian Forest's obligation to deliver gas to the pool is not expected to change as a result of the sale. For further information concerning the ProMark sale, see Note 3 of Notes to Consolidated Financial Statements of this Form 10-K.

Competition

The oil and natural gas industry is intensely competitive. Competition is particularly intense in the acquisition of prospective oil and natural gas properties and oil and gas reserves. Forest's competitive position depends on our geological, geophysical and engineering expertise, our acreage position and property base, our financial resources, our ability to develop properties and our ability to select, acquire and develop proved reserves. We compete with a substantial number of other companies including many companies with larger technical staffs and greater financial and operational resources. Some of these companies not only engage in the acquisition, exploration, development and production of oil and natural gas reserves, but also carry on refining operations, generate electricity and market refined products. We also compete with major and independent oil and gas companies in the marketing and sale of oil and gas to transporters, distributors and end users. The oil and natural gas industry competes with other industries supplying energy and fuel to industrial, commercial and individual consumers. Forest competes with other oil and natural gas companies in attempting to secure drilling rigs and other equipment necessary for drilling and completion of wells. Such equipment may be in short supply from time to time. Finally, companies not previously investing in oil and natural gas may choose to acquire reserves to establish a firm supply or simply as an investment. Such companies provide competition for Forest.

Forest's business is affected not only by such competition, but also by general economic developments, governmental regulations and other factors that affect our ability to market our oil and natural gas production. The prices of oil and natural gas realized by Forest are highly volatile. The price of oil is generally dependent on world supply and demand, while the price we receive for our natural gas is tied to a variety of factors such as the price of competitive fuels, the spot price at the Henry Hub, and local competition for pipeline capacity in the specific markets in which such gas is produced. Declines in crude oil prices or natural gas prices adversely impact Forest's activities. Our financial position and resources may also adversely affect our competitive position. Lack of available funds or financing alternatives can prevent us from executing our operating strategy and from deriving the expected benefits therefrom. For further information concerning Forest's financial position, see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, in this Form 10-K.

Regulation

Our oil and gas operations are subject to various U.S. federal, state and local laws and regulations and foreign laws and regulations.

United States. Various aspects of our oil and natural gas operations are regulated by administrative agencies under statutory provisions of the states where such operations are conducted and by certain agencies of the Federal government for operations on Federal leases. All of the jurisdictions in which we own or operate producing crude oil and natural gas properties have statutory provisions regulating the exploration for and production of crude oil and natural gas, including provisions requiring permits for the drilling of wells and maintaining bonding requirements in order to drill or operate wells and provisions relating to the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units and the number of wells which may be drilled in an area and the unitization or pooling of crude oil and natural gas properties. In this regard, some states can order the pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

The Federal Energy Regulatory Commission (FERC) regulates the transportation and sale for resale of natural gas in interstate commerce under the Natural Gas Act of 1938 (NGA) and the Natural Gas Policy Act of 1978 (NGPA). In the past, the Federal government has regulated the prices at which oil and gas could be sold. The Natural Gas Wellhead Decontrol Act of 1989 (the Decontrol Act) removed all NGA and NGPA price and nonprice controls affecting producers' wellhead sales of natural gas effective January 1, 1993. While sales by producers of natural gas, and all sales of crude oil, condensate and natural gas liquids can currently be made at uncontrolled market prices, Congress could enact price controls in the future.

Commencing in 1992, the FERC issued Order No. 636 and subsequent orders (collectively, Order No. 636), which require interstate pipelines to provide transportation services separate from the pipelines' sales of gas. Also, Order No. 636 requires pipelines to provide open-access transportation on a basis that is equal for all gas supplies. The courts have largely affirmed the significant features of Order No. 636 and numerous related orders pertaining to the individual pipelines, although certain appeals remain pending and the FERC continues to review and modify its open access regulations. Commencing in February 2000, the FERC issued Order No. 637 and subsequent orders (collectively, Order No. 637), which imposed a number of reforms intended to further enhance competition in natural gas markets. Most major aspects of Order No. 637 were upheld in judicial review, though certain issues were remanded to FERC, have been considered on remand, and are pending rehearing at FERC.

While any additional FERC action on these matters would affect Forest only indirectly, these changes are intended to further enhance competition in natural gas markets. We cannot predict whether and to what extent the FERC's regulations will survive rehearing and further judicial review and, if so, whether the FERC's actions will achieve the goal of increasing competition in natural gas markets in which our natural gas is sold. However, we do not believe that we will be affected materially differently than other natural gas producers and markets with which and in which we compete.

The Outer Continental Shelf Lands Act (OCSLA) requires that all pipelines operating on or across the Outer Continental Shelf (the OCS) provide open-access, non-discriminatory service. Commencing in April 2000, FERC issued Order No. 639 and subsequent orders (collectively, Order No. 639), which imposed certain reporting requirements applicable to "gas service providers" operating on the OCS concerning their prices and other terms and conditions of service. The purpose of Order No. 639 is to provide regulators and other interested parties with sufficient information to detect and to remedy discriminatory conduct by such service providers. FERC has stated that these reporting rules apply to OCS gatherers and has clarified that they may also apply to other OCS service providers including platform operators performing dehydration, compression, processing and related services for third parties. The U.S. District Court overturned the FERC's reporting rules as exceeding its authority under OCSLA. The FERC has recently appealed this decision, which was affirmed on appeal through petitions to the U.S. Supreme Court and are pending. We cannot predict whether and to what extent these regulations might be reinstated, and what effect, if any, they may have on our financial condition or operations. The rules, if reinstated, may increase the frequency of claims of discriminatory service, may decrease competition among OCS service providers and may lessen the willingness of OCS gathering companies to provide service on a discounted basis.

Certain operations that we conduct are on federal oil and gas leases, which are administered by the Bureau of Land Management (BLM) and the Minerals Management Service (MMS). These leases contain relatively standardized terms and require compliance with detailed BLM and MMS regulations and orders pursuant to the OCSLA (which are subject to change by the MMS). Many onshore leases contain stipulations limiting activities that may be conducted on the lease. The stipulations are unique to particular geographic areas and may limit the times during which activities on the lease may be conducted, the manner in which certain activities may be conducted or, in some cases, may ban any surface activity. For offshore operations, lessees must obtain MMS approval for exploration, development and production plans prior to the commencement of such operations. In addition to permits required from other agencies (such as the Environmental Protection Agency), lessees must obtain a permit from the BLM or the MMS, as applicable, prior to the commencement of drilling. Lessees must also comply with detailed BLM or MMS regulations, as applicable, governing, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of OCS wells, calculation of royalty payments and the valuation of production for this purpose and removal of facilities. To cover the various obligations of lessees on the OCS, the MMS generally requires that lessees post substantial bonds or other acceptable assurances that such obligations will be met, unless the MMS exempts the lessee from such obligations. The cost of such bonds or other surety can be substantial and we can provide no assurance that we can continue to obtain bonds or other surety in all cases. Under certain circumstances, the BLM or MMS, as applicable, may require our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition and operations.

In March 2000, the MMS issued a final rule modifying the valuation procedures for the calculation of royalties owed for crude oil sales. When oil production sales are not in arms-length transactions, the new royalty calculation will base the valuation of oil production on spot market prices instead of the posted prices that were previously utilized. We do not believe that this rule will have a material adverse effect on our operations.

Additional proposals and proceedings that might affect the oil and gas industry are regularly considered by Congress, states, the FERC and the courts. We cannot predict when or whether any such proposals may become effective. In the past, the natural gas industry has been heavily regulated. We can give no assurance that the regulatory approach currently pursued by the FERC will continue indefinitely. We do not anticipate, however, that compliance with existing federal, state and local laws, rules and regulations will have a material or significantly adverse effect upon our capital expenditures, earnings or competitive position. No material portion of Forest's business is subject to renegotiation of profits or termination of contracts or subcontracts at the election of the Federal government.

Canada. The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. It is not expected that any of these controls or regulations will affect our operations in a manner materially different than they would affect other oil and gas companies of similar size. We are unable to predict what additional legislation or amendments may be created.

Oil and natural gas exported from Canada is subject to regulation by the National Energy Board (NEB), an independent federal regulatory agency and the government of Canada. Exporters are free to negotiate with purchasers, provided that the export contracts must meet certain criteria prescribed by the NEB. Natural gas exports for a term of less than two years or for a term two to 20 years (in quantities of more than 30,000 cubic meters per day), must be made pursuant to a NEB order. Oil exports may be made pursuant to export contracts with terms not exceeding one year, in the case of light crude, and not exceeding two years, in the case of heavy crude, provided that an order approving any export has been obtained from the NEB. Any natural gas or oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export license from the NEB and the government of Canada. The provinces in which our operations are located, mainly Alberta and British Columbia, also regulate the volume of natural gas which may be removed for consumption elsewhere.

In addition, each province has regulations that govern land tenure, royalties, production rates and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from private lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

In Alberta, certain producers of oil or natural gas are entitled to a credit against the royalties to the Crown by virtue of the ARTC (Alberta Royalty Tax Credit) program. The credit is determined by applying a specified rate (25-75%) to a maximum of $2 million CDN of Alberta Crown royalties payable for each producer. Canadian Forest is eligible for ARTC credits only on eligible properties acquired and wells drilled after the change of control that occurred when Canadian Forest was acquired by Forest. Production from properties acquired from corporations claiming maximum entitlement to ARTC will generally not be eligible.

In British Columbia, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the quantity of oil produced and the value of the oil. Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production. The royalty payable on natural gas is determined by a sliding scale based on the greater of the amount obtained by the producer and a prescribed minimum price. The minimum royalty for natural gas produced in association with oil is 8% and for other natural gas is 15%.

The federal government has jurisdiction over the exploration and development of oil and gas resources in the Northwest Territories of Canada. The federal regulatory regime reflects the extended timelines and increased capital expenditures inherent in working in the northern environment, providing for work commitments and work deposits coupled with the suspension and/or reimbursement of rentals and royalties at earlier developmental stages. This regime is subject to change as development in the Northwest Territories evolves toward a more conventional model. It is also possible that jurisdiction over the oil and gas resources in these territories could be transferred to the territorial governments. We are unable to predict whether any evolution or transfer of jurisdiction to the territorial governments would affect our activities in the Northwest Territories.

Our right to produce oil and gas from the Northwest Territories is subject to conversion of certain instruments (i.e., exploration licenses or significant discovery licenses) into production licenses. The right to such conversion is subject to an application process and regulatory approval. In addition, the right to produce may be dependent on the negotiation of a pooling agreement or the imposition of a forced pooling order. Until the finalization of such agreement or order, it is not possible to finally determine our production in such lands.

Environmental Matters. Extensive U.S. federal, state and local laws, as well as laws of foreign countries, govern oil and natural gas operations, regulate the discharge of materials into the environment or otherwise relate to environmental protection. Numerous governmental agencies, such as the U.S. Environmental Protection Agency (commonly called the EPA), issue regulations to implement and enforce such laws. Environmental laws and regulations are often difficult and costly to comply with and substantial administrative, civil and even criminal penalties can be imposed for failure to comply. These laws and regulations may, in certain circumstances, impose "strict liability" for environmental contamination, rendering an owner or lessee liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of the owner or lessee. This regulatory burden on the oil and natural gas industry increases its cost of doing business and consequently affects its profitability. Changes in existing environmental laws or the adoption of new environmental laws have the potential to adversely affect our operations or earnings, as well as the oil and gas exploration and production industry in general. While we believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us, we cannot give any assurance that we will not be adversely affected in the future.

The Oil Pollution Act of 1990 (OPA) and regulations thereunder impose a variety of requirements on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in U.S. waters. A "responsible party" includes the owner or operator of a pipeline, vessel or onshore facility, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages from oil spills. OPA also requires operators of offshore OCS facilities to demonstrate to the MMS that they possess at least $35 million in financial resources that are available to pay for costs that may be incurred in responding to an oil spill. This financial responsibility amount can increase up to a maximum of $150 million if the MMS determines that a greater amount is justified based on specific risks posed by the operations or if the worst case oil-spill discharge volume possible at a facility exceeds applicable threshold volumes established by the MMS. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Even if applicable, the liability limits for offshore facilities require the responsible party to pay all removal costs, plus up to $75 million in other damages, while the liability limits for onshore facilities are $350 million. Few defenses exist to the liability imposed by OPA.

The U.S. Federal Water Pollution Control Act (commonly called the Clean Water Act) imposes restrictions and strict controls regarding the discharge of produced waters and other oil and gas wastes in "waters of the United States," a broadly-defined term that includes all navigable waters. Many state discharge regulations and the federal National Pollutant Discharge Elimination System generally prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the oil and gas industry into coastal waters. Although the costs to comply with these zero discharge mandates under federal or state law may be significant, the entire industry is expected to experience similar costs and we believe that these costs will not have a material adverse impact on our financial condition and operations.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended (commonly called CERCLA but also known as "Superfund") and comparable state laws impose liability without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current owner and operator of the disposal site or sites where the release occurred and companies that transported or disposed or arranged for the transport or disposal of the hazardous substances that have been released at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. In the ordinary course of Forest's operations, substances may be generated that fall within the definition of "hazardous substances." Although we have utilized operating and disposal practices that were standard in the industry at the time, wastes associated with oil and gas exploration and production operations may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where such wastes have been taken for disposal. Moreover, we may own or operate properties that in the past were operated by third parties whose operations were not under our control. Those properties and any wastes that may have been disposed or released on them may be subject to CERCLA, and analogous state laws, and we potentially could be required to remediate such properties.

In Canada, the oil and natural gas industry is currently subject to environmental regulation pursuant to provincial and federal legislation that provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized with oil and gas industry operations. In addition, wells and facility sites must be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures. A breach of such legislation may result in the imposition of fines and penalties, the revocation of licenses and authorizations or civil liability for pollution damage.

Although we maintain insurance against some, but not all, of the risks described above, including insuring the costs of clean-up operations, public liability and physical damage, there is no assurance that such insurance will be adequate to fully cover all such costs or that such insurance will continue to be available in the future or that such insurance will be available at premium levels that justify its purchase. The occurrence of a significant environmental-related event not fully insured or indemnified against could have a material adverse effect on our financial condition and operations.

We have established guidelines to be followed to comply with U.S. and Canadian environmental laws and regulations. We employ an environmental department whose responsibilities include providing assurance that our operations are carried out in accordance with applicable environmental guidelines and safety precautions. Although we maintain pollution insurance against the costs of clean-up operations, public liability and physical damage, there is no assurance that such insurance will be adequate to cover all such costs or that such insurance will continue to be available in the future. In addition, any oil and gas activities conducted by us outside of North America are potentially subject to similar foreign governmental controls and restrictions pertaining to the environment. To date we believe that compliance with existing requirements of such governmental bodies has not had a material effect on our operations.

We believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. We are committed to meeting our responsibilities to protect the environment wherever we operate and anticipate making increased expenditures as a result of increasingly stringent laws relating to the protection of the environment.

For further information regarding certain environmental matters, see Item 3, Legal Proceedings, in this Form 10-K.

Available Information

Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to reports filed pursuant to Sections 13(a) and 15(d) of the Securities Exchange Act of 1934 are available on our website, *www.forestoil.com*, as soon as reasonably practicable after such reports are electronically filed with the Securities and Exchange Commission. In addition our corporate governance guidelines, code of ethics, and charters for the Audit Committee, Compensation Committee and Nominating and Corporate Governance Committee are also available on our website. Copies of the foregoing information is available to shareholders upon written request addressed to the attention of the Secretary of Forest at 1600 Broadway Street, Suite 2200, Denver, Colorado 80202.

Forward-Looking Statements

The information in this Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts or present facts, that address activities, events, outcomes and other matters that Forest plans, expects, intends, assumes, believes, budgets, predicts, forecasts, projects, estimates or anticipates (and other similar expressions) will, should or may occur in the future are forward-looking statements. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Form 10-K, in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors.

These forward-looking statements appear in a number of places and include statements with respect to, among other things:

- estimates of our oil and gas reserves;
- estimates of our future natural gas and liquids production, including estimates of any increases in oil and gas production;
- planned capital expenditures and availability of capital resources to fund capital expenditures;
- our outlook on oil and gas prices;
- the impact of political and regulatory developments;
- our future financial condition or results of operations and our future revenues and expenses; and
- our business strategy and other plans and objectives for future operations.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of oil and gas. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures and the other risks described in Part II, Item 7, under the caption "—Risk Factors." The financial results of our foreign operations are also subject to currency exchange rate risks.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by our reservoir engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ from the quantities of oil and natural gas that are ultimately recovered.

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements express or implied, included in this Form 10-K and attributable to Forest are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that Forest or persons acting on its behalf may issue. Forest does not undertake to update any forward-looking statements to reflect events or circumstances after the date of filing this Form 10-K with the Securities and Exchange Commission, except as required by law.

Item 2. Properties

Forest's principal proved reserves and producing properties are located in the United States in Louisiana, New Mexico, Oklahoma, Texas, Utah, Wyoming, Alaska and the Gulf of Mexico, and in Canada in Alberta. In addition, we have acreage in various locations outside North America.

Reserves

Information regarding Forest's proved and proved developed oil and gas reserves and the standardized measure of discounted future net cash flows and changes therein is included in Note 13 of Notes to Consolidated Financial Statements. See also Part II, Item 7, Management's Discussion and

Analysis of Financial Condition and Results of Operations—Risk Factors—*Estimates of oil and gas reserves are uncertain and inherently imprecise*, for additional information regarding estimates of proved reserves.

Since January 1, 2003 we have not filed any oil or natural gas reserve estimates or included any such estimates in reports to any Federal or foreign governmental authority or agency, other than the Securities and Exchange Commission (SEC) and the Department of Energy (DOE). There were no differences between the reserve estimates included in the SEC report, the DOE report and those included herein, except for production and additions and deletions due to the difference in the "as of" dates of such reserve estimates.

Forest's estimated proved reserves were 1,296 BCFE at December 31, 2003 compared to estimated proved reserves of 1,560 BCFE at December 31, 2002. Approximately 62% of our estimated proved reserves at December 31, 2003 were natural gas and our estimated proved developed reserves represented approximately 75% of total estimated proved reserves.

Forest's year-end 2003 estimates of proved reserves were independently reviewed by two independent petroleum engineering firms. Ryder Scott Company independently reviewed our estimates of the reserves attributable to certain properties in the United States and Canada, except the properties acquired by us on December 31, 2003 in the Permian Basin and South Texas, which were independently reviewed by DeGolyer and MacNaughton.

In conducting an independent review of Forest's estimates of proved reserves each petroleum engineering firm prepared independent estimates of reserves for specific fields. The estimates prepared by each petroleum engineering firm were presented to Forest by field for oil, gas and natural gas liquids. The estimates prepared by the engineering firms were then compared to the estimates prepared by Forest in the aggregate on a gas equivalent basis. Together, these firms independently reviewed estimates relating to properties constituting approximately 88% of our reserves based on their discounted value and volumes. In the aggregate, for the properties reviewed, the estimates of proved reserve quantities prepared by the two independent petroleum engineering firms as part of their reviews were lower than Forest's estimates by approximately 8%. Upon consummation of their reviews, Ryder Scott Company and DeGolyer and MacNaughton each provided Forest with their opinions that Forest's estimates of proved reserves for the properties reviewed by them complied with the definitions and disclosure guidelines of the SEC.

2003 Reserve Revisions. During 2003 we revised downward our estimate of proved reserves by a total of approximately 473 BCFE. The downward revision of our estimates was due to information received from production results, drilling activity and other events that occurred primarily in the latter part of 2003. The revisions are not expected to have a material impact on our near-term hydrocarbon production volumes.

Approximately 62% of the total revisions was attributable to the downward revision of our estimate of proved oil reserves in the Redoubt Shoal Field in the Cook Inlet, Alaska. We reduced our estimate of proved oil reserves associated with our Redoubt Shoal Field in Alaska from our 2002 year-end estimate by approximately 49 million barrels, or approximately 85% of the estimated proved oil reserves of this field as of December 31, 2002. Of this revision, approximately 36 million barrels were classified as proved undeveloped as of December 31, 2002. Our estimate of proved oil reserves attributable to the Redoubt Shoal Field was approximately 8 million barrels as of December 31, 2003. On December 31, 2003, Forest's net daily oil production at the Redoubt Shoal Field was approximately 1,650 barrels per day from three wells. On that date one well was shut in for pump repair.

Production results in 2003 from Redoubt Shoal, which began production in December 2002, were lower than those originally estimated. In addition, data from wells drilled in 2003 in Redoubt Shoal, when integrated with pre-existing data, reflected significantly lower oil in place than the estimates at December 31, 2002, lower overall recovery efficiencies and economic cutoffs. During the second half of 2003 Forest undertook an integrated field study of the Redoubt Shoal Field examining the production performance, field data and well data for 2003 activity. The revision was a result of the study, after applying economic cutoffs. In addition to preparing and reporting its own internal estimates of proved reserves at Redoubt Shoal, Forest also engaged Ryder Scott Company to prepare independent estimates of proved reserves at Redoubt Shoal as of the end of 2003, 2002 and 2001.

Cumulative investment in exploration, delineation and development of the Redoubt Shoal Field by Forest and its predecessor, Forcenergy Inc (Forcenergy), through December 31, 2003 was approximately $310 million. As of December 31, 2003, we estimated total future development capital expenditures, excluding abandonment, for the Redoubt Shoal Field to be approximately $53 million. This amount includes the remaining cost of implementing the water injection project described below.

Forest's future development plans for the Redoubt Shoal Field currently include the implementation of a water injection project for the purpose of maintaining the average Hemlock reservoir pressure, conserving the natural energy of the reservoir and assisting oil recovery.

Implementation of the water injection project is currently planned to begin within the next two years. Our current plans call for the drilling of two oil wells and one water injection well and the conversion of three wells from production to water injection, over several years.

We also had downward revisions in our estimated proved reserves for other properties in the fourth quarter of 2003 totaling approximately 143 BCFE. These revisions were in addition to 36 BCFE of downward revisions to estimated proved reserves taken previously in 2003. These downward revisions are due to a variety of factors, including recent production performance and revised field development plans.

Production

The following table shows our net liquids and natural gas production for the years ended December 31, 2003, 2002 and 2001:

	Net Natural Gas and Liquids Production		
	2003	**2002**	**2001**
United States:			
Natural Gas (MMCF)	84,368	78,543	97,400
Liquids (MBBLS)	7,686	7,477	9,239
Total (MMCFE)	130,484	123,405	152,834
Canada:			
Natural Gas (MMCF)	12,609	13,525	10,994
Liquids (MBBLS)	1,015	1,180	1,361
Total (MMCFE)	18,699	20,605	19,160
Consolidated:			
Natural Gas (MMCF)	96,977	92,068	108,394
Liquids (MBBLS)	8,701	8,657	10,600
Total (MMCFE)	149,183	144,010	171,994

Average Sales Prices

The following table sets forth production volumes and average sales prices per MCF of natural gas and per barrel of liquids for the years ended December 31, 2003, 2002 and 2001:

	United States			Canada		
	2003	2002	2001	2003	2002	2001
Natural Gas:						
Sales volumes (MMCF)	84,368	78,543	97,400	12,609	13,525	10,994
Sales price received (per MCF)	$ 5.27	3.18	4.33	3.09	2.05	2.56
Effects of energy swaps and collars (per MCF)(1)	$ (.52)	.14	.18	—	—	—
Average sales price (per MCF)	$ 4.75	3.32	4.51	3.09	2.05	2.56
Liquids:						
Oil and condensate:						
Sales volumes (MBBLS)	7,221	6,792	8,264	629	739	955
Sales price received (per BBL)	$ 29.08	24.30	23.92	28.57	23.37	22.96
Effects of energy swaps and collars (per BBL)(1)	$ (4.04)	(1.90)	.62	—	—	—
Average sales price (per BBL)	$ 25.04	22.40	24.54	28.57	23.37	22.96
Natural gas liquids:						
Sales volumes (MBBLS)	465	685	975	386	441	406
Average sales price (per BBL)	$ 18.58	11.57	15.81	20.88	13.35	17.17
Total liquids sales volumes (MBBLS)	7,686	7,477	9,239	1,015	1,180	1,361
Average sales price (per BBL)	$ 24.65	21.40	23.62	25.65	19.63	21.23
Total Sales Volumes:						
Sales volumes (MMCFE)	130,484	123,405	152,834	18,699	20,605	19,160
Average sales price (per MCFE)(1)	$ 4.52	3.41	4.30	3.47	2.47	2.97
Oil and gas production expense (per MCFE)	$ 1.07	1.17	1.12	.77	.67	.82

(1) Commodity swaps and collars were transacted to hedge the price of spot market volumes against price fluctuations. Hedged natural gas volumes were 49,990 MMCF, 36,050 MMCF, and 42,870 MMCF for the years ended December 31, 2003, 2002 and 2001, respectively. Hedged oil and condensate volumes were 4,597,500 barrels, 3,921,500 barrels, and 3,742,500 barrels for 2003, 2002 and 2001, respectively. These arrangements have been designated as cash flow hedges for accounting purposes and, as a result, the effective portion of the net gains and losses were accounted for as increases and decreases of oil and gas sales. The aggregate net gains (losses) related to our cash flow hedges were $(72,863,000), ($1,742,000), and $22,781,000 for the years ended December 31, 2003, 2002 and 2001, respectively. Those arrangements that are not designated as cash flow hedges for accounting purposes are recorded as non-operating income or expense. Average sales prices have been adjusted to reflect effects of energy swaps and collars.

Productive Wells

The following summarizes our total gross and net productive wells at December 31, 2003:

	Productive Wells(1)	
	United States	Canada
Gross(2)		
Gas	1,011	231
Oil	2,716	346
Totals(3)	3,727	577
Net(4)		
Gas	390	116
Oil	1,267	216
Totals	1,657	332

(1) Productive wells are producing wells and wells capable of production, including injection wells, salt water disposal wells, service wells and wells that are shut-in.

(2) The number of gross wells is the total number of wells in which a working interest is owned.

(3) Includes 6 dual completions in the United States and 8 dual completions in Canada. Dual completions are counted as one well. If either completion is an oil completion, the well is classified as an oil well.

(4) The number of net wells is the sum of the fractional working interests owned in gross wells, expressed as whole numbers.

Developed and Undeveloped Acreage

Forest held acreage as set forth below at December 31, 2003 and 2002. A majority of the developed acreage is subject to mortgage liens securing our bank indebtedness. See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, and Note 4 of Notes to Consolidated Financial Statements in this Form 10-K.

	Developed Acreage(1)		Undeveloped Acreage(2)	
	Gross(3)	Net(4)	Gross(3)	Net(4)
United States:				
Gulf Coast	1,058,316	482,651	416,177	306,648
Western	312,958	98,636	251,999	114,926
Alaska	305,030	37,379	1,438,220	1,208,798
	1,676,304	618,666	2,106,396	1,630,372
Canada	209,189	102,887	1,419,937	794,722
International:				
South Africa	—	—	8,986,446	5,167,647
Gabon	—	—	2,409,276	2,409,276
Switzerland	—	—	1,850,000	925,000
Germany	—	—	1,050,807	315,241
Albania	—	—	855,123	320,670
Italy	—	—	940,926	743,230
Romania	—	—	1,073,693	1,073,693
			17,166,271	10,954,757
Total acreage at December 31, 2003	1,885,493	721,553	20,692,604	13,379,851
United States	1,297,337	428,311	1,876,857	1,466,570
Canada	210,475	106,657	1,238,150	534,380
International	—	—	18,637,048	12,067,753
Total acreage at December 31, 2002	1,507,812	534,968	21,752,055	14,068,703

(1) Developed acres are those acres which are spaced or assigned to productive wells.

(2) Undeveloped acres are those acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves. It should not be confused with undrilled acreage held by production under the terms of a lease.

(3) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(4) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres, expressed as whole numbers.

Approximately 5% and 13% of our North American net undeveloped acreage at December 31, 2003 is held under leases that have terms that will expire in 2004 and 2005, respectively, if not extended by exploration or production activities.

In addition, 36% and 13% of our International net undeveloped acreage is expected to be relinquished in 2004 and 2005, respectively, as part of contractual commitments in South Africa, Gabon and Albania.

Drilling Activity

During the years ended December 31, 2003, 2002 and 2001, Forest drilled gross and net exploratory and development wells as set forth below. This information does not include wells drilled under farmout agreements, royalty interests ownership or any other wells in which we do not have a working interest.

	United States			Canada			International		
	2003	2002	2001	2003	2002	2001	2003	2002	2001
Gross Exploratory Wells:									
Dry(1)	5	5	8	1	6	3	3	—	2
Productive(2)	8	1	69	5	4	15	1	—	2
	13	6	77	6	10	18	4	—	4
Net Exploratory Wells:(3)									
Dry(1)	4.2	2.3	4.9	.7	3.5	1.4	1.5	—	1.0
Productive(2)	6.7	.7	38.3	3.1	1.9	8.9	.5	—	1.4
	10.9	3.0	43.2	3.8	5.4	10.3	2.0	—	2.4
Gross Development Wells:									
Dry(1)	9	4	2	1	2	2	—	—	—
Productive(2)	39	43	8	32	4	—	—	—	—
	48	47	10	33	6	2	—	—	—
Net Development Wells:(3)									
Dry(1)	5.6	2.3	1.3	.3	.7	—	—	—	—
Productive(2)	23.0	23.5	5.4	12.7	3.0	.7	—	—	—
	28.6	25.8	6.7	13.0	3.7	.7	—	—	—

(1) A dry well (hole) is a well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

(2) Productive wells are producing wells and wells capable of production, including wells that are shut-in.

(3) The number of net wells is the sum of the fractional working interests owned in gross wells, expressed as whole numbers and fractions thereof.

At December 31, 2003 Forest had 5 exploratory wells (2.3 net) and 8 development wells (3.1 net) that were in the process of being drilled.

Delivery Commitments

A significant portion of Canadian Forest's natural gas production in 2003 was sold through the Canadian Netback Pool which was administered by ProMark on behalf of Canadian Forest. The gas marketing business of ProMark was sold to Cinergy on March 1, 2004. Canadian Forest will continue to sell a significant portion of its natural gas production into the Canadian Netback Pool, which Cinergy will administer pursuant to a contract administration agreement. Also, under our agreement with Cinergy, Canadian Forest will sell and Cinergy will purchase for a period of five years all of Canadian Forest's natural gas that is not otherwise subject to the Canadian Netback Pool or existing contracts. Cinergy will pay for the natural gas based on published indices less applicable transportation costs. At

December 31, 2003, the natural gas quantities and weighted average contract prices related to the fixed price contracts of the Canadian Netback Pool were as follows:

	Canadian Netback Pool Sales Commitment	
	BCF	Weighted Average Contract Price per MCF
2004	5.5	$2.66 CDN
2005	5.5	$2.75 CDN
2006	5.5	$2.86 CDN
2007	5.5	$2.96 CDN
2008	5.5	$3.08 CDN
2009	3.0	$3.86 CDN
2010	1.7	$5.21 CDN
2011	.7	$5.50 CDN

As a producer in the Canadian Netback Pool, Canadian Forest will be paid a netback price that reflects all of the revenue from approved customers less the costs of delivery (including transportation, audit and shortfall makeup costs) and an administrator marketing fee.

In 2003 Canadian Forest supplied 42% of the Canadian Netback Pool sales quantity; the amount supplied represented 71% of Canadian Forest's 2003 natural gas production. In order to satisfy its supply obligations to the Canadian Netback Pool, Canadian Forest may be required to cover its obligations in the market.

The administrator of the Canadian Netback Pool, now Cinergy, is required to acquire gas in the event of a shortfall between the gas supply and market obligations. A shortfall could occur if a gas producer fails to deliver its contractual share of the supply obligations of the Canadian Netback Pool. The cost of purchasing gas to cover any shortfall is a cost of the Canadian Netback Pool. The prices paid for shortfall gas would typically be spot market prices and may differ from the prices received from customers of the Canadian Netback Pool. Higher spot prices would reduce the average price paid to the gas producers in the Canadian Netback Pool, including Canadian Forest.

In addition to its commitments to the Canadian Netback Pool, Canadian Forest is committed to sell natural gas at the following quantities and weighted average prices:

	Natural Gas	
	BCF	Sales Price per MCF
2004	.5	$3.96 CDN
2005	.5	$4.11 CDN
2006	.4	$4.27 CDN

There were no long-term delivery commitments in the United States as of December 31, 2003.

Item 3. Legal Proceedings

Forest, in the ordinary course of business, is a party to various lawsuits, claims and proceedings, including those identified below. While we believe that the amount of any potential loss would not be material to our consolidated financial position, the ultimate outcome of these matters is inherently difficult to predict with any certainty. In the event of an unfavorable outcome, the potential loss could have an adverse effect on our results of operations and cash flow in the reporting periods in which any such actions are resolved.

Alaska Proceeding. In May, 2002, Cook Inlet Keeper, a non-governmental third party, filed a challenge in the Superior Court in Anchorage, Alaska (the trial court) to the regulatory review and approval process for Forest's development and production phase of our Redoubt Shoal project (the Production Project). On February 2, 2004, the trial court ruled that certain legislation which became law in 2003 mooted Cook Inlet Keeper's challenge and, therefore, affirmed the State's approval of the Production Project. While we will continue our vigorous opposition to Cook Inlet Keeper's challenge, the outcome of the litigation is inherently difficult to predict with any certainty. However, the Company does not believe that this legal matter could have a material effect on the results of future periods in the event of an unfavorable outcome.

Environmental Matters. The Company is involved in a number of governmental proceedings in the ordinary course of business, including the environmental matters described below. Forest believes that the potential penalty for each of the proceedings described below could involve penalties in excess of $100,000. Forest believes, however, that mitigating circumstances will result in total monetary penalties of $150,000 to $300,000 for all three proceedings combined.

Forest owns and operates a platform located in the Cook Inlet, Alaska. Discharges from the platform have on occasion exceeded the limits allowed by the EPA discharge permit. Forest recently received permission from the State of Alaska to inject the effluent into a disposal well rather than discharge it into the Cook Inlet.

Forest also owns a non-operating working interest in the King Salmon platform in the Cook Inlet in Alaska. In September 2002, while injecting oil based drilling mud and cuttings into the annulus of the well, the operator observed an oil sheen on the water near the platform and ceased further injections. The U.S. Coast Guard initiated an enforcement action based on the apparent discharges into the Cook Inlet. In addition, the State of Alaska Department of Environmental Conservation has indicated that it may also initiate an enforcement action.

In addition, Forest received a Findings of Violation for alleged violations of the Clean Water Act involving discharges from 1999 to 2002 from facilities in the Gulf of Mexico that were previously operated by Forcenergy. All alleged violations have been remedied.

Item 4. Submission of Matters to a Vote of Security Holders

No matter was submitted to a vote of our shareholders during the fourth quarter of the fiscal year ended December 31, 2003.

Item 4A. Executive Officers of Forest

The following persons were serving as executive officers of Forest as of March 1, 2004.

Name	Age	Years with Forest	Office(1)
H. Craig Clark	47	3	President and Chief Executive Officer, and a director since July 31, 2003. Mr. Clark joined Forest in September 2001, and served as President and Chief Operating Officer through July 2003. Mr. Clark was previously employed by Apache Corporation in Houston, Texas, an independent energy company, from 1989 to 2001. He served in various management positions during this period, including Executive Vice President—U.S. Operations and Chairman and Chief Executive Officer of Pro Energy, an affiliate of Apache.
David H. Keyte	47	16	Executive Vice President and Chief Financial Officer since November 1997. Mr. Keyte served as our Vice President and Chief Financial Officer from December 1995 to November 1997 and our Vice President and Chief Accounting Officer from December 1993 to December 1995.
Forest D. Dorn	49	26	Senior Vice President—Corporate Services since December 2000. Mr. Dorn served as Senior Vice President—Gulf Coast Region from November 1997 to December 2000, Vice President—Gulf Coast Region from August 1996 to October 1997 and Vice President and General Business Manager from December 1993 to August 1996.
Leonard C. Gurule	47	1	Senior Vice President—Alaska since joining the Company on September 22, 2003. Between 2000 and September 2003, Mr. Gurule served on the boards of several local community and non-profit organizations and managed his own investment portfolio. From 1987 to 2000, he served in various capacities at Atlantic Richfield Co., including Chairman of the Board and Chief Executive Officer of Virginia Indonesia, a company owned by ARCO, and manager of ARCO's Prudhoe Bay operations and construction activities, engineering support to ARCO's Alaskan exploration activities and petroleum engineering support to ARCO's Kuparuk field.

Name	Age	Years with Forest	Office(1)
James W. Knell	53	16	Senior Vice President—Gulf Coast Region since December 2000. Mr. Knell served as Vice President—Gulf Coast Offshore from May 1999 to December 2000, Gulf Coast Offshore Business Unit Manager from March 1998 to May 1999, Gulf Coast Region Business Unit Manager from November 1997 to March 1998 and Corporate Drilling and Production Manager from December 1991 to November 1997.
John F. McIntyre III	48	5	Senior Vice President—since May 2003. Prior to that from September 1998 to April 2003, he served as Senior Vice President of Forest Oil International Corporation, one of our wholly owned subsidiaries. Prior to joining Forest in September 1998, he served as Joint Venture Manager for YPF, a oil and gas company in Argentina.
Newton W. Wilson III	53	3	Senior Vice President—General Counsel and Secretary since December 2000. Mr. Wilson served as a consultant to Mariner Energy LLC from 1999 to December 2000 and a consultant to Sterling City Capital from 1998 to 1999. He served in various capacities at Union Texas Petroleum Holdings, Inc. from 1993-1998, and was President and Chief Operations Officer of Union Texas Americas Ltd. from 1996 to 1998.
Matthew A. Wurtzbacher	41	5	Senior Vice President—Corporate Planning and Development since May 2003. From December 2000 to May 2003, he served as our Vice President—Corporate Planning and Development and from June 1998 to December 2000, he served as Manager—Operational Planning and Corporate Engineering.
Joan C. Sonnen	50	14	Vice President—Controller and Chief Accounting Officer since December 2000. Ms. Sonnen served as our Vice President—Controller and Corporate Secretary from May 1999 to December 2000 and has served as our Controller since December 1993.

Name	Age	Years with Forest	Office(1)
R. Scot Woodall	42	4	Vice President—Western United States business unit since March 2004. Mr. Woodall joined Forest in October 2000 and served as Production and Engineering Manager for the Western Region. From 1992 to September 2000 he served as Operations and Engineering Manager—Rocky Mountain Division, at Santa Fe Synder Corporation.

(1) The term of office of each officer is one year from the date of his or her election immediately following the last annual meeting of shareholders and until the officer's respective successor has been elected and qualified or until his or her earlier death, resignation or removal from office whichever occurs first.

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

Common Stock

Forest has one class of common shares outstanding, its common stock, par value $.10 per share (Common Stock). Forest's Common Stock is traded on the New York Stock Exchange under the symbol "FST". On February 27, 2004, there were 53,733,381 outstanding shares of our Common Stock held by 799 holders of record. The number of holders does not include the shareholders for whom shares are held in a "nominee" or "street" name.

The table below reflects the high and low intraday sales prices of the Common Stock on the New York Stock Exchange composite tape during each fiscal quarterly period of 2002 and 2003. There were no dividends declared on the Common Stock in 2002 or 2003. On February 27, 2004, the closing price of Forest Common Stock was $25.95.

		High	Low
2002:	First Quarter	$29.95	$23.50
	Second Quarter	32.44	26.95
	Third Quarter	28.75	20.69
	Fourth Quarter	29.06	22.97
2003:	First Quarter	28.75	19.65
	Second Quarter	27.02	20.52
	Third Quarter	25.40	19.80
	Fourth Quarter	29.56	23.21

Warrants

Forest's warrants are quoted on the NASDAQ Bulletin Board. At December 31, 2003, Forest had three series of warrants outstanding.

2004 Warrants. At December 31, 2003, Forest had outstanding 236,030 warrants expiring on February 15, 2004 (the 2004 Warrants), which were held by 422 holders of record. Each 2004 Warrant entitled the holder to purchase 0.8 shares of Common Stock for $16.67, or an equivalent per share price of $20.84. From January 1, 2004 through February 15, 2004, 210,337 warrants were exercised via both cash and cashless exercise provisions pursuant to which 151,938 shares of Common Stock were issued. On February 15, 2004, the remaining 2004 Warrants expired unexercised.

2005 Warrants. At February 27, 2004, Forest had outstanding 237,394 warrants expiring on February 15, 2005 (the 2005 Warrants), which were held by 425 holders of record. Each 2005 Warrant entitles the holder to purchase 0.8 shares of Common Stock for $20.83, or an equivalent per share price of $26.04. Forest's 2005 Warrants are quoted on the NASDAQ Bulletin Board under the symbol "FTYLZ.OB." On February 27, 2004, or the last day of activity prior thereto, the closing price of the 2005 Warrants was $2.31. The table below reflects the high and low intraday sales prices of the 2005 Warrants on the NASDAQ Bulletin Board during each fiscal quarter in 2002 and 2003.

		High	Low
2002:	First Quarter	$ 8.00	$ 6.20
	Second Quarter	9.80	7.50
	Third Quarter	9.65	6.50
	Fourth Quarter	7.95	5.00
2003:	First Quarter	7.00	3.05
	Second Quarter	3.90	2.51
	Third Quarter	2.85	1.25
	Fourth Quarter	3.50	1.50

Subscription Warrants. At February 27, 2004, Forest also had outstanding 1,752,355 subscription warrants (the Subscription Warrants), which were held by 10 holders of record. Each Subscription Warrant entitles the holder to purchase 0.8 shares of Common Stock for $10.00, or an equivalent per share price of $12.50. The Subscription Warrants expire on March 20, 2010 or earlier upon notice of expiration by Forest if, after March 20, 2004, the market price of the Common Stock has exceeded 300% of the exercise price, or $37.50 per share, for a period of 30 consecutive trading days. Forest's Subscription Warrants are quoted on the NASDAQ Bulletin Board under the symbol "FTYLL.OB". On February 27, 2004, or the last day of activity prior thereto, the closing price of the Subscription Warrants was $13.00. The table below reflects the high and low intraday sales prices of the Subscription Warrants on the NASDAQ Bulletin Board during each fiscal quarter in 2002 and 2003.

		High	Low
2002:	First Quarter	$15.00	$15.00
	Second Quarter	17.75	14.50
	Third Quarter	14.13	11.00
	Fourth Quarter	14.91	9.75
2003:	First Quarter	13.75	9.00
	Second Quarter	10.00	9.30
	Third Quarter	14.00	10.25
	Fourth Quarter	15.00	15.00

Forest's warrants were originally issued by Forcenergy in connection with its plan of reorganization under the Bankruptcy Code, and were converted into warrants to purchase Forest common stock pursuant to our merger with Forcenergy on December 7, 2000. The issuance of Forest common stock upon exercise of the warrants is exempt from registration under the Securities Act of 1933 pursuant to section 1145 of the Bankruptcy Code. During 2003, Forest issued 1,573 shares of common stock pursuant to the exercise of warrants.

Dividend Restrictions

Forest's present or future ability to pay dividends is governed by (i) the provisions of the New York Business Corporation Law, (ii) Forest's 8% Senior Notes due 2008, Forest's 8% Senior Notes due 2011 and Forest's 7¾% Senior Notes due 2014, and (iii) our credit facilities dated as of December 7, 2000 with JPMorgan Chase and JPMorgan Chase Bank, Toronto Branch. The provisions in the indentures pertaining to the 8% Senior Notes due 2008 and 2011 and the 7¾% Senior Notes due 2014, and the credit facilities limit our ability to make restricted payments, which include dividend payments.

Forest has not paid dividends on its Common Stock during the past five years and does not presently anticipate that it will do so in the foreseeable future. The future payment of dividends, if any, on the Common Stock is within the discretion of the Board of Directors and will depend on Forest's earnings, capital requirements, financial condition and other relevant factors. There is no assurance that Forest will pay any dividends. For further information regarding our equity securities and our ability to pay dividends on our Common Stock, see Notes 4 and 6 of Notes to Consolidated Financial Statements.

For equity compensation plan information, see Part III, Item 12, Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, of this Form 10-K.

PART II

Item 6. Selected Financial and Operating Data

The following table sets forth selected financial and operating data of Forest as of and for each of the years in the five-year period ended December 31, 2003. This data should be read in conjunction with Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, and the Consolidated Financial Statements and Notes thereto.

On December 7, 2000, Forest completed its merger with Forcenergy. The merger was accounted for as a pooling of interests for accounting and financial reporting purposes. Under this method of accounting, the recorded assets and liabilities of Forest and Forcenergy were carried forward to the combined company at their recorded amounts on the date of the merger. Income and expense amounts reported for the combined company for 2000 include amounts attributable to the operations of both Forest and Forcenergy for the entire year. Forcenergy was merged into Forest on the date of the merger and, accordingly, all amounts attributable to periods after the merger represent the operations of the combined entities. The results of operations of Forcenergy prior to December 31, 1999, the effective date of its reorganization and fresh-start reporting, are not included in the financial statements of the combined company. In conjunction with the merger with Forcenergy, Forest effected a 1-for-2 reverse stock split. Unless otherwise indicated, all share and per share amounts included herein give retroactive effect to this reverse stock split.

	Years Ended December 31,				
	2003	2002	2001	2000	1999
	(In Thousands Except Per Share Amounts, Volumes and Prices)				
FINANCIAL DATA					
Revenue:					
Oil and gas sales	$ 655,193	471,740	714,852	623,624	189,895
Processing income, net	1,985	1,128	(85)	213	3,104
Total revenue	$ 657,178	472,868	714,767	623,837	192,999
Net earnings from continuing operations	$ 90,228	21,083	106,437	117,151	20,276
(Loss) income from discontinued operations (net of tax)	(7,731)	193	(2,694)	13,457	(1,233)
Cumulative effect of change in accounting principle for recording asset retirement obligation (net of tax)	5,854	—	—	—	—
Net earnings	$ 88,351	21,276	103,743	130,608	19,043
Net earnings attributable to common stock	$ 88,351	21,276	103,743	126,440	19,043
Weighted average number of common shares outstanding	49,450	46,935	47,674	46,330	23,971
Basic earnings (loss) per share:					
Earnings attributable to common stock from continuing operations	$ 1.82	.45	2.23	2.44	.85
Loss from discontinued operations (net of tax)	(.15)	—	(.05)	.29	(.06)
Cumulative effect of change in accounting principle for recording asset retirement obligation (net of tax)	.12	—	—	—	—
Earnings attributable to common stock	$ 1.79	.45	2.18	2.73	.79
Diluted earnings (loss) per share:					
Earnings attributable to common stock from continuing operations	$ 1.79	.44	2.16	2.36	.84
Loss from discontinued operations (net of tax)	(.15)	—	(.05)	.28	(.05)
Cumulative effect of change in accounting principle for recording asset retirement obligation (net of tax)	.11	—	—	—	—
Earnings attributable to common stock	$ 1.75	.44	2.11	2.64	.79
Total assets	$2,683,548	1,924,681	1,796,369	1,752,378	1,474,689
Long-term debt	$ 929,971	767,219	594,178	622,234	686,153
Other long-term liabilities	$ 294,670	44,576	37,950	31,241	25,112
Shareholders' equity	$1,185,798	921,211	923,943	858,966	558,984

	Years Ended December 31,				
	2003	2002	2001	2000	1999
	(In Thousands Except Per Share Amounts, Volumes and Prices)				
OPERATING DATA					
Annual production:					
Gas (MMCF)	96,977	92,068	108,394	113,842	61,702
Liquids (MBBLS)	8,701	8,657	10,600	11,427	4,397
Average sales price:					
Gas (per MCF)	$ 4.53	3.13	4.32	3.23	2.18
Liquids (per Barrel)	$ 24.77	21.16	23.31	22.46	13.51
Capital expenditures, net of asset sales(1)	$ 716,554	352,812	416,316	372,688	104,612
Proved Reserves:					
Gas (MMCF)	808,068	813,394	828,549	844,058	825,623
Liquids (MBBLS)	81,324	124,366	119,549	89,241	97,086
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$2,307,930	2,053,148	1,346,653	3,694,431	1,419,022
Prices used in calculating present value at end of year proved reserves:					
Gas (per MCF):					
United States	$ 5.79	4.16	2.66	9.52	2.37
Canada	$ 4.52	3.30	2.06	6.11	1.66
Liquids (per BBL):					
United States	$ 29.89	27.85	17.01	23.84	22.38
Canada	$ 27.84	26.63	15.05	23.59	19.98

(1) Does not include estimated discounted asset retirement obligations of $63.7 million related to assets placed in service during the year ended December 31, 2003.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

All expectations, forecasts, assumptions and beliefs about our future financial results, condition, operations, strategic plans and performance are forward-looking statements, as described in more detail in Part I, Item 1, Business—Forward-Looking Statements, of this Form 10-K. Our actual results may differ materially because of a number of risks and uncertainties. Some of these risks and uncertainties are detailed under the heading "—Risk Factors" below and elsewhere in this Form 10-K. Historical statements made herein are accurate only as of the date of filing of this Form 10-K with the Securities and Exchange Commission and may be relied upon only as of that date.

The following discussion and analysis should be read in conjunction with Forest's Consolidated Financial Statements and Notes thereto.

Overview

We are an independent oil and gas company engaged in the acquisition, exploration, development and production of natural gas and liquids in North America and selected international locations. 2003 was a year mixed with successes and significant disappointments and a year in which we changed our corporate leadership and strategies.

2003 Highlights:

The successes included:

- better production performance (149 BCFE in 2003 vs. 144 BCFE in 2002),
- significantly higher revenue (primarily as a result of higher production and oil and gas prices),
- lower lease operating expenses ($4.5 million lower in 2003 than 2002 despite a $6 million increase in production and ad valorem taxes),
- significantly higher net income (resulting from higher production, higher realized oil and gas prices and lower expenses),
- continued drilling success on deep shelf prospects in the Gulf of Mexico, and
- acquisitions totaling 322 BCFE of estimated proved reserves in properties located in the Gulf of Mexico, Gulf Coast, South Texas and the Permian Basin. These properties were acquired for a total of $391 million (net of taxes) or $1.22 per MCFE and will add to our production in 2004.

Despite these successes, we experienced disappointing production performance and drilling results in a number of areas, the most significant of which was the Redoubt Shoal Field in the Cook Inlet of Alaska. The total downward revisions of estimated proved reserves taken in 2003 was 473 BCFE, of which approximately 62% was attributable to a downward revision of our estimated proved oil reserves at Redoubt Shoal Field. Proved reserves were 1,296 BCFE at year-end 2003, a year over year reduction of approximately 17%. See "*—2003 Reserve Revisions*" below.

In 2003 we also experienced a leadership change and revised our strategies. In the third quarter of 2003, we named a new chief executive officer and split the CEO and Chairman of the Board positions, also naming a new non-executive Chairman. Our new leadership revised our strategies late in the third quarter. We established a four-point plan to achieve increased value for our investors, consisting of:

- a focus on cost control,
- reduced exposure to frontier exploration in favor of lower risk exploitation,
- pursuit of asset acquisitions as an integral part of our investment program, and

• a focus on our financial strength to fund growth.

We implemented our plan in the fourth quarter and acquired 244 BCFE of proved reserves in that quarter. These acquisitions now make up almost 20% of our proved reserve base.

One of these strategies, the focus on our financial strength to fund growth, could be a distinct challenge. Over time, we would like to achieve a debt/capitalization percentage of 30-40%. As of December 31, 2003 our debt/capitalization percentage was 44%. When appropriate, we intend to access capital markets, including equity markets, to finance larger acquisitions and help us achieve our debt/capitalization goals.

2003 Reserve Revisions:

During 2003 we revised downward our estimates of proved reserves by a total of approximately 473 BCFE. The downward revision of our estimates was due to information received from production results, drilling activity and other events that occurred primarily in the latter part of 2003. The revisions are not expected to have a material impact on our near-term hydrocarbon production volumes.

Approximately 62% of the total revisions was attributable to the downward revision of our estimate of proved oil reserves in the Redoubt Shoal Field in the Cook Inlet, Alaska. We reduced our estimate of proved oil reserves associated with our Redoubt Shoal Field in Alaska from our 2002 year-end estimate by approximately 49 million barrels, or approximately 85% of the estimated proved oil reserves of this field as of December 31, 2002. Of this revision, approximately 36 million barrels were classified as proved undeveloped as of December 31, 2002. Our estimate of proved oil reserves attributable to the Redoubt Shoal Field was approximately 8 million barrels as of December 31, 2003.

Cumulative investment in exploration, delineation and development of the Redoubt Shoal Field by Forest and its predecessor, Forcenergy, through December 31, 2003 was approximately $310 million. As of December 31, 2003, we estimated total future development capital expenditures, excluding abandonment, for the Redoubt Shoal Field to be approximately $53 million.

We also had downward revisions in our estimated proved reserves for other properties in the fourth quarter of 2003 totaling approximately 143 BCFE. These revisions were in addition to 36 BCFE of downward revisions to estimated proved reserves taken previously in 2003. These downward revisions are due to a variety of factors, including recent production performance and revised field development plans.

As a result of the revisions:

• Our global borrowing base under our credit facilities was reduced from $575 million at December 31, 2003 to $480 million at March 4, 2004.

• The rating agencies may downgrade our credit rating. In February 2004, following announcement of our downward reserve revisions, Forest was placed on "credit watch" by both rating agencies. A downgrade in our credit rating would increase the cost of amounts borrowed under our credit facility and could increase the cost and/or reduce the availability of any additional long-term debt.

• There could be an increase in the cost or amount of credit support (insurance, letters of credit, bonds) required by our counterparties. We could also be required to agree to stricter debt covenants that would restrict our operating flexibility.

We do not believe that the revisions to our estimates of proved reserves or the effects on our liquidity or financial condition will create an event of non-compliance with any of our debt covenants. See "Liquidity and Capital Resources" below.

As a result of the revisions, we are subject to writedowns of our U.S. and Canadian full cost pools under "ceiling test" limitations pursuant to full cost accounting at higher commodity price thresholds than we were prior to the revisions. If we were to record writedowns, shareholders' equity could be reduced significantly.

2004 Outlook:

In executing our plan in 2004, we face a number of uncertainties and challenges. First, while we hedge the price risk for a portion of our production, oil and gas prices, which have a significant impact on our cash flow remain volatile and uncertain. Also, net income will be adversely impacted by the higher depletion expense resulting from our downward revisions to our estimate of proved reserves in 2003. While we believe that there will be a large number of oil and gas acquisition opportunities in 2004 and that we have the skills to make sound acquisitions, we also believe that the competition for these opportunities will be significant. In addition, we have made and will make changes in 2004 to our organization to enhance productivity. While we believe that these changes, over time, will improve our performance, they could, in the short run, negatively impact performance. The borrowing base under our bank facility has been reduced due to the downward revision of our estimates of proved reserves in 2003. We believe, however, that we have adequate liquidity to accomplish our exploration and development spending plan and to also make a meaningful amount of oil and gas property acquisitions. Forest's anticipated expenditures for exploration and development in 2004 are estimated to range from $275 million to $325 million.

Overall, our outlook for 2004 is a positive one. We have changed our direction with four key strategies. The execution of tactics to accomplish these strategies is well underway. We made two sizeable acquisitions in the fourth quarter of 2003 and we are actively pursuing others. We will reduce frontier exploration spending, and we plan to pursue some high-impact exploration spending. We will continue to emphasize cost control in all areas, including general and administrative costs. If the current favorable oil and gas price environment continues, we expect to generate cash flow in 2004 in excess of our expected capital expenditures. In summary, we will continue to take the necessary actions to accomplish our overall objective to enhance shareholder value and to seek prudent growth.

Results of Operations

Net earnings for 2003 were $88.4 million compared to net earnings of $21.3 million in 2002. The increase in earnings was due primarily to the combination of higher average oil and gas sales prices, higher sales volumes, and lower oil and gas production expense.

Net earnings for 2002 were $21.3 million compared to net earnings of $103.7 million in 2001. The decrease in earnings was the result of lower sales volumes and lower average oil and gas sales prices, offset partially by lower operating expenses. Lower sales volumes were primarily the result of property sales in the fourth quarter of 2001, hurricane downtime in the Gulf of Mexico in 2002 and normal declines caused by reduced capital expenditures.

Oil and Gas Sales

Sales volumes, weighted average sales prices, and oil and gas sales revenue for the years ended December 31, 2003, 2002 and 2001 were as follows:

	Years Ended December 31,				
	2003	% Change	2002	% Change	2001
Natural Gas					
Sales volumes (MMCF):					
United States	84,368		78,543		97,400
Canada	12,609		13,525		10,994
Total	96,977	5%	92,068	(15)%	108,394
Sales price received (per MCF)	$ 4.98		3.01		4.16
Effects of energy swaps and collars (per MCF)(1)	(.45)		.12		.16
Average sales price (per MCF)	$ 4.53	45%	3.13	(28)%	4.32
Liquids					
Oil and condensate:					
Sales volumes (MBBLS)	7,850		7,531		9,219
Sales price received (per BBL)	$ 29.03		24.21		23.82
Effects of energy swaps and collars (per BBL)(1)	(3.71)		(1.72)		.55
Average sales price (per BBL)	$ 25.32		22.49		24.37
Natural gas liquids:					
Sales volumes (MBBLS)	851		1,126		1,381
Average sales price (per BBL)	$ 19.62		12.27		16.21
Total Liquids sales volumes (MBBLS):					
United States	7,686		7,477		9,239
Canada	1,015		1,180		1,361
Total	8,701	1%	8,657	(18)%	10,600
Average sales price (per BBL)	$ 24.77	17%	21.16	(9)%	23.31
Total Sales Volumes (MMCFE)					
United States	130,484		123,405		152,834
Canada	18,699		20,605		19,160
Total	149,183	4%	144,010	(16)%	171,994
Average sales price (per MCFE)(1)	$ 4.39	34%	3.28	(21)%	4.15
Total Oil and Gas Sales (in thousands)					
Natural gas	$439,700		288,542		467,767
Oil, condensate and natural gas liquids	215,493		183,198		247,085
Total	$655,193	39%	471,740	(34)%	714,852

(1) Commodity swaps and collars were transacted to hedge the price of spot market volumes against price fluctuations. Hedged natural gas volumes were 49,990 MMCF, 36,050 MMCF and 42,870 MMCF in 2003, 2002 and 2001, respectively. Hedged oil and condensate volumes were 4,597,500 barrels, 3,921,500 barrels, and 3,742,500 barrels in 2003, 2002 and 2001, respectively. These arrangements have been designated as cash flow hedges for accounting purposes and, as a result, the effective portion of the net gains and losses were accounted for as increases and decreases of oil and gas sales. The aggregate net gains (losses) related to our cash flow hedges were $(72,863,000), $(1,742,000) and $22,781,000 for the years ended December 31, 2003, 2002 and 2001, respectively. Those arrangements that are not designated as cash flow hedges for accounting purposes are recorded as non-operating income or expense. Average sales prices have been adjusted to reflect effects of energy swaps and collars.

The increase in oil and gas sales revenue in 2003 compared to 2002 was the result of increased price realizations for both oil and gas, combined with higher sales volumes. In the United States, increases in our sales volumes were attributable primarily to acquisitions made during 2003. In Canada, our sales volumes decreased in 2003 due primarily to higher royalty volumes in the current higher price environment, plant maintenance and the effects of property divestitures in 2002.

The decrease in oil and gas sales revenue in 2002 compared to 2001 was primarily the result of lower product prices and production volumes. Volume decreases were due primarily to the Gulf Coast business unit. Our Gulf of Mexico properties were impacted by the sale of 50% of Forest's interests in the South Marsh Island and Vermilion areas in the fourth quarter of 2001, and also experienced hurricane downtime and normal production declines that were the result of reduced capital expenditures.

Oil and Gas Production Expense

The components of oil and gas production expense for the years ended December 31, 2003, 2002 and 2001 were as follows:

	Years Ended December 31,				
	2003	% Change	2002	% Change	2001
			(In Thousands)		
Direct operating expense and workovers	$125,212	(5)%	131,153	(15)%	154,048
Product transportation	9,536	(33)%	14,174	(9)%	15,579
Production and ad valorem taxes	19,422	45%	13,372	(20)%	16,623
Total oil and gas production expense	$154,170	(3)%	158,699	(15)%	186,250
Oil and gas production expense (per MCFE)	$ 1.03	(6)%	1.10	2%	1.08

Oil and gas production expense includes direct costs incurred to operate and maintain wells and related equipment and facilities, costs of expensed workovers, product transportation costs from the wellhead to the sales point and production and ad valorem taxes. The reduction in 2003 compared to 2002, on both an absolute and a per-unit basis, reflects cost reduction measures employed throughout Forest's operations, offset somewhat by increases in production and ad valorem taxes that were the direct result of higher product sales prices. The decrease in production expense in 2002 compared to 2001 was due primarily to lower direct operating expense.

General and Administrative Expense; Overhead

The following table summarizes the components of total overhead costs incurred during the periods:

	Years Ended December 31,				
	2003	% Change	2002	% Change	2001
			(In Thousands)		
Overhead costs capitalized	$24,519	(6)%	26,000	21%	21,474
General and administrative costs expensed	36,322	(4)	37,642	29	29,138
Total overhead costs	$60,841	(4)%	63,642	26%	50,612
Number of salaried employees at end of year	346	(3)%	356	1%	352

The 4% decrease in overhead costs in 2003 resulted primarily from cost reduction measures in corporate areas and from higher fixed rate overhead recoveries. Cost reductions were achieved despite the inclusion of approximately $3.6 million attributable to severance costs and termination of the

Canadian defined benefit pension plan. The 26% increase in 2002 compared to 2001 was attributable primarily to increases in employee related expenses, legal expense and insurance expense, lower fixed rate overhead cost recoveries for production operations as a result of the Gulf of Mexico property sale and the related change in operatorship of those properties, and lower fixed rate overhead cost recoveries for drilling activities due to decreased capital spending in the 2002 period. The percentage of overhead capitalized remained relatively constant, ranging between 40% and 42% for 2003, 2002 and 2001.

Merger and Seismic License Costs

Merger and seismic licensing costs of $9.8 million in 2001 included banking, legal, accounting, printing and other consulting costs related to the merger with Forcenergy in December, 2000, including severance paid to terminated employees, office closures, employee relocation, data migration, systems integration and costs of transferring seismic licenses from Forcenergy to Forest.

Depreciation and Depletion; Impairments

Depreciation and depletion expense for the years ended December 31, 2003, 2002 and 2001 was as follows:

	Years Ended December 31,				
	2003	% Change	2002	% Change	2001
			(In Thousands)		
Depreciation and depletion expense	$234,822	27%	185,288	(17)%	224,176
Depletion expense per MCFE	$ 1.55	23%	1.26	(2)%	1.29

The 27% increase in depletion expense and the 23% increase in the per-unit depletion rate in 2003 compared to 2002 were due primarily to downward revisions in estimated proved reserves totaling approximately 473 BCFE in 2003. These revisions, which occurred primarily in the fourth quarter of 2003, resulted in a fourth quarter depletion rate of $2.00 per MCFE. The 17% decrease in depletion expense in 2002 compared to 2001 was attributable primarily to lower production volumes.

At December 31, of the years listed below Forest had the following costs of undeveloped properties which were not subject to depletion:

	United States	Canada	International	Total
		(In Thousands)		
2003	$66,339	34,922	56,747	158,008
2002	$77,863	27,240	66,533	171,636
2001	$86,460	48,577	51,577	186,614

In 2003, Forest recorded impairments of oil and gas properties located outside of North America of $16.9 million ($10.5 million net of taxes), related primarily to evaluations of projects in Albania, Italy, Romania, Switzerland and Tunisia. Of this amount, approximately $10.3 million related to our 35% interest in a project in Albania. No impairments were recorded in 2002. In 2001, Forest recorded impairments of oil and gas properties located outside North America of $18.1 million ($11.2 million net of taxes). Of this amount, approximately $10.0 million ($6.2 million net of taxes) related to Albania. Impairments were also recognized in other countries in 2001 based on expiration of certain concessions and evaluations of projects in those countries.

Accretion of Asset Retirement Obligation

Accretion expense of approximately $13.8 million was related to the accretion of Forest's asset retirement obligation pursuant to SFAS No. 143, adopted January 1, 2003. SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Using a cumulative effect approach, in the first quarter of 2003 Forest recorded an increase to net property and equipment of approximately $102.3 million (net of tax), an asset retirement obligation liability of approximately $96.5 million (net of tax) and an after tax credit of approximately $5.9 million for the cumulative effect of the change in accounting principle.

Other Expense, Net

The components of other expense, net for the years ended December 31, 2003, 2002 and 2001 were as follows:

	Years Ended December 31,		
	2003	2002	2001
	(In Thousands)		
Loss on extinguishment of debt	$3,975	5,262	6,066
Franchise taxes	1,679	1,080	1,420
Forest's share of (income) loss of equity method investee	2,043	(30)	2,460
Foreign currency translation losses (gains) on subordinated debt	—	(332)	7,872
Realized and unrealized losses (gains) on derivative instruments	(383)	2,041	(11,932)
Write-off of receivables due from Enron for physical sales of natural gas	—	—	8,305
Other	(350)	(339)	(2,594)
Total other expense	$6,964	7,682	11,597

Losses on extinguishment of debt relate to redemptions of our 8¾% and our 10½% Senior Subordinated Notes for amounts in excess of par value. Franchise taxes are paid to the states of Texas and Louisiana based on capital investment deployed in these states, determined by apportioning total capital as defined by law. Forest's share of income or loss of equity method investee relates to our 40% ownership of a pipeline company that transports our crude oil in Alaska. Foreign currency translation gains and losses relate to the translation of U.S. dollar-denominated notes issued by Canadian Forest. All of the outstanding notes were redeemed in September 2002.

Interest Expense

Interest expense of $49.3 million in 2003 was 2% lower than 2002, primarily because the effects of higher average debt balances were more than offset by lower average interest rates on variable and fixed rate debt and by amortization of gains recognized on termination of interest rate swaps. Interest expense of $50.4 million in 2002 was 1% higher than 2001 due primarily to debt balances that were, on average, 19% higher, offset partially by significantly lower interest rates on variable and fixed rate debt.

Current and Deferred Income Tax Expense

Forest recorded current income tax expense of $693,000 in 2003 compared to $228,000 in 2002 and $2.4 million in 2001. The increase in 2003 compared to 2002 was due primarily to changes in the Federal Alternative Minimum Tax and the exhaustion of certain state net operating losses. The decrease in 2002 compared to 2001 was due primarily to decreases in pre-tax profitability and reduced state tax provisions.

Deferred income tax expense was $53.9 million in 2003 compared to $11.8 million in 2002, and $76.9 million in 2001. The increase in 2003 compared to 2002 was attributable to increased pre-tax profitability and an increase in permanent tax differences, partially offset by a decrease in Canadian taxes of $7,332,000 due to a Canadian federal income tax rate reduction from 28% to 21% over a five year period beginning in 2003. The decrease in 2002 compared to 2001 was due primarily to lower pre-tax profitability.

Results of Discontinued Operations

On March 1, 2004, the assets and business operations of our Canadian marketing subsidiary, ProMark, were sold to Cinergy for $11.2 million CDN. Under the terms of the purchase and sale agreement, Cinergy will market natural gas on behalf of Canadian Forest for five years, unless subject to prior contractual commitments, and will also administer the netback pool formerly administered by ProMark. We could receive additional contingent payments over the next five years if Cinergy meets certain earnings goals with respect to the acquired business. As a result of Forest's fourth quarter 2003 decision to sell the gas marketing operations of ProMark, ProMark's results of operations have been reported as discontinued operations in the consolidated statements of operations for all years presented. The components of (loss) income from discontinued operations for the years ended December 31, 2003, 2002 and 2001 are as follows:

	Years Ended December 31,		
	2003	2002	2001
	(In Thousands)		
Marketing income, net	$ 2,728	2,825	3,550
General and administrative expense	(1,921)	(1,484)	(1,376)
Interest income (expense)	(59)	—	111
Other income, net	606	9	—
Depreciation	(1,325)	(933)	(1,857)
Impairment of contract value	—	—	(3,239)
Current income tax benefit (expense)	27	(40)	(2)
Deferred income tax expense	(2,623)	(184)	119
Loss on sale of discontinued operations	(5,164)	—	—
	$(7,731)	193	(2,694)

Liquidity and Capital Resources

Liquidity is a measure of a company's ability to access cash. We have historically addressed our long-term liquidity requirements through the use of bank credit facilities and cash provided by operating activities as well as through the issuance of debt and equity securities, when market conditions permit. The prices we receive for future oil and natural gas production and the level of production have significant impacts on operating cash flows. We are unable to predict with any degree of certainty the prices we will receive for our future oil and gas production.

We continually examine alternative sources of long-term capital, including bank borrowings, the issuance of debt instruments, the sale of common stock, preferred stock or other equity securities, sales of non-strategic assets, prospects and technical information and joint venture financing. Availability of these sources of capital and, therefore, our ability to execute our operating strategy will depend upon a number of factors, some of which are beyond our control.

In 2003, we revised downward our estimates of proved reserves by 473 Bcfe. As a result of the revisions:

- Our global borrowing base under our credit facilities was reduced from $575 million at December 31, 2003 to $480 million at March 4, 2004.

- The rating agencies may downgrade our credit rating. A downgrade in our credit rating would increase the cost of amounts borrowed under our credit facility and could increase the cost and/or reduce the availability of any additional long-term debt. We could also be required to agree to stricter debt covenants that would restrict our operating flexibility.
- There could be an increase in the cost or amount of credit support (insurance, letters of credit, bonds) required by our counterparties.

We do not believe that the revisions to our estimates of proved reserves or the effects on our liquidity or financial condition will create an event of non-compliance with any of our debt covenants.

Working Capital. Working capital is the amount by which current assets exceed current liabilities. It is not unusual for Forest to have deficits in working capital, exclusive of the effects of derivatives and abandonment liabilities, at the end of a period. Such working capital deficits are principally the result of accounts payable related to exploration and development costs. Settlement of these payables is funded by cash flow from operations or, if necessary, by drawdowns on bank credit facilities.

Forest had a working capital deficit, exclusive of the after-tax effects of derivatives and abandonment liabilities, of approximately $11.8 million at December 31, 2003 compared to a corresponding deficit of approximately $15.2 million at December 31, 2002. The change was due primarily to an increase in accounts receivable offset partially by an increase in accounts payable and a decrease in other current assets.

The increases in both accounts receivable and accounts payable are primarily attributable to revenue and joint interest operations resulting from higher product prices and recent acquisitions. The decrease in current assets relates primarily to decreases in cash calls outstanding and prepaid taxes.

Cash Flow. Historically, one of our primary sources of capital has been net cash provided by operating activities. Net cash provided by operating activities, net cash used by investing activities and net cash provided (used) by financing activities for the years ended December 31, 2003, 2002 and 2001 were as follows:

	Years Ended December 31,				
	2003	% Change	2002	% Change	2001
			(In Thousands)		
Net cash provided by operating activities	$ 381,984	100%	190,772	(62)%	500,810
Net cash used by investing activities	(659,181)	85%	(356,613)	(16)%	(423,656)
Net cash provided (used) by financing activities	274,549	61%	170,828	310%	(81,533)

The increase in net cash provided by operating activities in 2003 compared to 2002 was due primarily to higher average oil and gas prices. The increase in cash used by investing activities in 2003 was due primarily to the acquisition of certain oil and natural gas properties in October 2003, and the purchase of 100% of the stock of a private company on December 31, 2003. Net cash provided by financing activities in 2003 included net bank borrowings of $197.5 million and net proceeds from the issuance of common stock and the exercise of options and warrants of approximately $141.8 million in the aggregate, partially offset by cash used for the redemption of the 10½% Senior Subordinated Notes of $69.4 million in the aggregate. The 2002 period included net borrowings of bank debt of $75.4 million, proceeds from the settlement of interest rate swaps of $35.6 million and net proceeds of $146.8 million from the issuance of the 7¾% Senior Notes, offset by repurchases of the 10½% Senior Subordinated Notes of $23.9 million in the aggregate and repurchases and redemptions of the 8¾% Senior Subordinated Notes of $66.2 million in the aggregate.

The decrease in net cash provided by operating activities in 2002 compared to 2001 was due primarily to lower product prices and decreased production. The decrease in cash used for investing activities in 2002 compared to 2001 was due primarily to decreased exploration and development activity in 2002, offset partially by lower property sales in 2002 compared to 2001. Net cash provided by financing activities in 2002 included net bank debt borrowings of $75.4 million, proceeds from the settlement of interest rate swaps of $35.6 million and net proceeds of $146.8 million from the issuance of the 7¾% Senior Notes, offset by repurchases of the 10½% Senior Subordinated Notes of $23.9 million and repurchases and redemptions of the 8¾% Senior Subordinated Notes of $66.2 million in the aggregate. The 2001 period included net repayments of bank debt of $313.6 million, cash used for redemption of 8¾% Senior Subordinated Notes of $131.9 million, cash used for the purchase of treasury stock of $55.8 million, and net cash proceeds of $420.6 million in the aggregate from the issuance of two series of 8% Senior Notes.

Capital Expenditures. Expenditures for property acquisition, exploration and development were as follows:

	Years Ended December 31,		
	2003	2002	2001
	(In Thousands)		
Property acquisition costs:			
Proved properties	$420,022	3,938	31
Undeveloped properties	4,223	(13)	—
	424,245	3,925	31
Exploration costs:			
Direct costs	90,715	89,117	214,194
Overhead capitalized	13,549	13,246	9,820
	104,264	102,363	224,014
Development costs:			
Direct costs	189,269	235,177	328,962
Overhead capitalized	10,970	12,755	11,654
	200,239	247,932	340,616
Total capital expenditures for property development, acquisition and exploration(1)	$728,748	354,220	564,661

(1) Does not include estimated discounted asset retirement obligations of $63.7 million related to assets placed in service during the year ended December 31, 2003.

Forest's anticipated expenditures for exploration and development in 2004 are estimated to range from $275 million to $325 million. We intend to meet our 2004 capital expenditure financing requirements using cash flows generated by operations, sales of assets and, if necessary, borrowings under bank credit facilities. There can be no assurance, however, that we will have access to sufficient capital to meet these capital requirements. The planned levels of capital expenditures could be reduced if we experience lower than anticipated net cash provided by operations or develop other needs for liquidity, or could be increased if we experience increased cash flow or access additional sources of capital.

In addition, while we intend to continue a strategy of acquiring reserves that meet our investment criteria, no assurance can be given that we can locate or finance any property acquisitions.

Bank Credit Facilities. We have credit facilities totaling $600 million, consisting of a $500 million U.S. credit facility through a syndicate of banks led by JPMorgan Chase and a $100 million Canadian credit facility through a syndicate of banks led by JPMorgan Chase Bank, Toronto Branch. The credit facilities mature in October 2005. In October 2003, we amended the credit facilities to allow us the option of electing to have availability under the credit facilities governed by a borrowing base (Global Borrowing Base), rather than financial covenants. We can exercise the option one time per year and any such election will be irrevocable for a period of one year. The determination of the Global Borrowing Base is made by the lenders taking into consideration the estimated value of our oil and gas properties in accordance with the lenders' customary practices for oil and gas loans. Effective October 30, 2003, we elected to determine availability based on the Global Borrowing Base. Under the Global Borrowing Base, availability will be re-determined semi-annually and the available borrowing amount could be increased or reduced. In addition, Forest and the lenders each have discretion at any time, but not more than once during any calendar year, to have the global borrowing base redetermined. The recent redetermination will not limit these discretionary redeterminations.

If a borrowing base redetermination is less than the outstanding borrowings under the credit facilities, we would be required to repay the amount representing the excess of outstanding borrowings within a prescribed period. If we were unable to pay the excess amount, it would cause an event of default.

In March 2004, in conjunction with the significant downward revisions to our estimated proved oil and gas reserves, we redetermined the Global Borrowing Base. Effective March 4, 2004, the Global Borrowing Base was set at $480 million, with $460 million allocated to the U.S. credit facility and $20 million allocated to the Canadian credit facility. Under the terms of the credit facility, the Global Borrowing Base will next be redetermined in the second quarter of 2004 and the amount of available borrowing could be adjusted at that time.

At December 31, 2003, the unused borrowing amount under the Global Borrowing Base was approximately $276 million in addition to amounts outstanding. On March 4, 2004, after the borrowing base redetermination, our unused borrowing amount was approximately $165 million in addition to amounts outstanding.

At December 31, 2003, there were outstanding borrowings of $291 million under the U.S. credit facility and $1.5 million under the Canadian credit facility, at a weighted average interest rate of 2.36%. In addition to outstanding borrowings under Forest's credit facilities, there were outstanding borrowings in the amount of $30 million under a small credit facility of an acquired company. That facility was repaid and terminated January 2, 2004, using additional borrowings under Forest's U.S. credit facility. At March 4, 2004, there were outstanding borrowings of $309 million under the U.S. credit facility at a weighted average interest rate of 2.31% and there were no borrowings under the Canadian credit facility. At December 31, 2003, we had used the credit facilities for letters of credit in the amount of $5.7 million. At March 4, 2004, we had used the credit facilities for letters of credit in the amount of $5.5 million.

The credit facilities include terms and covenants that place limitations on certain types of activities, including restrictions or requirements with respect to additional debt, liens, asset sales, hedging activities, investments, dividends, and mergers and acquisitions, and include financial covenants. Interest rates and other terms of borrowing under the credit facilities will vary based on our credit ratings and financial condition, as governed by certain financial tests. In particular, any time that availability is not governed by the Global Borrowing Base, the amount available and our ability to borrow under the credit facility is determined by the financial covenants. Under the Global Borrowing Base, the financial covenants can still affect the amount available and our ability to borrow amounts under the credit facility.

In addition, the credit facilities are collateralized by our assets. The U.S. credit facility is secured by a lien on, and a security interest in, a portion of our proved oil and gas properties and related assets in the United States and Canada, a pledge of 65% of the capital stock of Canadian Forest and its parent, 3189503 Canada Ltd., and a pledge of 100% of the capital stock of Forest Pipeline Company. The Canadian credit facility is secured by a lien on the assets of Canadian Forest. Under certain circumstances, we could be obligated to pledge additional assets as collateral.

Credit Ratings. Our bank credit facilities and our senior notes are separately rated by two ratings agencies: Moody's and S&P. In addition, Moody's and S&P have assigned Forest a general corporate credit rating. From time to time, our assigned credit ratings may change. In assigning ratings, the ratings agencies evaluate a number of factors, such as our industry segment, volatility of our industry segment, the geographical mix and diversity of our asset portfolio, the allocation of properties and exploration and drilling activities among short-lived and longer-lived properties, the need and ability to replace reserves, our cost structure, our debt and capital structure and our general financial condition and prospects.

As a result of the significant downward reserve revisions to our estimated proved resrves in 2003, the rating agencies may downgrade our credit rating. In February 2004, following the announcement of our downward revisions to our estimates of proved oil and gas reserves, Forest was placed on "credit watch" by both ratings agencies.

Our bank credit facilities include conditions that are linked to our credit rating. The fees and interest rates on our commitments and loans, as well as our collateral obligations, are affected by our credit ratings. The agreements governing our senior notes do not include adverse triggers that are tied to our credit ratings. The terms of our senior notes include provisions that will allow us greater flexibility if the credit ratings improve to investment grade and other tests have been satisfied. In this event, we would have no further obligation to comply with certain restrictive covenants contained in the indentures governing the senior notes. Our ability to raise funds and the costs of such financing activities may be affected by our credit rating at the time any such activities are conducted.

Dispositions of Assets. As a part of our ongoing operations, we routinely dispose of non-strategic assets. Assets with marginal value or which are not consistent with our operating strategy are identified for sale or trade.

During 2003, we disposed of properties with estimated proved reserves of approximately 7.4 BCF of natural gas and 2,303,000 barrels of oil for total proceeds of approximately $14,445,000. During 2002, we disposed of properties with estimated proved reserves of approximately 3.4 BCF of natural gas and 738,000 barrels of oil for total proceeds of approximately $5,465,000. During 2001, we disposed of properties with estimated proved reserves of approximately 69.8 BCF of natural gas and 4,868,000 barrels of oil for total proceeds of approximately $152,872,000. Of this amount, approximately $118,000,000 related to properties located in the offshore Gulf of Mexico area in which we sold 50% of our interests in connection with a strategic joint venture program.

On March 1, 2004 we sold the gas marketing assets of ProMark to Cinergy. Cinergy will administer on a prospective basis the Canadian Netback Pool. For further information see Part I, Item 1, Business—Sales and Markets, of this Form 10-K.

Common Stock Offerings. In October 2003, Forest issued 5,123,000 shares of common stock at a price of $23.10 per share. Net proceeds from this offering were approximately $112,600,000 after deducting underwriting discounts and commissions and estimated offering expenses. Forest used the net proceeds from the offering to fund a portion of the acquisition of properties from Unocal.

In January 2003, we issued 7,850,000 shares of common stock at a price of $24.50 per share. Net proceeds from this offering (before any exercise of the underwriters' over-allotment option), were approximately $184,400,000 after deducting underwriting discounts and commissions and the estimated expenses of the offering. Forest used the net proceeds from the offering to repurchase, immediately following the closing of the offering, 7,850,000 shares from The Anschutz Corporation and certain of its affiliates. The shares repurchased were cancelled immediately upon repurchase. In February 2003, an additional 900,000 shares of common stock were issued pursuant to exercise of the underwriters' over-allotment option. The net proceeds of $21,168,000 were used for general corporate purposes.

Securities Redeemed and Repurchased. In January 2003 we redeemed the remaining $65,970,000 outstanding principal amount of our 10½% Senior Subordinated Notes at 105.25% of par value, resulting in a loss of $3,975,000 recorded in the first quarter of 2003.

Contractual Obligations. The following table summarizes our contractual obligations as of December 31, 2003:

	2004	2005	2006	2007	2008	After 2008	Total
			(In Thousands)				
Bank debt(1)	$30,000	292,542	—	—	—	—	322,542
Other long-term debt(2)	—	—	—	—	265,000	310,000	575,000
Operating leases(3)	5,166	4,292	2,111	1,338	893	848	14,648
Unconditional purchase obligations(4)	21,004	17,744	13,283	1,743	1,563	1,529	56,866
Approved capital projects(5)	13,449	—	—	—	—	—	13,449
Total contractual obligations	$69,619	314,578	15,394	3,081	267,456	312,377	982,505

(1) Bank debt consists of $292.5 million related to our U.S. and Canadian credit facilities and $30 million of bank debt assumed in conjunction with our acquisition of a private company on December 31, 2003. The bank debt assumed in the acquisition was subsequently paid on January 2, 2004 with proceeds from our U.S. credit facility. For a more detailed discussion of our long-term debt, see Item 7A, Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk and Note 4 of Notes to Consolidated Financial Statements.

(2) Other long-term debt consists of our senior notes. For a more detailed discussion of our long-term debt, see Item 7A, Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk and Note 4 of Notes to Consolidated Financial Statements.

(3) Consists primarily of leases for office space and leases for well equipment rentals.

(4) Consists primarily of firm commitments for gathering, processing and pipeline capacity. Gathering, processing and pipeline capacity commitments in areas that have secondary markets may be mitigated in the future if firm capacities are no longer required. Canadian Forest, on behalf of the Canadian Netback Pool, has firm commitments for pipeline capacity of approximately $44,646,000 through 2009. Canadian Forest, as one of the producers in the Canadian Netback Pool, supplied 42% of the gas to the Canadian Netback Pool in 2003.

(5) Consists of our net share of budgeted expenditures under Authorizations for Expenditure (AFEs) that were approved by us and our joint venture partners as of December 31, 2003. Includes AFEs for which Forest is the operator as well as those operated by others.

In addition to the above commitments, we are committed to make approximately $38.5 million of capital expenditures over the next five years pursuant to the terms of foreign concession arrangements and an exploration agreement in Canada. Nonperformance under these agreements could result in the loss of acreage and concession rights. We also have other long-term liabilities of approximately $24.1 million, primarily related to benefit obligations for which neither the ultimate settlement amounts nor timing of payment can be precisely determined in advance. As of December 31, 2003, $22.1 million of assets were held in trust to satisfy these obligations.

Forest also makes delay rental payments to lessors during the primary terms of oil and gas leases to delay drilling of wells, usually for one year. Although we are not obligated to make such payments, discontinuing them would result in the loss of the oil and gas lease. Our total maximum commitment under these leases, through 2014, totaled approximately $6.3 million as of December 31, 2003.

Estimated costs related to future abandonment liabilities are recorded on our balance sheet. There are currently no contractual obligations related to these costs.

Off-balance Sheet Arrangements. We have no off-balance sheet arrangements.

Other Obligations. We hold a 40% equity interest in an affiliate that owns a petroleum pipeline system within the Cook Inlet area of Alaska. In our capacity as a shareholder, we have agreed to fund our proportionate share of the operating costs and expenses of this affiliate. We may have contingent obligations in the event the affiliate experiences cash deficiencies. In addition, we may have other contingent obligations if the affiliate is unable to meet its indemnification requirements or its obligations to the operator of the pipeline. We are unable to predict or quantify the amount of these obligations, although we have obtained insurance to mitigate the impacts of certain possible outcomes.

Surety Bonds. In the ordinary course of our business and operations, we are required to post surety bonds from time to time with third parties, including governmental agencies. As of February 28, 2004, we have obtained surety bonds from a number of insurance and bonding institutions covering certain of our operations in the United States and Canada in the aggregate amount of approximately $31,896,000. In connection with their administration of offshore leases in the Gulf of Mexico, the MMS annually evaluates each lessee's plugging and abandonment liabilities. The MMS reviews this information and applies certain financial tests including, but not limited to, current asset and net worth tests. The MMS determines whether each lessee is financially capable of paying the estimated costs of such plugging and abandonment liabilities. We annually provide the MMS with our financial information. If we do not satisfy the MMS requirements, we could be required to post supplemental bonds. In the past, Forest has not been required to post supplemental bonds; however, we cannot assure you that we will satisfy the financial tests and remain on the list of MMS lessees exempt from the supplemental bonding requirements. We cannot predict or quantify the amount of any such supplemental bonds or the annual premiums related thereto, but the amount could be substantial. See Part I, Regulation in this Form 10-K for further information.

As a result of the significant downward revisions in our estimated proved reserves in 2003, there could be an increase in the cost of and/or the amount of credit support (insurance, letters of credit, bonds) required by our counterparties.

Critical Accounting Policies, Estimates, Judgments and Assumptions

Alternatives exist among accounting methods we use to report our financial results. The choice of an accounting method can have a significant impact on reported amounts. In addition, application of generally accepted accounting principles requires the use of estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements as well as the revenues and expenses reported during the period. Changes in these estimates, judgments and assumptions will occur as a result of future events, and, accordingly, actual results could differ from amounts estimated.

The more significant areas requiring the use of assumptions, judgments and estimates relate to volumes of oil and gas reserves used in calculating depletion, the amount of future net revenues used in computing the ceiling test limitations and the amount of future capital costs and abandonment obligations used in such calculations. Assumptions, judgments and estimates are also required in determining impairments of undeveloped properties, the valuation of deferred tax assets, and the estimation of fair values for derivative instruments.

The use of estimates, judgments and assumptions and the potential effects thereof are further described in "—Risk Factors—Estimates of oil and gas reserves are uncertain and inherently imprecise" in this Item 7 and in Notes to Consolidated Financial Statements.

Full Cost Method of Accounting. We use the "full cost method" of accounting for our oil and gas operations. Separate cost centers are maintained for each country in which we incur costs. All costs incurred in the acquisition, exploration and development of properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes and overhead related to exploration and development activities) are capitalized. The fair value of estimated future costs of site restoration, dismantlement and abandonment activities is capitalized, with a corresponding asset retirement obligation liability recorded. Capitalized costs applicable to each full cost center are depleted using the units of production method based on conversion to common units of measure using one barrel of oil as an equivalent to six thousand cubic feet of natural gas. Changes in estimates of reserves or future development costs are accounted for prospectively in the depletion calculations. Assuming consistent production year over year, our depletion expense will be significantly higher or lower if we significantly decrease or increase our estimates of remaining proved reserves.

Investments in unproved properties, including related capitalized interest costs, if any, are not depleted pending the determination of the existence of proved reserves. Unproved properties are assessed periodically to ascertain whether impairment has occurred. Unproved properties whose costs are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties, and geographic and geologic data obtained relating to the properties. Where it is not practicable to individually assess the amount of impairment of properties for which costs are not individually significant, such properties are grouped for purposes of assessing impairment. The amount of impairment assessed is added to the costs to be amortized in the appropriate full cost pool.

Where proved reserves are established, the net capitalized costs of oil and gas properties may not exceed a "ceiling limitation" which is based on the present value of estimated future net cash flows from proved reserves including the effects of derivative instruments, discounted at 10%, plus the lower of cost or estimated fair value of unproved properties, all net of expected income tax effects. To the extent the net capitalized costs of oil and gas properties exceed the ceiling limit, the excess is charged to earnings.

Changes in estimates of discounted future net revenues will affect the calculation of the ceiling limitation. We did not have any writedowns related to the full cost ceiling limitation in 2003, 2002 or 2001. As of December 31, 2003, the ceiling limitation exceeded the carrying value of our oil and gas properties by approximately $410 million in the U.S. and $13.1 million (CDN) in Canada. Estimates of discounted future net cash flows at December 31, 2003 were based on average natural gas prices of approximately $5.79 per MCF in the U.S. and approximately $4.52 per MCF in Canada and on average liquids prices of approximately $29.89 per barrel in the U.S. and approximately $27.84 per barrel in Canada. A reduction in oil and gas prices and/or estimated quantities of oil and gas reserves would reduce the ceiling limitation in the U.S. and Canada and could result in a ceiling test writedown. In particular, our Canadian full cost pool could be adversely impacted by moderate declines in commodity prices. In 2003, we revised downward our estimates of proved reserves by 473 BCFE. As a result of the revisions, we are subject to writedowns of our U.S. and Canadian full cost pools under "ceiling test" limitations pursuant to full cost accounting at higher commodity price thresholds than we were prior to the revisions. If we were to record writedowns, shareholders' equity could be reduced significantly.

In countries where the existence of proved reserves has not yet been determined, leasehold costs, seismic costs and other costs incurred during the exploration phase remain capitalized as unproved property costs until proved reserves have been established or until exploration activities cease. If exploration activities result in the establishment of proved reserves, amounts are reclassified as proved properties and become subject to depreciation, depletion and amortization and the application of the ceiling limitation. If exploration efforts are unsuccessful in establishing proved reserves and exploration activities cease, the amounts accumulated as unproved costs are charged against earnings as impairments. As of December 31, 2003, costs related to these international projects of approximately $56.7 million were not being depleted pending determination of the existence of proved reserves. In 2003, we recorded an impairment of $16.9 million ($10.5 million net of taxes) related primarily to concessions in Albania, Italy, Romania, Switzerland and Tunisia. No impairments were recorded in 2002. In 2001, we recorded impairments of $18.1 million ($11.2 million net of tax). Of this amount, approximately $10.0 million ($6.2 million net of taxes) was related to Albania. Impairments were also recognized in other countries based on expiration of certain concessions and evaluations of projects in those countries.

Under the alternative "successful efforts method" of accounting, surrendered, abandoned and impaired leases, delay lease rentals, dry holes and overhead costs are expensed as incurred. Capitalized costs are depleted on a property by property basis under the successful efforts method. Impairments are assessed on a property by property basis and are charged to expense when assessed.

We believe the full cost method is the appropriate method to use to account for our oil and gas exploration and development activities, because we conduct significant exploration programs in the Gulf of Mexico, in Canada and in various international regions and the full cost method more appropriately reports the costs of these exploration programs as part of an overall investment in discovering and developing proved reserves.

Fair Values of Derivative Instruments. We periodically hedge a portion of our oil and gas production through swap and collar agreements. The purpose of the hedges is to provide a measure of stability to our cash flows in an environment of volatile oil and gas prices and to manage the exposure to commodity price risk. We recognize the fair value of all derivative instruments as assets or liabilities on the balance sheet. The accounting treatment for the changes in fair value is dependent upon whether or not a derivative instrument is a cash flow hedge or a fair value hedge, and upon whether or not the derivative qualifies as an effective hedge. Changes in fair value of cash flow hedges are recognized, to the extent the hedge is effective, in other comprehensive income until the hedged item is recognized in earnings. For fair value hedges to the extent the hedge is effective, there is no effect on the statement of operations because changes in fair value of the derivative offset changes in the fair value of the hedged item. For derivative instruments that do not qualify as fair value hedges or cash flow hedges, changes in fair value are recognized in earnings as other income or expense.

The estimation of fair values for our hedging derivatives requires substantial judgment. The fair values of our derivatives are estimated on a monthly basis using an option-pricing model. The option-pricing model uses various factors that include closing exchange prices on the NYMEX, volatility and the time value of options. The estimated future prices are compared to the prices fixed by the hedge agreements, and the resulting estimated future cash inflows (outflows) over the terms of the hedges are discounted using estimated weighted average cost capital. These pricing and discounting variables are sensitive to market volatility as well as to changes in future price forecasts, regional price differentials and interest rates.

Entitlements Method of Accounting for Oil and Gas Sales. We account for oil and gas sales using the "entitlements method." Under the entitlements method, revenue is recorded based upon our ownership share of volumes sold, regardless of whether we have taken our ownership share of such volumes. We record a receivable or a liability to the extent we receive less or more than our share of the volumes and related revenue. Under the alternative "sales method" of accounting for oil and gas sales, revenue is recorded based on volumes taken by us or allocated to us by third parties, regardless of whether such volumes are more or less than our ownership share of volumes produced. Reserve estimates are adjusted to reflect any overproduced or underproduced positions. Receivables or payables are recognized on a company's balance sheet only to the extent that remaining reserves are not sufficient to satisfy volumes over- or under-produced.

Make-up provisions and ultimate settlements of volume imbalances are generally governed by agreements between Forest and its partners with respect to specific properties or, in the absence of such agreements, through negotiation. The value of volumes over- or under-produced can change based on changes in commodity prices.

The entitlements method of accounting for oil and gas sales allows for recognition of revenue based on Forest's actual share of jointly owned production, and matches revenue with related operating expenses. In addition, it provides balance sheet recognition of the estimated value of product imbalances. As of December 31, 2003 Forest had recorded the following amounts in the accompanying balance sheet related to our gas imbalances:

	Value (In Thousands)	Volumes (MMCF)
Gas imbalance receivable	$ 16,161	5,353
Gas imbalance liability	(12,733)	(5,016)
Net gas imbalance receivable	$ 3,428	337

Valuation of Deferred Tax Assets. We use the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are determined based on differences between the financial statement carrying values and their respective income tax bases (temporary differences). Future income tax assets and liabilities are measured using the tax rates expected to be in effect when the temporary differences are likely to reverse. The effect on future income tax assets and liabilities of a change in tax rates is included in operations in the period in which the change is enacted. The amount of future income tax assets recognized is limited to the amount of the benefit that is more likely than not to be realized.

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. Based upon the level of historical taxable income and projections for future taxable income over the periods which the deferred tax assets are deductible, management believes it is more likely than not that we will realize the benefits of these deductible differences, net of the existing valuation allowances at December 31, 2003. The amount of the deferred tax asset considered realizable, however, could be reduced in the near term if estimates of future taxable income during the carryforward periods are reduced.

Impact of Recently Issued Accounting Pronouncements

In June 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 141, *Business Combinations* (SFAS No. 141) and Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* (SFAS No. 142). SFAS No. 141 addresses accounting and reporting for business combinations and is effective for all business combinations initiated after June 30, 2001. SFAS No. 142 addresses the accounting and reporting for acquired goodwill and other intangible assets. The new standard eliminates the requirement to amortize acquired goodwill; instead, such goodwill is required to be reviewed at least annually for impairment. The new standard also requires that, at a minimum, all intangible assets be aggregated and presented as a separate line item in the balance sheet. The adoption of SFAS No. 141 and SFAS No. 142 had no impact on the carrying value of our goodwill or intangible assets.

The Emerging Issues Task Force is currently considering two reporting issues regarding the application of certain provisions of SFAS No. 141 and SFAS No. 142 to companies in the extractive industries, including oil and gas companies. The issues are whether SFAS No. 141 and SFAS No. 142 require registrants to classify the costs of mineral rights associated with extracting oil and gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, we have included the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined that oil and gas companies are required to classify costs of mineral rights associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, we would be required to reclassify approximately $40 million to $50 million at December 31, 2003 and approximately $15 million to $20 million at December 31, 2002, out of oil and gas properties and into a separate intangible assets line item. Our total balance sheet, cash flows and results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with full cost accounting rules. Further, we do not believe the classification of the costs of mineral rights associated with extracting oil and gas as intangible assets would have any impact on our compliance with covenants under our debt agreements.

Statement of Financial Accounting Standards No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* (SFAS No. 149), was issued in April 2003. This statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS No. 133. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003. The adoption of SFAS No. 149 did not have a significant effect on our financial condition or results of operations.

Statement of Financial Accounting Standards No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* (SFAS No. 150), was issued May 2003. SFAS No. 150 establishes standards for how an issuer classifies and measures three classes of freestanding financial instruments (mandatorily redeemable instruments, instruments with repurchase obligations, and instruments with obligations to issue a variable number of shares) with characteristics of both liabilities and equity. Instruments within the scope of the statement must be classified as liabilities on the balance sheet. SFAS No. 150 is effective for all freestanding financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. Forest does not currently hold any financial instruments within the scope of SFAS No. 150.

In December 2003, the FASB issued FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities* (FIN 46R), which addresses how a business enterprise should evaluate whether it has a controlling financial interest in an entity through means other than voting rights and accordingly should consolidate the entity. FIN 46R replaces FASB Interpretation No. 46, *Consolidation of Variable Interest Entities*, which was issued in January 2003. We will be required to apply FIN 46R to variable interests in variable interest entities (VIEs), if any, created after December 31, 2003. We do not currently own any interests in VIEs; therefore, FIN 46R will not affect our consolidated financial statements.

Risk Factors

Forest has made in this Form 10-K, and may from time to time otherwise make in other public filings, press releases and discussions with management, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements include statements, among others, about Forest's operations, performance and financial results and condition, as described in more detail in Part I, Item 1 of this Form 10-K, under the heading "—Forward-Looking Statements." Such statements are subject to risks and uncertainties, and actual results may differ materially from those expressed or implied by the forward-looking statements. Some of these risks and uncertainties are detailed below and elsewhere in this Form 10-K and in Forest's other public filings, press releases and discussions with Forest's management. Forest undertakes no obligation to update or revise any forward-looking statements, except as required by law.

In addition to the information set forth elsewhere in this Form 10-K, the following factors should be carefully considered when evaluating Forest.

Oil and gas price declines could adversely affect Forest's revenue, cash flows and profitability. Prices for oil and natural gas fluctuate widely. Forest's revenues, profitability and future rate of growth depend substantially upon the prevailing prices of oil and natural gas. Increases and decreases in prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. The amount we can borrow from banks may be subject to redetermination based on changes in prices. In addition, we may have ceiling test write-downs when prices decline. Lower prices may also reduce the amount of oil and natural gas that Forest can produce economically. Any substantial or extended decline in the prices of or demand for oil and natural gas would have a material adverse effect on our financial condition and results of operations.

We cannot predict future oil and natural gas prices. Factors that can cause price fluctuations include:

- relatively minor changes in the supply of and demand for oil and natural gas;
- market uncertainty;
- the level of consumer product demand;
- weather conditions;
- domestic and foreign governmental regulations;
- the price and availability of alternative fuels;
- political and economic conditions in oil producing countries, particularly those in the Middle East;
- the foreign supply of oil and natural gas;
- the price of oil and gas imports; or
- general economic conditions.

Hedging transactions may limit our potential gains. In order to manage our exposure to price risks in the marketing of our oil and natural gas, we enter into oil and gas price hedging arrangements with respect to a portion of our expected production. Our hedges are limited in duration, usually for periods of one year or less. While intended to reduce the effects of volatile oil and gas prices, such transactions may limit our potential gains if oil and gas prices rise over the price established by the arrangements. In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;

- there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our future contracts fail to perform under the contracts; or
- a sudden unexpected event materially impacts oil or natural gas prices.

We cannot assure you that our hedging transactions will reduce the risk or minimize the effect of any decline in oil or natural gas prices. For further information concerning prices, market conditions and energy swap and collar agreements, see Part II, Item 7A, Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk of this Form 10-K, and Notes 8 and 10 of Notes to Consolidated Financial Statements.

Certain parties with whom we have long-term and short-term contracts may fail to perform. We have long-term and short-term contracts, including agreements for the sale of oil and natural gas. Parties to these agreements could fail to perform their contractual obligations as a result of circumstances that are beyond our control. Our ability to enforce these contractual obligations may be adversely affected by bankruptcy and other creditors' rights laws. We cannot guarantee that our oil and gas purchasers will not experience material changes in their financial condition that would impact our ability to collect outstanding amounts and efficiently market our oil and gas production.

We may not be able to obtain adequate financing to execute our operating strategy. We have historically addressed our long-term liquidity needs through the use of bank credit facilities and cash provided by operating activities as well as through the issuance of debt and equity securities when market conditions permit. We continue to examine the following alternative sources of long-term capital:

- bank borrowings or the issuance of debt securities;
- the issuance of common stock, preferred stock or other equity securities;
- sales of properties;
- the issuance of nonrecourse production-based financing or net profits interests;
- sales of prospects and technical information; and
- joint venture financing.

The availability of these sources of capital will depend upon a number of factors, some of which are beyond our control. These factors include general economic and financial market conditions, oil and natural gas prices and the value and performance of Forest. We may be unable to execute our operating strategy if we cannot obtain capital from these sources.

We may not be able to fund our planned capital expenditures. We spend and will continue to spend a substantial amount of capital for the development, exploration, acquisition and production of oil and natural gas reserves. Our capital expenditures for exploration and development during 2003 were \$305 million, and totaled \$350 million and \$565 million in 2002 and 2001, respectively. In addition, in 2003 and 2002 we expended \$424 million and \$4 million, respectively, for oil and gas property acquisitions. We expect such capital expenditures in 2004 to be approximately \$275 million to \$325 million. If low oil and natural gas prices, drilling or production delays, operating difficulties or other factors, many of which are beyond our control, cause our revenues and cash flows from operations to decrease, we may be limited in our ability to spend the capital necessary to complete our drilling and development program.

In October 2003, we elected to determine availability under our bank credit facility based on a global borrowing base that is re-determined semi-annually, and may be re-determined at other times during a year at the option of the Company or the lenders. In March 2004, we re-determined the global borrowing base due to the significant downward revisions in our estimated proved reserves at December 31, 2003. The global borrowing base was reduced and may be subject to further reductions if oil and gas prices decline or we have additional downward revisions. See "*—Leverage will materially affect our operations*" below.

In addition, if availability under our credit facilities is reduced as a result of a borrowing base limitation or the covenants and financial tests contained in the agreements, our ability to fund our planned capital expenditures could be adversely affected. After utilizing our available sources of financing, we could be forced to raise additional debt or equity proceeds to fund such expenditures. We cannot assure you that additional debt or equity financing or cash generated by operations will be available to meet these requirements.

A curtailment of capital spending could adversely affect our ability to replace production and our future cash flow from operations.

Estimates of oil and gas reserves are uncertain and inherently imprecise. This Form 10-K contains estimates of our proved oil and gas reserves and the estimated future net cash flows from such reserves. These estimates are based upon various assumptions, including assumptions required by the Securities and Exchange Commission relating to oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and gas prices, revenues, taxes, development expenditures and operating expenses may vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves set forth. In certain situations, hydrocarbon reservoirs underlying our properties may extend beyond the boundaries of our own acreage to adjacent acreage owned by others. In this case, our properties may also be susceptible to hydrocarbon drainage from production by the operators on those adjacent properties. Also, we may revise estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control. Such variances may be material. For example, see our discussion of 2003 reserve revisions in Part I, Item 2, Properties, of this Form 10-K.

At December 31, 2003, approximately 25% of our estimated proved reserves were undeveloped compared to 37% at December 31, 2002. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. In estimating our proved reserves we have assumed that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our oil and gas reserves and the costs associated with these reserves in accordance with generally accepted petroleum engineering and evaluation principles, we cannot assure you that actual costs will not vary from the estimates, that development will occur as scheduled or that the results will be as estimated. See Note 13 of Notes to Consolidated Financial Statements.

You should not assume that the present value of future net cash flows referred to in this Form 10-K is the current market value of our estimated oil and gas reserves. In accordance with Securities and Exchange Commission requirements, the estimated discounted future net cash flows from proved reserves are based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in consumption by purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of oil and gas properties will affect the timing of actual future net cash flows from estimated proved reserves and their present value. In addition, the 10% discount factor, which is required by the Securities and Exchange Commission to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor for Forest. The effective interest rate at various times and the risks associated with Forest or the oil and gas industry in general will affect the appropriateness of the 10% discount factor.

The process of estimating oil and gas reserves is a complex subjective process of estimating underground accumulations of oil and natural gas and their recoverability that cannot be measured in an exact way. Such process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. The accuracy of any reserve estimate depends on the quality of available data and the interpretation of such data. Therefore, these estimates are inherently imprecise.

Leverage will materially affect our operations. As of December 31, 2003, our long-term debt was approximately $930 million, including approximately $293 million outstanding under our global bank credit facilities. Our long-term debt represented 44% of our total capitalization at December 31, 2003.

Our level of debt affects our operations in several important ways, including the following:

- a significant portion of our cash flow from operations is used to pay interest on borrowings;
- the covenants contained in the agreements governing our debt limit our ability to borrow additional funds, to dispose of assets, or to pay dividends;
- the global borrowing base and the covenants contained in the agreements governing our debt may affect our flexibility in planning for, and reacting to, changes in business conditions;
- a high level of debt could impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes; and
- the terms of the agreements governing our debt permit our creditors to accelerate payments upon an event of default (including an event of default under other agreements) or a change of control.

In addition, we may alter our capitalization significantly in order to make future acquisitions or develop our properties. These changes in capitalization may increase our level of debt significantly. A high level of debt increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of debt depends on our future performance. General economic conditions and financial, business and other factors affect our operations, our future performance and our ability to raise additional capital. Many of these factors are beyond our control.

If we are unable to repay our debt at maturity out of cash on hand, we could attempt to refinance such debt, or repay such debt with the proceeds of any equity offering. We cannot assure you that we will be able to generate sufficient cash flow to pay the interest on our debt or that future debt or equity financing will be available to pay or refinance such debt. In October 2003, we elected to determine availability under our bank credit facility based on a global borrowing base that is re-determined semi-annually, and may be re-determined at other times during a year at our option or the lenders. In March 2004, we re-determined the global borrowing base due to the significant downward revisions in our estimated proved reserves at December 31, 2003. The global borrowing base was reduced, may be subject to further reductions if oil and gas prices decline or we have additional downward revisions. If, following such a redetermination, our outstanding borrowings exceed the amount of the re-determined borrowing base, we will be forced to repay a portion of the outstanding borrowings in excess of the re-determined borrowing base. We cannot assure you that we will have sufficient funds to make such repayments. If we are not able to negotiate renewals of our borrowings or to arrange new financing, we may have to sell significant assets. Any such sale would have a material adverse effect on our business and financial results. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, our credit ratings and our value and performance at the time of such offering or other financing. We cannot assure you that any such offering or refinancing can be successfully completed.

Lower oil and gas prices may cause us to record ceiling limitation writedowns. We use the full cost method of accounting to report our oil and gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under full cost accounting rules, the net capitalized costs of oil and gas properties may not exceed a "ceiling limit" which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%, plus the lower of cost or fair market value of unproved properties. If net capitalized costs of oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling test writedown." This charge would not impact cash flow from operating activities, but would reduce our shareholders' equity. The risk that we will be required to write down the carrying value of our oil and gas properties increases when oil and gas prices are low or volatile. In addition, writedowns may occur if we experience substantial downward adjustments to our estimated proved reserves or our undeveloped property values, if estimated future development costs increase or if purchasers cancel long-term contracts for our natural gas production. We cannot assure you that we will not experience ceiling test writedowns in the future. For example, our Canadian full cost pool, in particular, could be adversely impacted by moderate declines in commodity prices.

We may incur significant abandonment costs or be required to post substantial performance bonds in connection with the plugging and abandonment of wells, platforms and pipelines. We are responsible for the costs associated with the plugging of wells, the removal of facilities and equipment and site restoration on our oil and gas properties, pro rata to our working interest. Future liabilities for projected abandonment costs, net of estimated salvage values, are included as a reduction in the future cash flows from our reserves in our reserve reporting. As of December 31, 2003, our estimated discounted asset retirement obligation liability recorded in the balance sheet was approximately $211.4 million, primarily for properties in offshore Gulf of Mexico and Alaska waters. Approximately $20 million of abandonment costs are anticipated to be incurred in 2004, all of which are expected to be funded by cash flow from operations. Estimates of abandonment costs and their timing may change due to many factors, including actual drilling and production results, inflation rates, changes in abandonment techniques and technology, and changes in environmental laws and regulations.

We may not be able to replace production with new reserves. In general, the volume of production from oil and gas properties declines as reserves are depleted. The decline rates depend on reservoir characteristics. Many Gulf of Mexico reservoirs experience high decline rates, while the decline rates in long-lived fields in other regions are lower. Production from the Gulf Coast reservoirs represented approximately 58% of our total production in 2003 and is expected to be a greater percentage in 2004. Our reserves will decline as they are produced unless we acquire properties with proved reserves or conduct successful exploration and development activities. Forest's future natural gas and oil production is highly dependent upon its level of success in finding or acquiring additional reserves. The business of exploring for, developing or acquiring reserves is capital intensive and uncertain. We may be unable to make the necessary capital investment to maintain or expand our oil and gas reserves if cash flow from operations is reduced and external sources of capital become limited or unavailable. We cannot assure you that our future exploration, development and acquisition activities will result in additional proved reserves or that we will be able to drill productive wells at acceptable costs.

Our operations are subject to numerous risks of oil and gas drilling and production activities. Oil and gas drilling and production activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas reservoirs will be found. The cost of drilling and completing wells is often uncertain. Oil and gas drilling and production activities may be shortened, delayed or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;
- geological irregularities or pressure in formations;
- equipment failures or accidents;

- weather conditions;
- shortages in labor;
- shortages or delays in the delivery of equipment; and
- failure to secure necessary regulatory approvals and permits.

The prevailing prices of oil and natural gas also affect the cost of and the demand for drilling rigs, production equipment and related services.

We cannot assure you that the new wells we drill will be productive or that we will recover all or any portion of our investment. Drilling for oil and natural gas may be unprofitable. Drilling activities can result in dry wells and wells that are productive but do not produce sufficient net revenues after operating and other costs.

Our industry experiences numerous operating risks. The exploration, development and production of oil and natural gas involves risks. These operating risks include the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards. Environmental hazards include oil spills, gas leaks, pipeline ruptures or discharges of toxic gases. If any of these industry operating risks occur, we could have substantial losses. Substantial losses may be caused by injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. For example, a substantial portion of our oil and gas operations is located offshore in the Gulf of Mexico. The Gulf of Mexico area experiences tropical weather disturbances, some of which can be severe enough to cause substantial damage to facilities and possibly interrupt production. In accordance with industry practice, we maintain insurance against some, but not all, of the risks described above. We cannot assure you that our insurance will be adequate to cover losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase.

Our international operations may be adversely affected by currency fluctuations and economic and political developments. We have significant oil and gas operations in Canada. The expenses of such operations, which represented approximately 10% of consolidated cash costs of oil and gas operations, are payable in Canadian dollars. Most of the revenue from Canadian natural gas and oil sales, which represented 10% of total oil and gas revenue in 2003, is based upon U.S. dollars price indices. As a result, Canadian operations are subject to the risk of fluctuations in the relative value of the Canadian and U.S. dollars. We have also acquired additional oil and gas assets in other countries. Although there are no material operations in these countries, our foreign operations may also be adversely affected by political and economic developments, royalty and tax increases and other laws or policies in these countries, as well as U.S. policies affecting trade, taxation and investment in other countries. In South Africa we have an interest in offshore properties with the potential for gas production. No proved reserves have been assigned to these properties as commercial sales contracts have not been established. If we are unable to arrange for commercial use of these properties, we may not be able to recoup our investment and will not realize our anticipated financial and operating results for these properties.

Competition within our industry may adversely affect our operations. We operate in a highly competitive environment. Forest competes with major and independent oil and gas companies for the acquisition of desirable oil and gas properties and the equipment and labor required to develop and operate such properties. Forest also competes with major and independent oil and gas companies in the marketing and sale of oil and natural gas. Many of these competitors have financial and other resources substantially greater than ours.

Our future acquisitions may not contain economically recoverable reserves. A successful acquisition of producing properties requires an assessment of a number of factors beyond our control. These factors include recoverable reserves, future oil and gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with such assessments, we perform a review of the subject properties, which we believe is generally consistent with industry practices. However, such a review may not reveal all existing or potential problems. In addition, the review will not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every platform or well. Even when a platform or well is inspected, structural and environmental problems are not necessarily discovered. We are not always able to obtain contractual indemnification for pre-closing liabilities, including environmental liabilities. In addition, competition for producing oil and gas properties is intense and many of our competitors have financial and other resources which are substantially greater than those available to us. Therefore, we cannot assure you that we will be able to acquire oil and gas properties that contain economically recoverable reserves or that we will acquire such properties at acceptable prices.

There are uncertainties in successfully integrating our acquisitions. Integrating acquired businesses and properties involves a number of special risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and that unforeseen difficulties can arise in integrating operations and systems and retaining and assimilating the employees. In addition, although we perform a diligent review of the properties acquired in connection with such acquisitions in accordance with industry practices, such reviews are inherently incomplete. These reviews may not necessarily reveal all existing or potential problems or permit us to fully assess the deficiencies and potential associated with the properties. Any of these or similar risks could lead to potential adverse short-term or long-term effects on our operating results.

The marketability of our production depends largely upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities. Transportation space on such gathering systems and pipelines is occasionally limited and at times unavailable due to repairs or improvements being made to such facilities or due to such space being utilized by other companies with priority transportation agreements. The available capacity, or lack of available capacity, on these systems and facilities, could result in the shutting-in of producing wells or the delay or discontinuance of development plans for properties. Our access to transportation options can also be affected by U.S. federal and state and Canadian regulation of oil and gas production and transportation, general economic conditions, and changes in supply and demand. These factors and the availability of markets are beyond our control. If market factors dramatically change, the financial impact on Forest could be substantial and could adversely affect our ability to produce and market oil and natural gas.

Our oil and gas operations are subject to various governmental regulations that materially affect our operations. Our oil and gas operations are subject to various U.S. federal, state and local and Canadian federal and provincial governmental regulations. These regulations may be changed in response to economic or political conditions. Matters regulated include permits for discharges of wastewaters and other substances generated in connection with drilling operations, bonds or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs, reports concerning operations, the spacing of wells, and unitization and pooling of properties and taxation. At various times, regulatory agencies have imposed price controls and limitations on oil and gas production. In order to conserve supplies of oil and gas, these agencies have restricted the rates of flow of oil and gas wells below actual production capacity. In addition, the Federal Oil Pollution Act (OPA), as amended, requires operators of offshore facilities to prove that they have the financial capability to respond to costs that may be incurred in connection with potential oil spills. Under the OPA and other federal and state environmental statutes, owners and operators of certain defined facilities are strictly liable for such spills of oil and other regulated substances, subject to certain limitations. A substantial spill from one of our facilities could have a material adverse effect on our results of operations, competitive position or financial condition. U.S. and non-U.S. laws regulate production, handling, storage, transportation and disposal of oil and gas, by-products from oil and gas and other substances and materials produced or used in connection with oil and gas operations. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

We do not pay dividends. We have not declared any cash dividends on our common stock in a number of years and have no intention to do so in the near future. In addition, we are limited in the amount we can pay by our credit facilities and the indentures pursuant to which our subordinated notes were issued.

Our Restated Certificate of Incorporation and By-laws have provisions that discourage corporate takeovers and could prevent shareholders from realizing a premium on their investment. Certain provisions of our Restated Certificate of Incorporation and By-Laws and provisions of the New York Business Corporation Law may have the effect of delaying or preventing a change in control. Our directors are elected to staggered terms. Also, our Restated Certificate of Incorporation authorizes our board of directors to issue preferred stock without shareholder approval and to set the rights, preferences and other designations, including voting rights of those shares as the board may determine. Additional provisions include restrictions on business combinations, the availability of authorized but unissued common stock and notice requirements for shareholder proposals and director nominations. These provisions, alone or in combination with each other and with the rights plan described below, may discourage transactions involving actual or potential changes of control, including transactions that otherwise could involve payment of a premium over prevailing market prices to shareholders for their common stock.

Our board of directors has adopted a shareholder rights plan. The existence of the rights plan may impede a takeover of Forest not supported by the board of directors, including a proposed takeover that may be desired by a majority of our shareholders or involving a premium over the prevailing market price of our common stock.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk, including the effects of adverse changes in commodity prices, foreign currency exchange rates and interest rates as discussed below.

Commodity Price Risk

We produce and sell natural gas, crude oil and natural gas liquids for our own account in the United States and Canada. As a result, our financial results are affected when prices for these commodities fluctuate. Such effects can be significant. In order to reduce the impact of fluctuations in prices, we enter into long-term contracts for a portion of our production and use a hedging strategy. Under our hedging strategy, we enter into commodity swaps, collars and other financial instruments. All of our commodity swaps and collar agreements and a portion of our basis swaps in place at December 31, 2003 have been designated as cash flow hedges. These arrangements, which are based on prices available in the financial markets at the time the contracts are entered into, are settled in cash and do not require physical deliveries of hydrocarbons. We periodically assess the estimated portion of our anticipated production that is subject to hedging arrangements, and we adjust this percentage based on our assessment of market conditions and the availability of hedging arrangements that meet our criteria. Hedging arrangements covered 52%, 42%, and 47% of our consolidated production, on an equivalent basis, during the years ended December 31, 2003, 2002 and 2001, respectively.

Long-Term Sales Contracts. A significant portion of Canadian Forest's natural gas production is sold through the Canadian Netback Pool which was administered by ProMark on behalf of Canadian Forest in 2003 and early 2004. At December 31, 2003, the Canadian Netback Pool had entered into fixed price contracts to sell natural gas at the following quantities and weighted average prices:

		Natural Gas
	BCF	Contract Price per MCF
2004	5.5	$2.66 CDN
2005	5.5	$2.75 CDN
2006	5.5	$2.86 CDN
2007	5.5	$2.96 CDN
2008	5.5	$3.08 CDN
2009	3.0	$3.86 CDN
2010	1.7	$5.21 CDN
2011	.7	$5.50 CDN

The administrator of the Canadian Netback Pool aggregates gas from producers for sale to markets across North America. Currently, in addition to Canadian Forest, over 30 producers have contracted with the Canadian Netback Pool. The producers are paid a netback price which reflects all of the revenue from approved customers less the costs of delivery (including transportation, audit and shortfall makeup costs) and an operator marketing fee.

Canadian Forest, as one of the producers in the Canadian Netback Pool, is obligated to supply its contract quantity. In 2003, Canadian Forest supplied 42% of the total netback pool sales quantity. In the 2004 contract year, it is estimated that Canadian Forest will supply approximately 43% of the Canadian Netback Pool quantity. We expect that Canadian Forest's pro rata obligations as a gas producer will increase in 2005 and future years. In order to satisfy its supply obligations to the Canadian Netback Pool, Canadian Forest may be required to cover its obligations in the market.

The administrator of the Canadian Netback Pool, now Cinergy, is required to acquire gas in the event of a shortfall between the gas supply and market obligations. A shortfall could occur if a gas producer fails to deliver its contractual share of the supply obligations of the Canadian Netback Pool.

The cost of purchasing gas to cover any shortfall is a cost of the Canadian Netback Pool. The prices paid for shortfall gas would typically be spot market prices and may differ from the market prices received from the customers of the Canadian Netback Pool. Higher spot prices would reduce the average Canadian Netback Pool price paid to the gas producers, including Canadian Forest. Shortfalls in gas produced may occur in the future. We cannot predict with any certainty the amount of any such shortfalls.

In addition to its commitments to the Netback Pool, Canadian Forest is committed to sell natural gas at the following quantities and weighted average prices:

	Natural Gas	
	BCF	Contract Price per MCF
2004	.5	$3.95 CDN
2005	.5	$4.11 CDN
2006	.4	$4.27 CDN

Hedging Program. In a typical commodity swap agreement, Forest receives the difference between a fixed price per unit of production and a price based on an agreed upon published, third-party index if the index price is lower. If the index price is higher, Forest pays the difference. By entering into swap agreements we effectively fix the price that we will receive in the future for the hedged production. Our current swaps are settled in cash on a monthly basis. As of December 31, 2003, Forest had entered into the following swaps accounted for as cash flow hedges:

	Natural Gas		Oil (NYMEX WTI)	
	BBTUs per Day	Average Hedged Price per MMBTU	Barrels per Day	Average Hedged Price per BBL
First Quarter 2004	94.9	$5.03	11,850	$25.79
Second Quarter 2004	112.3	$4.72	12,850	$25.70
Third Quarter 2004	112.3	$4.72	10,850	$25.60
Fourth Quarter 2004	85.7	$4.78	6,850	$25.90
First Quarter 2005	70.0	$4.63	2,500	$25.45
Second Quarter 2005	70.0	$4.63	2,500	$25.45
Third Quarter 2005	70.0	$4.63	2,500	$25.45
Fourth Quarter 2005	70.0	$4.63	2,500	$25.45

Between January 1, 2004 and March 5, 2004, we did not enter into any additional swaps accounted for as cash flow hedges.

We also enter into collar agreements with third parties. A collar agreement is similar to a swap agreement, except that we receive the difference between the floor price and the index price only if the index price is below the floor price, and we pay the difference between the ceiling price and the index price only if the index price is above the ceiling price. In addition, Forest has entered into three-way collars with third parties. These instruments establish two floors and one ceiling. Upon settlement, if the index price is below the lowest floor, we receive the difference between the two floors. If the index price is between the two floors, we receive the difference between the higher of the two floors and the index price. If the index price is between the higher floor and the ceiling, we do not receive or pay any additional amounts. If the index price is above the ceiling, we pay the excess over the ceiling price.

Collars are also settled in cash, either on a monthly basis or at the end of their terms. By entering into collars, we effectively provide a floor for the price that we will receive for the hedged production; however, the collar also establishes a maximum price that we will receive for the hedged production if prices increase above the ceiling price. We enter into collars during periods of volatile commodity prices in order to protect against a significant decline in prices in exchange for foregoing the benefit of price increases in excess of the ceiling price on the hedged production. As of December 31, 2003, Forest had entered into the following gas and oil collars accounted for as cash flow hedges:

	Natural Gas		
	BBTUs Per Day	Average Floor Price per MMBTU	Average Ceiling Price per MMBTU
First Quarter 2004	60.8	$4.03	$5.77

	Oil (NYMEX WTI)		
	Barrels Per Day	Average Floor Price per BBL	Average Ceiling Price per BBL
First Quarter 2004	2,000	$22.00	$24.08

Between January 1, 2004 and March 5, 2004, we entered into the following additional collars accounted for as cash flow hedges:

	Natural Gas		
	BBTUs per Day	Average Floor Price per MMBTU	Average Ceiling Price per MMBTU
Fourth Quarter 2004	6.6	$5.00	$6.70
First Quarter 2005	10.0	$5.00	$6.70

As of December 31, 2003, Forest had entered into the following 3-way natural gas collars accounted for as cash flow hedges:

	Natural Gas			
	BBTUs per Day	Average Lower Floor Price Per MMBTU	Average Upper Floor Price Per MMBTU	Average Ceiling Price per MMBTU
First Quarter 2004	30.0	$3.50	$5.27	$8.75
Second Quarter 2004	25.0	$3.50	$4.75	$5.80
Third Quarter 2004	25.0	$3.50	$4.75	$5.80
Fourth Quarter 2004	11.7	$3.50	$4.75	$6.14

Between January 1, 2004 and March 5, 2004, we entered into the following additional 3-way collars accounted for as cash flow hedges:

	Oil (NYMEX WTI)			
	Barrels per Day	Average Lower Floor Price per BBL	Average Upper Floor Price per BBL	Average Ceiling Price per BBL
First Quarter 2005	1,500	$24.00	$28.00	$32.00
Second Quarter 2005	1,500	$24.00	$28.00	$32.00
Third Quarter 2005	1,500	$24.00	$28.00	$32.00
Fourth Quarter 2005	1,500	$24.00	$28.00	$32.00

We also use basis swaps in conjunction with natural gas swaps in order to fix the differential price between the NYMEX price and the index price at which the hedged gas is sold. As of December 31, 2003, Forest had entered into basis swaps designated as cash flow hedges with weighted average volumes of 31.3 BBTUs per day for 2004. Between January 1, 2004 and March 5, 2004, we did not enter into any additional basis swaps designated as cash flow hedges.

The fair value of our cash flow hedges based on the futures prices quoted on December 31, 2003 was a loss of approximately $55,437,000 ($34,433,000 after tax) which was recorded as a component of other comprehensive income.

As of December 31, 2003, Forest had entered into basis swaps that were not designated as cash flow hedges with weighted average volumes of 107.8 BBTUs per day for 2004 and weighted average volumes of 40.0 BBTUs per day for 2005. Between January 1, 2004 and March 5, 2004 we entered into additional basis swaps not designated as cash flow hedges with weighted average volumes of 1.7 BBTUs per day for 2004 and 32.6 BBTUs per day for 2005.

The fair value of our derivative instruments not designated as cash flow hedges based on the futures prices quoted on December 31, 2003 was a gain of approximately $39,000.

Foreign Currency Exchange Risk

We conduct business in several foreign currencies and thus are subject to foreign currency exchange rate risk on cash flows related to sales, expenses, financing and investing transactions. In the past, we have not entered into any foreign currency forward contracts or other similar financial instruments to manage this risk. Expenditures incurred relative to the foreign concessions held by Forest outside of North America have been primarily U.S. dollar-denominated, as have cash proceeds related to property sales and farmout arrangements.

Interest Rate Risk

The following table presents principal amounts and related average fixed interest rates by year of maturity for Forest's debt obligations at December 31, 2003:

	2005	2008	2011	2014	Total	Fair Value
	(Dollar Amounts in Thousands)					
Bank credit facilities:						
Variable rate(1)	$322,542	—	—	—	322,542	322,542
Average interest rate	2.48%	—	—	—	2.48%	
Long-term debt:						
Fixed rate	$ —	265,000	160,000	150,000	575,000	622,275
Coupon interest rate	—	8.00%	8.00%	7.75%	7.93%	
Effective interest rate(2)	—	7.13%	7.48%	6.56%	7.08%	

(1) Includes debt of $30,000,000 with an interest rate of 3.64% at December 31, 2003, which was paid on January 2, 2004. The average interest rate without this debt would have been 2.36%.

(2) The effective interest rate on the 8% Senior Notes due 2008, the 8% Senior Notes due 2011 and the 7¾% Senior Notes due 2014 will be reduced from the coupon rate as a result of amortization of the gains related to termination of related interest rate swaps.

Item 8. Financial Statements and Supplementary Data

Information concerning this Item begins on the following page.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

H. Craig Clark, our Chief Executive Officer, and David H. Keyte, our Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this Annual Report on Form 10-K. Based on the evaluation, they believe that:

- our disclosure controls and procedures were effective to ensure that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms; and
- our disclosure controls and procedures were effective to ensure that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 was accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Internal Control Over Financial Reporting

There has not been any change in our internal control over financial reporting that occurred during our quarterly period ended December 31, 2003 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Independent Auditors' Report

The Board of Directors and Shareholders
Forest Oil Corporation:

We have audited the accompanying consolidated balance sheets of Forest Oil Corporation and subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2003. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Forest Oil Corporation and subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2003, the Company adopted the provisions of Statement of Financial Accounting Standards Nos. 143 and 145; effective January 1, 2002, the Company adopted the provisions of Statement of Financial Accounting Standards No. 142; and effective January 1, 2001, the Company adopted the provisions of Statement of Financial Accounting Standards No. 133.

KPMG LLP

Denver, Colorado
March 6, 2004

FOREST OIL CORPORATION
CONSOLIDATED BALANCE SHEETS

	December 31, 2003	December 31, 2002
	(In Thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 11,509	13,166
Accounts receivable	158,954	111,760
Derivative instruments	4,130	3,241
Current deferred tax asset (Note 5)	23,302	10,310
Other current assets	17,465	21,994
Total current assets	215,360	160,471
Net property and equipment, at cost, full cost method (Note 4)	2,433,966	1,687,885
Deferred income taxes (Note 5)	—	41,022
Assets held for sale related to discontinued operations (Note 3)	8,589	12,525
Other assets	25,633	22,778
	$2,683,548	1,924,681
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 192,001	153,413
Accrued interest	3,869	6,857
Derivative instruments	49,838	29,120
Asset retirement obligation	23,243	—
Other current liabilities	4,158	2,285
Total current liabilities	273,109	191,675
Long-term debt (Note 4)	929,971	767,219
Asset retirement obligation	188,189	—
Other liabilities	33,758	28,199
Deferred income taxes (Note 5)	72,723	16,377
Shareholders' equity (Notes 4 and 6)		
Common stock, 55,631,924 shares in 2003, (49,125,773 shares in 2002)	5,563	4,913
Capital surplus	1,302,340	1,159,269
Accumulated deficit	(56,495)	(144,548)
Accumulated other comprehensive loss	(9,740)	(41,887)
Treasury stock, at cost, 2,076,731 shares in 2003 (2,101,481 shares in 2002)	(55,870)	(56,536)
Total shareholders' equity	1,185,798	921,211
	$2,683,548	1,924,681

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2003	2002	2001
	(In Thousands Except Per Share Amounts)		
Revenue:			
Oil and gas sales:			
Natural gas	$439,700	$288,542	467,767
Oil, condensate and natural gas liquids	215,493	183,198	247,085
Total oil and gas sales	655,193	471,740	714,852
Processing income (loss), net	1,985	1,128	(85)
Total revenue	657,178	472,868	714,767
Operating expenses:			
Oil and gas production	154,170	158,699	186,250
General and administrative	36,322	37,642	29,138
Merger and seismic licensing	—	—	9,836
Depreciation and depletion	234,822	185,288	224,176
Impairment of oil and gas properties	16,910	—	18,072
Accretion of asset retirement obligation	13,785	—	—
Total operating expenses	456,009	381,629	467,472
Earnings from operations	201,169	91,239	247,295
Other income and expense:			
Other expense, net	6,964	7,682	11,597
Interest expense	49,341	50,433	50,021
Total other income and expense	56,305	58,115	61,618
Earnings before income taxes, discontinued operations and cumulative effect of change in accounting principle	144,864	33,124	185,677
Income tax expense (Note 5):			
Current	693	228	2,363
Deferred	53,943	11,813	76,877
	54,636	12,041	79,240
Net earnings from continuing operations	90,228	21,083	106,437
(Loss) income from discontinued operations (net of tax) (Note 3)	(7,731)	193	(2,694)
Cumulative effect of change in accounting principle for recording asset retirement obligation (net of tax)	5,854	—	—
Net earnings	$ 88,351	21,276	103,743
Weighted average number of common shares outstanding:			
Basic	49,450	46,935	47,674
Diluted	50,353	48,207	49,282
Basic earnings per common share:			
Earnings from continuing operations	$ 1.82	.45	2.23
Loss from discontinued operations (net of tax)	(.15)	—	(.05)
Cumulative effect of change in accounting principle for recording asset retirement obligation (net of tax)	.12	—	—
Net earnings per common share	$ 1.79	.45	2.18
Diluted earnings per common share:			
Earnings from continuing operations	$ 1.79	.44	2.16
Loss from discontinued operations (net of tax)	(.15)	—	(.05)
Cumulative effect of change in accounting principle for recording asset retirement obligation (net of tax)	.11	—	—
Net earnings per common share	$ 1.75	.44	2.11

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common Stock	Capital Surplus	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total Shareholders' Equity
			(In Thousands)			
Balances at December 31, 2000	$4,840	1,139,136	(269,567)	(12,177)	(3,266)	858,966
Exercise of warrants to purchase 706 shares of Common Stock	—	17	—	—	—	17
Stock options exercised (Note 6)	57	7,970	—	—	—	8,027
Tax benefit of stock options exercised	—	40	—	—	—	40
Employee stock purchase plan (Note 6)	1	433	—	—	—	434
Purchase of 2,074,300 shares of treasury stock	—	—	—	—	(55,803)	(55,803)
Retirement of 156,522 shares of treasury stock	(15)	(2,803)	—	—	2,818	—
Stock option compensation (Note 6)	—	595	—	—	—	595
Cash in lieu of shares exchanged	—	(50)	—	—	—	(50)
Shares retired in lieu of taxes on restricted stock award	—	(56)	—	—	—	(56)
Comprehensive earnings:						
Net earnings	—	—	103,743	—	—	103,743
Unrealized loss on market value of investment	—	—	—	(426)	—	(426)
Unrealized gain on effective derivative instruments, net (Note 8)	—	—	—	19,293	—	19,293
Increase in unfunded pension liability (Note 7)	—	—	—	(4,251)	—	(4,251)
Foreign currency translation	—	—	—	(6,586)	—	(6,586)
Total comprehensive earnings						111,773
Balances at December 31, 2001	4,883	1,145,282	(165,824)	(4,147)	(56,251)	923,943
Exercise of warrants to purchase 17,971 shares of Common Stock	2	231	—	—	—	233
Stock options exercised (Note 6)	26	4,059	—	—	—	4,085
Tax benefit of stock options exercised	—	865	—	—	—	865
Tax benefit of additional acquired net operating losses and other tax assets	—	8,800	—	—	—	8,800
Employee stock purchase plan (Note 6)	3	457	—	—	—	460
Purchase of 21,894 shares of treasury stock	—	—	—	—	(560)	(560)
Retirement of 1,584 shares in lieu of taxes on restricted stock award	—	(43)	—	—	—	(43)
Other	(1)	(382)	—	—	275	(108)
Comprehensive loss:						
Net earnings	—	—	21,276	—	—	21,276
Unrealized loss on market value of investment	—	—	—	(94)	—	(94)
Unrealized loss on effective derivative instruments, net (Note 8)	—	—	—	(36,650)	—	(36,650)
Increase in unfunded pension liability (Note 7)	—	—	—	(3,595)	—	(3,595)
Foreign currency translation	—	—	—	2,599	—	2,599
Total comprehensive loss						(16,464)
Balances at December 31, 2002	4,913	1,159,269	(144,548)	(41,887)	(56,536)	921,211
Common stock issued, net of offering costs (Note 6)	602	132,982	—	—	—	133,584
Exercise of warrants to purchase 1,573 shares of Common Stock	—	33	—	—	—	33
Stock options exercised (Note 6)	46	7,386	—	—	—	7,432
Tax benefit of stock options exercised	—	1,014	—	—	—	1,014
Employee stock purchase plan (Note 6)	2	422	—	—	—	424
Retirement of 1,583 shares in lieu of taxes on restricted stock award	—	(44)	—	—	—	(44)
Issuance of treasury stock for option exercises	—	—	(298)	—	666	368
Other	—	1,278	—	—	—	1,278
Comprehensive earnings:						
Net earnings	—	—	88,351	—	—	88,351
Unrealized gain on market value of investment	—	—	—	481	—	481
Unrealized loss on effective derivative instruments, net (Note 8)	—	—	—	(17,076)	—	(17,076)
Increase in unfunded pension liability (Note 7)	—	—	—	(534)	—	(534)
Foreign currency translation	—	—	—	49,276	—	49,276
Total comprehensive earnings						120,498
Balances at December 31, 2003	$5,563	1,302,340	(56,495)	(9,740)	(55,870)	1,185,798

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2003	2002	2001
	(In Thousands)		
Cash flows from operating activities:			
Net earnings before cumulative effect of change in accounting principle	$ 82,497	21,276	103,743
Adjustments to reconcile net earnings before cumulative effect of change in accounting principle to net cash provided by operating activities:			
Depreciation and depletion	236,148	186,221	226,033
Impairment of oil and gas properties	16,910	—	18,072
Impairment of contract value	—	—	3,239
Accretion of asset retirement obligation	13,785	—	—
Amortization of deferred hedge gain	(4,561)	(791)	—
Amortization of deferred debt costs	2,315	2,233	1,793
Translation (gain) loss on subordinated debt	—	(332)	7,872
Unrealized (gain) loss on derivative instruments, net	(451)	788	1,353
Deferred income tax expense	61,730	11,997	76,757
Stock and stock option compensation	1,278	—	595
Loss on extinguishment of debt	3,975	5,262	6,066
Loss (earnings) in equity method investee	2,043	(30)	2,460
Other, net	967	(1,774)	(59)
(Increase) decrease in accounts receivable	(34,388)	23,196	66,358
Decrease (increase) in other current assets	6,281	7,929	(5,341)
Increase (decrease) in accounts payable	22,204	(59,065)	50,241
Decrease in accrued interest and other current liabilities	(28,749)	(6,138)	(58,372)
Net cash provided by operating activities	381,984	190,772	500,810
Cash flows from investing activities:			
Acquisition of subsidiary	(82,160)	—	—
Capital expenditures for property and equipment:			
Exploration, development and other acquisition costs	(583,332)	(354,220)	(564,661)
Other fixed assets	(2,251)	(4,057)	(4,527)
Proceeds from sale of assets	14,445	5,465	152,872
Increase in other assets, net	(5,883)	(3,801)	(7,340)
Net cash used by investing activities	(659,181)	(356,613)	(423,656)
Cash flows from financing activities:			
Proceeds from bank borrowings	865,511	466,760	766,986
Repayments of bank borrowings	(668,000)	(391,371)	(1,080,546)
Proceeds from termination of interest rate swaps	5,057	35,630	—
Issuance of 7¾% senior notes, net of offering costs	—	146,846	—
Issuance of 8% senior notes, net of offering costs	—	—	420,550
Repurchases of 8¾% senior subordinated notes	—	(66,248)	(131,933)
Redemption and repurchases of 10½% senior subordinated notes	(69,441)	(23,935)	(9,350)
Proceeds of common stock offerings, net of offering costs	318,216	—	—
Repurchase and retirement of common stock	(184,632)	—	—
Proceeds from the exercise of options and warrants	8,257	4,671	8,430
Purchase of treasury stock	—	(560)	(55,803)
(Decrease) increase in other liabilities, net	(419)	(965)	133
Net cash provided (used) by financing activities	274,549	170,828	(81,533)
Effect of exchange rate changes on cash	991	(208)	(1,237)
Net (decrease) increase in cash and cash equivalents	(1,657)	4,779	(5,616)
Cash and cash equivalents at beginning of year	13,166	8,387	14,003
Cash and cash equivalents at end of year	$ 11,509	13,166	8,387
Cash paid during the year for:			
Interest	$ 55,632	51,038	48,081
Income taxes	$ 1,968	720	4,527

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2003, 2002 and 2001

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Description of the Business—Forest Oil Corporation is engaged in the acquisition, exploration, development, production and marketing of natural gas and liquids. The Company was incorporated in New York in 1924, the successor to a company formed in 1916, and has been publicly held since 1969. The Company is active in several of the major exploration and producing areas in and offshore the United States and in Canada, and has exploratory interests in various other foreign countries.

Basis of Presentation and Principles of Consolidation—The consolidated financial statements include the accounts of Forest Oil Corporation and its consolidated subsidiaries (collectively, Forest or the Company). Significant intercompany balances and transactions are eliminated. The Company consolidates all subsidiaries in which it controls over 50% of the voting interests. Entities in which the Company does not have a direct or indirect majority voting interest are generally accounted for using the equity method. Under the equity method, the initial investment in the affiliated entity is recorded at cost and subsequently increased or reduced to reflect the Company's share of gains or losses or dividends received from the affiliate. The Company's share of the income or losses of the affiliate is included in the Company's reported net income.

Certain amounts in prior years' financial statements have been reclassified to conform to the 2003 financial statement presentation. Losses related to the extinguishment of debt in 2002 and 2001, previously presented as extraordinary items, have been reclassified to other expense in the accompanying statements of operations as a result of the Company's adoption of Statement of Financial Accounting Standards No. 145 on January 1, 2003.

As a result of the Company's fourth quarter 2003 decision to sell the gas marketing business of its Canadian marketing subsidiary, Producers Marketing Ltd. (ProMark), ProMark's results of operations have been presented as discontinued operations in the accompanying statements of operations. In prior years' financial statements, ProMark's marketing revenue, net of related expenses, was reported in marketing and processing, net.

Assumptions, Judgments and Estimates—In the course of preparing the consolidated financial statements, management makes various assumptions, judgments and estimates to determine the reported amounts of assets, liabilities, revenue and expenses, and in the disclosures of commitments and contingencies. Changes in these assumptions, judgments and estimates will occur as a result of the passage of time and the occurrence of future events and, accordingly, actual results could differ from amounts previously established.

The more significant areas requiring the use of assumptions, judgments and estimates relate to volumes of oil and gas reserves used in calculating depletion, the amount of future net revenues used in computing the ceiling test limitations and the amount of future capital costs and abandonment obligations used in such calculations. Assumptions, judgments and estimates are also required in determining impairments of undeveloped properties, valuing deferred tax assets and estimating fair values of derivative instruments.

Cash Equivalents—For purposes of the statements of cash flows, the Company considers all debt instruments with original maturities of three months or less to be cash equivalents.

Property and Equipment—The Company uses the full cost method of accounting for oil and gas properties. Separate cost centers are maintained for each country in which the Company has

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

operations. During 2003, 2002 and 2001, the Company's primary oil and gas operations were conducted in the United States and in Canada. All costs incurred in the acquisition, exploration and development of properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes, overhead related to exploration and development activities) and estimated future costs of site restoration, dismantlement and abandonment activities are capitalized. Capitalized costs applicable to each cost center are depleted using the units of production method based on conversion to common units of measure using one barrel of oil as an equivalent to six thousand cubic feet (MCF) of natural gas.

Investments in unproved properties, including related capitalized interest costs, are not depleted pending determination of the existence of proved reserves. Unproved properties are assessed periodically to ascertain whether impairment has occurred. Unproved properties whose costs are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties, and geographic and geologic data obtained relating to the properties. Where it is not practicable to individually assess the amount of impairment of properties for which costs are not individually significant, such properties are grouped for purposes of assessing impairment. The amount of impairment assessed is added to the costs to be amortized.

Undeveloped property costs not being depleted as of December 31, 2003, 2002 and 2001 were as follows:

	United States	Canada	International
		(In Thousands)	
December 31, 2003	$66,339	34,922	56,747
December 31, 2002	$77,863	27,240	66,533
December 31, 2001	$86,460	48,577	51,577

The undeveloped costs not being depleted at December 31, 2003 were incurred as follows:

	United States	Canada	International
2003	23%	17%	5%
2002	8%	3%	17%
2001	10%	24%	26%
2000	2%	12%	29%
1999	22%	18%	10%
1998	34%	7%	13%
1997	1%	1%	—
1996	—	18%	—
	100%	100%	100%

The Company holds interests in various projects located outside North America. Costs related to these international interests were not being depleted pending determination of the existence of proved reserves. In 2003, Forest recorded an impairment of $16,910,000 ($10,500,000 net of taxes) related primarily to concessions in Albania, Italy, Romania, Switzerland and Tunisia. No impairments were recorded in 2002. In 2001, Forest recorded impairments of $18,072,000 ($11,200,000 net of tax). Of this

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

amount, approximately $10,000,000 ($6,200,000 net of tax) was related to an unsuccessful well in Albania. Impairments in 2001 were also recognized in other countries based on expiration of certain concessions and evaluations of projects in these countries.

Depletion per unit of production (MCFE) for each of the Company's cost centers was as follows:

	United States	Canada
2003	$1.55	1.55
2002	1.30	1.08
2001	1.32	1.02

The depletion rate increases in 2003 were attributable to reductions in estimates of the Company's proved reserves, primarily in December, 2003. As a result, the depletion rates for the fourth quarter of 2003 were $2.04 and $1.74 per MCFE in the United States and Canada, respectively.

Pursuant to full cost accounting rules, capitalized costs less related accumulated depletion and deferred income taxes for each cost center may not exceed the sum of (1) the present value of future net revenue from estimated production of proved oil and gas reserves using current prices, including the effects of derivative instruments and a discount factor of 10%; plus (2) the cost of properties not being amortized, if any; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) income tax effects related to differences in the book and tax basis of oil and gas properties. There were no such provisions for impairment of oil and gas properties in 2003, 2002, or 2001, although our Canadian full cost pool, in particular, could be adversely impacted by moderate declines in commodity prices. Gain or loss is not recognized on the sale of oil and gas properties unless the sale significantly alters the relationship between capitalized costs and proved oil and gas reserves attributable to a cost center.

Furniture and fixtures, computer hardware and software and other equipment are depreciated on the straight-line or declining balance method based upon estimated useful lives of the assets ranging from five to 14 years.

Net property and equipment at December 31 consists of the following:

	2003	2002
	(In Thousands)	
Oil and gas properties	$ 4,748,477	3,763,080
Furniture and fixtures, computer hardware and software and other equipment	32,640	27,230
	4,781,117	3,790,310
Less accumulated depreciation, depletion and valuation allowance	(2,347,151)	(2,102,425)
	$ 2,433,966	1,687,885

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

Asset Retirement Obligations—Effective January 1, 2003, the Company adopted the provisions of Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (SFAS No. 143). SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred with a corresponding increase in the carrying amount of the related long-lived asset. The Company previously recorded estimated costs of future abandonment liabilities, net of estimated salvage values, as part of its provision for depreciation and depletion for oil and gas properties without recording a separate liability for such amounts. The Company's asset retirement obligations consist of costs related to the plugging of wells, the removal of facilities and equipment, and site restoration on oil and gas properties.

Upon adoption of SFAS No. 143 in the first quarter of 2003, the Company recorded an increase to net property and equipment of $165,370,000 ($102,321,000 net of tax), an asset retirement obligation liability of $155,972,000 ($96,467,000 net of tax) and an after tax credit of $5,854,000 for the cumulative effect of the change in accounting principle related to the depreciation and accretion amounts that would have been reported had the asset retirement obligations been recorded when incurred. Subsequent to initial measurement, the asset retirement liability is required to be accreted each period to present value. Capitalized costs are depleted as a component of the full cost pool using the units of production method.

The following table summarizes the activities for the Company's asset retirement obligation for the year ended December 31, 2003:

	Year Ended December 31, 2003 (In Thousands)
Asset retirement obligation at beginning of period	$ —
Liability recognized in transition	155,972
Accretion expense	13,785
Liabilities incurred	71,113
Liabilities settled	(23,308)
Revisions of estimated liabilities	(7,377)
Impact of foreign currency exchange rate	1,247
Asset retirement obligation at end of period	211,432
Less: current asset retirement obligation	23,243
Long-term asset retirement obligation	$188,189

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

The following sets forth the pro forma effect on net earnings and earnings per share for the years ended December 31, 2002 and 2001 as if SFAS No. 143 had been applied in those years:

	2002	2001
	(In Thousands Except Per Share Amounts)	
Net earnings:		
As reported	$21,276	103,743
Pro forma	$19,833	103,730
Basic earnings per share:		
As reported	$ .45	2.18
Pro forma	$ .42	2.18
Diluted earnings per share:		
As reported	$ .44	2.11
Pro forma	$ .41	2.10

If SFAS No. 143 had been adopted as of January 1, 2001, the pro forma asset retirement obligation would have been approximately $130,000,000, $141,000,000 and $155,972,000 at January 1, 2001, December 31, 2001 and December 31, 2002, respectively.

Financial Instruments—Forest periodically hedges a portion of its oil and gas production through swap and collar agreements. The purpose of the hedges is to provide a measure of stability to the Company's cash flows in an environment of volatile oil and gas prices and to manage the exposure to commodity price risk. Forest also periodically enters into interest rate swap agreements in an attempt to achieve a desired mix of fixed and floating rates in its debt portfolio. Interest rate swap agreements are generally designated as fair value hedges. Periodic settlements under the swap agreements are accounted for as adjustments to interest expense.

The Company recognizes the fair values of its derivative instruments as assets or liabilities on the balance sheet. The accounting treatment for the changes in fair value is dependent upon whether or not a derivative instrument is a cash flow or a fair value hedge, and upon whether or not the derivative qualifies as an effective hedge. Changes in fair value of cash flow hedges are recognized, to the extent the hedge is effective, in other comprehensive income until the hedged item is recognized in earnings. For fair value hedges, to the extent the hedge is effective, there is no effect on the statement of operations because changes in fair value of the derivative offset changes in the fair value of the hedged item. For derivative instruments that do not qualify as fair value hedges or cash flow hedges, changes in fair value are recognized in earnings as other income or expense.

Oil and Gas Sales—The Company accounts for oil and gas sales using the entitlements method. Under the entitlements method, revenue is recorded based upon the Company's share of volumes sold, regardless of whether the Company has taken its proportionate share of volumes produced. The Company records a receivable or payable to the extent it receives less or more than its proportionate share of the related revenue. As of December 31, 2003 and 2002, the Company had recorded the

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

following net long-term asset (liability) in the accompanying consolidated balance sheets related to its gas imbalances:

	Value		Volumes	
	2003	2002	2003	2002
	(In Thousands)		(MMCF)	
Gas imbalance receivable	$ 16,161	9,994	5,353	4,007
Gas imbalance liability	(12,733)	(12,481)	(5,016)	(5,001)
Net gas imbalance receivable (liability)	$ 3,428	(2,487)	337	(994)

In 2003, sales to three purchasers were approximately 15%, 10%, and 10% of total revenue. In 2002, sales to two purchasers were approximately 16% and 10% of total revenue and in 2001, sales to two purchasers were approximately 12% and 10% of total revenue.

Processing Income (Loss), Net—Processing income (loss), net consists of fees earned, net of expenses, attributable to volumes processed on behalf of third parties through Company-owned gas processing plants.

Income Taxes—The Company uses the asset and liability method of accounting for income taxes, which requires the recognition of deferred tax liabilities and assets for the expected future tax consequences of temporary differences between financial accounting bases and tax bases of assets and liabilities. The tax benefits of net operating loss carryforwards and other deferred taxes are recorded as an asset to the extent that management assesses the utilization of such assets to be more likely than not. When the future utilization of some portion of the deferred tax asset is determined not to be more likely than not, a valuation allowance is provided to reduce the recorded deferred tax assets. Management believes that it could implement tax planning strategies to prevent these carryforwards from expiring.

Foreign Currency Translation—The functional currency of Canadian Forest Oil Ltd. (Canadian Forest), the Company's wholly owned Canadian subsidiary, is the Canadian dollar. Assets and liabilities related to the Company's Canadian operations are generally translated at current exchange rates, and related translation adjustments are reported as a component of shareholders' equity in accumulated other comprehensive income or loss. Statement of operations accounts are translated at the average exchange rates during the period.

The Company was also required to recognize foreign currency translation gains or losses related to the 8¾% Senior Subordinated Notes due 2007 (the 8¾% Notes) because the debt was denominated in U.S. dollars. As a result of the change in the value of the Canadian dollar relative to the U.S. dollar, the Company reported non-cash translation (gains) losses of approximately $(332,000) and $7,872,000 for the years ended December 31, 2002 and 2001, respectively. Following the redemption of the 8¾% Notes during 2002, Forest has no debt issued in a currency other than the functional currency of the issuer.

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

Earnings (Loss) per Share—Basic earnings per share is computed by dividing net earnings attributable to common stock by the weighted average number of common shares outstanding during each period, excluding treasury shares.

Diluted earnings per share is computed by adjusting the average number of common shares outstanding for the dilutive effect, if any, of convertible preferred stock, stock options and warrants.

The following sets forth the calculation of basic and diluted earnings per share for the years ended December 31:

	2003	2002	2001
	(In Thousands Except Per Share Amounts)		
Earnings from continuing operations	$90,228	21,083	106,437
Weighted average common shares outstanding during the period	49,450	46,935	47,674
Add dilutive effects of stock options(1)	218	476	709
Add dilutive effects of warrants	685	796	899
Weighted average common shares outstanding including the effects of dilutive securities	50,353	48,207	49,282
Basic earnings from continuing operations	$ 1.82	.45	2.23
Diluted earnings from continuing operations	$ 1.79	.44	2.16

(1) At December 31, 2003, 2002 and 2001, options to purchase 2,117,213 shares, 1,909,050 shares and 1,594,750 shares, respectively, of common stock were outstanding, but were not included in the computation of diluted earnings per share because to do so would have been antidilutive. These options expire at various dates from 2006 to 2013.

Stock Based Compensation—The Company applies APB Opinion 25, *Accounting for Stock Issued to Employees*, and related Interpretations in accounting for its stock-based compensation plans. Accordingly, no compensation cost is recognized for options granted at a price equal to or greater than the fair market value of the common stock. Compensation cost is recognized over the vesting period of options granted at a price less than the fair market value of the common stock at the date of the grant. No compensation cost is recognized for stock purchase rights that qualify under Section 423 of the Internal Revenue Code as a non-compensatory plan. Had compensation cost for the Company's stock-based compensation plans been determined using the fair value of the options at the grant date as prescribed by Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based*

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

Compensation, the Company's pro forma net earnings and earnings per common share would be as follows:

	Years Ended December 31,		
	2003	2002	2001
	(In Thousands Except Per Share Amounts)		
Net earnings:			
As reported	$88,351	21,276	103,743
Pro forma	$73,728	8,997	92,187
Basic earnings per share:			
As reported	$ 1.79	0.45	2.18
Pro forma	$ 1.49	0.19	1.93
Diluted earnings per share:			
As reported	$ 1.75	0.44	2.11
Pro forma	$ 1.46	0.19	1.87

Comprehensive Earnings (Loss)—Comprehensive earnings (loss) is a term used to refer to net earnings (loss) plus other comprehensive income (loss). Other comprehensive income (loss) is comprised of revenues, expenses, gains and losses that under generally accepted accounting principles are reported as separate components of shareholders' equity instead of net earnings (loss). Items included in the Company's other comprehensive income (loss) for the years ended December 31, 2003, 2002 and 2001 are foreign currency gains (losses) related to the translation of the assets and liabilities of the Company's Canadian operations; changes in the unfunded pension liability; unrealized gains (losses) related to the change in fair value of securities available for sale; and unrealized gains (losses) related to the changes in fair value of derivative instruments designated as cash flow hedges.

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

The components of comprehensive earnings (loss) for the years ended December 31, 2003, 2002 and 2001 are as follows:

	Foreign Currency Translation	Unfunded Pension Liability	Unrealized Gain (Loss) on Securities Available for Sale	Unrealized Gain (Loss) on Derivative Instruments, Net	Accumulated Other Comprehensive Income (Loss)
			(In Thousands)		
Balance at December 31, 2000	$ (6,611)	(5,605)	39	—	(12,177)
2001 activity	(6,586)	(4,251)	(426)	19,293	8,030
Balance at December 31, 2001	(13,197)	(9,856)	(387)	19,293	(4,147)
2002 activity	2,599	(3,595)	(94)	(36,650)	(37,740)
Balance at December 31, 2002	$(10,598)	(13,451)	(481)	(17,357)	(41,887)
2003 activity	49,276	(534)	481	(17,076)	32,147
Balance at December 31, 2003	$ 38,678	(13,985)	—	(34,433)	(9,740)

Impact of Recently Issued Accounting Pronouncements—In June 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 141, *Business Combinations* (SFAS No. 141) and Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* (SFAS No. 142). SFAS No. 141 addresses accounting and reporting for business combinations and is effective for all business combinations initiated after June 30, 2001. SFAS No. 142 addresses the accounting and reporting for acquired goodwill and other intangible assets. The new standard eliminates the requirement to amortize acquired goodwill; instead, such goodwill is required to be reviewed at least annually for impairment. The new standard also requires that, at a minimum, all intangible assets be aggregated and presented as a separate line item in the balance sheet. The adoption of SFAS No. 141 and SFAS No. 142 had no impact on the carrying value of our goodwill or intangible assets.

The Emerging Issues Task Force is currently considering two reporting issues regarding the application of certain provisions of SFAS No. 141 and SFAS No. 142 to companies in the extractive industries, including oil and gas companies. The issues are whether SFAS No. 141 and SFAS No. 142 require registrants to classify the costs of mineral rights associated with extracting oil and gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, the Company has included the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined that oil and gas companies are required to classify costs of mineral rights associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, the Company would be required to reclassify approximately $40,000,000 to $50,000,000 at December 31, 2003 and approximately $15,000,000 to $20,000,000 at December 31, 2002, out of oil and gas properties and into a separate intangible assets line item. Forest's total balance sheet, cash flows and results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with full cost accounting rules. Further, the Company does not believe the classification of the costs of mineral rights associated with extracting oil and gas as intangible assets would have any impact on its compliance with covenants under its debt agreements.

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

Statement of Financial Accounting Standards No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* (SFAS No. 149), was issued in April 2003. This statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS No. 133. SFAS No. 149 is effective for contracts entered into or modified after June 30 2003. The adoption of SFAS No. 149 did not have a significant effect on the Company's financial condition or results of operations.

Statement of Financial Accounting Standards No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* (SFAS No. 150), was issued May 2003. SFAS No. 150 establishes standards for how an issuer classifies and measures three classes of freestanding financial instruments (mandatorily redeemable instruments, instruments with repurchase obligations, and instruments with obligations to issue a variable number of shares) with characteristics of both liabilities and equity. Instruments within the scope of the statement must be classified as liabilities on the balance sheet. SFAS No. 150 is effective for all freestanding financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. The Company does not currently hold any financial instruments within the scope of SFAS No. 150.

In December 2003, the FASB issued FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities* (FIN 46R), which addresses how a business enterprise should evaluate whether it has a controlling financial interest in an entity through means other than voting rights and, accordingly, should consolidate the entity. FIN 46R replaces FASB Interpretation No. 46, *Consolidation of Variable Interest Entities,* which was issued in January 2003. Forest will be required to apply FIN 46R to variable interests in variable interest entities (VIEs), if any, created after December 31, 2003. Forest does not currently own any interests in VIEs; therefore, FIN 46R will not affect the Company's consolidated financial statements.

(2) ACQUISITIONS:

During the fourth quarter of 2003, the Company completed an acquisition of certain oil and gas properties onshore South Louisiana and offshore Gulf of Mexico from Union Oil Company of California (Unocal). The estimated proved reserves acquired at closing were approximately 141 BCFE (unaudited). The majority of the properties were purchased in a transaction that closed on October 31, 2003. The remainder of the properties were purchased in two additional transactions that closed on November 12, 2003 and December 15, 2003. The acquisition was funded in part by the proceeds from a common stock offering and by borrowings under the Company's U.S. credit facility. The revenue and expenses of these properties have been included in Forest's consolidated financial statements since the closing dates.

On December 31, 2003, the Company purchased 100% of the stock of a private company with oil and gas assets located primarily in the Permian Basin and in five fields in South Texas. Estimated proved reserves acquired at closing were approximately 109 BCFE (unaudited). The acquisition included working capital, oil and gas assets and certain other financial assets and liabilities of the seller. The consolidated balance sheet of Forest as of December 31, 2003 includes the assets acquired and liabilities assumed in this transaction. The closing date of this transaction was December 31, 2003;

(2) ACQUISITIONS: (Continued)

therefore, no revenue or expenses for these properties have been included in Forest's consolidated financial statements.

The purchase price of the two acquisitions discussed above was allocated as follows:

	Acquisition from Unocal	Acquisition of Private Company
	(In Thousands)	
Allocation of Purchase Price:		
Current assets	$ —	5,924
Derivative asset—short-term	3,669	—
Proved properties	210,653	141,051
Asset retirement cost	48,615	3,627
Intangible leasehold costs	6,570	4,365
Other assets	5,676	2,684
Current liabilities	—	(9,183)
Derivative liability—short-term	(729)	—
Long-term debt	—	(30,000)
Asset retirement obligation	(48,615)	(3,627)
Other liabilities	(18,594)	—
Deferred taxes	—	(32,681)
Cash paid	$207,245	82,160

The purchase price allocations are preliminary because certain items such as the determination of the final tax basis and the fair value of certain assets and liabilities as of the acquisition dates have not been determined.

The following unaudited pro forma consolidated statements of operations information assumes that the two acquisitions discussed above occurred as of January 1, of each year:

	Pro Forma Year Ended December 31,	
	2003	2002
	(In Thousands Except Per Share Amounts)	
Total revenue	$860,072	656,276
Net earnings from continuing operations	$140,711	34,277
Net earnings	$138,834	34,470
Basic earnings per share	$ 2.54	.66
Diluted earnings per share	$ 2.50	.65

(3) PROMARK SALE:

On March 1, 2004, the assets and business operations of the Company's Canadian marketing subsidiary, ProMark, were sold to Cinergy Canada, Inc. (Cinergy) for $11,200,000 CDN. Under the terms of the purchase and sale agreement, Cinergy will market natural gas on behalf of the Company's Canadian exploration and production subsidiary, Canadian Forest Oil Ltd., for five years, unless subject

(3) PROMARK SALE: (Continued)

to prior contractual commitments, and will also administer the netback pool formerly administered by ProMark. Forest could receive additional contingent payments over the next five years if Cinergy meets certain earnings goals with respect to the acquired business.

As a result of the Company's fourth quarter 2003 decision to sell the gas and marketing operations of ProMark, ProMark's results of operations have been reported as discontinued operations in the accompanying financial statements. The components of assets held for sale related to discontinued operations at December 31, 2003 and 2002 are as follows:

	2003	2002
	(In Thousands)	
Goodwill(1)	$ 17,680	14,589
Long-term gas marketing contracts(2)	15,425	12,728
	33,105	27,317
Less accumulated amortization and write-down of discontinued operations	(24,516)	(14,792)
	$ 8,589	12,525

(1) Effective January 1, 2002, pursuant to SFAS No. 142, goodwill recorded in the acquisition of ProMark was no longer amortized but was tested annually for impairment. Prior thereto, goodwill was amortized on a straight-line basis over 20 years.

(2) Long-term gas marketing contracts were amortized based on estimated revenues over the life of the contracts. In 2001, the Company recorded an impairment of $3,239,000 of the gas marketing contracts to reflect the estimated fair market value of the contracts.

The components of (loss) income from discontinued operations for the years ended December 31, 2003, 2002 and 2001 are as follows:

	Years Ended December 31,		
	2003	2002	2001
	(In Thousands)		
Marketing revenue, net	$ 2,728	2,825	3,550
General and administrative expense	(1,921)	(1,484)	(1,376)
Interest income (expense)	(59)	—	111
Other income, net	606	9	—
Depreciation	(1,325)	(933)	(1,857)
Impairment of contract value	—	—	(3,239)
Current income tax benefit (expense)	27	(40)	(2)
Deferred income tax expense	(2,623)	(184)	119
Loss on sale of discontinued operations	(5,164)	—	—
	$(7,731)	193	(2,694)

(4) LONG-TERM DEBT:

Components of long-term debt are as follows:

	December 31, 2003				December 31, 2002			
	Principal	Unamortized Discount	Other	Total	Principal	Unamortized Discount	Other	Total
		(In Thousands)				(In Thousands)		
U.S. Credit Facility	$291,000	—	—	291,000	$ 95,000	—	—	95,000
Canadian Credit Facility	1,542	—	—	1,542	—	—	—	—
Bank debt assumed in acquisition(2)	30,000	—	—	30,000	—	—	—	—
8% Senior Notes Due 2008	265,000	(439)	10,258(1)	274,819	265,000	(536)	12,558(1)	277,022
8% Senior Notes Due 2011	160,000	—	6,671(1)	166,671	160,000	—	7,509(1)	167,509
7¾% Senior Notes Due 2014	150,000	(2,467)	18,406(1)	165,939	150,000	(2,706)	14,772(1)	162,066
10½% Senior Subordinated Notes Due 2006	—	—	—	—	65,970	(348)	—	65,622
	$897,542	(2,906)	35,335	929,971	$735,970	(3,590)	34,839	767,219

(1) Represents the unamortized portion of gains realized upon termination of interest rate swaps that were accounted for as fair value hedges. The gains are being amortized as a reduction of interest expense over the terms of the note issues.

(2) Paid on January 2, 2004 with borrowings under the Company's U.S. credit facility.

Bank Credit Facilities:

The Company has credit facilities totaling $600,000,000, consisting of a $500,000,000 U.S. credit facility through a syndicate of banks led by JPMorgan Chase and a $100,000,000 Canadian credit facility through a syndicate of banks led by JPMorgan Chase Bank, Toronto Branch. The credit facilities mature in October 2005. In October 2003, Forest amended the credit facilities to allow the Company the option of electing to have availability under the credit facilities governed by a borrowing base (Global Borrowing Base), rather than financial covenants. Forest can exercise the option one time per year and any such election will be irrevocable for a period of one year. The determination of the Global Borrowing Base is made by the lenders taking into consideration the estimated value of Forest's oil and gas properties in accordance with the lenders' customary practices for oil and gas loans. Effective October 30, 2003, the Company elected to determine availability based on the Global Borrowing Base. Under the Global Borrowing Base, availability will be redetermined semi-annually and the available borrowing amount could be increased or reduced. In addition, Forest and the lenders each have discretion at any time, but not more often than once during any calendar year, to have the Global Borrowing Base redetermined. The recent redetermination will not limit these discretionary redeterminations.

If a borrowing base redetermination is less than the outstanding borrowings under the credit facilities, the Company would be required to repay the amount representing the excess of outstanding borrowings within a prescribed period. If we were unable to pay the excess amount, it would cause an event of default.

In March 2004, in conjunction with the significant downward revisions to Forest's estimated proved oil and gas reserves, the Company redetermined the Global Borrowing Base. Effective March 4, 2004, the Global Borrowing Base was set at $480,000,000, with $460,000,000 allocated to the U.S. credit

(4) LONG-TERM DEBT: (Continued)

facility and $20,000,000 allocated to the Canadian credit facility. Under the terms of the credit facility, the Global Borrowing Base will next be redetermined in the second quarter of 2004 and the amount of available borrowing could be adjusted at that time.

The credit facilities include terms and covenants that place limitations on certain types of activities, including restrictions or requirements with respect to additional debt, liens, asset sales, hedging activities, investments, dividends, and mergers and acquisitions, and include financial covenants. Interest rates and other terms of borrowing under the credit facilities will vary based on the Company's credit ratings and financial condition, as governed by certain financial tests. In particular, any time that availability is not governed by the Global Borrowing Base, the amount available and the Company's ability to borrow under the credit facility is determined by the financial covenants. Under the Global Borrowing Base, the financial covenants can still affect the amount available and the Company's ability to borrow amounts under the credit facility.

In addition, the credit facilities are collateralized by the Company's assets. The U.S. credit facility is secured by a lien on, and a security interest in, a portion of the Company's proved oil and gas properties and related assets in the United States and Canada, a pledge of 65% of the capital stock of Canadian Forest and its parent, 3189503 Canada Ltd., and a pledge of 100% of the capital stock of Forest Pipeline Company. The Canadian credit facility is secured by a lien on the assets of Canadian Forest. Under certain circumstances, the Company could be obligated to pledge additional assets as collateral.

At December 31, 2003, there were outstanding borrowings of $291,000,000 under the U.S. credit facility at a weighted average interest rate of 2.34% and there were outstanding borrowings of $1,542,000 under the Canadian credit facility at a weighted average interest rate of 4.63%. At December 31, 2003, Forest had used the credit facilities for letters of credit in the amount of $4,686,000 U.S. and $1,353,000 CDN. In conjunction with Forest's acquisition of a private company on December 31, 2003, Forest assumed $30,000,000 of bank debt with an interest rate of 3.64%. This debt was subsequently paid by Forest and the related credit facility terminated on January 2, 2004 using additional borrowings under Forest's U.S. credit facility.

8% Senior Notes Due 2008:

In June 2001, the Company issued $200,000,000 principal amount of 8% Senior Notes Due 2008 (the 8% Notes Due 2008) at par for proceeds of $199,500,000 (net of related offering costs). In October 2001, the Company issued an additional $65,000,000 principal amount of 8% Notes Due 2008 at 99% of par for proceeds of $63,550,000 (net of related offering costs).

8% Senior Notes Due 2011:

In December 2001, the Company issued $160,000,000 principal amount of 8% Senior Notes Due 2011 (the 8% Notes Due 2011) at par for proceeds of $157,500,000 (net of related offering costs).

7¾% Senior Notes Due 2014:

In 2002, the Company issued $150,000,000 principal amount of 7¾% Senior Notes due 2014 (the 7¾% Notes) at 98.09% of par for proceeds of $146,846,000 (net of related offering costs).

(4) LONG-TERM DEBT: (Continued)

10½% Senior Subordinated Notes Due 2006:

In February 1999, Forest issued $100,000,000 principal amount of 10½% Senior Subordinated Notes due 2006 (the 10½% Notes) at 98.8% of par.

In 2002, the Company repurchased $22,210,000 principal amount of 10½% Notes at approximately 107.8% of par value. In December 2001, the Company repurchased $8,820,000 principal amount of 10½% Notes at 106.0% of par value. As a result of these repurchases, Forest recorded losses of $1,198,000 and $621,000 in 2002 and 2001, respectively.

In January 2003, the Company redeemed the remaining $65,970,000 outstanding principal amount of 10½% Notes at 105.25% of par value. As a result of this redemption, Forest recorded a loss of approximately $3,975,000 in the first quarter of 2003.

8¾% Senior Subordinated Notes Due 2007:

In September 1997 Canadian Forest completed an offering of $125,000,000 of 8¾% Senior Subordinated Notes due 2007 (the 8¾% Notes), which were sold at 99.745% of par and guaranteed on a senior subordinated basis by the Company. In February 1998 Canadian Forest issued $75,000,000 principal amount of 8¾% Notes, an add-on to the September 1997 offering.

In 2002, the Company repurchased $5,300,000 principal amount of 8¾% Notes at approximately 103.5% of par value, and redeemed the $57,948,000 remaining outstanding principal amount of 8¾% Notes at 104.375% of par value. In 2001, the Company repurchased $129,152,000 principal amount of 8¾% Notes at an average price of 102.8% of par value. As a result of these repurchases and redemption, Forest recorded losses of $2,012,000 and $4,990,000 in 2002 and 2001, respectively.

The Company was required to recognize foreign currency translation gains or losses related to the 8¾% Notes because the debt was denominated in U.S. dollars and the functional currency of Canadian Forest is the Canadian dollar. As a result of the change in the value of the Canadian dollar relative to the U.S. dollar during 2002 and 2001, the Company reported noncash translation gains (losses) of approximately $332,000 and $(7,872,000), respectively, in those years.

(5) INCOME TAXES:

The income tax expense was different from amounts computed by applying the U.S. statutory Federal income tax rate for the following reasons:

	Years Ended in December 31,		
	2003	2002	2001
	(In Thousands)		
Federal income tax at 35% of income before income taxes, discontinued operations and cumulative effect of change in accounting principle	$50,702	11,593	64,987
State income taxes, net of Federal income tax benefits	3,820	815	5,569
Adjustment for additional acquired net operating losses and other tax assets	—	—	(31,670)
Change in the valuation allowance for deferred tax assets, including an increase in the valuation allowance in 2001 for additional acquired net operating losses and other tax assets of $31,670,000	925	(1,751)	36,301
Taxes related to foreign operations	2,747	1,360	3,541
Effect of taxable affiliate dividends	3,881	—	—
Effect of Canadian statutory rate reductions	(7,332)	—	—
Other	(107)	24	512
Total income tax expense	$54,636	12,041	79,240

Deferred income taxes generally result from recognizing income and expenses at different times for financial and tax reporting. In the United States, the largest differences are the tax effect of the capitalization of certain development, exploration and other costs under the full cost method of accounting, recording proceeds from the sale of properties in the full cost pool, and the provision for impairment of oil and gas properties for financial accounting purposes. In Canada, differences result in part from accelerated cost recovery of oil and gas capital expenditures for tax purposes.

(5) INCOME TAXES: (Continued)

The components of the net deferred tax liability by geographical segment at December 31, 2003 and 2002 are as follows:

	December 31, 2003		
	United States	Canada	Total
	(In Thousands)		
Deferred tax assets:			
Allowance for doubtful accounts	$ 5,223	—	5,223
Investment in subsidiaries	2,807	—	2,807
Accrual for medical and retirement benefits	3,071	—	3,071
Unrealized losses on derivative contracts, net	20,990	—	20,990
Net operating loss carryforwards	211,260	475	211,735
Capital loss carryforward	—	4,612	4,612
Depletion carryforward	7,554	—	7,554
Alternative minimum tax credit carryforward	2,483	—	2,483
Other	932	(445)	487
Total gross deferred tax assets	254,320	4,642	258,962
Less valuation allowance	(116,556)	(4,612)	(121,168)
Net deferred tax assets	137,764	30	137,794
Deferred tax liabilities:			
Property and equipment	(162,790)	(24,425)	(187,215)
Total gross deferred tax liabilities	(162,790)	(24,425)	(187,215)
Net deferred tax liabilities	$ (25,026)	(24,395)	(49,421)

(5) INCOME TAXES: (Continued)

	December 31, 2002		
	United States	Canada	Total
	(In Thousands)		
Deferred tax assets:			
Allowance for doubtful accounts	$ 5,329	—	5,329
Investment in subsidiaries	2,140	—	2,140
Accrual for medical and retirement benefits	2,771	—	2,771
Unamortized proceeds from interest rate swap settlements	13,239	—	13,239
Unrealized losses on derivative contracts, net	10,795	—	10,795
Net operating loss carryforwards	210,156	—	210,156
Capital loss carryforward	—	4,354	4,354
Depletion carryforward	7,554	—	7,554
Alternative minimum tax credit carryforward	2,324	—	2,324
Other	2,769	1,421	4,190
Total gross deferred tax assets	257,077	5,775	262,852
Less valuation allowance	(121,913)	(4,354)	(126,267)
Net deferred tax assets	135,164	1,421	136,585
Deferred tax liabilities:			
Property and equipment	(83,832)	(16,417)	(100,249)
Deferred income on long term contracts	—	(869)	(869)
Other	—	(512)	(512)
Total gross deferred tax liabilities	(83,832)	(17,798)	(101,630)
Net deferred tax assets (liabilities)	$ 51,332	(16,377)	34,955

The net deferred tax assets are reflected in the accompanying balance sheets as follows:

	December 31, 2003		
	United States	Canada	Total
	(In Thousands)		
Current deferred tax assets	$ 23,302	—	23,302
Non-current deferred tax liabilities	(48,328)	(24,395)	(72,723)
Net deferred tax liabilities	$(25,026)	(24,395)	(49,421)

(5) INCOME TAXES: (Continued)

	December 31, 2002		
	United States	Canada	Total
	(In Thousands)		
Non-current deferred tax assets	$41,022	—	41,022
Current deferred tax assets	10,310	—	10,310
Non-current deferred tax liabilities	—	(16,377)	(16,377)
Net deferred tax assets (liabilities)	$51,332	(16,377)	34,955

The net changes in the valuation allowance for the years ended December 31, 2003, 2002 and 2001 were as follows:

	2003	2002	2001
	(In Thousands)		
Increase (decrease) in the valuation allowance for deferred tax assets, including an increase in the valuation allowance in 2001 for additional acquired net operating losses and other tax assets of $31,670,000	$ —	(1,751)	35,160
Decrease in the valuation allowance for net operating loss carryforward expirations	(5,099)	—	—
Net increase (decrease) in the valuation allowance	$(5,099)	(1,751)	35,160

The Alternative Minimum Tax (AMT) credit carryforward available to reduce future U.S. Federal regular taxes aggregated $2,483,000 at December 31, 2003. This amount may be carried forward indefinitely. U.S. Federal regular and AMT net operating loss carryforwards at December 31, 2003 were approximately $575,961,000 and $470,307,000, respectively. Of these amounts, approximately $333,117,000 and $270,310,000 were acquired by the Company in its merger with Forcenergy Inc (Forcenergy) in 2000. The Company's regular and AMT net operating losses will expire in the years indicated below:

	Regular	AMT
	(In Thousands)	
2004	$ 76,263	53,291
2005	59,296	43,918
2006	26,369	14,996
2007	21,684	7,992
2008	64,024	8,394
2009	31,616	41,591
2010	45,954	54,523
2011	3,505	1,794
2012	206	2,158
2017	69,109	67,599
2018	39,143	40,587
2019	1,310	1,310
2022	137,482	132,154
	$575,961	470,307

(5) INCOME TAXES: (Continued)

AMT net operating loss carryforwards can be used to offset 90% of AMT income in future years.

Canadian tax pools relating to the exploration, development and production of oil and natural gas which are available to reduce future Canadian Federal income taxes aggregated approximately $211,663,000 ($274,459,000 CDN) at December 31, 2003. These tax pool balances are deductible on a declining balance basis ranging from 4% to 100% of the balance annually, and are composed of costs incurred for oil and gas properties, developmental and exploration expenditures, as follows:

	(Canadian dollars)
Canadian Capital Cost Allowance	$ 43,797
Canadian Development Expense	37,643
Canadian Exploration Expense	146,589
Canadian Oil and Gas Property Expense	46,430
	$274,459

Of these amounts, approximately $15,424,000 ($20,000,000 CDN) represents amounts acquired from predecessor companies and is limited in use to income derived from assets acquired. Other Canadian tax pools and loss carryforwards available to reduce future Canadian Federal income taxes were approximately $14,870,000 ($19,281,000 CDN) at December 31, 2003. The amounts may be carried forward indefinitely.

The Company's ability to use some of its net operating loss carryforwards and certain other tax attributes to reduce current and future U.S. Federal taxable income is subject to limitations under the Internal Revenue Code. In particular, the Company's ability to utilize such carryforwards is limited due to the occurrence of "ownership changes" within the meaning of Section 382 of the Internal Revenue Code. "Ownership changes" occurred in the Company in 1995 following the issuance of securities to The Anschutz Corporation, in 1996 following a public stock issuance, and in 2000 following the merger with Forcenergy.

"Ownership changes" occurred in Forcenergy in 1995 as a result of an Initial Public Offering and merger with Ashlawn group and in 2000 following its emergence from bankruptcy. These ownership changes will affect the use of tax attributes acquired in the Forcenergy merger. Portions of Forcenergy's net operating loss carryforwards and other tax attributes are further limited due to "ownership changes" that occurred with respect to businesses acquired by Forcenergy in 1997.

Approximately $101,000,000 of Forest's net operating loss carryforwards will be subject to an annual limitation of approximately $5,800,000. In addition, the Company's ability to utilize substantially all of Forcenergy's built-in losses and net operating loss carryforwards will be subject to an overall annual limitation of approximately $22,000,000. Additional limitations affect the Company's ability to utilize certain portions of Forcenergy's built-in losses and net operating loss carryforwards generated prior to 1997. Because of these limitations, approximately $153,803,000 of these losses will not be realized before they expire. The Company believes it is more likely than not that additional carryforwards will expire before they can be realized and has provided a valuation allowance for its estimate of the total amounts that will not ultimately be realized due to limitations imposed by Section 382.

(6) COMMON STOCK:

Common Stock:

At December 31, 2003 the Company had 200,000,000 shares of Common Stock, par value $.10 per share, authorized.

In October 2003, Forest issued 5,123,000 shares of common stock at a price of $23.10 per share. Net proceeds from this offering were approximately $112,600,000 after deducting underwriting discounts and commissions and estimated offering expenses. Forest used the net proceeds from the offering to fund a portion of the acquisition of properties from Unocal.

In January 2003, the Company issued 7,850,000 shares of common stock at a price of $24.50 per share. Net proceeds from this offering (before any exercise of the underwriters' over-allotment option) were approximately $184,400,000 after deducting underwriting discounts and commissions and estimated offering expenses. Forest used the net proceeds from the offering, before deduction of estimated offering expenses, to repurchase, immediately following the closing of the offering, 7,850,000 shares from The Anschutz Corporation and certain of its affiliates (Anschutz). The shares repurchased by Forest were purchased at a price of $23.52 per share and were cancelled immediately upon repurchase. In February 2003, an additional 900,000 shares of common stock were issued, also at a price of $24.50 per share, pursuant to exercise of the underwriters' over-allotment option for net proceeds of $21,168,000 after deducting underwriting discounts and commissions.

Rights Agreement:

In October 1993, the Board of Directors adopted a shareholders' rights plan (the Plan) and entered into the Rights Agreement. The Company distributed one Preferred Share Purchase Right (the Rights) for each outstanding share of the Company's Common Stock. The Rights are exercisable only if a person or group acquires 20% or more of the Company's Common Stock or announces a tender offer which would result in ownership by a person or group of 20% or more of the Common Stock.

In October 2003 the Board of Directors of Forest entered into the First Amended and Restated Rights Agreement (the First Amended Rights Agreement). The rights issued under the First Amended Rights Agreement will expire on October 29, 2013, unless earlier exchanged or redeemed, and entitle the holder thereof to purchase 1/100th of a preferred share at an initial purchase price of $120.

Warrants:

At December 31, 2003 the Company had outstanding 236,030 warrants to purchase shares of its Common Stock (the 2004 Warrants). Each 2004 Warrant entitled the holder to purchase 0.8 shares of Common Stock for $16.67, or an equivalent per share price of $20.84. From January 1, 2004 through February 15, 2004, 210,337 of the 2004 Warrants were exercised via both cash and cashless exercise provisions pursuant to which 151,938 shares of Common Stock were issued. The remaining 2004 Warrants expired unexercised on February 15, 2004.

At December 31, 2003 the Company had outstanding 238,001 warrants to purchase shares of its Common Stock (the 2005 Warrants). Each 2005 Warrant entitles the holder to purchase 0.8 shares of Common Stock for $20.83, or an equivalent per share price of $26.04. The 2005 Warrants expire on February 15, 2005.

(6) COMMON STOCK: (Continued)

At December 31, 2003 the Company had outstanding 1,752,355 warrants to purchase shares of its Common Stock (Subscription Warrants). Each Subscription Warrant entitles the holder to purchase 0.8 shares of Common Stock for $10.00, or an equivalent per share price of $12.50. The Subscription Warrants are detachable and expire on March 20, 2010 or earlier upon notice of expiration by the Company if, after March 20, 2004, the market price of the Common Stock has exceeded 300% of the exercise price of the Subscription Warrants, or $37.50 per share, for a period of 30 consecutive trading days.

Stock Options:

In 2001, the Company adopted the Forest Oil Corporation 2001 Stock Incentive Plan (the 2001 Plan) under which stock options, restricted stock and other awards may be granted to employees, consultants and non-employee directors. In 2003, the Company amended the 2001 Plan to increase the number of shares reserved for issuance. The aggregate number of shares of Common Stock which the Company may issue under the 2001 Plan may not exceed 3,800,000 shares. The exercise price of an option shall not be less than the fair market value of one share of Common Stock on the date of grant. Options under the 2001 Plan generally vest in increments of 25% on each of the first four anniversary dates of the date of grant and have a term of ten years.

The Company had a Stock Incentive Plan (the 1996 Plan) that expired on March 5, 2002 under which non-qualified stock options and restricted stock were granted to employees and director stock awards were granted to non-employee directors. Under the 1996 Plan the exercise price of an option could not be less than 85% of the fair market value of one share of Common Stock on the date of grant. Options granted under the 1996 Plan generally vested in increments of 20% on the date of grant and on each of the first four anniversary dates of the date of the grant.

The following table summarizes the activity in the Company's stock-based compensation plans for the years ended December 31, 2003, 2002 and 2001:

	Number of Shares	Weighted Average Exercise Price	Number of Shares Exercisable
Outstanding at December 31, 2000	3,733,773	$22.70	2,033,573
Granted at fair value	929,650	26.63	
Exercised	(573,805)	13.99	
Cancelled	(127,276)	28.04	
Outstanding at December 31, 2001	3,962,342	$24.71	2,072,342
Granted at fair value	105,300	29.62	
Exercised	(265,164)	15.42	
Cancelled	(186,934)	29.90	
Outstanding at December 31, 2002	3,615,544	$25.26	2,374,436
Granted at fair value	749,000	23.00	
Exercised	(486,508)	16.03	
Cancelled	(402,157)	29.91	
Outstanding at December 31, 2003	3,475,879	$25.52	2,375,158

(6) COMMON STOCK: (Continued)

The fair value of each option granted in 2003, 2002 and 2001 was estimated using the Black-Scholes option pricing model. The following assumptions were used to compute the weighted average fair market value of options granted:

	2003	2002	2001
Expected life of options	5 years	5 years	5 years
Risk free interest rates	2.27%-3.61%	2.76%-4.64%	3.52%-4.91%
Estimated volatility	56.44%	57.80%	60.61%
Dividend yield	0.0%	0.0%	0.0%
Weighted average fair market value of options granted during the year	$11.71	$15.90	$14.79

The following table summarizes information about options outstanding at December 31, 2003:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$12.50-20.00	554,616	5.58	$17.19	551,616	$17.18
20.75-22.50	302,550	6.88	22.22	143,050	22.27
22.60-23.26	497,000	9.16	23.25	70,000	23.26
23.30-25.00	423,913	7.97	24.95	223,342	24.96
25.16-28.00	451,750	5.61	27.30	350,600	27.45
28.33-29.56	40,000	7.05	28.94	22,250	28.92
29.75	890,800	6.92	29.75	743,950	29.75
29.88-35.00	282,500	6.50	32.46	238,600	32.63
35.50	27,750	3.86	35.50	27,750	35.50
36.88	5,000	6.99	36.88	4,000	36.88
	3,475,879	6.92	$25.52	2,375,158	$25.76

Stock Purchase Plan:

Under the 1999 Employee Stock Purchase Plan (the ESPP), the Company is authorized to issue up to 125,000 shares of Common Stock. Employees who are regularly scheduled to work more than 20 hours per week and more than five months in any calendar year may participate in the ESPP. Under the terms of the plan, employees can choose each quarter to have up to 15% of their annual base earnings withheld to purchase Common Stock, up to a limit of $25,000 of Common Stock per calendar year. The purchase price of the Common Stock is 85% of the lower of its beginning-of-quarter or end-of-quarter market price. The employee is restricted from selling the shares of Common Stock purchased under the ESPP for a period of six months after purchase. Under the ESPP, the Company sold 21,403 shares, 20,160 shares and 19,140 shares of Common Stock to employees in 2003, 2002 and 2001, respectively. The fair value of each stock purchase right granted during 2003, 2002 and 2001 was

(6) COMMON STOCK: (Continued)

estimated using the Black-Scholes option pricing model. The following assumptions were used to compute the weighted average fair market value of purchase rights granted:

	2003	2002	2001
Expected option life	3 months	3 months	3 months
Risk free interest rates	0.89%-1.22%	1.59%-1.79%	1.72%-4.28%
Estimated volatility	56.44%	57.80%	60.61%
Dividend yield	0.0%	0.0%	0.0%
Weighted average fair market value of purchase rights granted	$8.54	$8.89	$9.60

(7) EMPLOYEE BENEFITS:

United States Pension Plan and Postretirement Benefits:

The Company has a qualified defined benefit pension plan which covers certain employees and former employees in the United States (Pension Plan). The Pension Plan was curtailed and all benefit accruals were suspended effective May 31, 1991. The Company also has a non-qualified unfunded supplementary retirement plan (the Supplemental Executive Retirement Plan) that provides certain retired executives with defined retirement benefits in excess of qualified plan limits imposed by Federal tax law. Benefit accruals under this plan were suspended effective May 31, 1991 in connection with suspension of benefit accruals under the Pension Plan. Amounts for both the Pension Plan and the Supplemental Executive Retirement Plan are combined in the "Pension Benefits" column below. Contributions to be made in 2004 to the Pension Plan and Supplemental Retirement Plan are expected to be approximately $260,000 for the 2003 plan year and approximately $1,500,000 for the 2004 plan year.

The weighted average asset allocations of the Pension Plan at December 31, 2003 and 2002 were:

	2003	2002
Fixed income securities	59%	65%
Equity securities	36%	34%
Other	5%	1%
	100%	100%

The overall investment goal for the Pension Plan is to have an investment return which allows it to achieve its actuarial interest rate and exceeds the rate of inflation. In order to manage risk, in terms of volatility, the portfolio was designed to avoid a loss of 20% over any single year and the portfolio should express no more volatility than experienced by the S&P 500 Stock Index.

The assets of the Pension Plan are invested with a view toward the long-term in order to fulfill the obligations promised to participants as well as to control future levels of funding. The long-term goal for equity securities exposure is considered to be 50% of the assets of the Pension Plan at market value. The maximum allowable equity exposure is 60%. There is no specified minimum equity exposure for any point in time. The long-term goal for fixed income exposure is considered to be 50% of the assets of the Pension Plan at market value. The maximum allowable fixed income exposure is 70%.

(7) EMPLOYEE BENEFITS: (Continued)

There is no specified minimum fixed income exposure for any point in time. This asset allocation is designed to achieve an appropriate balance between capital appreciation, preservation of capital and current income.

The discount rate used to determine benefit obligations was reduced from 6.50% at December 31, 2002 to 6.0% at December 31, 2003. The discount rate reflects the market rate of return on investment grade fixed income securities.

Forest developed its expected rate of return on plan assets by evaluating input from external consultants and long-term inflation assumptions. The expected long-term rate of return is based on the target allocation of plan assets.

In addition to the defined benefit pension plans described above, the Company also accrues expected costs of providing postretirement benefits to employees in the United States, their beneficiaries and covered dependents in accordance with Statement of Financial Accounting Standards No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions* (SFAS No. 106). These amounts, which consist primarily of medical benefits payable on behalf of retirees in the United States, are presented in the "Postretirement Benefits" column below. Contributions to be made in 2004 for post retirement benefits other than pensions are expected to be approximately $500,000, net of retiree contributions.

The following tables set forth the plans' benefit obligations, fair value of plan assets and funded status at December 31, 2003 and 2002:

Benefit Obligations:	**Pension Benefits**		**Postretirement Benefits**	
	2003	**2002**	**2003**	**2002**
	(In Thousands)		**(In Thousands)**	
Projected benefit obligation at the beginning of the year	$28,774	28,019	8,089	6,902
Service cost	—	—	530	576
Interest cost	1,814	1,728	523	467
Actuarial loss	1,656	1,350	886	763
Benefits paid	(2,398)	(2,323)	(619)	(677)
Retiree contributions	—	—	81	58
Projected benefit obligation at the end of the year	$29,846	28,774	9,490	8,089

(7) EMPLOYEE BENEFITS: (Continued)

Fair Value of Plan Assets:	Pension Benefits		Postretirement Benefits	
	2003	2002	2003	2002
	(In Thousands)		(In Thousands)	
Fair value of plan assets at beginning of the year	$19,836	21,615	—	—
Actual return on plan assets	2,742	(288)	—	—
Plan participants' contribution	—	—	81	58
Employer contribution	1,904	832	538	619
Benefits paid	(2,398)	(2,323)	(619)	(677)
Fair value of plan assets at the end of the year	$22,084	19,836	—	—

Funded Status:	Pension Benefits		Postretirement Benefits	
	2003	2002	2003	2002
	(In Thousands)		(In Thousands)	
Excess of projected benefit obligation over plan assets	$(7,762)	(8,938)	(9,490)	(8,089)
Unrecognized actuarial loss	10,955	11,408	1,438	552
Net amount recognized	$ 3,193	2,470	(8,052)	(7,537)
Amounts recognized in the balance sheet consist of:				
Accrued benefit liability	$(7,762)	(8,938)	(8,052)	(7,537)
Accumulated other comprehensive income	10,955	11,408	—	—
Net amount recognized	$ 3,193	2,470	(8,052)	(7,537)

(7) EMPLOYEE BENEFITS: (Continued)

The following tables set forth the components of the net periodic cost of the plans and the underlying weighted average actuarial assumptions for the years ended December 31, 2003, 2002, and 2001:

	Pension Benefits			Postretirement Benefits		
	2003	2002	2001	2003	2002	2001
	(In Thousands)			(In Thousands)		
Service cost	$ —	—	—	530	576	482
Interest cost	1,814	1,728	1,944	523	467	431
Expected return on plan assets	(1,362)	(1,452)	(1,921)	—	—	—
Recognized actuarial (gain) loss	728	268	240	—	—	(1)
Total net periodic expense	$ 1,180	544	263	1,053	1,043	912
Assumptions used to determine net periodic expense:						
Discount rate	6.50%	7.00%	7.00%	6.50%	7.00%	7.50%
Expected return on plan assets	7.00%	7.00%	9.00%	n/a	n/a	n/a
Assumptions used to determine benefit obligations:						
Discount rate	6.00%	6.50%	7.00%	6.00%	6.50%	7.00%

Assumed health care cost trend rates have a significant effect on the amounts reported for postretirement benefits. A one-percentage-point change in assumed health care cost trend rates would have the following effects for 2003:

	Postretirement Benefits	
	1% Increase	1% Decrease
	(In Thousands)	
Effect on service and interest cost components	$ 224	$ (172)
Effect on postretirement benefit obligation	$1,538	$(1,237)

For measurement purposes, the annual rate of increase in the per capita cost of covered health care benefits was held constant at 5.5% during 2003 and thereafter.

As a result of suspension of benefit accruals under the Pension Plan and the Supplemental Executive Retirement Plan, the Company records as a liability the unfunded pension liabilities attributable to these plans. The following changes in the minimum unfunded pension liability were recorded as adjustments to other comprehensive income (in thousands):

2003	$(1,387)
2002	$(3,595)
2001	$(4,251)

In December 2003, a new Medicare bill was enacted that provides prescription drug coverage to Medicare-eligible retirees. In its present form, the Company's U.S. medical plan provides prescription drug benefits to certain Medicare-eligible retirees. The results contained in these financial statements do not anticipate any changes to the U.S. retiree medical plan in light of the Medicare legislation. The

(7) EMPLOYEE BENEFITS: (Continued)

Company is currently studying the impact of the new legislation and the resulting impact, if any, on its financial statements. Specific authoritative guidance on the accounting for the federal subsidy is pending and that guidance, when issued, may require changes to previously reported information.

Canadian Pension Plan and Postretirement Benefits:

Canadian Forest had a non-contributory defined benefit pension plan (the Defined Benefit Pension Plan). Effective December 31, 2003, Canadian Forest has no further obligations under its Defined Benefit Pension Plan. Under a plan to wind up the Defined Benefit Pension Plan, the participating employees were provided an option to transfer an actuarially computed value to their defined contribution pension plan or to have an annuity purchased on their behalf from an insurance company. At December 31, 2003, all annuities had been purchased or computed values transferred out, resulting in the recognition of a net loss of $753,000 CDN in 2003. Applications have been made to the provincial and federal governments to formally wind up the plan. Approvals are expected before June, 2004.

All employees of Canadian Forest participate in a Defined Contribution Pension Plan. Until 2003, contributions were taken from the surplus in the Defined Benefit Pension Plan. In 2003, contributions of $384,000 CDN were funded to the Defined Contribution Pension Plan and expensed.

Canadian Forest also accrues expected costs of providing postretirement benefits to certain of its Canadian employees, their beneficiaries and covered dependents in accordance with SFAS No. 106. These amounts, which consist primarily of medical and dental benefits payable on behalf of retirees in Canada, are presented in the "Postretirement Benefits" column below. The postretirement benefit is closed to new participants. In the future, it is expected that the Company will make contributions equal to benefits to be paid out. The benefits expected to be paid in each year from 2004 - 2008 are $25,290(CDN), $27,754(CDN), $30,383(CDN), $33,165(CDN), and $36,243(CDN), respectively. The aggregate benefits expected to be paid in the five years from 2009 - 2013 are $240,402(CDN).

The following tables set forth the estimated benefit obligations, fair value of plan assets and funded status of the Canadian Defined Benefit Plan and Canadian postretirement benefits at December 31, 2003 and 2002:

Benefit Obligations:	**Pension Benefits**		**Postretirement Benefits**	
	2003	**2002**	**2003**	**2002**
	(In Thousands of Canadian Dollars)			
Projected benefit obligation at the beginning of the year	$ 6,069	5,260	700	—
Service cost	375	404	17	723
Interest cost	378	376	32	—
Actuarial (gain) loss	343	614	(218)	—
Benefits paid	(7,165)	(585)	(24)	(23)
Projected benefit obligation at the end of the year	$ —	6,069	507	700

(7) EMPLOYEE BENEFITS: (Continued)

Fair Value of Plan Assets:	Pension Benefits		Postretirement Benefits	
	2003	2002	2003	2002
	(In Thousands of Canadian Dollars)			
Fair value of plan assets at beginning of the year	$ 7,145	6,900	—	—
Actual return on plan assets	(919)	776	—	—
Employer contributions	939	54	24	23
Benefits paid	(7,165)	(585)	(24)	(23)
Fair value of plan assets at the end of the year	$ —	7,145	—	—

Funded Status:	Pension Benefits		Postretirement Benefits	
	2003	2002	2003	2002
	(In Thousands of Canadian Dollars)			
Excess of assets over projected benefit obligation	$—	1,076	(507)	(700)
Unamortized transitional obligation asset	—	(1,819)	—	—
Unamortized net actuarial loss	—	925	—	—
Net amount recognized	$—	182	(507)	(700)

The following table sets forth the components of net periodic pension cost and the underlying weighted average actuarial assumptions for the years ended December 31, 2003, 2002, and 2001. The amounts shown include costs of both of the Canadian plans.

	Pension Benefits			Postretirement Benefits	
	2003	2002	2001	2003	2002
	(In Thousands of Canadian Dollars)				
Service cost	$ 375	404	379	17	723
Interest cost	378	376	336	32	—
Expected return on plan assets	(361)	(484)	(509)	—	—
Amortization of transition asset	(227)	(227)	(227)	—	—
Recognized actuarial (gains) losses	182	13	—	(218)	—
Settlement gain	(157)	—	—	—	—
Curtailment loss	900	—	—		
Total net periodic pension expense (benefit)	$1,090	82	(21)	(169)	723
Assumptions used to determine net periodic expense (benefit):					
Discount rate	n/a	6.50%	6.70%	6.75%	7.00%
Expected return on plan assets	n/a	7.00%	7.00%	n/a	n/a
Assumptions used to determine benefit obligations:					
Discount rate	n/a	6.50%	6.70%	6.75%	7.00%

(7) EMPLOYEE BENEFITS: (Continued)

For measurement purposes, the annual rate of increase in the per capita cost of covered health care benefits for Canadian Forest was assumed to be 4% per year for the dental plan, 5% per year for Provincial health care and 14.25% in 2004, 13.5% in 2005, 12.75% in 2006 and 12% thereafter for the medical plan.

United States Retirement Savings Plans:

The Company sponsors a qualified tax-deferred savings plan for its employees in the United States in accordance with the provisions of Section 401(k) of the Internal Revenue Code. Employees may defer up to 80% of their compensation, subject to certain limitations. In 2002 and 2001, the Company matched employee contributions up to 5% of eligible employee compensation. Effective January 1, 2003, the Company matching percentage increased to 6% of eligible employee compensation. Effective January 1, 2004, the Company matching percentage increased to 7% of eligible employee compensation. The expense associated with the Company's contributions was $1,448,000 in 2003, $1,184,000 in 2002 and $882,000 in 2001. In each of these years, the Company matched employee contributions in cash.

The Company also sponsored a qualified tax-deferred savings plan in accordance with the provisions of Section 401(k) of the Internal Revenue Code for employees formerly employed by Forcenergy. This plan was merged into the Forest Oil 401(k) plan effective August 1, 2001. Employees could defer up to 15% of their compensation, subject to certain limitations. The Company matched employee contributions up to 50% of the first 5% of the employee compensation. The expense associated with the Company's contributions was $125,000 in 2001.

Canadian Savings Plan:

Canadian Forest also provides a savings plan which is available to all of its employees. Employees may contribute up to 4% of their salary, subject to certain limitations, with Canadian Forest matching the employee contribution in full. The expense associated with Canadian Forest's contributions to the plan was approximately $215,000 in 2003, $169,000 in 2002 and $160,000 in 2001.

Deferred Compensation Plans:

The Company has an Executive Deferred Compensation Plan (the Executive Plan) pursuant to which certain executives may defer a portion of their compensation after contributing the maximum allowable amount to the 401(k) plan. The deferred compensation plan is not funded, but the Company records a liability for matching contributions and accrues interest on each executive's account balance at the rate of 1% per month. The expense associated with the Company's matching contributions and interest was $241,000 in 2003, $187,000 in 2002 and $122,000 in 2001, and the liability was approximately $1,066,000 and $1,090,000 at December 31, 2003 and 2002, respectively.

The Company adopted a Salary Deferral Compensation Plan (the Salary Deferral Compensation Plan) and Change of Control Deferred Compensation Plan (the Change of Control Plan) in the fourth quarter of 2002. Eligibility to participate in these plans was initially limited to officers of the Company. The Salary Deferral Compensation Plan was amended January 1, 2003 to allow Forest Oil directors to participate in the plan. Under the terms of the Salary Deferral Compensation Plan, a participant may

(7) EMPLOYEE BENEFITS: (Continued)

defer a percentage of his or her base salary, bonuses and possibly certain equity awards. The Change of Control Plan allows participants to make one-time deferrals of compensation that they would otherwise receive upon a change in control of the Company. Under both plans, the Company deposits the deferred amounts in a trust (a so-called "rabbi trust"). Assets of the trusts would be available to creditors of the Company in the event of the Company's insolvency or bankruptcy. The fair value of amounts deferred under the Salary Deferral Compensation Plan was $1,054,000. Deferrals will not occur under the Change of Control Plan until a change of control event. The taxable income and losses of the trusts were included in the computation of the Company's taxable income. Tax deductions for any compensation deferred under these plans will be delayed until the funds held in the trusts are distributed to the participants.

Split Dollar Life Insurance:

The Company provides life insurance benefits for certain retirees under split dollar life insurance plans. Under the life insurance plans, the Company is assigned a portion of the benefits which is designed to recover the premiums paid. Until August 2002, the Company also provided life insurance benefits to two officers under split dollar life insurance plans. The Company has suspended payment of premiums for officers pending clarification under the Sarbanes-Oxley Act of 2002.

(8) FINANCIAL INSTRUMENTS:

The Company recognizes the fair value of its derivative instruments as assets or liabilities on the balance sheet. The accounting treatment for the changes in fair value is dependent upon whether or not a derivative instrument is a cash flow hedge or a fair value hedge, and upon whether or not the derivative qualifies as an effective hedge. Changes in fair value of cash flow hedges are recognized, to the extent the hedge is effective, in other comprehensive income until the hedged item is recognized in earnings. For fair value hedges, to the extent the hedge is effective, there is no effect on the statement of operations because changes in fair value of the derivative offset changes in the fair value of the hedged item. For derivative instruments that do not qualify as fair value hedges or cash flow hedges, changes in fair value are recognized in earnings as other income or expense.

Interest Rate Swaps:

In 2002 and 2001 the Company entered into two interest rate swaps intended to exchange the fixed interest rate on a specified principal amount of the 8% Notes due 2011 and the 8% Notes due 2008 for a variable rate based on LIBOR plus specified basis points over the term of the notes. The interest rate swaps were treated as fair value hedges for accounting purposes. In August 2002, the Company sold a call option on these two interest rate swaps. The call option was not designated as a hedge. On September 30, 2002 the Company terminated the two interest rate swaps and settled the call option. The Company received approximately $20,858,000 (net of accrued settlements of approximately $1,779,000) in connection with termination of the interest rate swaps. Those aggregate gains were deferred and added to the carrying value of the related debt, and are being amortized as reductions of interest expense over the remaining terms of the note issues. The Company recorded approximately $1,823,000 in 2002 as a realized loss on derivative instruments as a result of settlement of the call option.

(8) FINANCIAL INSTRUMENTS: (Continued)

In 2002, the Company entered into an interest rate swap intended to exchange the fixed interest rate on a specified principal amount of the 7¾% Notes for a variable rate based on LIBOR plus specified basis points over the term of the notes. On December 27, 2002 the Company terminated this interest rate swap. The Company received approximately $14,772,000 (net of accrued settlements of approximately $1,128,000) in connection with termination of the interest rate swap. The gain was deferred and added to the carrying value of the related debt, and is being amortized as a reduction of interest expense over the remaining term of the note issue.

In August 2003, the Company entered into two interest rate swaps as fair value hedges of $150,000,000 principal amount of 7¾% Senior Notes due 2014. The swaps were intended to exchange the fixed interest rate on the notes for a variable rate based on the six-month LIBOR plus specified basis points over the term of the note issue. On October 1, 2003 the Company terminated these interest rate swaps and received approximately $5,057,000 (net of accrued settlements of approximately $938,000) in connection with the termination. The aggregate gain was deferred and added to the carrying value of the related debt, and is being amortized as a reduction of interest expense over the remaining term of the note issue.

During the years ended December 31, 2003 and 2002, the Company recognized net gains of $5,499,000 and $9,802,000, respectively, under the terminated interest rate swaps, which were recorded as reductions of interest expense.

Commodity Swaps, Collars and Basis Swaps:

Forest periodically hedges a portion of its oil and gas production through swap, basis swap and collar agreements. The purpose of the hedges is to provide a measure of stability to the Company's cash flows in an environment of volatile oil and gas prices and to manage the exposure to commodity price risk.

All of the Company's commodity swaps and collar agreements and a portion of its basis swaps in place at December 31, 2003 have been designated as cash flow hedges. At December 31, 2003 the Company had a derivative asset of $4,136,000 (of which $4,130,000 was classified as current), a derivative liability of $59,534,000 (of which $49,838,000 was classified as current), a deferred tax asset of $20,990,000 (of which $17,308,000 was classified as current) and accumulated other comprehensive loss of approximately $34,433,000.

The Company's gains (losses) under these agreements recognized in the Company's statements of operations were:

	Years Ended December 31,		
	2003	2002	2001
	(In Thousands)		
Derivatives designated as cash flow hedges	$(72,863)	(1,742)	22,781
Derivatives not designated as cash flow hedges	383	(2,041)	11,932
Total gain (loss)	$(72,480)	(3,783)	34,713

(8) FINANCIAL INSTRUMENTS: (Continued)

In a typical swap agreement, Forest receives the difference between a fixed price per unit of production and a price based on an agreed upon published, third party index when the index price is lower. When the index price is higher, Forest pays the difference. By entering into swap agreements the Company effectively fixes the price that it will realize in the future for the hedged production. Forest's current swaps are settled in cash on a monthly basis. As of December 31, 2003, Forest had entered into the following swaps accounted for as cash flow hedges:

	Natural Gas		Oil (NYMEX WTI)	
	BBTUs per Day	Average Hedged Price per MMBTU	Barrels per Day	Average Hedged Price per Barrel
First Quarter 2004	94.9	$5.03	11,850	$25.79
Second Quarter 2004	112.3	$4.72	12,850	$25.70
Third Quarter 2004	112.3	$4.72	10,850	$25.60
Fourth Quarter 2004	85.7	$4.78	6,850	$25.90
First Quarter 2005	70.0	$4.63	2,500	$25.45
Second Quarter 2005	70.0	$4.63	2,500	$25.45
Third Quarter 2005	70.0	$4.63	2,500	$25.45
Fourth Quarter 2005	70.0	$4.63	2,500	$25.45

Forest also enters into collar agreements with third parties. A collar agreement is similar to a swap agreement, except that the Company receives the difference between the floor price and the index price only when the index price is below the floor price, and the Company pays the difference between the ceiling price and the index price only when the index price is above the ceiling price. Collars are also settled in cash, either on a monthly basis or at the end of their terms. By entering into collars, the Company effectively provides a floor for the price that it will receive for the hedged production; however, the collar also establishes a maximum price that the Company will receive for the hedged production when prices increase above the ceiling price. The Company enters into collars during periods of volatile commodity prices in order to protect against a significant decline in prices in exchange for forgoing the benefit of price increases in excess of the ceiling price on the hedged production. As of December 31, 2003, the Company had entered into the following gas and oil collars accounted for as cash flow hedges:

	BBTUs per Day	Average Floor Price per MMBTU	Average Ceiling Price per MMBTU
First Quarter 2004	60.8	$4.03	$5.77

	Oil (NYMEX WTI)		
	Barrels per Day	Average Floor Price per BBL	Average Ceiling Price per BBL
First Quarter 2004	2,000	$22.00	$24.08

In addition, Forest has entered into three-way collars with third parties. These instruments establish two floors and one ceiling. Upon settlement, if the index price is below the lowest floor, the Company receives the difference between the two floors. If the index price is between the two floors,

(8) FINANCIAL INSTRUMENTS: (Continued)

the Company receives the difference between the higher of the two floors and the index price. If the index price is between the higher floor and the ceiling, the Company does not receive or pay any amounts. If the index price is above the ceiling, the Company pays the excess over the ceiling price.

As of December 31, 2003, Forest had entered into the following 3-way natural gas collars accounted for as cash flow hedges:

	Natural Gas			
	BBTUs per Day	Average Lower Floor Price per MMBTU	Average Upper Floor Price per MMBTU	Average Ceiling Price per MMBTU
First Quarter 2004	30.0	$3.50	$5.27	$8.75
Second Quarter 2004	25.0	$3.50	$4.75	$5.80
Third Quarter 2004	25.0	$3.50	$4.75	$5.80
Fourth Quarter 2004	11.7	$3.50	$4.75	$6.14

The Company also uses basis swaps in connection with natural gas swaps in order to fix the price differential between the NYMEX price and the index price at which the hedged gas is sold. At December 31, 2003, there were basis swaps designated as cash flow hedges in place for calendar 2004 with weighted average volumes of 31.3 BBTUs per day. At December 31, 2003 there were basis swaps not designated as cash flow hedges in place with weighted average volumes of 107.8 BBTUs per day for 2004 and weighted average volumes of 40.0 BBTUs per day for 2005.

The Company is exposed to risks associated with swap and collar agreements arising from movements in the prices of oil and natural gas and from the unlikely event of non-performance by the counterparties to the swap and collar agreements.

Set forth below is the estimated fair value of certain financial instruments, along with the methods and assumptions used to estimate such fair values as of December 31, 2003:

Cash and cash equivalents, accounts receivable and accounts payable:

The carrying amount of these instruments approximates fair value due to maturity.

Senior Notes:

The fair value of the Company's 8% Notes Due 2008 was approximately $288,850,000 based upon quoted market prices for the notes. The fair value of the Company's 8% Notes Due 2011 was approximately $174,800,000, based upon quoted market prices for the notes. The fair value of the Company's 7¾% Notes due 2014 was approximately $158,625,000 based upon quoted market prices for the notes.

Energy swap agreements:

The fair value of the Company's energy swap agreements was a loss of approximately $49,783,000, based upon the discounted intrinsic value of the derivatives.

(8) FINANCIAL INSTRUMENTS: (Continued)

Energy collar agreements:

The fair value of the Company's energy collar agreements was a loss of approximately $5,855,000, based upon the discounted intrinsic value and option value of the derivatives.

Basis swap agreements:

The fair value of the Company's basis swap agreements was a gain of approximately $240,000, based upon the discounted intrinsic value of the derivatives.

(9) RELATED PARTY TRANSACTIONS:

Beginning in 1995, the Company consummated certain transactions with The Anschutz Corporation pursuant to which Anschutz acquired a significant ownership position in the Company. In January 2003 the Company issued 7,850,000 shares of stock to the public at a gross price of $24.50 per share and used the net proceeds from the offering to repurchase 7,850,000 shares of common stock from Anschutz and certain of its affiliates at a price of $23.52 per share. The shares were cancelled immediately upon repurchase. As of December 31, 2003 Anschutz owned 13% of Forest's outstanding common shares and, in addition, held options to purchase 10,000 shares of common stock and warrants to purchase 522,216 shares of common stock.

In 1998, Forest purchased certain oil and gas assets from Anschutz and since that time the parties entered into additional agreements concerning these properties. As a result of these agreements, Forest acquired, along with interests in other properties, a 70% interest in two South African concessions. Forest is the operator of the South Africa concession blocks and is reimbursed by Anschutz for general, technical and administrative overhead.

Regarding the South African concession blocks in connection with Forest's activities related to the development of the Ibhubesi Gas Field, offshore South Africa, a Participation Agreement was signed March 13, 2003 with The Petroleum Oil and Gas Corporation of South Africa (Pty) Limited (PetroSA) and Anschutz Overseas South Africa (Pty) Limited (Anschutz Overseas). Under the terms of the Participation Agreement PetroSA contributed US$30 million towards a drilling program that started in 2003 in order to earn an undivided 24% cost-bearing interest (16.8% from Forest and 7.2% from Anschutz Overseas) in certain sub-lease agreements covering portions of the South African offshore acreage, including the Ibhubesi Gas Field. As of February 27, 2004, the parties' interests were as follows: Forest 53.2%, Anschutz Overseas 22.8% and PetroSA 24.0%.

(10) COMMITMENTS AND CONTINGENCIES:

Future rental payments for office facilities and equipment and well equipment under the remaining terms of non-cancelable operating leases are $5,166,000, $4,292,000, $2,111,000, $1,338,000 and $893,000 for the years ending December 31, 2004 through 2008, respectively.

Net rental payments applicable to exploration and development activities and capitalized in the oil and gas property accounts aggregated $5,893,000 in 2003, $4,109,000 in 2002, and $6,343,000 in 2001. Net rental payments charged to expense amounted to $8,334,000 in 2003, $7,546,000 in 2002, and

(10) COMMITMENTS AND CONTINGENCIES: (Continued)

$8,241,000 in 2001. Rental payments include the short-term lease of vehicles. There are no leases which are accounted for as capital leases.

A significant portion of Canadian Forest's natural gas production is sold through the Canadian Netback Pool which was administered by ProMark on behalf of Canadian Forest in 2003 and early 2004. At December 31, 2003, the Canadian Netback Pool had entered into fixed price contracts to sell natural gas at the following quantities and weighted average prices:

	Natural Gas	
	BCF	Contract Price per MCF
2004	5.5	$2.66 CDN
2005	5.5	$2.75 CDN
2006	5.5	$2.86 CDN
2007	5.5	$2.96 CDN
2008	5.5	$3.08 CDN
2009	3.0	$3.86 CDN
2010	1.7	$5.21 CDN
2011	.7	$5.50 CDN

The administrator of the Canadian Netback Pool aggregates gas from producers for sale to markets across North America. Currently, in addition to Canadian Forest, over 30 producers have contracted with the Canadian Netback Pool. The producers are paid a netback price which reflects all of the revenue from approved customers less the costs of delivery (including transportation, audit and shortfall makeup costs) and an operator marketing fee.

Canadian Forest, as one of the producers in the Canadian Netback Pool, is obligated to supply its contract quantity. In 2003 Canadian Forest supplied 42% of the total netback pool sales quantity. For 2004, it is estimated that Canadian Forest will supply approximately 43% of the Canadian Netback Pool quantity. In order to satisfy its supply obligations to the Canadian Netback Pool, Canadian Forest may be required to cover its obligations in the market.

The administrator of the Canadian Netback Pool, now Cinergy, is required to acquire gas in the event of a shortfall between the gas supply and market obligations. A shortfall could occur if a gas producer fails to deliver its contractual share of the supply obligations of the Canadian Netback Pool. The cost of purchasing gas to cover any shortfall is a cost of the Canadian Netback Pool. The prices paid for shortfall gas would typically be spot market prices and may differ from the market prices received from customers of the Canadian Netback Pool. Higher spot prices would reduce the average Canadian Netback Pool price paid to the gas producers, including Canadian Forest. Shortfalls in gas produced may occur in the future. The Company cannot predict with any certainty the amount of any such shortfalls.

(10) COMMITMENTS AND CONTINGENCIES: (Continued)

In addition to its commitments to the Canadian Netback Pool, Canadian Forest is committed to sell natural gas at the following quantities and weighted average prices:

	Natural Gas	
	BCF	Contract Price per MCF
2004	.5	$3.96 CDN
2005	.5	$4.11 CDN
2006	.4	$4.27 CDN

Forest, in the ordinary course of business, is a party to various lawsuits, claims and proceedings, including those identified below. While we believe that the amount of any potential loss would not be material to our consolidated financial position, the ultimate outcome of these matters is inherently difficult to predict with any certainty. In the event of an unfavorable outcome, the potential loss could have an adverse effect on Forest's results of operations and cash flow in the reporting periods in which any such actions are resolved.

Alaska Proceeding. In May, 2002, Cook Inlet Keeper, a non-governmental third party, filed a challenge in the Superior Court in Anchorage, Alaska (the trial court) to the regulatory review and approval process for Forest's development and production phase of its Redoubt Shoal project (the Production Project). On February 2, 2004, the trial court ruled that certain legislation which became law in 2003 mooted Cook Inlet Keeper's challenge and, therefore, affirmed the State's approval of the Production Project. While the Company will continue its vigorous opposition to Cook Inlet Keeper's challenge, the outcome of the litigation is inherently difficult to predict with any certainty. However, the Company does not believe that this legal matter could have a material effect on the results of future periods in the event of an unfavorable outcome.

(11) SELECTED QUARTERLY FINANCIAL DATA (unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In Thousands Except Per Share Amounts)			
2003(1)				
Revenue	$168,072	154,245	161,329	173,532
Earnings from operations	$ 72,900	54,495	53,272	20,502
Net earnings from continuing operations	$ 34,256	23,537	26,321	6,114
Net earnings (loss)	$ 38,871	23,412	26,340	(272)
Basic earnings per share from continuing operations	$ .72	.49	.55	.11
Basic earnings (loss) per share	$ .81	.49	.55	(.01)
Diluted earnings per share from continuing operations	$ .70	.48	.54	.11
Diluted earnings (loss) per share	$ .80	.48	.54	(.01)
2002(1)(2)				
Revenue(3)	$ 95,701	126,108	124,072	126,987
Earnings from operations	$ 10,644	28,608	24,359	27,627
Net earnings from continuing operations	$ (1,788)	11,010	2,578	9,283
Net earnings (loss)	$ (1,784)	10,958	2,909	9,193
Basic (loss) earnings per share from continuing operations	$ (.04)	.23	.05	.20
Basic (loss) earnings per share	$ (.04)	.23	.06	.20
Diluted (loss) earnings per share from continuing operations	$ (.04)	.23	.05	.19
Diluted (loss) earnings per share	$ (.04)	.23	.06	.19

(1) In conjunction with the Company's fourth quarter 2003 decision to sell its Canadian marketing subsidiary, ProMark, the financial information for each of the quarters of 2003 and 2002 has been restated to report ProMark's results of operations as discontinued operations.

(2) In the first quarter of 2003 the Company began presenting losses related to the extinguishment of debt as other expense. As a result, extraordinary items related to losses on extinguishment of debt for all quarters in 2002 have been reclassified to other expense.

(3) In the third quarter of 2002 the Company began presenting revenue and expenses from processing activities as a net revenue line item in the statement of operations. Revenue for the first two quarters of 2002 has been restated to reflect the net presentation of the Company's processing activities.

(12) BUSINESS AND GEOGRAPHICAL SEGMENTS:

Segment information has been prepared in accordance with Statement of Financial Accounting Standards No. 131, *Disclosures About Segments of an Enterprise and Related Information*. At December 31, 2003, Forest had five reportable segments consisting of oil and gas operations in five business units (Gulf Region, Western United States, Alaska, Canada and International). On March 1, 2004 the assets and business operations of the Company's gas marketing subsidiary, ProMark, were sold to Cinergy, as discussed in Note 3. Accordingly, in conjunction with the Company's fourth quarter 2003 decision to sell the gas marketing business of ProMark, ProMark's results of operations have been reported as discontinued operations and the segment reporting for 2002 and 2001 has been restated to exclude the marketing activities of ProMark. The Company's remaining processing activities are not significant and therefore are not reported as a separate segment, but are included as a reconciling item in the information below. In addition, in the first quarter of 2003 the Company modified its business unit structure by combining the Gulf of Mexico Offshore Region and the Gulf Coast Onshore Region into the Gulf Region for increased efficiencies. Therefore, segment information for the 2002 and 2001 periods has been restated to give effect to this combination.

The segments were determined based upon the type of operations in each business unit and the geographical location of each. The segment data presented below was prepared on the same basis as the consolidated financial statements.

Year ended December 31, 2003

	Oil and Gas Operations						
	Gulf Coast	Western	Alaska	Total United States	Canada	International	Total Company
	(In Thousands)						
Revenue	$ 416,454	98,388	75,375	590,217	64,976	—	655,193
Expenses:							
Oil and gas production	75,011	23,188	41,482	139,681	14,489	—	154,170
General and administrative	9,090	2,528	4,790	16,408	3,955	495	20,858
Depletion	148,745	18,547	34,851	202,143	28,917	—	231,060
Impairment of oil and gas properties	—	—	—	—	—	16,910	16,910
Accretion of asset retirement obligation	10,130	910	2,302	13,342	423	20	13,785
Earnings from operations	$ 173,478	53,215	(8,050)	218,643	17,192	(17,425)	218,410
Capital expenditures(1)	$ 412,072	193,014	68,933	674,019	46,518	8,211	728,748
Property and equipment, net	$1,231,680	414,510	418,968	2,065,158	304,138	56,747	2,426,043

(1) Does not include estimated discounted asset retirement obligations of $63.7 million related to assets placed in service during the year ended December 31, 2003.

(12) BUSINESS AND GEOGRAPHICAL SEGMENTS: (Continued)

Information for reportable segments relates to the Company's 2003 consolidated totals as follows:

	(In Thousands)
Earnings from operations for reportable segments	$218,410
Processing income, net	1,985
Corporate general and administrative expense	(15,464)
Administrative asset depreciation	(3,762)
Other expense, net	(6,964)
Interest expense	(49,341)
Earnings before income taxes, discontinued operations and cumulative effect of change in accounting principle	$144,864

Year ended December 31, 2002

	Oil and Gas Operations						
	Gulf Coast	Western	Alaska	Total United States	Canada	International	Total Company
				(In Thousands)			
Revenue	$292,347	63,054	65,475	420,876	50,864	—	471,740
Expenses:							
Oil and gas production	82,331	21,572	40,988	144,891	13,808	—	158,699
General and administrative	19,293	6,041	7,570	32,904	4,738	—	37,642
Depletion	123,409	17,614	18,818	159,841	21,326	—	181,167
Earnings from operations	67,314	17,827	(1,901)	83,240	10,992	—	94,232
Capital expenditures	115,256	37,578	163,836	316,670	21,286	16,264	354,220
Property and equipment, net	$785,024	231,507	368,223	1,384,754	229,773	66,533	1,681,060

Information for reportable segments relates to the Company's 2002 consolidated totals as follows:

	(In Thousands)
Earnings from operations for reportable segments	$94,232
Processing income, net	1,128
Administrative asset depreciation	(4,121)
Other expense, net	(7,682)
Interest expense	(50,433)
Earnings before income taxes, discontinued operations and cumulative effect of change in accounting principle	$33,124

(12) BUSINESS AND GEOGRAPHICAL SEGMENTS: (Continued)

Year ended December 31, 2001

	Oil and Gas Operations						
	Gulf Coast	Western	Alaska	Total United States	Canada	International	Total Company
				(In Thousands)			
Revenue	$496,845	78,356	82,655	657,856	56,996	—	714,852
Expenses:							
Oil and gas production	108,668	23,766	38,021	170,455	15,795	—	186,250
General and administrative	15,060	4,135	4,932	24,127	5,011	—	29,138
Depletion	167,721	16,282	18,117	202,120	17,664	—	219,784
Impairment of oil and gas properties	—	—	—	—	—	18,072	18,072
Earnings from operations	205,396	34,173	21,585	261,154	18,526	(18,072)	261,608
Capital expenditures	316,536	45,333	106,260	468,129	63,193	33,339	564,661
Property and equipment, net	$790,759	211,905	223,099	1,225,763	233,577	51,577	1,510,917

Information for reportable segments relates to the Company's 2001 consolidated totals as follows:

	(In Thousands)
Earnings before income taxes, discontinued operations and cumulative effect of change in accounting principle:	
Earnings from operations for reportable segments	$261,608
Processing loss, net	(85)
Administrative asset depreciation	(4,392)
Merger and seismic licensing expense	(9,836)
Other expense, net	(11,597)
Interest expense	(50,021)
Earnings before income taxes, discontinued operations and cumulative effect of change in accounting principle	$185,677

(13) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (unaudited):

The following information is presented in accordance with Statement of Financial Accounting Standards No. 69, *Disclosure about Oil and Gas Producing Activities* (SFAS No. 69).

(A) **Costs Incurred in Oil and Gas Exploration and Development Activities.** The following costs were incurred in oil and gas exploration and development activities during the years ended December 31, 2003, 2002 and 2001:

	United States	Canada	International	Total
	(In Thousands)			
2003				
Property acquisition costs (undeveloped leases and proved properties)	$424,223	—	22	424,245
Exploration costs	64,061	32,014	8,189	104,264
Development costs	185,735	14,504	—	200,239
Total acquisition, exploration, and development costs	674,019	46,518	8,211	728,748
Estimated discounted future abandonment costs	63,293	443	—	63,736
Total costs incurred	$737,312	46,961	8,211	792,484
2002				
Property acquisition costs (undeveloped leases and proved properties)	$ 3,925	—	—	3,925
Exploration costs	72,698	13,401	16,264	102,363
Development costs	240,047	7,885	—	247,932
Total	$316,670	21,286	16,264	354,220
2001				
Property acquisition costs (undeveloped leases and proved properties)	$ (207)	238	—	31
Exploration costs	145,882	44,793	33,339	224,014
Development costs	322,454	18,162	—	340,616
Total	$468,129	63,193	33,339	564,661

(13) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (unaudited): (Continued)

(B) Aggregate Capitalized Costs. The aggregate capitalized costs relating to oil and gas activities at the end of each of the years indicated were as follows:

	2003	2002	2001
		(In Thousands)	
Costs related to proved properties	$4,585,988	3,588,128	3,208,348
Costs related to unproved properties:			
Costs subject to depletion	4,481	3,316	13,355
Costs not subject to depletion	158,008	171,636	186,614
	4,748,477	3,763,080	3,408,317
Less accumulated depletion and valuation allowance	(2,322,434)	(2,082,020)	(1,897,400)
	$2,426,043	1,681,060	1,510,917

(13) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (unaudited): (Continued)

(C) **Results of Operations from Producing Activities.** Results of operations from producing activities for the years ended December 31, 2003, 2002 and 2001 are presented below. Income taxes are different from income taxes shown in the Consolidated Statements of Operations because this table excludes general and administrative and interest expense.

	United States	Canada	Total
	(In Thousands)		
2003			
Oil and gas sales	$590,217	64,976	655,193
Expenses:			
Production expense	139,681	14,489	154,170
Depletion expense	202,143	28,917	231,060
Accretion of asset retirement obligation	13,362	423	13,785
Income tax expense	89,312	9,404	98,716
Total expenses	444,498	53,233	497,731
Results of operations from producing activities	$145,719	11,743	157,462
2002			
Oil and gas sales	$420,876	50,864	471,740
Expenses:			
Production expense	144,891	13,808	158,699
Depletion expense	159,841	21,326	181,167
Income tax expense	44,135	5,576	49,711
Total expenses	348,867	40,710	389,577
Results of operations from producing activities	$ 72,009	10,154	82,163
2001			
Oil and gas sales	$657,856	56,996	714,852
Expenses:			
Production expense	170,455	15,795	186,250
Depletion expense	202,120	17,664	219,784
Income tax expense	108,407	8,013	116,420
Total expenses	480,982	41,472	522,454
Results of operations from producing activities	$176,874	15,524	192,398

The Company recorded impairments of its international oil and gas properties of $16,910,000 in 2003 and $18,072,000 in 2001.

(D) **Estimated Proved Oil and Gas Reserves.** The Company's estimate of its net proved and proved developed oil and gas reserves and changes for 2003, 2002 and 2001 follows. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from

(13) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (unaudited): (Continued)

known reservoirs under existing economic and operating conditions; i.e., prices and costs as of the date the estimate is made.

Prices include consideration of changes in existing prices provided only by contractual arrangement, but not on escalations based on future conditions. Purchases of reserves in place represent volumes recorded on the closing dates of the acquisitions for financial accounting purposes.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved mechanisms of primary recovery are included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

	Liquids (MBBLS)			Gas (MMCF)		
	United States	Canada	Total	United States	Canada	Total
Balance at December 31, 2000	80,120	9,121	89,241	723,266	120,792	844,058
Revisions of previous estimates	878	680	1,558	(22,137)	3,789	(18,348)
Extensions and discoveries	44,000	135	44,135	133,933	46,221	180,154
Production	(9,239)	(1,361)	(10,600)	(97,400)	(10,994)	(108,394)
Sales of reserves in place	(4,833)	(35)	(4,868)	(68,979)	(867)	(69,846)
Purchases of reserves in place	69	14	83	56	869	925
Balance at December 31, 2001	110,995	8,554	119,549	668,739	159,810	828,549
Revisions of previous estimates	3,419	170	3,589	1,002	(18,565)	(17,563)
Extensions and discoveries	10,544	11	10,555	85,460	10,205	95,665
Production	(7,477)	(1,180)	(8,657)	(78,543)	(13,525)	(92,068)
Sales of reserves in place	(97)	(641)	(738)	(324)	(3,059)	(3,383)
Purchases of reserves in place	68	—	68	2,076	118	2,194
Balance at December 31, 2002	117,452	6,914	124,366	678,410	134,984	813,394
Revisions of previous estimates	(60,652)	885	(59,767)	(94,895)	(19,136)	(114,031)
Extensions and discoveries	674	468	1,142	36,314	14,647	50,961
Production	(7,686)	(1,015)	(8,701)	(84,368)	(12,609)	(96,977)
Sales of reserves in place	(2,303)	—	(2,303)	(7,364)	—	(7,364)
Purchases of reserves in place	26,587	—	26,587	162,085	—	162,085
Balance at December 31, 2003	74,072	7,252	81,324	690,182	117,886	808,068
Proved developed reserves at:						
December 31, 2000	53,385	9,121	62,506	546,789	83,824	630,613
December 31, 2001	45,909	8,554	54,463	491,757	123,168	614,925
December 31, 2002	61,398	6,914	68,312	496,056	79,777	575,833
December 31, 2003	53,942	6,917	60,859	518,317	91,781	610,098

(13) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (unaudited): (Continued)

During 2003 Forest revised downward its estimate of proved reserves by a total of approximately 473 BCFE. The downward revision of the Company's estimates was due to information received from production results, drilling activity and other events that occurred primarily in the latter part of 2003.

Approximately 62% of the total revisions was attributable to the downward revision of the Company's estimate of proved oil reserves in the Redoubt Shoal Field in the Cook Inlet, Alaska. Forest reduced its estimate of proved oil reserves associated with its Redoubt Shoal Field in Alaska from its 2002 year-end estimate by approximately 49 million barrels, or approximately 85% of the estimated proved oil reserves in the field as of December 31, 2002. Of this revision, approximately 36 million barrels were classified as proved undeveloped as of December 31, 2002. Forest estimate of proved oil reserves attributable to the Redoubt Shoal Field was approximately 8 million barrels as of December 31, 2003.

(E) Standardized Measure of Discounted Future Net Cash Flows. Future oil and gas sales and production and development costs have been estimated using prices and costs in effect at the end of the years indicated, except in those instances where the sale of oil and natural gas is covered by contracts, in which case, the applicable contract prices, including fixed and determinable escalations, were used for the duration of the contract. Thereafter, the current spot price was used. All cash flow amounts, including income taxes, are discounted at 10%.

Future income tax expenses are estimated using an estimated combined federal and state income tax rate of 38% in the United States and a combined Federal and Provincial rate of 34.62% in Canada. Estimates for future general and administrative and interest expense have not been considered.

Changes in the demand for oil and natural gas, inflation and other factors make such estimates inherently imprecise and subject to substantial revision. This table should not be construed to be an estimate of the current market value of the Company's proved reserves. Management does not rely upon the information that follows in making investment decisions.

	December 31, 2003		
	United States	Canada	Total
	(In Thousands)		
Future oil and gas sales	$6,215,949	734,742	6,950,691
Future production costs	(1,534,859)	(180,760)	(1,715,619)
Future development costs	(375,406)	(26,228)	(401,634)
Future abandonment costs	(306,654)	(8,296)	(314,950)
Future income taxes	(962,745)	(110,379)	(1,073,124)
Future net cash flows	3,036,285	409,079	3,445,364
10% annual discount for estimated timing of cash flows	(974,915)	(162,519)	(1,137,434)
Standardized measure of discounted future net cash flows	$2,061,370	246,560	2,307,930

(13) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (unaudited): *(Continued)*

Present value of future net cash flows before income taxes was $2,622,207 in the United States and $293,054,000 in Canada at December 31, 2003.

	December 31, 2002		
	United States	Canada	Total
	(In Thousands)		
Future oil and gas sales	$6,191,349	628,996	6,820,345
Future production costs	(1,486,637)	(120,133)	(1,606,770)
Future development costs	(465,081)	(31,826)	(496,907)
Future abandonment costs	(157,309)	(2,665)	(159,974)
Future income taxes	(988,477)	(126,994)	(1,115,471)
Future net cash flows	3,093,845	347,378	3,441,223
10% annual discount for estimated timing of cash flows	(1,250,048)	(138,027)	(1,388,075)
Standardized measure of discounted future net cash flows	$1,843,797	209,351	2,053,148

Present value of future net cash flows before income taxes was $2,323,870,000 in the United States and $262,257,000 in Canada at December 31, 2002.

	December 31, 2001		
	United States	Canada	Total
	(In Thousands)		
Future oil and gas sales	$3,679,113	462,773	4,141,886
Future production costs	(957,645)	(126,656)	(1,084,301)
Future development costs	(346,695)	(6,035)	(352,730)
Future abandonment costs	(150,675)	(2,822)	(153,497)
Future income taxes	(331,912)	(69,341)	(401,253)
Future net cash flows	1,892,186	257,919	2,150,105
10% annual discount for estimated timing of cash flows	(715,546)	(87,906)	(803,452)
Standardized measure of discounted future net cash flows	$1,176,640	170,013	1,346,653

Present value of future net cash flows before income taxes was $1,345,743,000 in the United States and $197,025,000 in Canada at December 31, 2001.

(13) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (unaudited): (Continued)

Changes in the Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves An analysis of the changes in the standardized measure of discounted future net cash flows during each of the last three years is as follows:

	December 31, 2003		
	United States	Canada	Total
	(In Thousands)		
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at beginning of year	$1,843,797	209,351	2,053,148
Changes resulting from:			
Sales of oil and gas, net of production costs	(450,536)	(50,487)	(501,023)
Net changes in prices and future production costs	180,818	40,305	221,123
Net changes in future development costs	(71,827)	(6,897)	(78,724)
Extensions, discoveries and improved recovery	141,622	31,936	173,558
Previously estimated development costs incurred during the period	185,823	14,416	200,239
Revisions of previous quantity estimates	(596,760)	(24,702)	(621,462)
Sales of reserves in place	(29,565)	—	(29,565)
Purchases of reserves in place	706,376	—	706,376
Accretion of discount on reserves at beginning of year before income taxes	232,387	26,226	258,613
Net change in income taxes	(80,765)	6,412	(74,353)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year	$2,061,370	246,560	2,307,930

In 2003, the Company recorded significant reductions in its estimates of proved reserves in the Redoubt Shoal Field in Alaska. These revisions were anomalous to the Company's reserve base in that the reserves from this field realize lower sales prices and higher operating costs than the United States properties as a whole. For this reason, the changes in standardized measure of discounted future net cash flows relating to the Company's U.S. proved oil and gas reserves for the year ended December 31, 2003 represent the sum of the changes in standardized measure for the Company's Redoubt Shoal Field (calculated on a stand-alone basis) and the changes in standardized measure for the Company's other U.S. properties (calculated on an aggregate basis).

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2003 was based on average natural gas prices of approximately $5.79 per MCF in the U.S. and approximately $4.52 per MCF in Canada and on average liquids prices of approximately $29.89 per barrel in the U.S. and approximately $27.84 per barrel in Canada.

(13) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (unaudited): (Continued)

	December 31, 2002		
	United States	Canada	Total
		(In Thousands)	
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at beginning of year	$1,176,640	170,013	1,346,653
Changes resulting from:			
Sales of oil and gas, net of production costs	(277,113)	(37,056)	(314,169)
Net changes in prices and future production costs	821,159	119,484	940,643
Net changes in future development costs	(160,173)	(18,174)	(178,347)
Extensions, discoveries and improved recovery	138,241	10,414	148,655
Previously estimated development costs incurred during the period	227,980	7,197	235,177
Revisions of previous quantity estimates	89,629	(27,670)	61,959
Sales of reserves in place	(454)	(8,702)	(9,156)
Purchases of reserves in place	4,284	36	4,320
Accretion of discount on reserves at beginning of year before income taxes	134,574	19,703	154,277
Net change in income taxes	(310,970)	(25,894)	(336,864)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year	$1,843,797	209,351	2,053,148

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2002 was based on average natural gas prices of approximately $4.16 per MCF in the U.S. and approximately $3.30 per MCF in Canada and on average liquids prices of approximately $27.85 per barrel in the U.S. and approximately $26.63 per barrel in Canada.

(13) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (unaudited): (Continued)

	December 31, 2001		
	United States	Canada	Total
	(In Thousands)		
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at beginning of year	$ 3,372,152	322,279	3,694,431
Changes resulting from:			
Sales of oil and gas, net of production costs	(487,401)	(43,986)	(531,387)
Net changes in prices and future production costs	(3,900,193)	(327,716)	(4,227,909)
Net changes in future development costs	(122,581)	(16,569)	(139,150)
Extensions, discoveries and improved recovery	633,549	41,474	675,023
Previously estimated development costs incurred during the period	311,412	17,550	328,962
Revisions of previous quantity estimates	(24,714)	8,283	(16,431)
Sales of reserves in place	(132,305)	(1,708)	(134,013)
Purchases of reserves in place	1,634	1,005	2,639
Accretion of discount on reserves at beginning of year before income taxes	460,577	47,154	507,731
Net change in income taxes	1,064,510	122,247	1,186,757
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year	$ 1,176,640	170,013	1,346,653

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2001 was based on average natural gas prices of approximately $2.66 per MCF in the U.S. and approximately $2.06 per MCF in Canada and on average liquids prices of approximately $17.01 per barrel in the U.S. and approximately $15.05 per barrel in Canada.

PART III

Item 10. Directors and Executive Officers of the Registrant

The information concerning Forest's directors required by this Item is incorporated by reference to the information under the captions "Proposal No. 1—Election of Directors" in the definitive Proxy Statement concerning its Annual Meeting of Shareholders to be held on May 13, 2004 (the "2004 Proxy Statement").

The information concerning Forest's executive officers required by this Item is incorporated by reference to the information set forth under the caption "Executive Officers of Forest" included in Part I, Item 4A of this Form 10-K.

The information concerning compliance with Section 16(a) of the Securities Exchange Act of 1934, as amended, required by this Item is incorporated by reference to the information set forth under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" in the 2004 Proxy Statement.

The information concerning Forest's Audit Committee, Audit Committee financial expert and code of ethics is incorporated by reference to the information set forth under the caption "Corporate Governance Principles and Information About the Board and its Committees" in the 2004 Proxy Statement.

Item 11. Executive Compensation

The information required by this Item is incorporated by reference to the information under the captions "Executive Compensation" and "Stock Performance Graph" in the 2004 Proxy Statement.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this Item is incorporated by reference to the information under the caption "Common Stock Ownership of Certain Beneficial Owners and Management" in the 2004 Proxy Statement.

Item 13. Certain Relationships and Related Transactions

The information required by this Item is incorporated by reference to the information under the caption "Certain Relationships and Related Transactions" in the 2004 Proxy Statement.

Item 14. Principal Accounting Fees and Services

The information required by this Item is incorporated by reference to the information under the captions "Proposal No. 2—Ratification of Independent Auditors" and "Report of the Audit Committee" in the 2004 Proxy Statement.

PART IV

Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

(a) The following documents are filed as part of this report or are incorporated by reference:

(1) Financial Statements:

1. Independent Auditors' Report
2. Consolidated Balance Sheets—December 31, 2003 and 2002
3. Consolidated Statements of Operations—Years ended December 31, 2003, 2002 and 2001
4. Consolidated Statements of Shareholders' Equity—Years ended December 31, 2003, 2002 and 2001
5. Consolidated Statements of Cash Flows—Years ended December 31, 2003, 2002 and 2001
6. Notes to Consolidated Financial Statements—Years ended December 31, 2003, 2002 and 2001

(2) Financial Statement Schedules:

All schedules have been omitted because the information is either not required or is set forth in the financial statements or the notes thereto.

(3) Exhibits: See the Index of Exhibits listed in Item 15(c) hereof for a list of those exhibits filed as part of this Form 10-K.

(b) Reports on Form 8-K:

The following current reports on Form 8-K or 8-K/A reported events during the fourth quarter ending December 31, 2003.

Date of Report	Item Reported	Financial Statements Filed
October 17, 2003	Item 5	None
October 31, 2003	Item 2 and Item 7	None
October 31, 2003	Item 2 and Item 7	Yes
November 4, 2003	Item 7 and Item 12*	None
December 31, 2003	Item 7 and Item 9*	None

* Information included pursuant to Item 9 and Item 12 is not deemed filed for the purposes of Section 18 of the Securities Exchange Act of 1934.

(c) Index of Exhibits:

Exhibit Number	Exhibits
3.1	Restated Certificate of Incorporation of Forest Oil Corporation dated October 14, 1993, incorporated herein by reference to Exhibit 3(i) to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 1993 (File No. 0-4597).
3.2	Certificate of Amendment of the Restated Certificate of Incorporation, dated as of July 20, 1995, incorporated herein by reference to Exhibit 3(i)(a) to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 1995 (File No. 0-4597).
3.3	Certificate of Amendment of the Certificate of Incorporation, dated as of July 26, 1995, incorporated herein by reference to Exhibit 3(i)(b) to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 1995 (File No. 0-4597).

Exhibit Number	Exhibits
3.4	Certificate of Amendment of the Certificate of Incorporation dated as of January 5, 1996, incorporated herein by reference to Exhibit 3(i)(c) to Forest Oil Corporation's Registration Statement on Form S-2 (File No. 33-64949).
3.5	Certificate of Amendment of the Certificate of Incorporation dated as of December 7, 2000, incorporated herein by reference to Exhibit 3(i)(d) to Form 10-K for Forest Oil Corporation for the year ended December 31, 2000 (File No. 001-13515).
3.6	Restated Bylaws of Forest Oil Corporation dated as of February 14, 2001, incorporated herein by reference to Exhibit 3(ii) to Form 10-K for Forest Oil Corporation for the year ended December 31, 2000 (File No. 001-13515).
3.7	Amendment No. 1, dated as of February 25, 2003, to the Restated Bylaws of Forest Oil Corporation dated as of February 14, 2001, incorporated herein by reference to Exhibit 99.1 to Forest Oil Corporation's Current Report on Form 8-K dated February 25, 2003 (File No. 001-13515).
3.8	Amendment No. 2, dated October 17, 2003, to the Restated Bylaws of Forest Oil Corporation dated as of February 14, 2001, incorporated herein by reference to Exhibit 3.1 to Forest Oil Corporation's Current Report on Form 8-K dated October 17, 2003 (File No. 001-13515).
4.1	Indenture dated as of June 21, 2001 between Forest Oil Corporation and State Street Bank and Trust Company, incorporated herein by reference to Exhibit 4.2 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2001 (File No. 001-13515).
4.2	Indenture dated as of December 7, 2001 between Forest Oil Corporation and State Street Bank and Trust Company, incorporated herein by reference to Exhibit 4.5 to Forest Oil Corporation's Registration Statement on Form S-4 dated February 6, 2002 (File No. 333-82254).
4.3	Indenture dated as of April 25, 2002 between Forest Oil Corporation and State Street Bank and Trust Company, incorporated herein by reference to Exhibit 4.6 to Forest Oil Corporation's Registration Statement on Form S-4 dated June 11, 2002 (File No. 333-90220).
4.4	First Amended and Restated Rights Agreement, dated as of October 17, 2003, between Forest Oil Corporation and Mellon Investor Services LLC, incorporated herein by reference to Exhibit 4.1 to Forest Oil's Current Report on Form 8-K, dated October 17, 2003 (File No. 001-13515).
4.5	Registration Rights Agreement, dated as of July 10, 2000, by and between Forest Oil Corporation and the other signatories thereto, incorporated herein by reference to Exhibit 4.15 to Forest Oil Corporation Registration Statement on Form S-4, dated November 6, 2000 (File No. 333-49376).
4.6	Registration Rights Agreement dated as of May 19, 1995 between Forest Oil Corporation and The Anschutz Corporation incorporated by reference to Exhibit 4.21 to Form 10-K for Forest Oil Corporation for the year ended December 31, 1995 (File No. 001-13515).
4.7	Credit Agreement, dated as of October 10, 2000, among Forest Oil Corporation, the lenders party thereto, Bank of America, N.A., as U.S. Syndication Agent, Citibank, N.A., as U.S. Documentation Agent, and The Chase Manhattan Bank, as Global Administrative Agent, incorporated herein by reference to Exhibit 4.12 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2000 (File No. 001-13515).

Exhibit Number	Exhibits
4.8	Canadian Credit Agreement, dated as of October 10, 2000, among Canadian Forest Oil Ltd., the subsidiary borrowers from time to time parties thereto, the lenders party thereto, Bank of Montreal, as Canadian Syndication Agent, The Toronto-Dominion Bank, as Canadian Documentation Agent, The Chase Manhattan Bank of Canada, as Canadian Administrative Agent, and The Chase Manhattan Bank, as Global Administrative Agent, incorporated herein by reference to Exhibit 4.14 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2000 (File No. 001-13515).
4.9	Mortgage, Deed of Trust, Assignment, Security Agreement, Financing Statement and Fixture Filing from Forest Oil Corporation to Robert C. Mertensotto, trustee, and Gregory P. Williams, trustee (Utah), and The Chase Manhattan Bank, as Global Administrative Agent, dated as of December 7, 2000, incorporated herein by reference to Exhibit 4.13 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2000 (File No. 001-13515).
4.10	First Amendment to Combined Credit Agreement dated as of May 24, 2001, by and between Forest Oil Corporation, Canadian Forest Oil Ltd., each of the lenders that is a party thereto, Bank of America, N.A., as U.S. Syndication Agent, Citibank, N.A., as U.S. Documentation Agent, The Chase Manhattan Bank of Canada, as Canadian Administrative Agent, Bank of Montreal, as Canadian Syndication Agent, The Toronto-Dominion Bank, as Canadian Documentation Agent, and JPMorgan Chase, successor to The Chase Manhattan Bank, as Global Administrative Agent, incorporated herein by reference to Exhibit 4.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2001 (File No. 001-13515).
4.11	Second Amendment to Combined Credit Agreements dated as of April 3, 2002, by and between Forest Oil Corporation, Canadian Forest Oil Ltd., each of the lenders that is a party thereto, Bank of America, N.A., as U.S. Syndication Agent, Citibank, N.A., as U.S. Documentation Agent, J.P. Morgan Bank Canada, successor to The Chase Manhattan Bank of Canada, as Canadian Administrative Agent, Bank of Montreal, as Canadian Syndication Agent, The Toronto-Dominion Bank, as Canadian Documentation Agent, and J.P. Morgan Chase, successor to The Chase Manhattan Bank, as Global Administrative Agent, incorporated herein by reference to Exhibit 4.17 to Forest Oil Corporation's Registration Statement on Form S-4 dated June 11, 2002 (File No. 333-90220).
4.12	Third Amendment to Combined Credit Agreements dated as of May 31, 2002, by and between Forest Oil Corporation, Canadian Forest Oil Ltd., each of the lenders that is a party thereto, Bank of America, N.A., as U.S. Syndication Agent, Citibank, N.A., as U.S. Documentation Agent, J.P. Morgan Bank Canada, successor to The Chase Manhattan Bank of Canada, as Canadian Administrative Agent, Bank of Montreal, as Canadian Syndication Agent, The Toronto-Dominion Bank, as Canadian Documentation Agent, and JPMorgan Chase, successor to The Chase Manhattan Bank, as Global Administrative Agent, incorporated herein by reference to Exhibit 4.18 Forest Oil Corporation's Registration Statement on Form S-4 dated June 11, 2002 (File No. 333-90220).
4.13	Fourth Amendment to Combined Credit Agreement dated as of October 8, 2002, among Forest Oil Corporation, Canadian Forest Oil Ltd., and the subsidiary borrowers from time to time parties thereto, each of the lenders that is party thereto, Bank of America, N.A., as U.S. Syndication Agent, Citibank, N.A., as U.S. Documentation Agent, J.P. Morgan Bank Canada, successor to The Chase Manhattan Bank of Canada, as Canadian Administrative Agent, Bank of Montreal, as Canadian Syndication Agent, The Toronto-Dominion Bank, as Canadian Documentation Agent, and JPMorgan Chase Bank, successor to The Chase Manhattan Bank, as Global Administrative Agent, incorporated herein by reference to Exhibit 4.1 to Forest Oil Corporation's Current Report on Form 8-K, dated as of January 15, 2003 (File No. 1-13515).

Exhibit Number	Exhibits
4.14	Fifth Amendment to Combined Credit Agreements, dated as of January 7, 2003, among Forest Oil Corporation, Canadian Forest Oil Ltd., and the subsidiary borrowers from time to time parties thereto, each of the lenders that is a party thereto, Bank of America, N.A., as U.S. Syndication Agent, Citibank, N.A., as U.S. Documentation Agent, J.P. Morgan Bank Canada, successor to The Chase Manhattan Bank of Canada, as Canadian Administrative Agent, Bank of Montreal, as Canadian Syndication Agent, The Toronto-Dominion Bank, as Canadian Documentation Agent, and JPMorgan Chase Bank, successor to The Chase Manhattan Bank, as Global Administrative Agent, incorporated herein by reference to Exhibit 4.2 to Forest Oil Corporation's Current Report on Form 8-K, dated as of January 15, 2003 (File No. 1-13515).
4.15	Sixth Amendment to Combined Credit Agreement dated March 19, 2003, among Forest Oil Corporation, Canadian Forest Oil Ltd., and the subsidiary borrowers from time to time parties thereto, each of the lenders that is party thereto, Bank of America, N.A., as U.S. Syndication Agent, Citibank, N.A., as U.S. Documentation Agent, J.P. Morgan Bank Canada, successor to The Chase Manhattan Bank of Canada, as Canadian Administrative Agent, Bank of Montreal, as Canadian Syndication Agent, The Toronto-Dominion Bank, as Canadian Documentation Agent, and JPMorgan Chase Bank, successor to the Chase Manhattan Bank, as Global Administrative Agent, incorporate herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended March 31, 2003 (File No. 001-13515).
4.16	Seventh Amendment to Combined Credit Agreements, dated as of October 15, 2003, among Forest Oil Corporation, Canadian Forest Oil Ltd., and the subsidiary borrowers from time to time parties thereto, each of the lenders that is a party thereto, Bank of America, N.A., as U.S. Syndication Agent, Citibank, N.A., as U.S. Documentation Agent, J.P. Morgan Bank Canada, successor to the Chase Manhattan Bank of Canada, as Canadian Administrative Agent, Bank of Montreal, as Canadian Syndication Agent, The Toronto-Dominion Bank, as Canadian Documentation Agent, and JPMorgan Chase Bank, successor to The Chase Manhattan Bank, as Global Administrative Agent, incorporate herein by reference to Exhibit 10.4 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2003 (File No. 001-13515).
4.17†	Eighth Amendment to Combined Credit Agreements, dated March 4, 2004 among Forest Oil Corporation, Canadian Forest Oil Ltd., and the subsidiary borrowers from time to time parties thereto, each of the lenders that is a party thereto, Bank of America, N.A., as U.S. Syndication Agent, Citibank, N.A., as U.S. Documentation Agent, JPMorgan Chase Bank, Toronto Branch, successor to the Chase Manhattan Bank of Canada, as Canadian Administrative Agent, Bank of Montreal, as Canadian Syndication Agent, The Toronto-Dominion Bank, as Canadian Documentation Agent, and JPMorgan Chase Bank, successor to The Chase Manhattan Bank, as Global Administrative Agent.
10.1*	Description of Executive Life Insurance Plan, incorporated herein by reference to Exhibit 10.2 to Form 10-K for Forest Oil Corporation for the year ended December 31, 1991 (File No. 0-4597).
10.2*	Form of non-qualified Supplemental Executive Retirement Plan, incorporated herein by reference to Exhibit 10.4 to Form 10-K for Forest Oil Corporation for the year ended December 31, 1990 (File No. 0-4597).
10.3*	Form of Executive Retirement Agreement, incorporated herein by reference to Exhibit 10.5 to Form 10-K for Forest Oil Corporation for the year ended December 31, 1990 (File No. 0-4597).
10.4*	Forest Oil Corporation 1996 Stock Incentive Plan and Option Agreement, incorporated herein by reference to Exhibit 4.1 to Form S-8 for Forest Oil Corporation dated June 7, 1996 (File No. 0-4597).

Exhibit Number	Exhibits
10.5*	First Amendment to Forest Oil Corporation 1996 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2001 (File No. 001-13515).
10.6*	Second Amendment to Forest Oil Corporation 1996 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2001 (File No. 001-13515).
10.7*	Form of Executive Severance Agreement, incorporated herein by reference to Exhibit 10.9 to Form 10-K for Forest Oil Corporation for the year ended December 31, 1993 (File No. 0-4597).
10.8*	Form of First Amendment to Severance Agreement, incorporated herein by reference to Exhibit 10.4 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2001 (File No. 001-13515).
10.9*	Form of Executive Severance Agreement, incorporated herein by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2001 (File No. 001-13515).
10.10*	Form of Executive Severance Agreement, incorporated herein by reference to Exhibit 10.10 to Forest Oil Corporation's Registration Statement on Form S-4 dated February 6, 2002 (File No. 333-82254).
10.11*	Form of Amendment to Severance Agreement, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2003 (File No. 001-13515).
10.12*	Form of Executive Severance Agreement, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2003 (File No. 001-13515).
10.13*	Forest Oil Corporation 2001 Stock Incentive Plan, incorporated herein by reference to Exhibit 4.1 to Form S-8 for Forest Oil Corporation dated June 6, 2001 (File No. 333-62408).
10.14*	Amendment No.1 to Forest Oil Corporation's 2001 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2003 (File No. 001-13515).
10.15*	Form of Employee Stock Option Agreement, incorporated herein by reference to Exhibit 4.2 to Form S-8 for Forest Oil Corporation dated June 6, 2001 (File No. 333-62408).
10.16*	Form of Non-Employee Director Stock Option Agreement, incorporated herein by reference to Exhibit 4.2 to Form S-8 for Forest Oil Corporation dated June 6, 2001 (File No. 333-62408).
10.17*	Forest Oil Corporation Pension Trust Agreement dated as of January 1, 2002 by and between Forest Oil Corporation and the trustees named therein or their successors, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2002 (File No. 1-13515).
10.18*†	Retirement Savings Plan of Forest Oil Corporation, as Amended and Restated effective August 1, 2001.
10.19*	First Amendment to Retirement Savings Plan of Forest Oil Corporation dated April 12, 2002, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2002 (File No. 1-13515).

Exhibit Number	Exhibits
10.20*	Second Amendment to Retirement Savings Plan of Forest Oil Corporation dated November 13, 2002, incorporated herein by reference to Exhibit 10.19 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2002 (File No. 001-13515).
10.21*†	Third Amendment to Retirement Savings Plan of Forest Oil Corporation dated November 13, 2003.
10.22*	Forest Oil Corporation Amended and Restated Salary Deferral Copmensation Plan, incorporated herein by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2002 (File No. 1-13515).
10.23*	Forest Oil Corporation Change of Control Deferred Compensation Plan, incorporated herein by refrence to Exhibit 10.18 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2002 (File No. 001-13515).
10.24*†	Forest Oil Corporation Executive Deferred Compensation Plan, effective as of July 1, 1994.
10.25*	First Amendment to Forest Oil Corporation Executive Deferred Compensation Plan dated November 13, 2002, incorporated herein by reference to Exhibit 10.20 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2002 (File No. 001-13515).
10.26*	Second Amendment to Forest Oil Corporation Executive Deferred Compensation Plan dated February 3, 2003, incorporated herein by reference to Exhibit 10.21 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2002 (File No. 001-13515).
10.27*	Purchase and Sale Agreement by and between Forest Oil Corporation, Union Oil Company of California, Pure Resources, L.P., Pure Partners, L.P., and PRS Offshore L.P., dated September 20, 2003, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2003 (File No. 001-13515).
21.1†	List of Subsidiaries of Registrant.
23.1†	Consent of KPMG LLP.
23.2†	Consent of Ryder Scott Company, L.P.
23.3†	Consent of DeGolyer and MacNaughton.
24.1	Powers of Attorney (included on the signature pages hereof).
31.1†	Certification of Principal Executive Officer of Forest Oil Corporation as required by Rule 13a-14(a) of the Securities Act of 1934.
31.2†	Certification of Principal Financial Officer of Forest Oil Corporation as required by Rule 13a-14(a) of the Securities Act of 1934.
32.1**	Certification of Chief Executive Officer of Forest Oil Corporation pursuant to 18 U.S.C. §1350.
32.2**	Certification of Chief Financial Officer of Forest Oil Corporation pursuant to 18 U.S.C. §1350.

* Contract or compensatory plan or arrangement in which directors and/or officers participate.

** Not considered to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section.

† Indicates exhibits filed with this Form 10-K.

SIGNATURES

Pursuant to the requirements of Section 13 of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

FOREST OIL CORPORATION
(Registrant)

Date: March 15, 2004

By: /s/ H. CRAIG CLARK

H. Craig Clark
President and
Chief Executive Officer

Power of Attorney

The officers and directors of Forest Oil Corporation, whose signatures appear below, hereby constitute and appoint H. Craig Clark, Joan C. Sonnen and Newton W. Wilson III, and each of them (with full power to each of them to act alone), the true and lawful attorney-in-fact to sign and execute, on behalf of the undersigned, any amendment(s) to this Form 10-K Annual Report for the year ended December 31, 2003, and any instrument or document filed as part of, as an exhibit to or in connection with any amendment, and each of the undersigned does hereby ratify and confirm as his own act and deed all that said attorneys shall do or cause to be done by virtue thereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant in the capacities and on the dates indicated.

Signatures	Title	Date
/s/ H. CRAIG CLARK H. Craig Clark	President and Chief Executive Officer and Director (Principal Executive Officer)	March 15, 2004
/s/ DAVID H. KEYTE David H. Keyte	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 15, 2004
/s/ JOAN C. SONNEN Joan C. Sonnen	Vice President—Controller and Chief Accounting Officer (Principal Accounting Officer)	March 15, 2004

Signatures	Title	Date
/s/ FORREST E. HOGLUND Forrest E. Hoglund	Chairman of the Board of Directors	March 15, 2004
/s/ WILLIAM L. BRITTON William L. Britton	Director	March 15, 2004
/s/ CORTLANDT S. DIETLER Cortlandt S. Dietler	Director	March 15, 2004
/s/ DOD. A. FRASER Dod. A. Fraser	Director	March 15, 2004
/s/ JAMES H. LEE James H. Lee	Director	March 15, 2004
/s/ PATRICK R. MCDONALD Patrick R. McDonald	Director	March 15, 2004

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ADDITIONAL INFORMATION

PRINCIPAL OFFICES

HEADQUARTERS
1600 Broadway, Suite 2200
Denver, Colorado 80202
303.812.1400

ALASKA
310 K Street, Suite 700
Anchorage, Alaska 99501
907.258.8600

CANADIAN FOREST OIL LTD.
800 - 6th Avenue S.W., Suite 600
Calgary, Alberta, Canada T2P 3G3
403.292.8000

LOUISIANA
3838 North Causeway Blvd.
Lakeway Three, Suite 2300
Metairie, Louisiana 70002
504.838.7022

4023 Ambassador Caffery Pkwy
Building C, Suite 200
Lafayette, Louisiana 70503
337.264.0500

SOUTH AFRICA
Forest Exploration International (SA) (Pty) Ltd.
Suite 0B, Nautica, The Waterclub, Beach Road
Granger Bay, 8005
Cape Town, South Africa
27.21.401.4140

TEXAS
1101 E. Pool Road
Odessa, Texas 79766
432.333.5252

INDEPENDENT AUDITORS

KPMG LLP
707 Seventeenth Street, Suite 2700
Denver, Colorado 80202
303.296.2323

INDEPENDENT RESERVE ENGINEERS

Ryder Scott Company
1100 Louisiana, Suite 3800
Houston, Texas 77002-5218
713.651.9191

STOCK

Common Stock Listed and Traded on:
The New York Stock Exchange
NYSE Symbol – FST

TRANSFER AGENT AND REGISTRAR FOR COMMON STOCK

Mellon Investor Services LLC
85 Challenger Road
Ridgefield Park, New Jersey 07660
800.635.9270

TDD for Hearing Impaired: 800.231.5469
Foreign Shareholders: 201.329.8660
TDD Foreign Shareholders: 201.329.8354
www.melloninvestor.com

INVESTOR RELATIONS

Additional information, including Investor Package, may be obtained from:

Forest Oil Corporation
Michael N. Kennedy, Manager – Investor Relations
1600 Broadway, Suite 2200
Denver, Colorado 80202
InvestorRelations@forestoil.com
or visit our website at www.forestoil.com

ANNUAL MEETING OF SHAREHOLDERS

The annual meeting of shareholders of Forest Oil Corporation will be held at the Colorado State Bank Building
1600 Broadway, 5th Floor
Denver, Colorado
Thursday, May 13, 2004 at 9:00 AM MT

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