DEVON ENERGY CORP/DE

FORM 10-K
(Annual Report)

Filed 03/07/03 for the Period Ending 12/31/02

Address	333 W. SHERIDAN AVENUE
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2002

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
COMMISSION FILE NUMBER 000-30176

DEVON ENERGY CORPORATION

(Exact name of Registrant as Specified in its Charter)

DELAWARE	73-1567067
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
20 NORTH BROADWAY, OKLAHOMA CITY, OKLAHOMA	73102-8260
(Address of Principal Executive Offices)	(Zip Code)

REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE:
(405) 235-3611

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	American Stock Exchange
4.9% Convertible Debentures, due 2008	The New York Stock Exchange
4.95% Convertible Debentures, due 2008	The New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:
NONE

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. [X] 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 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. [X]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). [X] Yes No [ ]

The aggregate market value of the voting stock held by non-affiliates of the Registrant as of June 28, 2002, was $7,639,933,692.

On March 1, 2003, 155,195,958 shares of common stock and 1,680,637 exchangeable shares of Devon's wholly-owned subsidiary, Northstar

Energy Corporation, were outstanding. Each exchangeable share is exchangeable for one share of Devon common stock.

DOCUMENTS INCORPORATED BY REFERENCE

None

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DEFINITIONS

As used in this document:

"Mcf" means thousand cubic feet

"MMcf" means million cubic feet

"Bcf" means billion cubic feet

"MMBtu" means million British thermal units, a measure of heating value

"Bbl" means barrel

"MBbls" means thousand barrels

"MMBbls" means million barrels

"Boe" means equivalent barrels of oil

"MBoe" means thousand equivalent barrels of oil

"MMBoe" means million equivalent barrels of oil

"Oil" includes crude oil and condensate

"NGLs" means natural gas liquids

"Domestic" means the properties of the Company in the onshore continental United States and the offshore Gulf of Mexico

"Canada" means the division of the Company encompassing oil and gas properties located in Canada

"International" means the division of the Company encompassing oil and gas properties that lie outside the United States and Canada

DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

This report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included or incorporated by reference in this report, including, without limitation, statements regarding the Company's future financial position, business strategy, budgets, projected revenues, projected costs and plans and objectives of management for future operations, are forward-looking statements. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as "may," "will," "expect," "intend," "project," "estimate," "anticipate," "believe," or "continue" or the negative thereof or variations thereon or similar terminology. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from the Company's expectations ("Cautionary Statements") include, but are not limited to, the Company's assumptions about energy markets, production levels, reserve levels, operating results, competitive conditions, technology, the availability of capital resources, capital expenditure obligations, the supply and demand for oil, natural gas, NGLs and other products or services, the price of oil, natural gas, NGLs and other products or services, currency exchange rates, the weather, inflation, the availability of goods and services, drilling risks, future processing volumes and pipeline throughput, general economic conditions, either internationally or nationally or in the jurisdictions in which Devon or its subsidiaries are doing business, legislative or regulatory changes, including changes in environmental regulation, environmental risks and liability under federal, state and foreign environmental laws and regulations, the securities or capital markets and other factors disclosed under "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," "Item 2. Properties -- Proved Reserves and Estimated Future Net Revenue"

"Item 7A. Quantitative and Qualitative Disclosure About Market Risk" and elsewhere in this report. All subsequent written and oral forward-looking statements attributable to the Company, or persons acting on its behalf, are expressly qualified in their entirety by the cautionary statements. The Company assumes no duty to update or revise its forward-looking statements based on changes in internal estimates or expectations or otherwise.

PART I

ITEM 1. BUSINESS

GENERAL

Devon Energy Corporation, including its subsidiaries, ("Devon" or the "Company") is an independent energy company engaged primarily in oil and gas exploration, development and production, the acquisition of producing properties, the transportation of oil, gas, and NGLs and the processing of natural gas. Through its predecessors, Devon began operations in 1971 as a privately-held company. In 1988, the Company's common stock began trading publicly on the American Stock Exchange under the symbol "DVN". In addition, commencing on December 15, 1998, a new class of Devon exchangeable shares began trading on The Toronto Stock Exchange under the symbol "NSX". These shares are essentially equivalent to Devon common stock. However, because they are issued by Devon's wholly-owned subsidiary, Northstar Energy Corporation ("Northstar"), they qualify as a domestic Canadian investment for Canadian shareholders. They are exchangeable at any time, on a one-for-one basis, for common shares of Devon.

The principal and administrative offices of Devon are located at 20 North Broadway, Oklahoma City, OK 73102-8260 (telephone 405/235-3611).

Devon operates oil and gas properties in the United States, Canada and internationally. Devon's North American properties are concentrated within five geographic areas. Operations in the United States are focused in the Permian Basin, the Mid-Continent, the Rocky Mountains and onshore and offshore Gulf Coast. Canadian operations are focused in the Western Canadian Sedimentary Basin in Alberta and British Columbia. Operations outside North America currently include Azerbaijan, Brazil, China and West Africa. In addition to its oil and gas operations, Devon has a large marketing and midstream business. This includes marketing natural gas, crude oil and NGLs. Marketing and midstream also includes the construction and operation of pipelines, storage and treating facilities and gas processing plants. (A detailed description of Devon's significant properties and associated 2002 developments can be found under "Item 2. Properties beginning on page 13 hereof).

At December 31, 2002, Devon's estimated proved reserves were 1,609 MMBoe, of which 60% were natural gas reserves and 40% were oil and NGLs reserves. The present value of pre-tax future net revenues discounted at 10% per annum assuming essentially constant prices ("10% Present Value") of such reserves was $15.3 billion. After taxes, the present value was $10.4 billion. Devon is one of the top five public independent oil and gas companies based in the United States, as measured by oil and gas reserves.

AVAILABILITY OF REPORTS

Devon makes available free of charge on its internet website, www.dvn.com, its Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(a) of the Securities Exchange Act of 1934 as soon as reasonably practicable after it electronically files or furnishes them to the Securities Exchange Commission.

STRATEGY

Devon's primary objectives are to build reserves, production, cash flow and earnings per share by (a) acquiring oil and gas properties, (b) exploring for new oil and gas reserves and (c) optimizing production and value from existing oil and gas properties. Devon's management seeks to achieve these objectives by
(a) concentrating its properties in core areas to achieve economies of scale,
(b) acquiring and developing high profit margin properties, (c) continually disposing of marginal and non-strategic properties, (d) balancing reserves between oil and gas, (e) maintaining a high degree of financial flexibility, and
(f) enhancing the value of Devon's production through marketing and midstream activities.

During 1988, Devon expanded its capital base with its first issuance of common stock to the public. This transaction began a substantial expansion program that has continued through the subsequent years. Devon has used a two-pronged strategy of acquiring producing properties and engaging in drilling activities to achieve this expansion. Total proved reserves increased from 8 MMBoe at year-end 1987 (without giving effect to the 1998 and 2000 mergers accounted for as poolings of interests) to 1,609 MMBoe at year-end 2002.

Devon's objective, however, is to increase value per share, not simply to increase total assets. Proved reserves have grown from 1.31 Boe per share at year-end 1987 (without giving effect to the 1998 and 2000 poolings) to 10.03 Boe per share at year-end 2002. This represents a compound annual growth rate of 14.5%. Another measure of value per share is oil and gas production per share. Production increased from 0.18 Boe per share in 1987 (without giving effect to the 1998 and 2000 poolings) to 1.17 Boe per share in 2002, a compound annual growth rate of 13.3%.

DEVELOPMENT OF BUSINESS

On February 24, 2003, Devon and Ocean Energy Inc. ("Ocean") announced their intention to merge. In the transaction, Devon will issue 0.414 of a share of its common stock for each outstanding share of Ocean common stock. Also, Devon will assume approximately $1.8 billion of debt from Ocean. The transaction is subject to approval by the stockholders of both companies, as well as certain regulatory approvals. If approved, the transaction is expected to be consummated shortly after the stockholder meetings.

On January 24, 2002, Devon completed its acquisition of Mitchell Energy & Development Corp. ("Mitchell"). Under the terms of this merger, Devon issued approximately 30 million shares of Devon common stock and paid $1.6 billion in cash to the Mitchell stockholders. The cash portion of the acquisition was funded from borrowings under a $3.0 billion senior unsecured term loan credit facility. The Mitchell merger added approximately 404 million Boe to Devon's proved reserves.

Following the Mitchell merger announcement in August 2001, Devon announced on September 4, 2001, that it had entered into an agreement to acquire Anderson Exploration Ltd. ("Anderson") for approximately $3.5 billion in cash. This acquisition closed on October 15, 2001, and therefore had an impact on Devon's results for the last two and one-half months of 2001. The Anderson acquisition added approximately 534 million Boe to Devon's proved reserves.

To fund the cash portions of these two acquisitions, as well as to pay related transaction costs and retire certain long-term debt assumed from Mitchell and Anderson, Devon entered into long-term debt agreements in October 2001 that totaled $6 billion. Half of this total consisted of $3 billion of notes and debentures issued on October 3, 2001. Of this total, $1.25 billion bears interest at 7.875% and matures in September 2031. The remaining $1.75 billion bears interest at 6.875% and matures in September 2011.

The remaining $3 billion of the $6 billion of long-term debt is in the form of a credit facility that bears interest at floating rates. As of December 31, 2002, $1.9 billion of the original $3 billion balance had been retired. The primary sources of the repayments were the 2002 issuance of $1 billion of debt securities, of which $0.8 billion was used to pay down debt, and $1.4 billion from the sale of certain oil and gas properties, of which $1.1 billion was used to pay down debt. As of December 31, 2002, the balance outstanding under the term loan credit facility was $1.1 billion at an average rate of 2.5%. Principal payments due on this debt are $0.3 billion in April 2006 and $0.8 billion in October 2006.

During 2002, Devon disposed of approximately $1.4 billion of properties. Also in 2002, Devon spent $1.5 billion in its exploration and drilling efforts. See further discussion of Devon's 2002 exploration and drilling efforts in "Item
2. Properties."

FINANCIAL INFORMATION ABOUT SEGMENTS AND GEOGRAPHICAL AREAS

Note 13 to the consolidated financial statements included in Item 8.
Financial Statements and Supplementary Data of this report contains information on Devon's segments and geographical areas.

DRILLING ACTIVITIES

Devon is engaged in numerous drilling activities on properties presently owned and intends to drill or develop other properties acquired in the future. Devon's 2003 drilling activities will be focused in the Rocky Mountains, Permian Basin, Mid-Continent, Gulf of Mexico and onshore Gulf Coast areas in the U.S., the Western Sedimentary basin of Canada and in China and West Africa outside North America.

The following tables set forth the results of Devon's drilling activity for the past five years.

UNITED STATES PROPERTIES

	DEVELOPMENT WELLS						EXPLORATORY WELLS		
	GROSS(1)			NET(2)			GROSS(1)		
	PRODUCTIVE	DRY	TOTAL	PRODUCTIVE	DRY	TOTAL	PRODUCTIVE	DRY	TOTAL
1998	374	1	375	153.69	0.10	153.79	24	21	45
1999	547	8	555	345.35	3.80	349.15	71	9	80
2000	890	13	903	512.18	6.80	518.98	95	11	106
2001	961	19	980	638.26	12.91	651.17	148	17	165
2002	933	7	940	725.79	4.67	730.46	21	18	39
Total	3,705	48	3,753	2,375.27	28.28	2,403.55	359	76	435

	EXPLORATORY WELLS		
	NET(2)		
	PRODUCTIVE	DRY	TOTAL
1998	11.36	7.54	18.90
1999	51.91	5.78	57.69
2000	80.09	7.41	87.50
2001	122.61	11.53	134.14
2002	19.60	12.00	31.60
Total	285.57	44.26	329.83

CANADIAN PROPERTIES

	DEVELOPMENT WELLS						EXPLORATORY WELLS		
	GROSS(1)			NET(2)			GROSS(1)		
	PRODUCTIVE	DRY	TOTAL	PRODUCTIVE	DRY	TOTAL	PRODUCTIVE	DRY	TOTAL
1998	112	15	127	74.88	11.04	85.92	45	37	82
1999	65	9	74	29.61	3.45	33.06	39	23	62
2000	130	6	136	68.74	3.25	71.99	70	27	97
2001	163	26	189	100.91	16.53	117.44	82	21	103
2002	408	20	428	300.93	15.05	315.98	196	37	233
Total	878	76	954	575.07	49.32	624.39	432...	145	577

	EXPLORATORY WELLS		
	NET(2)		
	PRODUCTIVE	DRY	TOTAL
1998	32.99	30.50	63.49
1999	25.15	16.03	41.18
2000	40.60	19.27	59.87
2001	63.96	14.05	78.01
2002	128.78	27.47	156.25
Total	291.48	107.32	398.80

INTERNATIONAL PROPERTIES

DEVELOPMENT WELLS EXPLORATORY WELLS

	Development Wells GROSS(1) PRODUCTIVE	GROSS(1) DRY	GROSS(1) TOTAL	NET(2) PRODUCTIVE	NET(2) DRY	NET(2) TOTAL	Exploratory Wells GROSS(1) PRODUCTIVE	GROSS(1) DRY	GROSS(1) TOTAL
1998	59	2	61	18.90	0.60	19.50	9	18	27
1999	42	2	44	10.00	0.60	10.60	1	4	5
2000	75	1	76	19.71	0.50	20.21	1	9	10
2001	84	1	85	21.71	0.51	22.22	6	17	23
2002	41	--	41	8.75	--	8.75	--	4	4
Total	301	6	307	79.07	2.21	81.28	17	52	69

EXPLORATORY WELLS

	NET(2) PRODUCTIVE	NET(2) DRY	NET(2) TOTAL
1998	2.90	8.20	11.10
1999	0.50	1.60	2.10
2000	0.33	6.01	6.34
2001	1.96	9.30	11.26
2002	--	1.77	1.77
Total	5.69	26.88	32.57

TOTAL PROPERTIES

	DEVELOPMENT WELLS GROSS(1) PRODUCTIVE	GROSS(1) DRY	GROSS(1) TOTAL	NET(2) PRODUCTIVE	NET(2) DRY	NET(2) TOTAL	EXPLORATORY WELLS GROSS(1) PRODUCTIVE	GROSS(1) DRY	GROSS(1) TOTAL
1998	545	18	563	247.47	11.74	259.21	78	76	154
1999	654	19	673	384.96	7.85	392.81	111	36	147
2000	1,095	20	1,115	600.63	10.55	611.18	166	47	213
2001	1,208	46	1,254	760.88	29.95	790.83	236	55	291
2002	1,382	27	1,409	1,035.47	19.72	1,055.19	217	59	276
Total	4,884	130	5,014	3,029.41	79.81	3,109.22	808	273	1,081

EXPLORATORY WELLS

	NET(2) PRODUCTIVE	NET(2) DRY	NET(2) TOTAL
1998	47.25	46.24	93.49
1999	77.56	23.41	100.97
2000	121.02	32.69	153.71
2001	188.53	34.88	223.41
2002	148.38	41.24	189.62
Total	582.74	178.46	761.20

(1) Gross wells are the sum of all wells in which Devon owns an interest.

(2) Net wells are the sum of Devon's working interests in gross wells.

As of December 31, 2002, Devon was participating in the drilling of 76 gross (60.71 net) wells in the U.S., 49 gross (28.93 net) wells in Canada and 8 gross (0.89 net) wells internationally. Of these wells, through February 15, 2003, 51 gross (40.91 net) wells in the U.S. and 42 gross (25.07 net) wells in Canada had been completed as productive. An additional 1 gross (.30 net) well in the U.S., 1 gross (.50 net) well in Canada and 1 gross (0.50 net) well internationally were dry holes. The remaining wells were still in process.

CUSTOMERS

Devon sells its gas production to a variety of customers including pipelines, utilities, gas marketing firms, industrial users and local distribution companies. Existing gathering systems and interstate and intrastate pipelines are used to consummate gas sales and deliveries.

The principal customers for Devon's crude oil production are refiners, remarketers and other companies, some of which have pipeline facilities near the producing properties. In the event pipeline facilities are not conveniently available, crude oil is trucked or barged to storage, refining or pipeline facilities.

No purchaser accounted for over 10% of Devon's revenues in 2002.

OIL AND NATURAL GAS MARKETING

Oil Marketing. Devon's oil production is sold under both long-term (one year or more) and short-term (less than one year) agreements at prices negotiated with third parties

Natural Gas Marketing. Devon's gas production is also sold under both long-term and short-term agreements at prices negotiated with third parties. Although exact percentages vary daily, as of February 2003 approximately 75% of Devon's natural gas production was sold under short-term contracts at variable or market-sensitive prices. These market-sensitive sales are referred to as "spot market" sales. Another 22% were committed under various long-term contracts (one year or more) which dedicate the natural gas to a purchaser for an extended period of time, but still at market sensitive prices. Devon's remaining gas production was sold under fixed price contracts: 2% under short-term agreements and 1% under long-term contracts.

Under both long-term and short-term contracts, typically either the entire contract (in the case of short-term contracts) or the price provisions of the contract (in the case of long-term contracts) are re-negotiated from daily intervals up to one-year intervals. The spot market has become progressively more competitive in recent years. As a result, prices on the spot market have been volatile.

The spot market is subject to volatility as supply and demand factors in various regions of North America fluctuate. In addition to fixed price contracts, Devon periodically enters into hedging arrangements or firm delivery commitments with a portion of its gas production. These activities are intended to support targeted gas price levels and to manage the Company's exposure to gas price fluctuations. (See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk.")

COMPETITION

The oil and gas business is highly competitive. Devon encounters competition by major integrated and independent oil and gas companies in acquiring drilling prospects and properties, contracting for drilling equipment and securing trained personnel. Intense competition occurs with respect to marketing, particularly of natural gas. Certain competitors have resources that substantially exceed those of Devon.

SEASONAL NATURE OF BUSINESS

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters sometimes lessen this fluctuation. In addition, pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations.

GOVERNMENT REGULATION

Devon's operations are subject to various levels of government controls and regulations in the United States, Canada and internationally.

UNITED STATES REGULATION

In the United States, legislation affecting the oil and gas industry has been pervasive and is under constant review for amendment or expansion. Pursuant to such legislation, numerous federal, state and local departments and agencies have issued extensive rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Such laws and regulations have a significant impact on oil and gas drilling, gas processing plants and production activities, increase the cost of doing business and, consequently, affect profitability. Inasmuch as new legislation affecting the oil and gas industry is commonplace and existing laws and regulations are frequently amended or reinterpreted, Devon is unable to predict the future cost or impact of complying with such laws and regulations. Devon considers the cost of environmental protection a necessary and manageable part of its business. Devon has been able to plan for and comply with new environmental initiatives without materially altering its operating strategies.

Exploration and Production. Devon's United States operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for the drilling of wells; maintaining bonding requirements in order to drill or operate wells; implementing spill prevention plans; submitting notification and receiving permits relating to the presence, use and release of certain materials incidental to oil and gas operations; and regulating the location of wells, the method of drilling and casing wells, the use, transportation, storage and disposal of fluids and materials used in connection with drilling and production activities, surface usage and the restoration of properties upon which wells have been drilled, the plugging and abandoning of wells and the transporting of production. Devon's operations are also subject to various conservation matters, including the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in a unit, and the unitization or pooling of oil and gas properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases, which may make it more difficult to develop oil and gas properties. In addition, state conservation laws establish maximum rates of production from oil and gas wells, generally limit the venting or flaring of gas, and impose certain requirements regarding the ratable purchase of production. The effect of these regulations is to limit the amounts of oil and gas Devon can produce from its wells and to limit the number of wells or the locations at which Devon can drill.

Certain of Devon's oil and gas leases, including its offshore Gulf of Mexico leases, most of its leases in the San Juan Basin and many of Devon's leases in southeast New Mexico and Wyoming, are granted by the federal government and administered by various federal agencies, including the Minerals Management Service of the Department of the Interior ("MMS"). Such leases require compliance with detailed federal regulations and orders which regulate, among other matters, drilling and operations on lands covered by these leases, and calculation and disbursement of royalty payments to the federal government. The MMS has been particularly active in recent years in evaluating and, in some cases, promulgating new rules and regulations regarding competitive lease bidding and royalty payment obligations for production from federal lands. The Federal Energy Regulatory Commission ("FERC") also has jurisdiction over certain offshore activities pursuant to the Outer Continental Shelf Lands Act.

Environmental and Occupational Regulations. Various federal, state and local laws and regulations concerning the discharge of incidental materials into the environment, the generation, storage, transportation and disposal of contaminants or otherwise relating to the protection of public health, natural resources, wildlife and the environment, affect Devon's exploration, development, processing, and production operations and the costs attendant thereto. These laws and regulations increase Devon's overall operating expenses. Devon maintains levels of insurance customary in the industry to limit its financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of oil, salt water or other substances. However, 100% coverage is not maintained concerning any environmental claim, and no coverage is maintained with respect to any penalty or fine required to be paid by Devon because of its violation of any federal, state or local law. Devon is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment. Devon's unreimbursed expenditures in 2002 concerning such matters were immaterial, but Devon cannot predict with any reasonable degree of certainty its future exposure concerning such matters.

Devon is also subject to laws and regulations concerning occupational safety and health. Due to the continued changes in these laws and regulations, and the judicial construction of same, Devon is unable to predict with any reasonable degree of certainty its future costs of complying with these laws and regulations. Devon considers the cost of safety and health compliance a necessary and manageable part of its business. Devon has been able to plan for and comply with new initiatives without materially altering its operating strategies.

Devon maintains its own internal Environmental, Health and Safety Department. This department is responsible for instituting and maintaining an environmental and safety compliance program for Devon. The program includes field inspections of properties and internal assessments of Devon's compliance procedures.

Devon is subject to certain laws and regulations relating to environmental remediation activities associated with past operations, such as the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") and similar state statutes. In response to liabilities associated with these activities, accruals have been established when reasonable estimates are possible. Such accruals primarily include estimated costs associated with remediation. Devon has not used discounting in determining its accrued liabilities for environmental remediation, and no material claims for possible recovery from third party insurers or other parties related to environmental costs have been recognized in Devon's consolidated financial statements. Devon adjusts the accruals when new remediation responsibilities are discovered and probable costs become estimable, or when current remediation estimates must be adjusted to reflect new information.

Certain of Devon's subsidiaries acquired in past mergers are involved in matters in which it has been alleged that such subsidiaries are potentially responsible parties ("PRPs") under CERCLA or similar state legislation with respect to various waste disposal areas owned or operated by third parties. As of December 31, 2002, Devon's consolidated balance sheet included $8 million of non-current accrued liabilities, reflected in "Other liabilities," related to these and other environmental remediation liabilities. Devon does not currently believe there is a reasonable possibility of incurring additional material costs in excess of the current accruals recognized for such environmental remediation activities. With respect to the sites in which Devon subsidiaries are PRPs, Devon's conclusion is based in large part on (i) Devon's participation in consent decrees with both other PRPs and the Environmental Protection Agency, which provide for performing the scope of work required for remediation and contain covenants not to sue as protection to the PRPs, (ii) participation in groups as a de minimis PRP, and (iii) the availability of other defenses to liability. As a result, Devon's monetary exposure is not expected to be material.

CANADIAN REGULATIONS

The oil and 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 Devon's Canadian operations in a manner materially different than they would affect other oil and gas companies of similar size. The following are the most important areas of control and regulation.

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

Royalties and Incentives. Each province and the federal government of Canada have legislation and regulations governing land tenure, royalties, production rates and taxes, environmental protection and other matters under their respective jurisdictions. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the parties. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production with the royalty rate dependent in part upon prescribed reference prices, well productivity, geographical location, field discovery date and the type and quality of the petroleum product produced. From time to time, the governments of Canada, Alberta and British Columbia have also established incentive programs such as royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects. These incentives generally have the effect of increasing the cash flow to the producer.

Pricing and Marketing. The price of oil and natural gas sold is determined by negotiation between buyers and sellers. An order from the National Energy Board ("NEB") is required for oil exports from Canada. Any oil export to be made pursuant to an export contract of longer than one year, in the case of light crude, and two years, in the case of heavy crude, duration (up to 25 years) requires an exporter to obtain an export license from the NEB. The issue of such a license requires the approval of the Government of Canada. Natural gas exported from Canada is also subject to similar regulation by the NEB. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts in excess of two years must continue to meet certain criteria prescribed by the NEB. The governments of Alberta and British Columbia also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

Environmental Regulation. The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of fines and penalties. Devon is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment. Devon's unreimbursed expenditures in 2002 concerning such matters were immaterial, but Devon cannot predict with any reasonable degree of certainty its future exposure concerning such matters.

Kyoto Protocol. In December 2002 the Government of Canada ratified the Kyoto Protocol. This protocol calls for Canada to reduce its greenhouse gas emissions to 6 percent below 1990 levels during the period between 2008 and 2012. The protocol will only become legally binding when it is ratified by at least 55 countries, covering at least 55 percent of the emissions addressed by the protocol. If the protocol becomes legally binding, it is expected to affect the operation of all industries in Canada, including the oil and gas industry. As details of the implementation of this protocol have yet to be announced, the effect on Devon cannot be determined at this time.

Investment Canada Act. The Investment Canada Act requires Government of Canada approval, in certain cases, of the acquisition of control of a Canadian business by an entity that is not controlled by Canadians. In certain circumstances, the acquisition of natural resource properties may be considered to be a transaction requiring such approval.

INTERNATIONAL REGULATIONS

The oil and gas industry is subject to various types of regulation throughout the world. Legislation affecting the oil and gas industry has been pervasive and is under constant review for amendment or expansion. Pursuant to such legislation, government agencies have issued extensive rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Such laws and regulations have a significant impact on oil and gas drilling and production activities, increase the cost of doing business and, consequently, affect profitability. Inasmuch as new legislation affecting the oil and gas industry is commonplace and existing laws and regulations are frequently amended or reinterpreted, Devon is unable to predict the future cost or impact of complying with such laws and regulations. The following are significant areas of regulation.

Exploration and Production. Devon's oil and gas concessions and permits are granted by host governments and administered by various foreign government agencies. Such foreign governments require compliance with detailed regulations and orders which regulate, among other matters, drilling and operations on areas covered by concessions and permits and calculation and disbursement of royalty payments, taxes and minimum investments to the government.

Regulation includes requiring permits for the drilling of wells; maintaining bonding requirements in order to drill or operate wells; implementing spill prevention plans; submitting notification and receiving permits relating to the presence, use and release of certain materials incidental to oil and gas operations; and regulating the location of wells, the method of drilling and casing wells, the use, transportation, storage and disposal of fluids and materials used in connection with drilling and production activities, surface usage and the restoration of properties upon which wells have been drilled, the plugging and abandoning of wells and the transporting of production. Devon's operations are also subject to regulations which may limit the number of wells or the locations at which Devon can drill.

Production Sharing Contracts. Many of Devon's international licenses are governed by Production Sharing Contracts (PSC) between the concessionaires and the granting government agency. PSCs are contracts that define and regulate the framework for investments, revenue sharing, and taxation of mineral interests in foreign countries. Unlike most domestic leases, PSCs have defined production terms and time limits of generally 30 years. Many PSCs allow for recovery of investments including carried government percentages. PSCs generally contain sliding scale revenue sharing provisions. For example, at either higher production rates or higher cumulative rates of return, PSCs allow governments to generally retain higher fractions of revenue.

Environmental Regulations. Various government laws and regulations concerning the discharge of incidental materials into the environment, the generation, storage, transportation and disposal of contaminants or otherwise relating to the protection of public health, natural resources, wildlife and the environment, affect Devon's exploration, development, processing and production operations and the costs attendant thereto. In general, this consists of preparing Environmental Impact Assessments in order to receive required environmental permits to conduct drilling or construction activities. Such regulations also typically include requirements to develop emergency response plans, waste management plans, and spill contingency plans. In some countries, the application of worldwide standards, such as ISO 14000 governing Environmental Management Systems, are required to be implemented for international oil and gas operations.

EMPLOYEES

As of December 31, 2002, Devon's staff consisted of 3,436 full-time employees. Devon believes that it has good labor relations with its employees.

ITEM 2. PROPERTIES

Substantially all of Devon's properties consist of interests in developed and undeveloped oil and gas leases and mineral acreage located in Devon's core operating areas and mid-stream assets. These interests entitle Devon to drill for and produce oil, natural gas and NGLs from specific areas. Devon's interests are mostly in the form of working interests and, to a lesser extent, overriding royalty, volumetric production payments, foreign government concessions, mineral and net profits interests and other forms of direct and indirect ownership in oil and gas properties.

Devon's most significant midstream asset is its 3,100 mile Bridgeport pipeline system and 650 MMcfd Bridgeport gas processing plant located in North Texas.

PROVED RESERVES AND ESTIMATED FUTURE NET REVENUE

Set forth below is a summary of the reserves which were evaluated by independent petroleum consultants for each of the years ended 2002, 2001 and 2000.

	2002		2001		2000	
	ESTIMATED	AUDITED	ESTIMATED	AUDITED	ESTIMATED	AUDITED
Domestic......................	12%	61%	67%	9%	80%	17%
Canada........................	31%	--%	43%	--%	100%	--%
International.................	100%	--%	100%	--%	100%	--%

Estimated reserves are those quantities of reserves which were estimated by an independent petroleum consultant. Audited reserves are those quantities of reserves which were estimated by Devon employees and audited by an independent petroleum consultant.

The domestic reserves were evaluated by the independent petroleum consultants of LaRoche Petroleum Consultants, Ltd. and Ryder Scott Company Petroleum Consultants in each of the years presented. The Canadian reserves were estimated by the independent petroleum consultants of AJM Petroleum Consultants in 2002; Paddock Lindstrom & Associates and Gilbert Laustsen Jung Associates, Ltd. in 2001; and Paddock Lindstrom & Associates in 2000. The International reserves were estimated by the independent petroleum consultants of Ryder Scott Company Petroleum Consultants in each of the years presented.

The following table sets forth Devon's estimated proved reserves, the estimated future net revenues therefrom and the 10% Present Value thereof as of December 31, 2002. These estimates correspond with the method used in presenting the "Supplemental Information on Oil and Gas Operations" in Note 14 to

Devon's Consolidated Financial Statements included herein, except that federal income taxes attributable to such future net revenues have been disregarded in the presentation below.

	TOTAL PROVED RESERVES	PROVED DEVELOPED RESERVES	PROVED UNDEVELOPED RESERVES
TOTAL RESERVES			
Oil (MMBbls)	444	260	184
Gas (Bcf)	5,836	4,618	1,218
NGL (MMBbls)	192	150	42
MMBoe(1)	1,609	1,180	429
Pre-tax Future Net Revenue ($ millions)(2)	27,270	19,297	7,973
Pre-tax 10% Present Value ($ millions)(2)	15,307	11,571	3,736
Standardized measure of discounted future net cash flows ($ millions)(3)	10,365		
U.S. RESERVES			
Oil (MMBbls)	147	135	12
Gas (Bcf)	3,552	2,802	750
NGL (MMBbls)	146	117	29
MMBoe(1)	885	719	166
Pre-tax Future Net Revenue ($ millions)(2)	13,578	11,281	2,297
Pre-tax 10% Present Value ($ millions)(2)	7,740	6,594	1,146
Standardized measure of discounted future net cash flows ($ millions)(3)	5,510		
CANADIAN RESERVES			
Oil (MMBbls)	149	119	30
Gas (Bcf)	2,284	1,816	468
NGL (MMBbls)	46	33	13
MMBoe(1)	576	455	121
Pre-tax Future Net Revenue ($ millions)(2)	10,566	7,871	2,695
Pre-tax 10% Present Value ($ millions)(2)	6,258	4,878	1,380
Standardized measure of discounted future net cash flows ($ millions)(3)	3,890		
INTERNATIONAL RESERVES			
Oil (MMBbls)	148	6	142
Gas (Bcf)	--	--	--
NGL (MMBbls)	--	--	--
MMBoe(1)	148	6	142
Pre-tax Future Net Revenue ($ millions)(2)	3,126	145	2,981
Pre-tax 10% Present Value ($ millions)(2)	1,309	99	1,210
Standardized measure of discounted future net cash flows ($ millions)(3)	965		

(1) Gas reserves are converted to Boe at the rate of six Mcf per Bbl of oil, based upon the approximate relative energy content of natural gas to oil, which rate is not necessarily indicative of the relationship of gas to oil prices. NGL reserves are converted to Boe on a one-to-one basis with oil. The respective prices of gas and oil are affected by market conditions and other factors in addition to relative energy content.

(2) Estimated future net revenue represents estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and development costs. The amounts shown do not give effect to non-property related expenses such as general and administrative expenses not related directly to oil and gas producing, debt service and future income tax expense or to depreciation, depletion and amortization.

These amounts were calculated using prices and costs in effect as of December 31, 2002. These prices were not changed except where different prices were fixed and determinable from applicable contracts. These assumptions yield average prices over the life of Devon's properties of $27.99 per Bbl of oil, $3.88 per Mcf of natural gas and $17.07 per Bbl of NGLs. These prices compare to December 31, 2002, New York Mercantile Exchange prices of $31.20 per Bbl for crude oil and of $4.74 per MMBtu for natural gas.

(3) See Note 14 to the consolidated financial statements included in Item 8 of this report.

No estimates of Devon's proved reserves have been filed with or included in reports to any federal or foreign governmental authority or agency since the beginning of the last fiscal year except (i) in filings with the SEC and Canadian Securities Regulators and (ii) in filings with the Department of Energy ("DOE"). Reserve estimates filed by Devon with the SEC and Canadian Securities Regulators correspond with the estimates of Devon reserves contained herein. Reserve estimates filed with the DOE are based upon the same underlying technical and economic assumptions as the estimates of Devon's reserves included herein. However, the DOE requires reports to include the interests of all owners in wells that Devon operates and to exclude all interests in wells that Devon does not operate.

The prices used in calculating the estimated future net revenues attributable to proved reserves do not necessarily reflect market prices for oil, gas and NGL production subsequent to December 31, 2002. There can be no assurance that all of the proved reserves will be produced and sold within the periods indicated, that the assumed prices will be realized or that existing contracts will be honored or judicially enforced.

The process of estimating oil, gas and NGLs reserves is complex, requiring significant subjective decisions in the evaluation of available geological, engineering and economic data for each reservoir. The data for a given reservoir may change substantially over time as a result of, among other things, additional development activity, production history and viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates may occur in the future.

PRODUCTION, REVENUE AND PRICE HISTORY

Certain information concerning oil and natural gas production, prices, revenues (net of all royalties, overriding royalties and other third party interests) and operating expenses for the three years ended December 31, 2002, is set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

WELL STATISTICS

The following table sets forth Devon's producing wells as of December 31, 2002:

	OIL WELLS		GAS WELLS		TOTAL WELLS	
	GROSS(1)	NET(2)	GROSS(1)	NET(2)	GROSS(1)	NET(2)
U.S.	6,869	2,777	9,632	6,892	16,501	9,669
Canada	2,808	1,695	4,066	2,307	6,874	4,002
International	20	3	--	--	20	3
Total	9,697	4,475	13,698	9,199	23,395	13,674

(1) Gross wells are the total number of wells in which Devon owns a working interest.

(2) Net refers to gross wells multiplied by Devon's fractional working interests therein.

Devon also held numerous overriding royalty interests in oil and gas wells, a portion of which are convertible to working interests after recovery of certain costs by third parties. After converting to working interests, these overriding royalty interests will be included in Devon's gross and net well count.

DEVELOPED AND UNDEVELOPED ACREAGE

The following table sets forth Devon's developed and undeveloped oil and gas lease and mineral acreage as of December 31, 2002.

	DEVELOPED		UNDEVELOPED	
	GROSS(1)	NET(2)	GROSS(1)	NET(2)
	(IN THOUSANDS)			
United States				
Permian Basin	565	297	1,029	462
Mid-Continent	1,070	783	1,809	1,179
Rocky Mountains	495	287	1,156	601
Gulf Coast				
Offshore	495	286	781	467
Onshore	524	243	218	91
Total Gulf Coast	1,019	529	999	558
Total U. S.	3,149	1,896	4,993	2,800
Canada	3,655	2,296	16,370	11,468
International	54	6	11,759	7,437
Grand Total	6,858	4,198	33,122	21,705

(1) Gross acres are the total number of acres in which Devon owns a working interest.

(2) Net refers to gross acres multiplied by Devon's fractional working interests therein.

OPERATION OF PROPERTIES

The day-to-day operations of oil and gas properties are the responsibility of an operator designated under pooling or operating agreements. The operator supervises production, maintains production records, employs field personnel and performs other functions. The charges under operating agreements customarily vary with the depth and location of the well being operated.

Devon is the operator of 14,001 of its wells. As operator, Devon receives reimbursement for direct expenses incurred in the performance of its duties as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged in the area to or by unaffiliated third parties. In presenting its financial data, Devon records the monthly overhead reimbursements as a reduction of general and administrative expense, which is a common industry practice.

ORGANIZATION STRUCTURE

Devon's North American properties are concentrated within five geographic areas. Operations in the United States are focused in the Permian Basin, the Mid-Continent, the Rocky Mountains and onshore and offshore Gulf Coast regions. Canadian operations are focused in the Western Canadian Sedimentary Basin in Alberta and British Columbia. Operations outside North America currently include Azerbaijan, Brazil, China and West Africa. Maintaining a tight geographic focus in selected core areas has allowed Devon to improve operating and capital efficiency.

UNITED STATES PROPERTIES

The Permian Basin

The Permian Basin includes portions of Southeast New Mexico and West Texas. These assets include conventional oil and gas properties from a wide variety of geologic formations and productive depths. The Permian Basin represented 9% of Devon's proved reserves at December 31, 2002.

Devon's leasehold position in Southeast New Mexico encompasses more than 102,000 acres of developed lands and 237,000 acres of undeveloped land and minerals. Historically, Devon has been a very active operator in this area developing gas from the high productivity Morrow formation and oil in the lower risk Delaware formation.

In the West Texas area of the Permian Basin, Devon maintains a base of oil production with long-life reserves. Many of these reserves are from both operated and non-operated positions in large enhanced oil recovery units such as the Wasson ODC Unit, the Willard Unit, the Reeves Unit, the North Welch Unit and the Anton Irish (Clearfork) Unit. These oil-producing units often exhibit long lives with low decline rates. Devon also owns a significant acreage position in West Texas with over 194,000 acres of developed lands and over 224,000 acres of undeveloped land and minerals at December 31, 2002.

Mid-Continent

The Mid-Continent region includes portions of Texas, Oklahoma, Kansas, Mississippi and Louisiana. These areas encompass a wide variety of geologic formations and productive depths and produce both oil and natural gas. Devon's Mid-Continent production has historically come from conventional oil and gas properties, but Devon has recently established two non-conventional gas operations in the Mid-Continent region: the Barnett Shale and the Cherokee coalbed methane project. The Mid-Continent region represented 30% of Devon's proved reserves at December 31, 2002.

The most significant asset acquired by Devon in its 2002 acquisition of Mitchell was a substantial interest in the Barnett Shale of North Texas. The Barnett Shale is known as a tight gas formation. This means that, in its natural state, the formation is resistant to the production of natural gas. Mitchell spent decades understanding how to efficiently develop and produce this gas. The resulting technology yielded a low-risk and highly profitable natural gas operation. Devon holds 525,000 net acres and over 1,100 producing wells in the Barnett Shale. Devon's average working interest is approximately 95%. The Barnett Shale is a unique, unconventional natural gas resource that offers immediate low-risk production growth and the potential for additional drilling locations.

Devon has experienced success extracting gas from the Barnett Shale by using light sand fracturing. Light sand fracturing yields better results than earlier techniques and is less expensive and can be used to complete new wells and to refracture existing wells. Refractured wells often exceed their original flow rates. Devon is also investigating horizontal drilling and closer well spacing to further enhance the value of the Barnett Shale.

Devon's marketing and midstream business transports, treats and processes its Barnett Shale production along with Barnett Shale production from unrelated third parties. The transport system consists of approximately 3,100 miles of pipeline, a 650 MMcf per day gas processing plant, and a 15,000 Bbls per day NGL fractionator.

In 2003, Devon plans to drill up to 450 new Barnett Shale wells and refracture 64 wells. Devon is also conducting exploratory pilot projects outside the core development area in an effort to expand the productive area. The Barnett Shale is expected to continue to be an important growth area for Devon for the foreseeable future. Current production from the Barnett Shale is approximately 345 MMcf and 21,700 Bbls of oil and NGLs per day net.

The other non-conventional asset Devon is developing in the Mid-Continent region is the Cherokee coalbed methane project. Coalbed methane is natural gas produced from underground coal deposits. Devon acquired over 400,000 net acres within the Cherokee area of Southeast Kansas and Northeast Oklahoma in 2001.

Devon's East Texas properties are a significant conventional asset. A large portion of this asset base was initially acquired in 1999. The Carthage and Bethany fields are two of the primary properties. These properties produce from the Cotton Valley sands, the Travis Peak sands and from shallower sands and carbonates. Devon operates over 500 producing wells in this area and utilizes a one to two rig drilling program to continue the low-risk, infill development of this area.

The 2002 acquisition of Mitchell added a complementary asset base to the East Texas area. These properties are located on the western side of the East Texas Basin and produce from the Bossier, Cotton Valley and Travis Peaks sands. Devon operates approximately 400 producing wells in this area and plans to continue the development drilling program with one to two rigs. Devon's current net production in East Texas is approximately 123 MMcf and 3,800 Bbls of oil and NGLs per day.

Rocky Mountain Region

Devon's operations in the Rocky Mountain region include properties in Wyoming, Utah, and Northern New Mexico. These assets include conventional oil and gas properties and coalbed methane projects. As of December 31, 2002, the Rocky Mountain region comprised 11% of Devon's proved reserves.

Devon began producing coalbed methane in the San Juan Basin of New Mexico in the mid-1980s and began drilling coalbed methane wells in the Powder River Basin of Wyoming in 1998. As of December 31, 2002, Devon has drilled over 1,500 coalbed methane wells in the Powder River Basin. Devon's net coalbed methane gas production from the basin was approximately 80 MMcf per day as of December 31, 2002, and Devon plans to drill more than 100 wells in the Powder River Basin in 2003. Current production in the basin is primarily from the Wyodak coal formation.

The deeper Big George formation is currently being tested by Devon and others with working interests in the area. Increased development in the Big George is subject to an Environmental Impact Statement, which has been completed and is expected to be approved within the next few months. Pending this approval and the success of current pilot projects, the Big George could significantly expand the coalbed methane play into the western portion of the Powder River Basin. Devon's leasehold in this area would allow for the development of four projects in the Big George.

Devon is also continuing to develop conventional gas operations at the Washakie field in Wyoming. Devon drilled 31 wells in 2002 and plans to drill another 30 wells in 2003. Devon has interests in over 200,000 acres. Devon's current net production from Washakie is approximately 77 MMcf and 1,100 Bbls of oil and NGLs per day.

GULF OF MEXICO AND GULF COAST

Devon is active in the offshore Gulf of Mexico and onshore South Texas and South Louisiana. Devon operates 100 structures in the Gulf of Mexico predominantly in the outer shelf area offshore Louisiana. The Gulf of Mexico and Gulf Coast region represented 5% of Devon's proved reserves at December 31, 2002.

Devon is applying four-component, or 4-C, seismic technology to identify prospects on large tracts of its shelf acreage. Traditional seismic techniques have not been successful in imaging reservoirs lying below shallow gas reservoirs and salt deposits, but 4-C seismic technology is allowing Devon's geoscientists to more accurately picture these unexplored formations. Devon has conducted two large 4-C seismic surveys offshore Louisiana and, in 2002, Devon drilled four successful wells in the West Cameron area based on 4-C data. Devon is also reprocessing large seismic data volumes using pre-stack depth migration to prospect for oil and gas in the outer shelf. In addition, Devon is utilizing new long cable 3-D seismic data to better image deep shelf prospects. Devon has developed a significant inventory of drilling opportunities for deeper gas near our infrastructure in offshore Louisiana and offshore Texas.

In the deepwater Gulf of Mexico, Devon participated in its first subsalt discovery in 1999 in the Enchilada Field located in Garden Banks 128. Since then Devon has operated several successful subsea completions ranging from Garden Banks to Viosca Knoll. Devon has experience with the successful installation and operation of subsea production equipment, which is an important component of any deepwater program. Devon's Pecten discovery in Viosca Knoll Block 694, a subsea tieback completed in 2001, is currently producing approximately 17 MMcf of gas per day.

Because deepwater exploration requires significant capital expenditures, Devon's strategy is to share projects with experienced partners to mitigate risk. In 2002, Devon entered into a four-well joint venture with ChevronTexaco that will earn Devon a 25% working interest in 71 deepwater blocks and 14 identified exploratory prospects. Devon also made a potentially significant discovery in 2002 in 8,200 feet of water at Cascade located in Walker Ridge Block 206 and plans to participate with other partners in four or five deepwater wells in 2003, including a confirmation well at Cascade.

Devon's operations in the Gulf Coast region include operations onshore in South Texas, where exploration for oil and gas is accelerating. Devon's activities in this area have focused on exploration in the Edwards, Wilcox and Frio/Vicksburg formations. Devon also acquired additional production and undeveloped acreage in the South Texas area from its acquisition of Mitchell.

CANADA

Devon's acquisition of Anderson in late 2001 significantly increased the relative importance of Devon's Canadian operations. The Anderson acquisition strengthened Devon's holdings in the Deep Basin located in Western Alberta and Eastern British Columbia, and the Foothills Region of Northeastern British Columbia. As of December 31, 2002, 36% of Devon's proved reserves were in Canada.

Devon had sought for years to obtain a significant acreage position in the Deep Basin, but other operators, including Anderson, already controlled most of the acreage. As a result of the Anderson acquisition, Devon now holds over 800,000 net acres in the Deep Basin. The profitability of Devon's operations in the Deep Basin is enhanced by its ownership in nine gas processing plants in the area. Devon plans to drill about 100 wells in the Deep Basin in 2003. These reservoirs tend to be rich in liquids, producing up to 100 barrels of NGLs with each MMcf of gas.

Late in 2002, Devon commenced production from the first of several wells it has drilled in the Grizzly Valley area of the Foothills Region of Northeastern British Columbia. Due to gas pipeline and processing limitations, initial production has been limited to 10 MMcf of gas per day. However, a pipeline extension slated for completion in the second quarter of 2003 should allow production to increase to about 35 MMcf per day.

Devon acquired from Anderson approximately 1.5 million net acres in the MacKenzie Delta region and the shallow waters of the Beaufort Sea in Northern Canada. In 2002, a Devon well in the MacKenzie Delta encountered over 110 feet of natural gas pay in the Kamik sand. Two to three more exploratory wells are planned by Devon in the MacKenzie Delta in 2003.

Devon has been active for over a decade in Northeastern British Columbia, an area in which Devon owns approximately 1.35 million net undeveloped acres of land. In 2002, Devon participated in the drilling of 67 gross wells and plans to participate in the drilling of approximately 93 wells in 2003.

The Peace River Arch area is a more mature area with both light oil and natural gas potential. Most of Devon's position in the Peace River Arch was acquired through the Anderson acquisition. Devon holds roughly 730,000 net undeveloped acres in the Peace River Arch, and the average production in 2002 was approximately 140 MMcf of natural gas and 7,500 Bbls of NGLs per day net. In 2003, Devon plans to participate in the drilling of 71 gross wells in the Peace River Arch. Devon has an interest in a production and processing infrastructure in the Peace River Arch, which enhances Devon's operations in the area.

In the Northern Plains region of Northeastern Alberta, Devon has been active for many years. While the area is a highly developed area with winter-only access, Devon is very active, drilling in excess of 100 gross wells per year. In 2002, average daily net production from the area was about 150 MMcf of natural gas and approximately 3,400 Bbls of NGLs net. Natural gas is encountered in multiple horizons at depths generally less than 1,300 feet. Devon holds approximately 2 million net undeveloped acres in this area.

Devon has about 400,000 net undeveloped acres in the central and southern region of Alberta and the average production from this area in 2002 was approximately 80 MMcf of natural gas and 20,000 Bbls of NGLs per day net. Planned activity in 2003 includes drilling approximately 70 gross wells that vary from deep Devonian tests to shallow Cretaceous tests.

Devon is also active in exploration for and production of "cold-flow" heavy oil in the Lloydminster area of Alberta and Saskatchewan where oil is found in multiple horizons generally at depths of 1,000 to 2,000 feet. In 2003, Devon plans to drill 134 gross wells with primarily a development focus. Average daily production from the area in 2002 was approximately 37 MMcf of natural gas and 13,750 Bbls of crude oil net.

Devon is also active in the evaluation of thermal heavy oil in Alberta through its 13% ownership interest in the Surmont project, operated by ConocoPhillips, and is actively evaluating the development of a 100% working interest heavy oil lease at Jackfish and an 83% working interest heavy oil project at Dover. Each of these heavy oil projects target bitumen (heavy tar-like oil) through the use of Steam Assisted Gravity Drainage whereby a pair of horizontal wells are utilized. Steam is injected in one well and is used to heat the bitumen to allow it to gravity drain to the other horizontal production well.

INTERNATIONAL

Devon's international activities are currently focused in development projects in Azerbaijan and China and deepwater exploration in the combined South Atlantic Margin of Brazil and West Africa. In 2002, Devon divested all remaining interests in Argentina, Indonesia and Egypt. As of December 31, 2002, 9% of Devon's proved reserves were in countries outside North America.

In Azerbaijan, Devon has a 5.6% carried working interest in the large Azeri-Chirag-Gunashli, or ACG, oil development project. Devon estimates that the ACG field contains over 4.6 billion barrels of gross proved oil reserves. The development project commenced in 2002. The Baku-T'Bilisi-Ceyhan (BTC) pipeline to export oil for this project has been approved by the governments of Azerbaijan, Georgia and Turkey.

In China, Devon is an acreage holder in the Pearl River Mouth Basin in the South China Sea and has been successful in discovering two new fields. Devon is currently developing the Devon operated Panyu development project and expects oil production from two offshore platforms and into a floating production- storage and offloading vessel to commence in late 2003. Gross capital expenditures for the project are $340 million, with Devon owning a 24.5% working interest. Peak production is expected to reach 58,000 Bbls of oil per day (15,000 Bbls of oil per day net to Devon) in 2004.

Devon's international exploration efforts are strategically focused in the combined South Atlantic deep water region of West Africa and Brazil. Devon's presence in West Africa began in 1992 with exploration efforts resulting in the discoveries of the Tchatamba fields in the shallow waters offshore Gabon. In this region, Devon has five blocks and holds over 3.2 million net acres. Devon plans to drill deepwater exploratory wells in its West Africa portfolio in Ghana and Gabon in 2003. In Brazil, Devon will be acquiring a 3-D survey in a Devon-operated deepwater block in early 2003 in order to identify future drilling opportunities.

SIGNIFICANT PROPERTIES

The following table sets forth proved reserve information on the most significant geographic areas in which Devon's properties are located as of December 31, 2002.

	Oil (MMBbls)	Gas (Bcfcf)	NGLs (MMBbls)	MMBoe(1)	MMBoe %(2)	10% PRESENT VALUE (IN MILLIONS)(3)	10% PRESENT VALUE %(4)	STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS (IN MILLIONS)(5)
UNITED STATES								
Permian Basin........	90	283	13	150	9.3%	$ 1,418	9.3%	
Mid-Continent........	9	2,103	116	475	29.5%	3,918	25.6%	
Rocky Mountain.......	22	835	9	170	10.6%	1,100	7.2%	
Gulf								
Offshore...........	23	194	4	60	3.7%	922	6.0%	
Onshore............	3	137	4	30	1.9%	382	2.5%	
Total............	26	331	8	90	5.6%	1,304	8.5%	
TOTAL U.S.	147	3,552	146	885	55.0%	7,740	50.6%	$ 5,510
CANADA								
Total(6)...........	149	2,284	46	576	35.8%	6,258	40.9%	3,890
INTERNATIONAL								
Total.............	148	--	--	148	9.2%	1,309	8.5%	965
Grand Total............	444	5,836	192	1,609	100.0%	$15,307	100.0%	$10,365

(1) Gas reserves are converted to Boe at the rate of six Mcf of gas per Bbl of oil, based upon the approximate relative energy content of natural gas to oil, which rate is not necessarily indicative of the relationship of gas to oil prices. NGL reserves are converted to Boe on a one-to-one basis with oil. The respective prices of gas and oil are affected by market and other factors in addition to relative energy content.

(2) Percentage which MMBoe for the basin or region bears to total MMBoe for all proved reserves.

(3) Determined in accordance with SEC guidelines, except that no effect is given to future income taxes.

(4) Percentages which present value for the basin or region bears to total present value for all proved reserves.

(5) Determined in accordance with SEC guidelines.

(6) Canadian dollars converted to U.S. dollars at the rate of $1 Canadian:
$0.6331 U.S.

TITLE TO PROPERTIES

Title to properties is subject to contractual arrangements customary in the oil and gas industry, liens for current taxes not yet due and, in some instances, other encumbrances. Devon believes that such burdens do not materially detract from the value of such properties or from the respective interests therein or materially interfere with their use in the operation of the business.

As is customary in the industry in the case of undeveloped properties, little investigation of record title is made at the time of acquisition (other than a preliminary review of local records). Investigations, generally including a title opinion of outside counsel, are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties.

ITEM 3. LEGAL PROCEEDINGS

ROYALTY MATTERS

Numerous gas producers and related parties, including Devon, have been named in various lawsuits filed by private litigants alleging violation of the federal False Claims Act. The suits allege that the producers and related parties used below-market prices, improper deductions, improper measurement techniques and transactions with affiliates which resulted in underpayment of royalties in connection with natural gas and natural gas liquids produced and sold from federal and Indian owned or controlled lands. The various suits have been consolidated by the United States Judicial Panel on Multidistrict Litigation for pre-trial proceedings in the matter of In re Natural Gas Royalties Qui Tam Litigation, MDL-1293, United States District Court for the District of Wyoming. Devon believes that it has acted reasonably, has legitimate and strong defenses to all allegations in the suits, and has paid royalties in good faith. Devon does not currently believe that it is subject to material exposure in association with these lawsuits, and no liability has been recorded in connection therewith.

Also, pending in federal court in Texas is a similar suit alleging underpaid royalties to the United States in connection with natural gas and natural gas liquids produced and sold from United States owned and/or controlled lands. The claims were filed by private litigants against Devon and numerous other producers, under the federal False Claims Act. The United States served notice of its intent to intervene as to certain defendants, but not Devon. Devon and certain other defendants are challenging the constitutionality of whether a claim under the federal False Claims Act can be maintained absent government intervention. Devon believes that it has acted reasonably and paid royalties in good faith. Devon does not currently believe that it is subject to material exposure in association with this litigation. As a result, Devon's monetary exposure in this suit is not expected to be material.

Devon is a defendant in certain private royalty owner litigation filed in Wyoming regarding deductibility of certain post production costs from royalties payable by Devon. The plaintiffs in these lawsuits propose to expand them into county or state-wide class actions relating specifically to transportation and related costs associated with Devon's Wyoming gas production. A significant portion of such production is, or will be, transported through facilities owned by Thunder Creek Gas Services, L.L.C., of which Devon owns a 75% interest. Devon believes that it has acted reasonably and paid royalties in good faith and in accordance with its obligations under its oil and gas leases and applicable law, and Devon does not believe that it is subject to material exposure in association with this litigation.

OTHER MATTERS

Devon is involved in other various routine legal proceedings incidental to its business. However, to Devon's knowledge as of the date of this report, there were no other material pending legal proceedings to which Devon is a party or to which any of its property is subject.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

There were no matters submitted to a vote of security holders during the fourth quarter of 2002.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

MARKET PRICE

Devon's common stock has been traded on the American Stock Exchange (the "AMEX") since September 29, 1988. Prior to September 29, 1988, Devon's common stock was privately held. Commencing on December 15, 1998, a new class of Devon exchangeable shares began trading on The Toronto Stock Exchange ("TSE") under the symbol "NSX". These shares are essentially equivalent to Devon common stock. However, because they are issued by Devon's wholly-owned subsidiary, Northstar, they qualify as a domestic Canadian investment for Canadian shareholders. They are exchangeable at any time, on a one-for-one basis, for common shares of Devon at the holder's option.

The following table sets forth the high and low sales prices for Devon common stock and exchangeable shares as reported by the AMEX and TSE for the periods indicated.

	AMERICAN STOCK EXCHANGE			THE TORONTO STOCK EXCHANGE		
	HIGH (US$)	LOW (US$)	AVERAGE DAILY VOLUME	HIGH (CN$)	LOW (CN$)	AVERAGE DAILY VOLUME
2001:						
Quarter Ended March 31, 2001......	66.75	52.30	977,648	102.85	78.19	8,941
Quarter Ended June 30, 2001.......	62.65	48.50	1,053,178	95.25	75.96	3,569
Quarter Ended September 30, 2001............................	55.25	30.55	1,582,815	84.40	49.00	5,367
Quarter Ended December 31, 2001...	41.25	31.45	1,279,434	64.71	51.91	3,044
2002:						
Quarter Ended March 31, 2002......	49.10	34.40	1,197,478	77.46	54.70	12,353
Quarter Ended June 30, 2002.......	52.28	45.05	1,005,613	79.54	71.50	2,840
Quarter Ended September 30, 2002............................	49.70	33.87	1,047,531	76.97	54.55	2,897
Quarter Ended December 31, 2002...	53.10	42.14	1,123,356	82.50	67.25	1,222

DIVIDENDS

Devon commenced the payment of regular quarterly cash dividends on its common stock on June 30, 1993, in the amount of $0.03 per share. Effective December 31, 1996, Devon increased its quarterly dividend payment to $0.05 per share. Devon anticipates continuing to pay regular quarterly dividends in the foreseeable future. Dividends are also paid on the exchangeable shares at the same rate and on the same dates as dividends paid on the common stock.

On February 25, 2003, there were 25,470 holders of record of Devon common stock and 295 holders of record for the exchangeable shares.

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial information (not covered by the independent auditors' report) should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," and the consolidated financial statements and the notes thereto included in "Item 8. Financial Statements and Supplementary Data." Note 2 to the consolidated financial statements included in Item 8 of this report contains information on mergers and acquisitions which occurred in 2002, 2001 and 2000, as well as unaudited pro forma financial data for the years 2002 and 2001. Note 1 to the consolidated financial statements included in Item 8 contains information on operations which were discontinued in 2002.

	YEAR ENDED DECEMBER 31,				
	2002	2001	2000	1999	1998
	(MILLIONS, EXCEPT PER SHARE DATA AND RATIOS)				
OPERATING RESULTS					
Oil sales	$ 909	784	906	436	236
Gas sales	2,133	1,878	1,474	616	335
NGLs sales	275	131	154	68	25
Marketing and midstream revenues	999	71	53	20	8
Total revenues	4,316	2,864	2,587	1,140	604
Lease operating expenses	621	467	388	249	186
Transportation costs	154	83	53	34	23
Production taxes	111	116	103	45	22
Marketing and midstream operating costs and expenses	808	47	28	10	3
Depreciation, depletion and amortization of property and equipment	1,211	831	662	379	212
Amortization of goodwill	--	34	41	16	--
General and administrative expenses	219	114	96	83	48
Expenses related to mergers	--	1	60	17	13
Reduction of carrying value of oil and gas properties	651	979	--	476	354
Total operating costs and expenses	3,775	2,672	1,431	1,309	861
Earnings (loss) from operations	541	192	1,156	(169)	(257)
Interest expense	(533)	(220)	(155)	(115)	(43)
Effects of changes in foreign currency exchange rates	1	(11)	(3)	13	(16)
Distributions on preferred securities of subsidiary trust	--	--	--	(7)	(10)
Change in fair value of financial instruments	28	(2)	--	--	--
Impairment of ChevronTexaco Corporation common stock	(205)	--	--	--	--
Other income	34	69	40	10	22
Net other expenses	(675)	(164)	(118)	(99)	(47)
Earnings (loss) from continuing operations before income taxes and cumulative effect of change in accounting principle	(134)	28	1,038	(268)	(304)

	YEAR ENDED DECEMBER 31,				
	2002	2001	2000	1999	1998
	(MILLIONS, EXCEPT PER SHARE DATA AND RATIOS)				
Income tax expense (benefit):					
Current	$ 23	48	120	18	(5)
Deferred	(216)	(43)	257	(93)	(98)
Total	(193)	5	377	(75)	(103)
Earnings (loss) from continuing operations before cumulative effect of change in accounting principle	59	23	661	(193)	(201)
Results of discontinued operations before income taxes	54	56	104	63	(58)
Income tax expense (benefit)	9	25	35	24	(23)
Net results of discontinued operations	45	31	69	39	(35)
Earnings (loss) before cumulative effect of change in accounting principle	104	54	730	(154)	(236)
Cumulative effect of change in accounting principle	--	49	--	--	--
Net earnings (loss)	$ 104	103	730	(154)	(236)
Net earnings (loss) applicable to common stockholders	$ 94	93	720	(158)	(236)
Basic net earnings (loss) per share:					
Earnings (loss) from continuing operations	$ 0.32	0.09	5.13	(2.13)	(2.83)
Net results of discontinued operations	$ 0.29	0.25	0.53	0.45	(0.49)
Cumulative effect of change in accounting principle	$ --	0.39	--	--	--
Net earnings (loss)	$ 0.61	0.73	5.66	(1.68)	(3.32)
Diluted net earnings (loss) per share:					
Earnings (loss) from continuing operations	$ 0.32	0.09	4.97	(2.13)	(2.83)
Net results of discontinued operations	$ 0.29	0.25	0.53	0.45	(0.49)
Cumulative effect of change in accounting principle	$ --	0.38	--	--	--
Net earnings (loss)	$ 0.61	0.72	5.50	(1.68)	(3.32)
Cash dividends per common share(1)	$ 0.20	0.20	0.17	0.14	0.10
Weighted average common shares outstanding:					
Basic	155	128	127	94	71
Diluted	156	130	132	99	77
Ratio of earnings to fixed charges(2)	N/A	1.12	7.34	N/A	N/A
Ratio of earnings to combined fixed charges and preferred stock dividends(2)	N/A	1.05	6.70	N/A	N/A

	DECEMBER 31,				
	2002	2001	2000	1999	1998
	(MILLIONS)				
BALANCE SHEET DATA					
Total assets	$16,225	13,184	6,860	6,096	1,931
Debentures exchangeable into shares of ChevronTexaco Corporation common stock	$ 662	649	760	760	--
Other long-term debt	$ 6,900	5,940	1,289	1,656	736
Convertible preferred securities of subsidiary trust	$ --	--	--	--	149
Stockholders' equity	$ 4,653	3,259	3,277	2,521	750

	YEAR ENDED DECEMBER 31,				
	2002	2001	2000	1999	1998
	(MILLIONS, EXCEPT PER UNIT DATA)				
CASH FLOW DATA					
Net cash provided by operating activities....	$ 1,754	1,910	1,589	539	330
Net cash used in investing activities........	$(2,046)	(5,285)	(1,173)	(768)	(607)
Net cash provided by (used in) financing activities...............................	$ 401	3,370	(390)	377	256
PRODUCTION, PRICE AND OTHER DATA(3)					
Production:					
Oil (MMBbls).............................	42	36	37	25	20
Gas (Bcf)................................	761	489	417	295	189
NGLs (MMBbls)............................	19	8	7	5	3
MMBoe(4).................................	188	126	113	79	55
Average prices:					
Oil (Per Bbl)............................	$ 21.71	21.41	24.99	17.78	12.28
Gas (Per Mcf)............................	$ 2.80	3.84	3.53	2.09	1.78
NGLs (Per Bbl)...........................	$ 14.05	16.99	20.87	13.28	8.08
Per Bo(4)................................	$ 17.61	22.19	22.38	14.22	11.09
Costs per Boe(4):					
Operating costs..........................	$ 4.71	5.29	4.81	4.15	4.29
Depreciation, depletion and amortization of oil and gas properties...............	$ 5.88	6.30	5.58	4.60	3.72

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(1) Devon acquired other entities via mergers in 1998 and 2000, and both mergers were accounted for using the pooling-of-interests method of accounting for business combinations. Therefore, the cash dividends per share presented for 1998 through 2000 are not representative of the actual amounts paid by Devon on an historical basis. For the years 1998 through 2000, Devon's historical cash dividends per share were $0.20 in each year.

(2) For purposes of calculating the ratio of earnings to fixed charges and the ratio of earnings to combined fixed charges and preferred stock dividends,
(i) earnings consist of earnings before income taxes, plus fixed charges;
(ii) fixed charges consist of interest expense, distributions on preferred securities of subsidiary trust, amortization of costs relating to indebtedness and the preferred securities of subsidiary trust, and one-third of rental expense estimated to be attributable to interest; and (iii) preferred stock dividends consist of the amount of pre-tax earnings required to pay dividends on the outstanding preferred stock. For the years 2002, 1999 and 1998, earnings were insufficient to cover fixed charges by $135 million, $264 million and $305 million, respectively. For the years 2002, 1999 and 1998, earnings were insufficient to cover combined fixed charges and preferred stock dividends by $151 million, $270 million and $305 million, respectively.

(3) The preceding production, price and other data exclude the amounts related to discontinued operations for all periods presented.

(4) Gas volumes are converted to Boe at the rate of six Mcf of gas per barrel of oil, based upon the approximate relative energy content of natural gas and oil, which rate is not necessarily indicative of the relationship of oil and gas prices. NGL volumes are converted to Boe on a one-to-one basis with oil. The respective prices of oil, gas and NGLs are affected by market and other factors in addition to relative energy content.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis addresses changes in Devon's financial condition and results of operations during the three year period of 2000 through 2002. Reference is made to "Item 6. Selected Financial Data" and "Item 8. Financial Statements and Supplementary Data."

OVERVIEW

On January 24, 2002, Devon completed its acquisition of Mitchell Energy & Development Corp. ("Mitchell"). Under the terms of this merger, Devon issued approximately 30 million shares of Devon common stock and paid $1.6 billion in cash to the Mitchell stockholders. The cash portion of the acquisition was funded from borrowings under a $3.0 billion senior unsecured term loan credit facility. The Mitchell merger added approximately 404 million Boe to Devon's proved reserves.

Following the Mitchell merger announcement in August 2001, Devon announced on September 4, 2001, that it had entered into an agreement to acquire Anderson Exploration Ltd. ("Anderson") for approximately $3.5 billion in cash. This acquisition closed on October 15, 2001, and therefore had an impact on Devon's results for the last two and one-half months of 2001. The Anderson acquisition added approximately 534 million Boe to Devon's proved reserves.

To fund the cash portions of these two acquisitions, as well as to pay related transaction costs and retire certain long-term debt assumed from Mitchell and Anderson, Devon entered into long-term debt agreements in October 2001 that totaled $6 billion. Half of this total consisted of $3 billion of notes and debentures issued on October 3, 2001. Of this total, $1.25 billion bears interest at 7.875% and matures in September 2031. The remaining $1.75 billion bears interest at 6.875% and matures in September 2011.

The remaining $3 billion of the $6 billion of long-term debt is in the form of a credit facility that bears interest at floating rates. As of December 31, 2002, $1.9 billion of the original $3 billion balance had been retired. The primary sources of the repayments were the issuance of $1 billion of debt securities, of which $0.8 billion was used to pay down debt, and $1.4 billion from the sale of certain oil and gas properties, of which $1.1 billion was used to pay down debt. As of December 31, 2002, the balance outstanding under the term loan credit facility was $1.1 billion at an average rate of 2.5%. Principal payments due on this debt are $0.3 billion in April 2006 and $0.8 billion in October 2006.

The Mitchell and Anderson acquisitions followed another significant acquisition. In August 2000, Devon closed its merger with Santa Fe Snyder Corporation. This transaction added approximately 386 million Boe to Devon's proved reserves.

In addition to the mergers and acquisitions, Devon's exploration and development efforts have also been significant contributors to Devon's growth. In 2002, Devon spent $1.5 billion in its exploration, drilling and development efforts. These costs included drilling 1,685 wells, of which 1,599 were completed as producers. In 2000 and 2001, Devon spent an aggregate of $2.0 billion in its exploration, drilling and development efforts. These costs included drilling 2,873 wells, of which 2,705 were completed as producers.

The following statistics illustrate the effects that Devon's mergers and acquisitions and its drilling and development activities have had on operations during the last three years. This data compares Devon's 2002 results to those of 2000 for Devon combined with Santa Fe Snyder, which was acquired in a merger accounted for under the pooling-of-interests method. Such comparison yields the following fluctuations:

- Proved reserves increased 651 million Boe, or 68%.

- Combined oil, gas and NGL production increased 75 million Boe, or 66%.

- Total revenues increased $1.7 billion, or 67%.

- Net cash provided by operating activities increased $165 million, or 10%.

During 2002, Devon marked its 14th anniversary as a public company. While Devon has consistently increased production over this 14-year period, volatility in oil, gas and NGL prices has resulted in considerable variability in earnings and cash flows. Prices for oil, natural gas and NGLs are determined primarily by market conditions. Market conditions for these products have been, and will continue to be, influenced by regional and worldwide economic activity, weather and other factors that are beyond Devon's control. Devon's future earnings and cash flows will continue to depend on market conditions.

Like all oil and gas exploration and production companies, Devon faces the challenge of natural production decline. As initial pressures are depleted, oil and gas production from a given well naturally decreases. Thus, an oil and gas exploration and production company depletes part of its asset base with each unit of oil or gas it produces. Historically, Devon has been able to overcome this natural decline by adding, through drilling and acquisitions, more reserves than it produces. Devon's future growth, if any, will depend on its ability to continue to add reserves in excess of production.

Because oil, gas and NGL prices are influenced by many factors outside of its control, Devon's management has focused its efforts on increasing oil and gas reserves and production and controlling expenses. Over its 14-year history as a public company, Devon has been able to reduce its controllable operating costs per unit of production. Devon's future earnings and cash flows are dependent on its ability to continue to contain operating costs at levels that allow for profitable production.

RESULTS OF OPERATIONS

REVENUES

Changes in oil, gas and NGL production, prices and revenues from 2000 to 2002 are shown in the following tables. (Unless otherwise stated, all dollar amounts in this report are expressed in U.S. dollars.)

	TOTAL				
	YEAR ENDED DECEMBER 31,				
	2002	2002 VS 2001	2001	2001 VS 2000	2000
Production					
Oil (MMBbls)	42	+17%	36	-3%	37
Gas (Bcf)	761	+56%	489	+17%	417
NGLs (MMBbls)	19	+138%	8	+14%	7
Oil, gas and NGLs (MMBoe)	188	+50%	126	+12%	113
Average Prices					
Oil (per Bbl)	$21.71	+1%	21.41	-14%	24.99
Gas (per Mcf)	$ 2.80	-27%	3.84	+9%	3.53
NGLs (per Bbl)	$14.05	-17%	16.99	-19%	20.87
Oil, gas and NGLs (per Boe)	$17.61	-21%	22.19	-1%	22.38
Revenues ($ in millions)					
Oil	$ 909	+16%	784	-13%	906
Gas	$2,133	+14%	1,878	+27%	1,474
NGLs	$ 275	+110%	131	-15%	154
Oil, gas and NGLs	$3,317	+19%	2,793	+10%	2,534

	DOMESTIC				
	YEAR ENDED DECEMBER 31,				
	2002	2002 VS 2001	2001	2001 VS 2000	2000
Production					
Oil (MMBbls)	24	-8%	26	-10%	29
Gas (Bcf)	482	+28%	376	+6%	355
NGLs (MMBbls)	14	+133%	6	+0%	6
Oil, gas and NGLs (MMBoe)	118	+24%	95	+1%	94
Average Prices					
Oil (per Bbl)	$21.99	-2%	22.36	-12%	25.45
Gas (per Mcf)	$ 2.91	-30%	4.17	+14%	3.67
NGLs (per Bbl)	$13.37	-22%	17.15	-16%	20.30
Oil, gas and NGLs (per Boe)	$17.87	-25%	23.80	+4%	22.95
Revenues ($ in millions)					
Oil	$ 524	-11%	586	-19%	727
Gas	$1,403	-11%	1,571	+20%	1,305
NGLs	$ 192	+86%	103	-24%	136
Oil, gas and NGLs	$2,119	-6%	2,260	+4%	2,168

	CANADA				
	YEAR ENDED DECEMBER 31,				
	2002	2002 VS 2001	2001	2001 VS 2000	2000
Production					
Oil (MMBbls)	16	+100%	8	+60%	5
Gas (Bcf)	279	+147%	113	+82%	62
NGLs (MMBbls)	5	+150%	2	+100%	1
Oil, gas and NGLs (MMBoe)	68	+134%	29	+81%	16
Average Prices					
Oil (per Bbl)	$21.00	+18%	17.84	-27%	24.46
Gas (per Mcf)	$ 2.62	-4%	2.73	+1%	2.71
NGLs (per Bbl)	$15.93	-3%	16.43	-38%	26.51
Oil, gas and NGLs (per Boe)	$16.96	+1%	16.80	-12%	19.18
Revenues ($ in millions)					
Oil	$ 331	+127%	146	+26%	116
Gas	$ 730	+138%	307	+82%	169
NGLs	$ 83	+196%	28	+56%	18
Oil, gas and NGLs	$1,144	+138%	481	+59%	303

	INTERNATIONAL				
	YEAR ENDED DECEMBER 31,				
	2002	2002 VS 2001	2001	2001 VS 2000	2000
Production					
Oil (MMBbls)	2	+0%	2	-33%	3
Gas (Bcf)	--	N/M	--	N/M	--
NGLs (MMBbls)	--	N/M	--	N/M	--
Oil, gas and NGLs (MMBoe)	2	+0%	2	-33%	3
Average Prices					
Oil (per Bbl)	$23.70	+1%	23.42	+9%	21.44
Gas (per Mcf)	$ --	N/M	--	N/M	--
NGLs (per Bbl)	$ --	N/M	--	N/M	--
Oil, gas and NGLs (per Boe)	$23.70	+1%	23.42	+9%	21.44
Revenues ($ in millions)					
Oil	$ 54	+4%	52	-17%	63
Gas	$ --	N/M	--	N/M	--
NGLs	$ --	N/M	--	N/M	--
Oil, gas and NGLs	$ 54	+4%	52	-17%	63

The average prices shown in the preceding tables include the effect of Devon's oil and gas commodity hedging activities. Following is a comparison of Devon's average prices with and without the effect of hedges for each of the last three years.

	WITH HEDGES			WITHOUT HEDGES		
	2002	2001	2000	2002	2001	2000
Oil (per Bbl)	$21.71	21.41	24.99	22.63	21.79	26.00
Gas (per Mcf)	$ 2.80	3.84	3.53	2.70	3.89	3.61
NGLs (per Bbl)	$14.05	16.99	20.87	14.05	16.99	20.87
Oil, gas and NGLs (per Boe)	$17.61	22.19	22.38	17.36	22.48	23.01

OIL REVENUES

2002 vs. 2001 Oil revenues increased $125 million in 2002. An increase in production of 6 million barrels caused oil revenues to increase by $112 million. The Anderson and Mitchell acquisitions accounted for 11 million barrels of increased production. This was partially offset by the effect of divestitures, which reduced 2002 production by 5 million barrels. A $0.30 per barrel increase in the average oil price in 2002 accounted for the remaining $13 million of increased oil revenues.

2001 vs. 2000 Oil revenues decreased $122 million in 2001. A $3.58 per barrel decrease in 2001's average price caused revenues to drop by $114 million. A decrease in production of one million barrels caused oil revenues to decrease by an additional $8 million. The October 2001 Anderson merger accounted for three million barrels of 2001 production. However, oil production from Devon's other properties declined four million barrels. This reduction was primarily the result of domestic and international properties which were sold prior to 2001 but whose production was included in 2000 prior to the sales.

GAS REVENUES

2002 vs. 2001 Gas revenues increased $255 million in 2002. An increase in production of 272 Bcf caused gas revenues to increase by $1.0 billion. The Anderson and Mitchell acquisitions accounted for 323 Bcf of increased production. This was partially offset by the effect of divestitures, which reduced 2002 production by 30 Bcf, and by natural declines in production. The effects of the net production increase were partially offset by a $1.04 per Mcf decrease in the average gas price in 2002.

2001 vs. 2000 Gas revenues increased $404 million in 2001. Of this total increase, $253 million was due to a 72 Bcf increase in production in 2001. The October 2001 Anderson merger accounted for 51 Bcf of the increase. Production from Devon's domestic properties increased 21 Bcf, due primarily to drilling and development in Devon's coalbed methane properties as well as the acquisition of certain properties in the second quarter of 2001. A $0.31 per Mcf increase in the average gas price in 2001 accounted for the remaining $151 million of increased gas revenues.

NGL REVENUES

2002 vs. 2001 NGL revenues increased $144 million in 2002. An 11 million barrel increase in 2002 production caused revenues to increase $202 million. The Anderson and Mitchell acquisitions accounted for 12 million barrels of increased production. This was partially offset by production lost from divestitures. The effects of the net production increase were partially offset by a $2.94 per barrel decrease in the average NGL price in 2002.

2001 vs. 2000 NGL revenues decreased $23 million in 2001. A decrease in 2001's average price of $3.88 per barrel caused NGL revenues to decrease $30 million. This was partially offset by a $7 million increase related to a production increase of one million barrels. The October 2001 Anderson merger accounted for all of the increase.

MARKETING AND MIDSTREAM REVENUES

2002 vs. 2001 Marketing and midstream revenues increased $928 million in 2002. The Mitchell acquisition included significant marketing and midstream assets which accounted for substantially all of the increase in revenues.

2001 vs. 2000 Marketing and midstream revenues increased $18 million in 2001. This increase was primarily the result of capacity additions to Devon's Wyoming gas pipeline systems.

OPERATING COSTS AND EXPENSES

The details of the changes in operating costs and expenses between 2000 and 2002 are shown in the table below.

	YEAR ENDED DECEMBER 31,				
	2002	2002 VS 2001	2001	2001 VS 2000	2000
Operating costs and expenses ($ in millions):					
Production and operating expenses:					
Lease operating expenses	$ 621	+33%	467	+20%	388
Transportation costs	154	+86%	83	+57%	53
Production taxes	111	-4%	116	+13%	103
Depreciation, depletion and amortization of oil and gas properties	1,106	+39%	793	+25%	632
Amortization of goodwill	--	-100%	34	-17%	41
Subtotal	1,992	+33%	1,493	+23%	1,217
Marketing and midstream operating costs and expenses	808	+1,619%	47	+68%	28
Depreciation and amortization of non-oil and gas properties	105	+176%	38	+27%	30
General and administrative expenses	219	+92%	114	+19%	96
Expenses related to mergers	--	-100%	1	-98%	60
Reduction of carrying value of oil and gas properties	651	-34%	979	N/M	--
Total	$3,775	+41%	2,672	+87%	1,431
Operating costs and expenses per Boe:					
Production and operating expenses:					
Lease operating expenses	$ 3.30	-11%	3.71	+8%	3.43
Transportation costs	0.82	+24%	0.66	+40%	0.47
Production taxes	0.59	-36%	0.92	+1%	0.91
Depreciation, depletion and amortization of oil and gas properties	5.88	-7%	6.30	+13%	5.58
Amortization of goodwill	--	-100%	0.27	-27%	0.37
Subtotal	10.59	-11%	11.86	+10%	10.76
Marketing and midstream operating costs and expenses(1)	4.29	+1,059%	0.37	+48%	0.25
Depreciation and amortization of non-oil and gas properties(1)	0.55	+83%	0.30	+11%	0.27
General and administrative expenses(1)	1.16	+27%	0.91	+7%	0.85
Expenses related to mergers(1)	--	-100%	0.01	-98%	0.53
Reduction of carrying value of oil and gas properties(1)	3.45	-56%	7.78	N/M	--
Total	$20.04	-6%	21.23	+68%	12.66

(1) Though per Boe amounts for these expense items may be helpful for profitability trend analysis, these expenses are not directly attributable to production volumes.

N/M -- Not meaningful.

OIL, GAS AND NGLS PRODUCTION AND OPERATING EXPENSES

The details of the changes in production and operating expenses related to oil, gas and NGLs producing activities between 2000 and 2002 are shown in the table below.

	YEAR ENDED DECEMBER 31,				
	2002	2002 VS 2001	2001	2001 VS 2000	2000
Expenses ($ in millions):					
Lease operating expenses	$ 621	+33%	467	+20%	388
Transportation costs	154	+86%	83	+57%	53
Production taxes	111	-4%	116	+13%	103
Total production and operating expenses	$ 886	+33%	666	+22%	544
Expenses per Boe:					
Lease operating expenses	$3.30	-11%	3.71	+8%	3.43
Transportation costs	0.82	+24%	0.66	+40%	0.47
Production taxes	0.59	-36%	0.92	+1%	0.91
Total production and operating expenses	$4.71	-11%	5.29	+10%	4.81

2002 vs. 2001 Lease operating expenses increased $154 million in 2002. The Anderson and Mitchell acquisitions accounted for $210 million of the increase. The historical Devon lease operating expenses decreased $56 million primarily due to divestitures. The drop in lease operating expenses per Boe from $3.71 in 2001 to $3.30 in 2002 was primarily related to the lower cost properties acquired in the Anderson and Mitchell acquisitions and the divestiture of some of Devon's higher cost properties.

Transportation costs represent those costs paid directly to third-party providers to transport oil, gas and NGL production sold downstream from the wellhead. Transportation costs increased $71 million in 2002 primarily due to an increase in gas production from the Anderson and Mitchell acquisitions.

The majority of Devon's production taxes are assessed on its onshore domestic properties. In the U.S., most of the production taxes are based on a fixed percentage of revenues. Therefore, the 6% decrease in domestic oil, gas and NGLs revenues was the primary cause of a 4% decrease in production taxes.

2001 vs. 2000 Recurring lease operating expenses increased $79 million in 2001. The Anderson acquisition accounted for $47 million of the increase in expenses. The remaining increase in recurring costs was primarily caused by higher third-party service, fuel and electricity costs.

Transportation costs increased $30 million in 2001. Of this increase, $12 million related to the Anderson acquisition. The remainder of the increase was primarily due to an increase in gas production from Devon's domestic drilling and development activities.

As previously stated, most of the U.S. production taxes are based on a fixed percentage of revenues. Therefore, the 4% increase in domestic oil, gas and NGL revenues was the primary cause of a 11% increase in domestic production taxes. Production taxes did not increase proportionately to the increase in revenues. This was primarily due to the fact that most of the increase in domestic revenues occurred in the Western division which has higher production tax rates than the other domestic divisions.

DEPRECIATION, DEPLETION AND AMORTIZATION ("DD&A")

DD&A of oil and gas properties is calculated as the percentage of total proved reserve volumes produced during the year, multiplied by the net capitalized investment in those reserves including estimated future development and dismantlement and abandonment costs (the "depletable base"). Generally, if reserve volumes are revised up or down, then the DD&A rate per unit of production will change inversely. However, if the depletable base changes, then the DD&A rate moves in the same direction. The per unit DD&A rate is not affected by production volumes. Absolute or total DD&A, as opposed to the rate per unit of production, generally moves in the same direction as production volumes. Oil and gas property DD&A is calculated separately on a country-by-country basis.

2002 vs. 2001 Oil and gas property related DD&A increased $313 million in 2002. A 50% increase in 2002's oil, gas and NGLs production caused DD&A to increase $394 million. The effects of the production increase were partially offset by a decrease in the combined U.S., Canadian and international DD&A rate from $6.30 per Boe in 2001 to $5.88 per Boe in 2002. The drop in the DD&A rate was primarily due to reductions of carrying value of oil and gas properties recorded in the fourth quarter of 2001 and the second quarter of 2002.

Non-oil and gas property DD&A increased $67 million in 2002 compared to 2001. Depreciation of the marketing and midstream assets acquired in the January 2002 Mitchell acquisition accounted for substantially all of the increase.

2001 vs. 2000 Oil and gas property related DD&A increased $161 million in 2001. Of this total increase, $70 million was due to the 12% increase in oil, gas and NGLs production in 2001. The remaining $91 million increase was due to an increase in the consolidated DD&A rate. This rate increased from $5.58 per Boe in 2000 to $6.30 per Boe in 2001.

Non-oil and gas property DD&A increased $8 million in 2001 compared to 2000. Depreciation of Devon's Wyoming gas pipeline systems accounted for the 2001 increase.

AMORTIZATION OF GOODWILL

Effective January 1, 2002, Devon adopted the remaining provisions of Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets (SFAS No. 142). Under SFAS No. 142, goodwill and intangible assets with indefinite useful lives are no longer amortized as they were prior to 2002, but are instead tested for impairment at least annually. Prior to the adoption of SFAS No. 142, Devon's goodwill amortization was $34 million and $41 million in 2001 and 2000, respectively.

MARKETING AND MIDSTREAM OPERATING COSTS AND EXPENSES

2002 vs. 2001 Marketing and midstream operating costs and expenses increased $761 million in 2002. The Mitchell acquisition included significant marketing and midstream assets which accounted for substantially all of the increase in revenues.

2001 vs. 2000 Marketing and midstream operating costs and expenses increased $19 million in 2001. This increase was primarily the result of capacity additions to Devon's Wyoming gas pipeline systems.

GENERAL AND ADMINISTRATIVE EXPENSES ("G&A")

Devon's net G&A consists of three primary components. The largest of these components is the gross amount of expenses incurred for personnel costs, office expenses, professional fees and other G&A items. The gross amount of these expenses is partially reduced by two offsetting components. One is the amount of G&A capitalized pursuant to the full cost method of accounting. The other is the amount of G&A reimbursed by working interest owners of properties for which Devon serves as the operator. These reimbursements are received during both the drilling and operational stages of a property's life. The gross amount of G&A incurred, less the amounts capitalized and reimbursed, is recorded as net G&A in the consolidated statements of operations. Net G&A includes expenses related to oil, gas and NGL exploration and production activities, as well as marketing and midstream activities. See the following table for a summary of G&A expenses by component.

	YEAR ENDED DECEMBER 31,				
	2002	2002 VS 2001	2001	2001 VS 2000	2000
	($ IN MILLIONS)				
Gross G&A	$387	+56%	248	+19%	209
Capitalized G&A	(97)	+26%	(77)	+24%	(62)
Reimbursed G&A	(71)	+25%	(57)	+12%	(51)
Net G&A	$219	+92%	114	+19%	96

2002 vs. 2001 Gross G&A increased $139 million primarily due to additional costs incurred as a result of the Anderson and Mitchell acquisitions. Also included in 2002's gross G&A was $13 million related to the abandonment of certain office space assumed in the Santa Fe Snyder merger. G&A was reduced $20 million due to an increase in the amount capitalized as part of oil and gas properties. G&A was also reduced $14 million by an increase in the amount of reimbursements on operated properties. Changes in both of the capitalized and reimbursed amounts were primarily related to the Anderson and Mitchell acquisitions.

2001 vs. 2000 Gross G&A increased $39 million primarily due to additional costs incurred as a result of the Anderson acquisition and additional personnel related costs. G&A was reduced $15 million due to an increase in the amount capitalized. The increase in capitalized G&A was primarily related to additional personnel related costs and increased acquisition, exploration and development activities. G&A was also reduced $6 million by an increase in the amount of reimbursements on operated properties. The increase in reimbursed G&A was primarily related to an increase in the number of operated properties.

EXPENSES RELATED TO MERGERS

Approximately $1 million of expenses were incurred in 2001 in connection with the Anderson acquisition. These costs related to Devon employees who were terminated as part of the Anderson acquisition.

Approximately $60 million of expenses were incurred in 2000 in connection with the Santa Fe Snyder merger. These expenses consisted primarily of severance and other benefit costs, investment banking fees, other professional expenses, costs associated with duplicate facilities and various transaction related costs. The pooling-of-interests method of accounting for business combinations required such costs to be expensed as opposed to capitalized as costs of the transaction.

REDUCTION OF CARRYING VALUE OF OIL AND GAS PROPERTIES

Under the full cost method of accounting, the net book value of oil and gas properties, less related deferred income taxes, may not exceed a calculated "ceiling." The ceiling limitation is the discounted estimated after-tax future net revenues from proved oil and gas properties plus the cost of properties not subject to amortization. The ceiling is imposed separately by country. In calculating future net revenues, current prices and costs are generally held constant indefinitely, and Devon does not include the effect of hedges in the calculation of the future net revenues. The calculation also dictates the use of a 10% discount factor. Therefore, the ceiling limitation is not necessarily indicative of the properties' fair value. The costs to be recovered are compared to the ceiling on a quarterly basis. If the costs to be recovered exceed the ceiling, the excess is written off as an expense, except as discussed in the following paragraph.

If, subsequent to the end of the quarter but prior to the applicable financial statements being published, prices increase to levels such that the ceiling would exceed the costs to be recovered, a writedown otherwise indicated at the end of the quarter is not required to be recorded. A writedown indicated at the end of a quarter is also not required if the value of additional reserves proved up on properties after the end of the quarter but prior to the publishing of the financial statements would result in the ceiling exceeding the costs to be recovered, as long as the properties were owned at the end of the quarter.

An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

During 2002 and 2001, Devon reduced the carrying value of its oil and gas properties by $651 and $883 million, respectively, due to the full cost ceiling limitations. The after-tax effect of these reductions in 2002 and 2001 was $371 million and $533 million, respectively. The following table summarizes these reductions by country.

	YEAR ENDED DECEMBER 31,			
	2002		2001	
	GROSS	NET OF TAXES	GROSS	NET OF TAXES
	(IN MILLIONS)			
United States	$ --	--	449	281
Canada	651	371	434	252
Total	$651	371	883	533

The 2002 Canadian reduction was primarily the result of lower prices. Under the purchase method of accounting for business combinations, acquired oil and gas properties are recorded at fair value as of the date of purchase. Devon estimates such fair value using its estimates of future oil, gas and NGL prices. In contrast, the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely. Accordingly, the resulting value is not necessarily indicative of the fair value of the reserves. The recorded fair values of oil and gas properties added from the Anderson acquisition in 2001 were based on expected future oil and gas prices that were higher than the June 30, 2002, prices used to calculate the Canadian ceiling.

Based on oil, natural gas and NGL cash market prices as of June 30, 2002, Devon's Canadian costs to be recovered exceeded the related ceiling value by $371 million. This after-tax amount resulted in a pre-tax reduction of the carrying value of Devon's Canadian oil and gas properties of $651 million in the second quarter of 2002. This reduction was the result of a sharp drop in Canadian gas prices during the last half of June 2002. The end of June reference prices used in the Canadian ceiling calculation, expressed in Canadian dollars based on an exchange ratio of $0.6585, were a NYMEX price of C$40.79 per barrel of oil and an AECO price of C$2.17 per MMBtu. The cash market prices of natural gas increased during the month of July 2002 prior to Devon's release of its second quarter results, but the increase was not sufficient to offset the entire reduction calculated as of June 30.

The 2001 domestic and Canadian reductions were also primarily the result of lower prices. The oil and gas properties added from the Anderson acquisition and other smaller acquisitions in 2001 were recorded at fair values that were based on expected future oil and gas prices higher than the December 31, 2001 prices used to calculate the ceiling. The year-end 2001 prices used to calculate the ceiling were based on a NYMEX oil price of $19.84 per barrel, a Henry Hub gas price of $2.65 per MMBtu and an AECO gas price of C$3.67 per MMBtu.

Additionally, during 2001, Devon elected to abandon operations in Thailand, Malaysia, Qatar and on certain properties in Brazil. After meeting the drilling and capital commitments on these properties, Devon determined that these properties did not meet Devon's internal criteria to justify further investment. Accordingly, Devon recorded a $96 million charge associated with the impairment of these properties. The after-tax effect of this reduction was $78 million.

The provisions of SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, which Devon was required to adopt effective January 1, 2002, are only required to be applied prospectively. As a result, these impairment charges have not been reclassified as part of the Discontinued Operations on the consolidated statements of operations.

OTHER INCOME (EXPENSES)

The details of the changes in other income (expenses) between 2000 and 2002 are shown in the table below.

	2002	2001	2000
	(IN MILLIONS)		
Other income (expenses):			
Interest expense:			
Interest based on debt outstanding	$(499)	(200)	(157)
(Accretion) amortization of debt (discount) premium, net	(13)	(10)	4
Facility and agency fees	(2)	(1)	(3)
Amortization of capitalized loan costs	(8)	(3)	(2)
Capitalized interest	4	3	3
Early retirement premiums	(8)	(7)	--
Other	(7)	(2)	--
Total interest expense	(533)	(220)	(155)
Effects of changes in foreign currency exchange rates	1	(11)	(3)
Change in fair value of financial instruments	28	(2)	--
Impairment of ChevronTexaco Corporation common stock	(205)	--	--
Other income	34	69	40
Total	$(675)	(164)	(118)

INTEREST EXPENSE

2002 vs. 2001 Interest expense increased $313 million in 2002. An increase in the average debt balance outstanding from $3.0 billion in 2001 to $8.3 billion in 2002 caused interest expense to increase $319 million. The increase in average debt outstanding was attributable primarily to the long-term debt issued and assumed as a result of the Mitchell and Anderson acquisitions.

The average interest rate on outstanding debt decreased from 6.6% in 2001 to 6.0% in 2002 due to the favorable rates on the borrowings under the $3 billion term loan credit facility. This facility's rates averaged less than 3% during 2002. The overall rate decrease caused interest expense to decrease $20 million in 2002. Other items included in interest expense that are not related to the debt balance outstanding were $14 million higher in 2002. Items not related to the balance of debt outstanding include early retirement premiums, facility and agency fees, amortization of costs and other miscellaneous items. Of the $14 million increase in other items during 2002, $5 million related to the amortization of capitalized loan costs and $3 million related to an increase in the accretion of debt discounts. These increases were primarily due to the additional debt incurred as a result of the Mitchell and Anderson acquisitions.

2001 vs. 2000 Interest expense increased $65 million in 2001. Of this total increase, $44 million was caused by an increase in the average debt balance outstanding from $2.3 billion in 2000 to $3.0 billion in 2001. The increase in average debt outstanding was attributable primarily to the long-term debt issued and assumed as a result of the October 2001 Anderson acquisition.

The average interest rate on outstanding debt decreased from 6.7% in 2000 to 6.6% in 2001. This rate decrease caused interest expense to decrease $1 million in 2001. Other items included in interest expense that are not related to the debt balance outstanding were $22 million higher in 2001 compared to 2000. The increase in other items was primarily related to an increase in accretion of discounts and a $7 million loss related to an early retirement premium.

The increase in accretion of debt discounts in 2001 was related to the adoption of Statement of Financial Accounting Standards No. 133 ("SFAS No. 133") effective January 1, 2001. Devon's debentures that are exchangeable into shares of ChevronTexaco Corporation ("ChevronTexaco") common stock were revalued as of August 17, 1999. This is the date the debentures were assumed as part of the PennzEnergy merger. Under SFAS No. 133, the total fair value of the debentures was allocated between the interest-bearing debt and the option to exchange ChevronTexaco common stock that is embedded in the debentures. Accordingly, the debt portion of the debentures was reduced by $140 million as of August 17, 1999. This discount is being accreted in interest expense, which has raised the effective interest rate on the debentures to 7.76% in 2001 compared to 4.92% recorded prior to 2001. The accretion in 2001 was $12 million.

EFFECTS OF CHANGES IN FOREIGN CURRENCY EXCHANGE RATES

2002 vs. 2001 As a result of the Anderson acquisition, a Canadian subsidiary has $400 million of fixed-rate senior notes which are denominated in U.S. dollars. Changes in the exchange rate between the U.S. dollar and the Canadian dollar from the dates the notes were acquired to the dates of repayment increase or decrease the expected amount of Canadian dollars eventually required to repay the notes. Such changes in the Canadian dollar equivalent balance of the debt are required to be included in determining net earnings for the period in which the exchange rate changes. The increase in the Canadian-to-U.S. dollar exchange rate from $0.628 at December 31, 2001 to $0.633 at December 31, 2002 resulted in a $1 million gain. The drop in the Canadian-to-U.S. dollar exchange rate from $0.642 at October 15, 2001 (when the debt was assumed) to $0.628 at December 31, 2001 resulted in an $11 million loss.

2001 vs. 2000 Until mid-January 2000, a Canadian subsidiary had certain fixed-rate senior notes which were denominated in U.S. dollars. In mid-January 2000, these notes were retired prior to maturity. The Canadian-to-U.S. dollar exchange rate dropped slightly in January prior to the debt retirement. As a result, $3 million of expense was recognized in 2000.

CHANGE IN FAIR VALUE OF FINANCIAL INSTRUMENTS

2002 vs. 2001 As required under the provisions of SFAS No. 133, Accounting for Derivative Instruments and Certain Hedging Activities and SFAS No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activities, an Amendment of SFAS No. 133, Devon records in its statements of operations the change in fair value of derivative instruments that do not qualify for hedge accounting treatment.

During 2002 and 2001, Devon recorded $20 million and $8 million, respectively, of gains related to changes in fair value. The gains related principally to the option embedded in Devon's debentures that are exchangeable into shares of ChevronTexaco common stock. Also, Devon recorded an $8 million net gain in 2002 and a $10 million net charge in 2001 related to the ineffectiveness of the various cash flow hedges.

IMPAIRMENT OF CHEVRONTEXACO CORPORATION COMMON STOCK

Devon owns approximately 7.1 million common shares of ChevronTexaco. The market value of these shares as of December 31, 2002, was approximately $472 million. Devon acquired these shares in its August 1999 acquisition of PennzEnergy Company. The shares are deposited with an exchange agent for possible exchange for $760 million of debentures that are exchangeable into the ChevronTexaco shares. The debentures, which mature in August 2008, were also assumed by Devon in the 1999 PennzEnergy acquisition.

Devon initially recorded the ChevronTexaco common shares at their market value at the closing date of the PennzEnergy acquisition, which was $95.38 per share, or an aggregate value of $677 million. Since then, as the ChevronTexaco shares have fluctuated in market value, the value of the shares on Devon's balance sheet has been adjusted to the applicable market value. Through September 30, 2002, any decreases in the value of the ChevronTexaco common shares were determined by Devon to be temporary in nature. Therefore, the changes in value were recorded directly to stockholders' equity and were not recorded in Devon's results of operations through September 30, 2002.

The determination that a decline in value of the ChevronTexaco shares is temporary or other than temporary is subjective and influenced by many factors. Among these factors are the significance of the decline as a percentage of the original cost, the length of time the stock price has been below original cost, the performance of the stock price in relation to the stock price of its competitors within the industry and the market in general, and whether the decline is attributable to specific adverse conditions affecting ChevronTexaco.

Beginning in July 2002, the market value of ChevronTexaco common stock began what has ultimately become a significant decline. The price per share decreased from $88.50 at June 30, 2002, to $69.25 per share at September 30, 2002, and to $66.48 per share at December 31, 2002. The year-end price of $66.48 represents a 25% decline since June 30, 2002, and a 30% decline from the original valuation in August 1999. As a result of the continuation of the decline in value during the fourth quarter of 2002, Devon determined that the decline is other than temporary, as that term is defined by accounting rules. Therefore, the $205 million cumulative decrease in the value of the ChevronTexaco common shares from the initial acquisition in August 1999 to December 31, 2002, was recorded as a noncash charge to Devon's results of operations in the fourth quarter of 2002. Net of the applicable tax benefit, the charge reduced net earnings by $128 million.

Depending on the future performance of ChevronTexaco's common stock, Devon may be required to record additional noncash charges in future periods if Devon determines that a decline in the value of such stock is other than temporary.

OTHER INCOME

2002 vs. 2001 Other income decreased $35 million, or 51% in 2002. Other income in 2001 included a $30 million gain from the settlement of a foreign exchange forward purchase contract entered into by Devon related to the funding of the Anderson acquisition. This gain did not recur in 2002.

2001 vs. 2000 Other revenues increased $29 million, or 73% in 2001. As discussed previously, 2001 other income included a $30 million gain from the settlement of a foreign exchange forward purchase contract entered into by Devon related to the funding of the Anderson acquisition.

INCOME TAXES

2001 vs. 2000 Devon's 2002 effective financial tax rate attributable to continuing operations was a benefit of 144% compared to an effective financial tax rate expense of 18% in 2001. Excluding the effects of the impairment of ChevronTexaco stock in 2002 and the reduction of carrying value of oil and gas properties in 2002 and 2001, the effective financial tax expense rates were 23% and 37% in 2002 and 2001, respectively.

The 2002 rate, excluding the ChevronTexaco common stock impairment and the oil and gas property writedown, was lower than the statutory federal tax rate primarily due to the tax benefits of certain foreign deductions. The 2001 rate, excluding the oil and gas property writedowns, was higher than the statutory federal tax rate due to the effect of state taxes, goodwill amortization that was not deductible for income tax purposes and the effect of foreign income taxes.

2001 vs. 2000 Devon's 2001 and 2000 effective financial tax expense rates were 18% and 36%, respectively. Excluding the effects of the reduction of carrying value of oil and gas properties in 2001, the effective financial tax expense rate was 37% in 2001. The 2001 rate was higher than the statutory federal tax rate of 35% due to the effect of state taxes, goodwill amortization that was not deductible for income tax purposes and the effect of foreign income taxes. The 2000 rate was higher than the statutory federal tax rate due to the effect of state taxes, goodwill amortization that was not deductible for income tax purposes and the effect of foreign income taxes, offset in part by the recognition of a benefit from the disposition of Devon's assets in Venezuela.

RESULTS OF DISCONTINUED OPERATIONS

Effective January 1, 2002, Devon was required to adopt SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, which supersedes both SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of and the accounting and reporting provisions of APB Opinion No. 30, Reporting the Results of Operations -- Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions, for the disposal of a segment of a business (as previously defined in that Opinion).

On April 18, 2002, Devon sold its Indonesian operations to PetroChina Company Limited for total cash consideration of $250 million. On October 25, 2002, Devon sold its Argentine operations to Petroleo Brasileiro S.A. for total cash consideration of $90 million. On January 27, 2003, Devon sold its Egyptian operations to IPR Transoil Corporation for total cash consideration of $7 million.

Under the provisions of SFAS No. 144, Devon has reclassified its Indonesian, Argentine and Egyptian activities as discontinued operations. This reclassification affects not only the 2002 presentation of financial results, but also the presentation of all prior periods' results.

Following are the components of the net results of discontinued operations for the years 2002, 2001 and 2000:

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS)		
Net gain on sale of discontinued operations	$31	--	--
Earnings from discontinued operations before income taxes	23	56	104
Income tax expense	9	25	35
Net results of discontinued operations	$45	31	69

2002 vs. 2001 The decrease in earnings from discontinued operations before income taxes and the related income taxes from 2001 to 2002 was primarily due to the sale of these operations during 2002.

2001 vs. 2000 The decrease in earnings from discontinued operations before income taxes and the related income taxes from 2000 to 2001 was primarily due to a decline in oil prices and the recognition of a $24 million reduction in the carrying value of Egyptian oil and gas properties. The reduction in Egypt was the result of high finding and development costs and negative revisions to proved reserves.

CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE

At the time of adoption of SFAS No. 133, Devon recorded a cumulative-effect-type adjustment to net earnings for a $49 million gain related to the fair value of derivatives that do not qualify as hedges. This gain included $46 million related to the option embedded in the debentures that are exchangeable into shares of ChevronTexaco common stock.

CAPITAL EXPENDITURES, CAPITAL RESOURCES AND LIQUIDITY

The following discussion of capital expenditures, capital resources and liquidity should be read in conjunction with the consolidated statements of cash flows included elsewhere in this report.

CAPITAL EXPENDITURES

Approximately $3.4 billion was spent in 2002 for capital expenditures. This total includes $1.7 billion related to the January 2002 Mitchell acquisition; $1.6 billion for other acquisitions and the drilling or development of oil and gas properties; and $0.1 billion related to marketing and midstream assets. These amounts compare to 2001 total expenditures of $5.2 billion ($3.5 billion of which related to the October 2001 Anderson acquisition and $1.6 billion of which was related to other acquisitions and the drilling or development of oil and gas properties) and 2000 total expenditures of $1.1 billion ($1.0 billion of which was related to the drilling or development of oil and gas properties.)

OTHER CASH USES

Devon's common stock dividends were $31 million, $25 million and $22 million in 2002, 2001 and 2000, respectively. Devon also paid $10 million of preferred stock dividends in 2002, 2001 and 2000.

During 2001, Devon repurchased 3,754,000 shares of common stock at an aggregate cost of $190 million or $50.71 per share. Devon also repurchased shares of its common stock in 2001 under an odd-lot repurchase program. Pursuant to this program, Devon purchased and retired 232,000 shares of its common stock for a total cost of $14 million, or $57.40 per share.

CAPITAL RESOURCES AND LIQUIDITY

Devon's primary source of liquidity has historically been net cash provided by operating activities ("operating cash flow"). This source has been supplemented as needed by accessing credit lines and commercial paper markets and issuing equity securities and long-term debt securities. In 2002, another major source of liquidity was $1.4 billion generated from sales of oil and gas properties.

Operating Cash Flow

Devon's operating cash flow is sensitive to many variables, the most volatile of which is pricing of the oil, natural gas and NGLs produced. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors are beyond Devon's control and are difficult to predict.

To mitigate some of the risk inherent in oil and natural gas prices, Devon has entered into various fixed-price physical delivery contracts and financial price swap contracts to fix the price to be received for a portion of future oil and natural gas production. Additionally, Devon has utilized price collars to set minimum and maximum prices on a portion of its production. The table below provides the volumes associated with these various arrangements as of January 31, 2003.

	FIXED-PRICE PHYSICAL DELIVERY CONTRACTS	PRICE SWAP CONTRACTS	PRICE COLLARS	TOTAL
Oil production (MMBbls)				
2003	--	--	20	20
2004	--	--	1	1
Natural gas production (Bcf)				
2003	16	35	239	290
2004	16	--	47	63

In addition to the above quantities, Devon also has fixed-price physical delivery contracts, for the years 2005 through 2011, covering Canadian natural gas production ranging from 8 Bcf to 14 Bcf per year. From 2012 through 2016, Devon also has Canadian gas volumes subject to fixed-price contracts, but the yearly volumes are less than 1 Bcf.

By removing the price volatility from a portion of its oil and natural gas production, Devon has mitigated, but not eliminated, the potential negative effect of declining prices on its operating cash flow. The combination of fixed-price contracts, price swaps and price collars currently in place represents approximately 55% of estimated 2003 oil production and 39% of estimated 2003 natural gas production.

It is Devon's policy to only enter into derivative contracts with investment grade rated counterparties deemed by management as competent and competitive market makers.

In December 2002, Devon announced that its capital expenditure budget for the year 2003 was approximately $1.8 billion. This capital budget represents the largest planned use of available operating cash flow. To a certain degree, the ultimate timing of these capital expenditures is within Devon's control. Therefore, if oil and natural gas prices decline to levels below its acceptable levels, Devon could choose to defer a portion of these planned 2003 capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity. Based upon current oil and gas price expectations for 2003, Devon anticipates that its operating cash flow will exceed its planned capital expenditures and other cash requirements for the year. Devon currently intends to accumulate any excess cash to fund future years' debt maturities. Additional alternatives could be considered based upon the actual amount, if any, of such excess cash.

Credit Lines

Other sources of liquidity are Devon's revolving lines of credit. On June 7, 2002, Devon renewed the $800 million, 364-day portion of its unsecured long-term credit facilities (the "Credit Facilities"). The Credit Facilities include a U.S. facility of $725 million (the "U.S. Facility") and a Canadian facility of $275 million (the "Canadian Facility").

The $725 million U.S. Facility consists of a Tranche A facility of $200 million and a Tranche B facility of $525 million. The Tranche A facility matures on October 15, 2004. Devon may borrow funds under the Tranche B facility until June 5, 2003 (the "Tranche B Revolving Period"). Devon may request that the Tranche B Revolving Period be extended an additional 364 days by notifying the agent bank of such request between 30 and 60 days prior to the end of the Tranche B Revolving Period. On June 6, 2003, at the end of the Tranche B Revolving Period, Devon may convert the then outstanding balance under the Tranche B facility to a two-year term loan by paying the Agent a fee of 12.5 basis points. The applicable borrowing rate would be at LIBOR plus 125 basis points. On December 31, 2002, there were no borrowings outstanding under the $725 million U.S. Facility. The available capacity under the U.S. Facility as of December 31, 2002, net of $25 million of outstanding letters of credit, was $700 million.

Devon may borrow funds under the $275 million Canadian Facility until June 5, 2003 (the "Canadian Facility Revolving Period"). Devon may request that the Canadian Facility Revolving Period be extended an additional 364 days by notifying the agent bank of such request between 30 and 60 days prior to the end of the Canadian Facility Revolving Period. Debt outstanding as of the end of the Canadian Facility Revolving Period is payable in semiannual installments of 2.5% each for the following five years, with the final installment due five years and one day following the end of the Canadian Facility Revolving Period. On December 31, 2002, there were no borrowings under the $275 million Canadian Facility.

Under the terms of the Credit Facilities, Devon has the right to reallocate up to $100 million of the unused Tranche B facility maximum credit amount to the Canadian Facility. Conversely, Devon also has the right to reallocate up to $100 million of unused Canadian Facility maximum credit amount to the Tranche B facility.

Amounts borrowed under the Credit Facilities bear interest at various fixed rate options that Devon may elect for periods up to six months. Devon has historically elected a rate that is based upon LIBOR, plus a margin dictated by Devon's debt rating. Borrowings under the Canadian Facility have also been made under a rate based upon the Bankers' Acceptance rate, plus a margin dictated by Devon's debt rating. Based upon its current debt rating, Devon can borrow under the Credit Facilities at a rate of between 45 and 125 basis points above LIBOR based upon usage and the tranche utilized, and 72.5 basis points above the Bankers' Acceptance rate. The Credit Facilities also provide for an annual facility fee of $1.4 million that is payable quarterly.

Devon also has access to short-term credit under its commercial paper program. Total borrowings under the U.S. Facility and the commercial paper program may not exceed $725 million. Commercial paper debt generally has a maturity of between seven to 90 days, although it can have a maturity of up to 365 days. Devon had no commercial paper debt outstanding at December 31, 2002.

On July 25, 2002, Devon renewed and increased its letter of credit and revolving bank facility ("LOC Facility") for its Canadian operations. This C$150 million LOC Facility will be used primarily by Devon's wholly-owned subsidiaries, Devon Canada Corporation and Northstar Energy Corporation, to issue letters of credit. As of December 31, 2002, C$109 million ($69 million converted to U.S. dollars using the December 31, 2002 exchange rate) of letters of credit were issued under the LOC Facility primarily for Canadian drilling commitments.

A portion of cash used in the Anderson and Mitchell acquisitions was provided by a $3 billion senior unsecured credit facility. This credit facility, which was entered into in October 2001, has a term of five years. The $3 billion credit facility was fully borrowed upon the closing of the Mitchell acquisition on January 24, 2002. However, as of December 31, 2002, $1.9 billion of the balance had been retired. The primary sources of the repayments were the issuance of $1 billion of debt securities, of which $0.8 billion was used to pay down debt, and $1.4 billion from the sale of certain oil and gas properties, of which $1.1 billion was used to pay down debt.

The remaining balance outstanding as of December 31, 2002 will mature as follows:

	(IN MILLIONS)
April 15, 2006	$ 335
October 15, 2006	800
	$1,135

This $3 billion facility includes various rate options which can be elected by Devon, including a rate based on LIBOR plus a margin. Through June 17, 2002, this margin was fixed at 100 basis points. Thereafter, the margin is based on Devon's debt rating. Based on Devon's current debt rating, the margin after June 17, 2002, is 100 basis points. As of December 31, 2002, the average interest rate on this facility was 2.5%.

Devon's Credit Facilities and its $3 billion term loan credit facility each contain only one material financial covenant. This covenant requires Devon to maintain a ratio of total funded debt to total capitalization of no more than 65%. The credit agreements contain definitions of total funded debt and total capitalization that include adjustments to the respective amounts reported in Devon's consolidated financial statements. In accordance with the agreements, total funded debt excludes the debentures that are exchangeable into shares of ChevronTexaco common stock. Also, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling property impairments or goodwill impairments. As of December 31, 2002, Devon's ratio of total funded debt to total capitalization, as defined in its credit agreements, was 55.0%.

Devon's access to funds from its Credit Facilities is not restricted under any "material adverse condition" clauses. It is not uncommon for credit agreements to include such clauses. These clauses can remove the obligation of the banks to fund the credit line if any condition or event would reasonably be expected to have a material and adverse effect on the borrower's financial condition, operations, properties or prospects considered as a whole, the borrower's ability to make timely debt payments, or the enforceability of material terms of the credit agreement. While Devon's Credit Facilities and its $3 billion term loan credit facility include covenants that require Devon to report a condition or event having a material adverse effect on the company, the obligation of the banks to fund the Credit Facilities is not conditioned on the absence of a material adverse effect.

Long-Term Debt Securities

On March 25, 2002, Devon sold $1 billion of 7.95% notes due April 15, 2032. The net proceeds received, after discounts and issuance costs, were $986 million. The debt securities are unsecured and unsubordinated obligations of Devon. The net proceeds were partially used to pay down $820 million on Devon's $3 billion term loan credit facility. The remaining $166 million of net proceeds was used in June

2002 to partially fund the early extinguishment of $175 million of 8.75% senior subordinated notes due June 15, 2007. The notes were redeemed at 104.375% of principal, or approximately $183 million.

Debt Ratings

Devon receives debt ratings from the major ratings agencies in the United States. In determining Devon's debt rating, the agencies consider a number of items including, but not limited to, debt levels, planned asset sales, near-term and long-term production growth opportunities, capital allocation challenges, liquidity, asset quality, cost structure, reserve mix, and commodity pricing levels.

Devon's current debt ratings are BBB with a stable outlook by Standard & Poor's, Baa2 with a negative outlook by Moody's and BBB with a stable outlook by Fitch. There are no "rating triggers" in any of Devon's contractual obligations that would accelerate scheduled maturities should Devon's debt rating fall below a specified level. Certain of Devon's agreements related to its oil and natural gas hedges do contain provisions that could require Devon to provide cash collateral in situations where Devon's liability under the hedge is above a certain dollar threshold and where Devon's debt rating is below investment grade (BBB- or Baa3). However, Devon's liability under these agreements would only exceed the threshold level in circumstances where the market prices for oil or natural gas were rising. It is unlikely that Devon's debt rating would be subjected to downgrades to non-investment grade levels during such a period of rising oil and natural gas prices.

As summarized earlier in this section, Devon's cost of borrowing under its Credit Facilities and its $3 billion term loan facility is predicated on its corporate debt rating. Therefore, even though a ratings downgrade would not accelerate scheduled maturities, it would adversely impact Devon's interest rate on its variable rate debt. Under the terms of the Credit Facilities and the term loan credit facility, a one-notch downgrade would increase Devon's fully drawn borrowing rates by 25 basis points for each facility. The average borrowing costs for the Credit Facilities would increase from LIBOR plus 95 basis points to LIBOR plus 120 basis points and the borrowing costs for the $3 billion term loan facility would increase from LIBOR plus 100 basis points to LIBOR plus 125 basis points. A ratings downgrade could also adversely impact Devon's ability to economically access future debt markets.

As of January 31, 2003, Devon was not aware of any potential ratings downgrades being contemplated by the rating agencies.

Contractual Obligations

A summary of Devon's contractual obligations as of December 31, 2002, is provided in the following table.

	PAYMENTS DUE BY YEAR						
	2003	2004	2005	2006	2007	AFTER 2007	TOTAL
	(IN MILLIONS)						
Long-term debt	$ --	336	347	1,262	--	5,725	7,670
Operating leases	30	33	28	24	20	86	221
Drilling obligations	151	34	37	1	--	--	223
Firm transportation agreements	97	83	61	52	45	221	559
Total	$278	486	473	1,339	65	6,032	8,673

Firm transportation agreements represent "ship or pay" arrangements whereby Devon has committed to ship certain volumes of gas for a fixed transportation fee. Devon has entered into these agreements to aid Devon in moving its gas production to market.

The above table does not include $94 million of letters of credit that have been issued by commercial banks on Devon's behalf which, if funded, would become borrowings under Devon's revolving credit facility. Most of these letters of credit have been granted by Devon's financial institutions to support

Devon's Canadian drilling commitments ($40 million of which are included in the above table). The $7.7 billion of long-term debt shown in the table excludes $113 million of discounts and a $5 million fair value adjustment, both of which are included in the December 31, 2002, book balance of the debt.

Pension Obligations

Devon accounts for its defined benefit pension plans using SFAS No. 87, Employer's Accounting for Pensions. Under SFAS 87, pension expense is recognized on an accrual basis over employees' approximate service periods. Pension expense calculated under SFAS 87 is generally independent of funding decisions or requirements. Devon recognized expense for its defined benefit pension plans of $16 million, $7 million, and $5 million in 2002, 2001 and 2000, respectively. Devon estimates that its pension expense will approximate $30 million in 2003.

As compared to the "projected benefit obligation," Devon's qualified and nonqualified defined benefit plans were underfunded by $179 million and $54 million at December 31, 2002 and 2001, respectively. The increase in the underfunded amount during 2002 was primarily caused by additional underfunded obligations assumed in the January 2002 Mitchell acquisition, losses on investments and actuarial losses. A detailed reconciliation of the 2002 activity is included in Note 10 to the accompanying consolidated financial statements. Of the $179 million underfunded status at the end of 2002, $75 million is attributable to various nonqualified defined benefit plans which have no plan assets. However, certain trusts have been established to assist Devon in funding the benefit obligations of such nonqualified plans. As of December 31, 2002, these trusts had investments with a market value of $53 million. The value of these trusts is included in noncurrent other assets in Devon's accompanying consolidated balance sheets.

As compared to the "accumulated benefit obligation," Devon's qualified defined benefit plans were underfunded by $82 million at December 31, 2002. The accumulated benefit obligation differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. Devon's current intentions are to fund this accumulated benefit obligation deficit over the two-year period ending December 31, 2004. The actual amount of contributions required during this period will depend on investment returns from the plan assets and any changes in actuarial assumptions made during the same period.

The calculation of pension expense and pension liability requires the use of a number of assumptions. Changes in these assumptions can result in different expense and liability amounts, and future actual experience can differ from the assumptions. Devon believes that the two most critical assumptions affecting pension expense and liabilities are the expected long-term rate of return on plan assets and the assumed discount rate.

Devon assumed that its plan assets would generate a long-term weighted average rate of return of 8.27% at December 31, 2002 and 2001, and 8.5% at December 31, 2000. Devon developed these expected long-term rate of return assumptions by evaluating input from external consultants and economists as well as long-term inflation assumptions. The expected long-term rate of return on plan assets is based on a target allocation of investment types in such assets. The target investment mix for Devon's plan assets are approximately 65% domestic equities, 15% international equities, and 20% fixed income instruments.

Devon believes that its long-term asset allocation on average will approximate the targeted allocation. Devon regularly reviews its actual asset allocation and periodically rebalances the investments to the targeted allocation when considered appropriate.

Pension expense increases as the expected rate of return on plan assets decreases. A decrease in Devon's long-term rate of return assumption of 100 basis points (from 8.27% to 7.27%) would increase the expected 2003 pension expense by approximately $3 million.

Devon discounted its future pension obligations using a weighted average rate of 6.72% at December 31, 2002, compared to 7.10% at December 31, 2001, and 7.65% at December 31, 2000. The discount rate is determined at the end of each year based on the rate at which obligations could be effectively settled. This rate is based on high-quality bond yields, after allowing for call and default risk.

Devon considers high quality corporate bond yield indices, such as Moody's Aa, when selecting the discount rate.

The pension liability and future pension expense both increase as the discount rate is reduced. Lowering the discount rate by 25 basis points (from 6.72% to 6.47%) would increase Devon's pension liability at December 31, 2002, by approximately $14 million, and increase its estimated 2003 pension expense by approximately $2 million.

At December 31, 2002, Devon had unrecognized actuarial losses of $152 million. These losses will be recognized as a component of pension expense in future years. Devon estimates that approximately $10 million, $9 million and $8 million of the unrecognized actuarial losses will be included in pension expense in 2003, 2004 and 2005, respectively. The $10 million estimated to be recognized in 2003 is a component of the total estimated 2003 pension expense of $30 million referred to earlier in this discussion.

Future changes in plan asset returns, assumed discount rates and various other factors related to the participants in Devon's defined benefit pension plans will impact future pension expense and liabilities. Devon cannot predict with certainty what these factors will be in the future.

CRITICAL ACCOUNTING POLICIES

FULL COST CEILING CALCULATIONS

Devon follows the full cost method of accounting for its oil and gas properties. The full cost method subjects companies to quarterly calculations of a "ceiling", or limitation on the amount of properties that can be capitalized on the balance sheet. If Devon's capitalized costs are in excess of the calculated ceiling, the excess must be written off as an expense. The ceiling limitation is imposed separately for each country in which Devon has oil and gas properties.

Devon's discounted present value of its proved oil, natural gas and NGL reserves is a major component of the ceiling calculation, and represents the component that requires the most subjective judgments. Estimates of reserves are forecasts based on engineering data, projected future rates of production and the timing of future expenditures. The process of estimating oil, natural gas and NGL reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. Different reserve engineers may make different estimates of reserve quantities based on the same data. Certain of Devon's reserve estimates are prepared by outside consultants, while other reserve estimates are prepared by Devon's engineers. See Note 14 of the accompanying consolidated financial statements.

The passage of time provides more qualitative information regarding estimates of reserves, and revisions are made to prior estimates to reflect updated information. In the past four years, Devon's annual revisions to its reserve estimates have averaged approximately 3% of the previous year's estimate. However, there can be no assurance that more significant revisions will not be necessary in the future. If future significant revisions are necessary that reduce previously estimated reserve quantities, it could result in a full cost property writedown. In addition to the impact of the estimates of proved reserves on the calculation of the ceiling, estimates of proved reserves are also a significant component of the calculation of DD&A.

While the quantities of proved reserves require substantial judgment, the associated prices of oil, natural gas and NGL reserves, and the applicable discount rate, that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that prices and costs in effect as of the last day of the period are generally held constant indefinitely. Therefore, the future net revenues associated with the estimated proved reserves are not based on Devon's assessment of future prices or costs, but rather are based on such prices and costs in effect as of the end of each quarter when the ceiling calculation is performed. In calculating the ceiling, Devon does not adjust the end-of-period price by the effect of cash flow hedges in place.

The ceiling calculation also dictates that a 10% discount factor is to be used to calculate the present value of net cash flows.

Because the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely, and requires a 10% discount factor, the resulting value is not indicative of the true fair value of the reserves. Oil and natural gas prices have historically been cyclical and, on any particular day at the end of a quarter, can be either substantially higher or lower than Devon's long-term price forecast that is a barometer for true fair value. Therefore, oil and gas property writedowns that result from applying the full cost ceiling limitation, and that are caused by fluctuations in price as opposed to reductions to the underlying quantities of reserves, should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

Devon recorded writedowns to its Canadian oil and gas properties as of June 30, 2002. Based on oil and natural gas cash market prices as of June 30, 2002, Devon's Canadian costs to be recovered exceeded the related ceiling value by $371 million. This after-tax amount resulted in a pre-tax reduction of the carrying value of Devon's Canadian oil and gas properties of $651 million in the second quarter of 2002. This reduction was the result of a sharp drop in Canadian gas prices during the last half of June 2002. The end of June reference prices used in the Canadian ceiling calculation, expressed in Canadian dollars based on an exchange ratio of $0.6585, were a NYMEX price of C$40.79 per barrel of oil and an AECO price of C$2.17 per MMBtu.

Devon also recorded writedowns to its domestic and Canadian oil and gas properties as of December 31, 2001. The domestic properties were reduced by $449 million and the Canadian properties were reduced by $434 million. The year-end 2001 prices used to calculate the ceiling were based on a NYMEX oil price of $19.84 per barrel, a Henry Hub gas price of $2.65 per MMBtu and an AECO gas price of C$3.67 per MMBtu.

If oil or gas prices at the end of future quarters drop below these June 30, 2002 or December 31, 2001 prices, or if Devon reduces its estimates of proved reserve quantities, further writedowns would likely occur.

FAIR VALUES OF DERIVATIVE INSTRUMENTS

The estimated fair values of Devon's derivative instruments are recorded on Devon's consolidated balance sheets. Substantially all of Devon's derivative instruments represent hedges of the price of future oil and natural gas production. Therefore, while fair values of such hedging instruments must be estimated as of the end of each reporting period, the changes in the fair values are not included in Devon's consolidated results of operations. Instead, the changes in fair value of hedging instruments are recorded directly to stockholders' equity until the hedged oil or natural gas quantities are produced.

The estimates of the fair values of Devon's hedging derivatives require substantial judgment. Devon obtains forward price and volatility data for all major oil and gas trading points in North America from independent third parties. These forward prices are compared to the price parameters contained in the hedge agreements, and the resulting estimated future cash inflows or outflows over the lives of the hedges are discounted using Devon's current borrowing rates under its revolving credit facilities. In addition, Devon estimates the option value of price floors and price caps using the Black-Scholes option pricing model. These pricing and discounting variables are sensitive to market volatility as well as changes in forward prices, regional price differentials and interest rates.

As stated earlier, substantially all of Devon's derivative instruments are hedges of the price of future oil and natural gas production. Devon is not involved in any speculative trading activities of derivatives.

BUSINESS COMBINATIONS

Devon has grown substantially during recent years through acquisitions of other oil and natural gas companies. Most of these acquisitions have been accounted for using the purchase method of accounting, and recent accounting pronouncements require that all future acquisitions will be accounted for using the purchase method.

Under the purchase method, the acquiring company adds to its balance sheet the estimated fair values of the acquired company's assets and liabilities. Any excess of the purchase price over the fair values of the tangible and intangible net assets acquired is recorded as goodwill. As of January 1, 2002, the accounting for goodwill has changed. In prior years, goodwill was amortized over its estimated useful life. As of 2002, goodwill is no longer amortized, but instead is assessed for impairment at least annually.

There are various assumptions made by Devon in determining the fair values of an acquired company's assets and liabilities. The most significant assumptions, and the ones requiring the most judgment, involve the estimated fair values of the oil and gas properties acquired. To determine the fair values of these properties, Devon prepares estimates of oil, natural gas and NGL reserves. These estimates are based on work performed by Devon's engineers and that of outside consultants. The judgments associated with these estimated reserves are described earlier in this section in connection with the full cost ceiling calculation.

However, there are factors involved in estimating the fair values of acquired oil, natural gas and NGL properties that require more judgment than that involved in the full cost ceiling calculation. As stated above, the full cost ceiling calculation applies current price and cost information to the reserves to arrive at the ceiling amount. By contrast, the fair value of reserves acquired in a business combination must be based on Devon's estimates of future oil, natural gas and NGL prices. Devon's estimates of future prices are based on its own analysis of pricing trends. These estimates are based on current data obtained with regard to regional and worldwide supply and demand dynamics such as economic growth forecasts. They are also based on industry data regarding natural gas storage availability, drilling rig activity, changes in delivery capacity, trends in regional pricing differentials and other fundamental analysis. Future price forecasts from independent third parties are noted when Devon makes its pricing estimates.

Devon's estimates of future prices are applied to the estimated reserve quantities acquired to arrive at estimates of future net revenues. For estimated proved reserves, the future net revenues are then discounted using a rate determined appropriate at the time of the business combination based upon Devon's cost of capital.

Devon also applies these same general principles in arriving at the fair value of unproved reserves acquired in a business combination. These unproved reserves are generally classified as either probable or possible reserves. Because of their very nature, probable and possible reserve estimates are more imprecise than those of proved reserves. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net revenues of probable and possible reserves are reduced by what Devon considers to be an appropriate risk-weighting factor in each particular instance. It is common for the discounted future net revenues of probable and possible reserves to be reduced by factors ranging from 30% to 80% to arrive at what Devon considers to be the appropriate fair values.

Generally, in Devon's business combinations, the determination of the fair values of oil and gas properties requires much more judgment than the fair values of other assets and liabilities. The acquired companies commonly have long-term debt that Devon assumes in the acquisition, and this debt must be recorded at the estimated fair value as if Devon had issued such debt. However, significant judgment on Devon's behalf is usually not required in these situations due to the existence of comparable market values of debt issued by Devon's peer companies.

Prior to the 2002 Mitchell acquisition, Devon's mergers and acquisitions have involved other entities whose operations were predominantly in the area of exploration, development and production activities related to oil and gas properties. However, in addition to exploration, development and production activities, Mitchell's business also included substantial marketing and midstream activities. Therefore, a portion of the Mitchell purchase price was allocated to the fair value of Mitchell's marketing and midstream facilities and equipment, which consisted primarily of natural gas processing plants and natural gas pipeline systems.

Because the Mitchell marketing and midstream assets primarily served gas producing properties that were also acquired by Devon from Mitchell, certain of the assumptions regarding future operations of the gas producing properties were also integral to the value of the marketing and midstream assets. For example, future quantities of natural gas estimated to be processed by natural gas processing plants were based on the same estimates used to value the proved and unproved gas producing properties. Future expected prices for marketing and midstream product sales were also based on price cases consistent with those used to value the oil and gas producing assets acquired from Mitchell. Based on historical costs and known trends and commitments, Devon also estimated future operating and capital costs of the marketing and midstream assets to arrive at estimated future cash flows. These cash flows were discounted at rates consistent with those used to discount future net cash flows from oil and gas producing assets to arrive at Devon's estimated fair value of the marketing and midstream facilities and equipment.

VALUATION OF GOODWILL

Effective January 1, 2002, Devon adopted the remaining provisions of SFAS No. 142, Goodwill and Other Intangible Assets. Under SFAS No. 142, goodwill and intangible assets with indefinite useful lives are no longer amortized, but are instead tested for impairment at least annually. This requires Devon to estimate the fair values of its own assets and liabilities in a manner similar to the process described above for a business combination. Therefore, considerable judgment similar to that described above in connection with estimating the fair value of an acquired company in a business combination is also required to assess goodwill for impairment on an annual basis.

IMPACT OF RECENTLY ISSUED ACCOUNTING STANDARDS NOT YET ADOPTED

In June 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. SFAS No. 143 requires liability recognition for retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms, and natural gas processing plants. The obligations included within the scope of SFAS No. 143 are those for which a company faces a legal obligation for settlement. The initial measurement of the asset retirement obligation is to be the discounted present fair value, defined as "the price that an entity would have to pay a willing third party of comparable credit standing to assume the liability in a current transaction other than in a forced or liquidation sale."

The asset retirement cost equal to the discounted fair value of the retirement obligation is to be capitalized as part of the cost of the related long-lived asset and allocated to expense using a systematic and rational method.

Devon will adopt SFAS No. 143 effective January 1, 2003 using a cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation.

Devon previously estimated costs of dismantlement, removal, site reclamation, and other similar activities in the total costs that are subject to depreciation, depletion, and amortization. However, Devon did not record a separate asset or liability for such amounts. Upon adoption of SFAS No. 143 on January 1, 2003, Devon expects to record a cumulative-effect-type adjustment for an increase to net earnings of between $10 million and $30 million, net of deferred tax expense of between $5 million and $15 million. Additionally, Devon expects to establish an asset retirement obligation of between $425 million and $475 million, an increase to property and equipment of between $375 million and $425 million and a decrease in accumulated DD&A of between $65 million and $95 million.

The FASB issued Statement No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections, on April 30, 2002. SFAS No. 145 will be effective for fiscal years beginning after May 15, 2002. This statement rescinds SFAS No. 4, Reporting Gains and Losses From Extinguishment of Debt, and requires that all gains and losses from extinguishment of debt should be classified as extraordinary items only if they meet the criteria in APB No. 30. Applying APB No. 30 will distinguish transactions that are part of an entity's recurring operations from those that are unusual or infrequent or that meet the criteria for classification as an extraordinary item. Any gain or loss on extinguishment of debt that was classified as an extraordinary item in prior periods presented that does not meet the criteria in APB No. 30 for classification as an extraordinary item must be reclassified. Devon early adopted the provisions related to SFAS No. 145 during the fourth quarter 2002. With the adoption of SFAS No. 145, a loss of $6 million resulting from extinguishment of debt in 1999 was reclassified from extraordinary loss to interest expense, and 1999's current income tax expense was reduced by the $2 million tax benefit related to the loss from early extinguishment.

The FASB issued Statement No. 146, Accounting for Costs Associated with Exit or Disposal Activities, in June 2002. SFAS No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force Issue No. 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs incurred in a Restructuring). SFAS No. 146 applies to costs incurred in an "exit activity", which includes, but is not limited to, a restructuring, or a "disposal activity" covered by SFAS No. 144.

SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred. Previously, under Issue 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. Statement No. 146 also establishes that fair value is the objective for initial measurement of the liability.

The provisions of SFAS No. 146 are effective for exit or disposal activities that are initiated after December 31, 2002. Devon currently has no such exit or disposal activities planned.

In November 2002, the FASB issued Interpretation No. 45, Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others, an interpretation of FASB Statements No. 5, 57 and 107 and a rescission of FASB Interpretation No. 34. This Interpretation elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees issued. The Interpretation also clarifies that a guarantor is required to recognize, at inception of a guarantee, a liability for the fair value of the obligation undertaken. The initial recognition and measurement provisions of the Interpretation are applicable to guarantees issued or modified after December 31, 2002 and are not expected to have a material effect on Devon's financial statements. The disclosure requirements are effective for financial statements of interim and annual periods ending after December 31, 2002 and are included in the notes to the accompanying consolidated financial statements.

In December 2002, the FASB issued SFAS No. 148, Accounting for Stock-Based Compensation -- Transition and Disclosure, an amendment of FASB Statement No.
123. This Statement amends FASB Statement No. 123, Accounting for Stock-Based Compensation, to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, this Statement amends the disclosure requirements of Statement No. 123 to require prominent disclosures in both annual and interim financial statements. Certain of the disclosure modifications are required for fiscal years ending after December 15, 2002 and are included in the notes to the accompanying consolidated financial statements.

In January 2003, the FASB issued Interpretation No. 46, Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51. Interpretation No. 46 requires a company to consolidate a variable interest entity if the company has a variable interest (or combination of variable interests) that will absorb a majority of the entity's expected losses if they occur, receive a majority of the entity's expected residual returns if they occur, or both. A direct or indirect ability to make decisions that significantly affect the results of the activities of a variable interest entity is a strong indication that a company has one or both of the characteristics that would require consolidation of the variable interest entity. Interpretation No. 46 also requires additional disclosures regarding variable interest entities. The new interpretation is effective immediately for variable interest entities created after January 31, 2003, and is effective in the first interim or annual period beginning after June 15, 2003, for variable interest entities in which a company holds a variable interest that it acquired before February 1, 2003. Devon owns no interests in variable interest entities, and therefore this new interpretation will not affect Devon's consolidated financial statements.

2003 ESTIMATES

The forward-looking statements provided in this discussion are based on management's examination of historical operating trends, the information which was used to prepare the December 31, 2002 reserve reports of independent petroleum engineers and other data in Devon's possession or available from third parties. Devon cautions that its future oil, natural gas and NGL production, revenues and expenses are subject to all of the risks and uncertainties normally incident to the exploration for and development, production and sale of oil, gas and NGLs. These risks include, but are not limited to, price volatility, inflation or lack of availability of goods and services, environmental risks, drilling risks, regulatory changes, the uncertainty inherent in estimating future oil and gas production or reserves, and other risks as outlined below. Additionally, Devon cautions that its future marketing and midstream revenues and expenses are subject to all of the risks and uncertainties normally incident to the marketing and midstream business. These risks include, but are not limited to, price volatility, environmental risks, regulatory changes, the uncertainty inherent in estimating future processing volumes and pipeline throughput, cost of goods and services and other risks as outlined below. Also, the financial results of Devon's foreign operations are subject to currency exchange rate risks. Additional risks are discussed below in the context of line items most affected by such risks.

SPECIFIC ASSUMPTIONS AND RISKS RELATED TO PRICE AND PRODUCTION ESTIMATES

Prices for oil, natural gas and NGLs are determined primarily by prevailing market conditions. Market conditions for these products are influenced by regional and worldwide economic conditions, weather and other local market conditions. These factors are beyond Devon's control and are difficult to predict. In addition to volatility in general, Devon's oil, gas and NGL prices may vary considerably due to differences between regional markets, transportation availability and costs and demand for the various products derived from oil, natural gas and NGLs. Substantially all of Devon's revenues are attributable to sales, processing and transportation of these three commodities. Consequently, Devon's financial results and resources are highly influenced by price volatility.

Estimates for Devon's future production of oil, natural gas and NGLs are based on the assumption that market demand and prices for oil, gas and NGLs will continue at levels that allow for profitable production of these products. There can be no assurance of such stability. Also, Devon's international production of oil, natural gas and NGLs is governed by payout agreements with the governments of the countries in which Devon operates. If the payout under these agreements is attained earlier than projected, Devon's net production and proved reserves in such areas could be reduced.

Estimates for Devon's future processing and transport of oil, natural gas and NGLs are based on the assumption that market demand and prices for oil, gas and NGLs will continue at levels that allow for profitable processing and transport of these products. There can be no assurance of such stability.

The production, transportation, processing and marketing of oil, natural gas and NGLs are complex processes which are subject to disruption due to transportation and processing availability, mechanical failure, human error, meteorological events including, but not limited to, hurricanes, and numerous other factors. The following forward-looking statements were prepared assuming demand, curtailment, producibility and general market conditions for Devon's oil, natural gas and NGLs during 2003 will be substantially similar to those of 2002, unless otherwise noted.

Given the general limitations expressed herein, following are Devon's forward-looking statements for 2003. Unless otherwise noted, all of the following dollar amounts are expressed in U.S. dollars. Amounts related to Canadian operations have been converted to U.S. dollars using an exchange rate of $0.65 U.S. dollar to $1.00 Canadian dollar. The actual 2003 exchange rate may vary materially from this estimated rate. Such variations could have a material effect on the following estimates.

Though Devon has completed several major property acquisitions and dispositions in recent years, these transactions are opportunity driven. Thus, Devon does not "budget", nor can it reasonably predict, the timing or size of such possible acquisitions or dispositions, if any. As discussed in Note 16 to the accompanying consolidated financial statements, on February 24, 2003, Devon announced its intent to merge with Ocean Energy, Inc. ("Ocean"). The following forward-looking estimates do not include the additional revenues and expenses that Devon will report in 2003 if this merger is consummated.

GEOGRAPHIC REPORTING AREAS FOR 2003

The following estimates of production, average price differentials and capital expenditures are provided separately for each of the following geographic areas:

- the United States;

- Canada; and

- International, which encompasses all oil and gas properties that lie outside of the United States and Canada.

YEAR 2003 POTENTIAL OPERATING ITEMS

OIL, GAS AND NGL PRODUCTION

Set forth in the following paragraphs are individual estimates of Devon's oil, gas and NGL production for 2003. On a combined basis, Devon estimates its 2003 oil, gas and NGL production will total between 178.1 and 186.9 MMBoe. Of this total, approximately 92% is estimated to be produced from reserves classified as "proved" at December 31, 2002.

OIL PRODUCTION

Devon expects its oil production in 2003 to total between 35.4 and 37.2 MMBbls. Of this total, approximately 92% is estimated to be produced from reserves classified as "proved" at December 31, 2002. The expected ranges of production by area are as follows:

	(MMBbls)
United States	19.1 to 20.1
Canada	13.5 to 14.2
International	2.8 to 2.9

OIL PRICES -- FLOATING

Devon's 2003 average prices for each of its areas are expected to differ from the NYMEX price as set forth in the following table. The NYMEX price is the monthly average of settled prices on each trading day for West Texas Intermediate Crude oil delivered at Cushing, Oklahoma.

	EXPECTED RANGE OF OIL PRICES LESS THAN NYMEX PRICE
United States	(\$3.00) to (\$2.00)
Canada	(\$6.25) to (\$4.25)
International	(\$2.80) to (\$1.80)

Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2003 oil production that otherwise is subject to floating prices. The floor and ceiling prices related to domestic and Canadian oil production are based on the NYMEX price. If the NYMEX price is outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. Any such settlements will either increase or decrease Devon's oil revenues for the period. Because Devon's oil volumes are often sold at prices that differ from the NYMEX price due to differing quality (i.e., sweet crude versus sour crude) and transportation costs from different geographic areas, the floor and ceiling prices of the various collars do not reflect actual limits of Devon's realized prices for the production volumes related to the collars.

To simplify presentation, Devon's costless collars as of January 31, 2003, have been aggregated in the following table according to similar floor prices and similar ceiling prices. The floor and ceiling prices shown are weighted averages of the various collars in each aggregated group.

AREA (RANGE OF FLOOR PRICES/CEILING PRICES)	Bbls/Day	WEIGHTED AVERAGE Floor Price Per Bbl	WEIGHTED AVERAGE Ceiling Price Per Bbl	MONTHS OF PRODUCTION
United States ($20.00 - $22.75/$27.05 - $28.65)	18,000	$21.65	$27.91	Jan - Dec
United States ($23.25 - $23.50/$28.25 - $30.00)	8,000	$23.38	$29.12	Jan - Dec
United States ($23.50 - $23.50/$28.25 - $30.75)	6,000	$23.50	$29.31	Jul - Dec
Canada ($20.00 - $21.00/$26.60 - $28.15)	5,000	$20.40	$27.37	Jan - Dec
Canada ($22.00 - $22.75/$27.00 - $28.40)	13,000	$22.29	$27.52	Jan - Dec
Canada ($23.25 - $23.50/$28.35 - $29.25)	5,000	$23.30	$28.79	Jan - Dec
Canada ($23.50 - $23.50/$28.80 - $29.75)	3,000	$23.50	$29.18	Jul - Dec

GAS PRODUCTION

Devon expects its 2003 gas production to total between 731 Bcf and 767 Bcf. Of this total, approximately 91% is estimated to be produced from reserves classified as "proved" at December 31, 2002. The expected ranges of production by area are as follows:

	(Bcf)
United States	472 to 495
Canada	259 to 272

GAS PRICES -- FIXED

Through various price swaps and fixed-price physical delivery contracts, Devon has fixed the price it will receive in 2003 on a portion of its natural gas production. The following table includes information on this fixed-price production by area. Where necessary, the prices have been adjusted for certain transportation costs that are netted against the prices recorded by Devon, and the prices have also been adjusted for the Btu content of the gas hedged.

	Mcf/DAY	Price/Mcf	MONTHS OF PRODUCTION
United States	97,148	$3.23	Jan - Dec
Canada	43,578	$2.30	Jan - Jun
Canada	43,578	$2.29	Jul - Dec

GAS PRICES -- FLOATING

For the natural gas production for which prices have not been fixed, Devon's 2003 average prices for each of its areas are expected to differ from the NYMEX price as set forth in the following table. The NYMEX price is represented by the first-of-month South Louisiana Henry Hub price index as published monthly in Inside FERC.

	EXPECTED RANGE OF GAS PRICES LESS THAN NYMEX PRICE
United States	($0.80) to ($0.30)
Canada	($0.90) to ($0.40)

Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2003 natural gas production that otherwise is subject to floating prices. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. Any such settlements will either increase or decrease Devon's gas revenues for the period. Because Devon's gas volumes are often sold at prices that differ from the related regional indices, and due to differing Btu contents of gas produced, the floor and ceiling prices of the various collars do not reflect actual limits of Devon's realized prices for the production volumes related to the collars.

To simplify presentation, Devon's costless collars as of January 31, 2003 have been aggregated in the following table according to similar floor prices and similar ceiling prices. The floor and ceiling prices shown are weighted averages of the various collars in each aggregated group.

The prices shown in the following table have been adjusted to a NYMEX-based price, using Devon's estimates of 2003 differentials between NYMEX and the specific regional indices upon which the collars are based. The floor and ceiling prices related to the domestic collars are based on various regional first-of-the-month price indices as published monthly by Inside FERC. The floor and ceiling prices related to the Canadian collars are based on the AECO index as published by the Canadian Gas Price Reporter.

		WEIGHTED AVERAGE		
AREA (RANGE OF FLOOR PRICES/CEILING PRICES)	MMBtu/DAY	FLOOR PRICE PER MMBtu	CEILING PRICE PER MMBtu	MONTHS OF PRODUCTION
United States ($3.28 - $3.28/$6.23 - $6.53)	40,000	$3.28	$6.38	Jan - Dec
United States ($3.28 - $3.28/$5.53 - $5.93)	55,000	$3.28	$5.74	Jan - Dec
United States ($3.25 - $3.28/$4.65 - $4.93)	70,000	$3.27	$4.80	Jan - Dec
United States ($3.00 - $3.28/$4.05 - $4.20)	130,000	$3.12	$4.11	Jan - Dec
United States ($3.28 - $3.45/$4.20 - $4.49)	110,000	$3.35	$4.37	Jan - Dec
United States ($3.44 - $3.44/$6.69 - $6.69)	5,000	$3.44	$6.69	Apr - Sep
Canada ($3.28 - $3.39/$6.85 - $7.13)	20,000	$3.34	$6.99	Jan - Dec
Canada ($3.38 - $3.57/$6.10 - $6.89)	80,000	$3.49	$6.52	Jan - Dec
Canada ($3.45 - $3.52/$4.27 - $4.89)	90,000	$3.48	$4.34	Jan - Dec
Canada ($3.66 - $3.67/$7.24 - $7.68)	30,000	$3.66	$7.44	Apr - Oct
Canada ($3.53 - $3.54/$5.27 - $5.96)	40,000	$3.54	$5.60	Jan - Dec

NGL PRODUCTION

Devon expects its 2003 production of NGLs to total between 20.9 MMBbls and 21.9 MMBbls. Of this total, 96% is estimated to be produced from reserves classified as "proved" at December 31, 2002. The expected ranges of production by area are as follows:

	(MMBBLS)
United States	16.6 to 17.4
Canada	4.3 to 4.5

MARKETING AND MIDSTREAM REVENUES AND EXPENSES

Devon's marketing and midstream revenues and expenses are derived primarily from its natural gas processing plants and natural gas transport pipelines. These revenues and expenses vary in response to several factors. The factors include, but are not limited to, changes in production from wells connected to the pipelines and related processing plants, changes in the absolute and relative prices of natural gas and NGLs, provisions of the agreements, and the amount of repair and workover activity required to maintain anticipated processing levels.

These factors, coupled with uncertainty of future natural gas and NGL prices, increase the uncertainty inherent in estimating future marketing and midstream revenues and expenses. Given these uncertainties, Devon estimates that 2003 marketing and midstream revenues will be between $1.18 billion and $1.25 billion and marketing and midstream expenses will be between $961 million and $1.02 billion.

PRODUCTION AND OPERATING EXPENSES

Devon's production and operating expenses include lease operating expenses, transportation costs and production taxes. These expenses vary in response to several factors. Among the most significant of these factors are additions to or deletions from Devon's property base, changes in production tax rates, changes in the general price level of services and materials that are used in the operation of the properties and the amount of repair and workover activity required. Oil, natural gas and NGL prices also have an effect on lease operating expenses and impact the economic feasibility of planned workover projects.

Given these uncertainties, Devon estimates that 2003 lease operating expenses will be between $611 million and $649 million, transportation costs will be between $141 million and $150 million, and production taxes will be between 3.7% and 4.2% of consolidated oil, natural gas and NGL revenues, excluding revenues related to hedges upon which production taxes are not incurred.

DEPRECIATION, DEPLETION AND AMORTIZATION ("DD&A")

The 2003 oil and gas property DD&A rate will depend on various factors. Most notable among such factors are the amount of proved reserves that will be added from drilling or acquisition efforts in 2003 compared to the costs incurred for such efforts, and the revisions to Devon's year-end 2002 reserve estimates that, based on prior experience, are likely to be made during 2003.

Based on these uncertainties, oil and gas property related DD&A expense for 2003 is expected to be between $1.1 billion and $1.2 billion. Additionally, Devon expects its DD&A expense related to non-oil and gas property fixed assets to total between $124 million and $132 million. This range includes $78 million to $83 million related to marketing and midstream assets. Based on these DD&A amounts and the production estimates set forth earlier, Devon expects its consolidated DD&A rate will be between $6.82 per Boe and $7.22 per Boe.

ACCRETION OF ASSET RETIREMENT OBLIGATION

As discussed in the previous section titled "Impact of Recently Issued Accounting Standards Not Yet Adopted", Devon adopted SFAS No. 143 effective January 1, 2003 using a cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation. SFAS No. 143 requires liability recognition for retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms, and natural gas processing plants. The obligations included within the scope of SFAS No. 143 are those for which a company faces a legal obligation for settlement. The initial measurement of the asset retirement obligation is to be the discounted present fair value, defined as "the price that an entity would have to pay a willing third party of comparable credit standing to assume the liability in a current transaction other than in a forced or liquidation sale." Because the asset retirement obligation is a discounted value, accretion will be recognized as the estimated date for settling the obligation draws closer.

As a result of the requirements of SFAS No. 143, Devon expects its 2003 accretion of its asset retirement obligation related to the adoption of SFAS 143 to be between $25 million and $35 million.

GENERAL AND ADMINISTRATIVE EXPENSES ("G&A")

Devon's G&A includes the costs of many different goods and services used in support of its business. These goods and services are subject to general price level increases or decreases. In addition, Devon's G&A varies with its level of activity and the related staffing needs as well as with the amount of professional services required during any given period. Should Devon's needs or the prices of the required goods and services differ significantly from current expectations, actual G&A could vary materially from the estimate. Given these limitations, consolidated G&A in 2003 is expected to be between $215 million and $229 million.

INTEREST EXPENSE

Future interest rates, debt outstanding and oil, natural gas and NGL prices have a significant effect on Devon's interest expense. Devon can only marginally influence the prices it will receive in 2003 from sales of oil, natural gas and NGLs and the resulting cash flow. These factors increase the margin of error inherent in estimating future interest expense. Other factors which affect interest expense, such as the amount and timing of capital expenditures, are within Devon's control.

Assuming no changes in fixed-rate debt balances during 2003, Devon's average balance of fixed-rate debt during 2003 will be $6.5 billion. The interest expense in 2003 related to this fixed-rate debt, including net accretion of related discounts, will be approximately $472 million. This fixed-rate debt removes the uncertainty of future interest rates from some, but not all, of Devon's long-term debt. Devon's floating rate debt is discussed in the following paragraphs.

As of January 31, 2003, Devon had $1.1 billion outstanding under its original $3.0 billion amortizing senior unsecured term loan credit facility. This credit facility, which was entered into in October 2001, has a term of five years. This credit facility is non-revolving.

The remaining balance outstanding as of January 31, 2003 will mature as follows:

	(IN MILLIONS)
April 15, 2006	$ 335
October 15, 2006	800
	$1,135

This $3 billion facility includes various rate options which can be elected by Devon, including a rate based on LIBOR plus a margin. The margin is based on Devon's debt rating. Based on Devon's current debt rating, the margin is 100 basis points. As of January 31, 2003, the average interest rate on this facility was 2.3%.

From time to time, Devon borrows under its $1 billion credit facilities. Borrowings under the U.S. facility, currently set at $725 million, may be borrowed at various rate options including LIBOR plus a margin with interest periods of up to six months. Borrowings under the Canadian facility, currently set at $275 million, may be made at various rate options including LIBOR plus a margin with interest periods up to six months, or Bankers Acceptances plus a margin with interest periods of 30 to 180 days. The current LIBOR margin ranges from 45 to 125 basis points based upon usage and the tranche utilized, and the current Bankers Acceptance margin is 72.5 basis points over the cost of funding. There were no borrowings under these facilities at January 31, 2003.

Devon also borrows under a $150 million Canadian dollar letter of credit facility which is primarily used to issue letters of credit in association with Devon's Canadian drilling commitments. As of December 31, 2002, there were $109 million Canadian dollars of issued letters of credit under this facility. Devon may also use this facility for general corporate purposes.

From time to time, Devon also borrows under its commercial paper facility. Total borrowings under the $725 million U.S. facility and the commercial paper program cannot exceed $725 million. There were no borrowings under the commercial paper facility as of December 31, 2002. Commercial paper borrowing costs are typically 20 to 50 basis points over LIBOR. Debt outstanding under this program is generally borrowed for seven to 90 day periods, and may be borrowed up to 365 days, at prevailing commercial paper market rates.

Devon has fixed the interest rate on $125 million Canadian dollars and $50 million U.S. dollars of its floating rate debt through swap agreements at average rates of 6.4% and 5.9%, respectively. The Canadian dollar swap agreements mature at various dates through July 2007 and the U.S. dollar swap agreement matures in May 2003.

Devon has also entered into an interest rate swap on its $125 million 8.05% senior notes due in 2004 to swap a fixed interest rate for a variable interest rate. The variable interest rate on this instrument is based on LIBOR plus a margin of 336 basis points. The interest rate swap is accounted for as a fair value hedge under SFAS 133.

Devon's interest expense totals have historically included payments of facility and agency fees, amortization of debt issuance costs, the effect of the interest rate swaps, and other miscellaneous items not related to the debt balances outstanding. Devon expects between $10 million and $20 million of such items to be included in its 2003 interest expense. Based on the information related to interest expense set forth herein and assuming no material changes in Devon's levels of indebtedness or prevailing interest rates, Devon expects its 2003 interest expense will be between $512 million and $522 million.

REDUCTION OF CARRYING VALUE OF OIL AND GAS PROPERTIES

Devon follows the full cost method of accounting for its oil and gas properties. Under the full cost method, Devon's net book value of oil and gas properties, less related deferred income taxes (the "costs to be recovered"), may not exceed a calculated "full cost ceiling." The ceiling limitation is the discounted estimated after-tax future net revenues from oil and gas properties plus the cost of properties not subject to amortization. The ceiling is imposed separately by country. In calculating future net revenues, current prices and costs are generally held constant indefinitely. The costs to be recovered are compared to the ceiling on a quarterly basis. If the costs to be recovered exceed the ceiling, the excess is written off as an expense. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

Because the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely, and requires a 10% discount factor, the resulting value is not indicative of the true fair value of the reserves. Oil and natural gas prices have historically been cyclical and, on any particular day at the end of a quarter, can be either substantially higher or lower than Devon's long-term price forecast that is a barometer for true fair value. Therefore, oil and gas property writedowns that result from applying the full cost ceiling limitation, and that are caused by fluctuations in price as opposed to reductions to the underlying quantities of reserves, should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

Because of the volatile nature of oil and gas prices, it is not possible to predict whether Devon will incur a full cost writedown in future periods.

EFFECTS OF CHANGES IN FOREIGN CURRENCY RATES

Devon's Canadian subsidiary has $400 million of fixed-rate senior notes which are denominated in U.S. dollars. Changes in the exchange rate between the U.S. dollar and the Canadian dollar during 2003 will increase or decrease the Canadian dollar equivalent balance of this debt. Such changes in the Canadian dollar equivalent balance of the debt are required to be included in determining net earnings for the period in which the exchange rate changes. Because of the variability of the exchange rate, it is not possible to estimate the effect which will be recorded in 2003. However, based on the January 31, 2003, Canadian-to-U.S. dollar exchange rate of $0.6540, for every $0.01 change in the exchange rate, Devon will record an effect (either income or expense) of approximately $9 million Canadian dollars. The resulting revenue or expense in U.S. dollars will depend on the currency exchange rate in effect throughout the year.

OTHER REVENUES

Devon's other revenues in 2003 are expected to be between $23 million and $26 million.

INCOME TAXES

Devon's financial income tax rate in 2003 will vary materially depending on the actual amount of financial pre-tax earnings. The tax rate for 2003 will be significantly affected by the proportional share of consolidated pre-tax earnings generated by U.S., Canadian and International operations due to the different tax rates of each country. There are certain tax deductions and credits that will have a fixed impact on 2003's income tax expense regardless of the level of pre-tax earnings that are produced. Given the uncertainty of its pre-tax earnings amount, Devon estimates that its consolidated financial income tax rate in 2003 will be between 20% and 40%. The current income tax rate is expected to be between 0% and 10%. The deferred income tax rate is expected to be between 20% and 30%. Significant changes in estimated capital expenditures, production levels of oil, gas and NGLs, the prices of such products, marketing and midstream revenues, or any of the various expense items could materially alter the effect of the aforementioned tax deductions and credits on 2003's financial income tax rates.

YEAR 2003 POTENTIAL CAPITAL SOURCES, USES AND LIQUIDITY

CAPITAL EXPENDITURES

Though Devon has completed several major property acquisitions in recent years, these transactions are opportunity driven. Thus, Devon does not "budget", nor can it reasonably predict, the timing or size of such possible acquisitions, if any. As discussed in Note 16 to the accompanying consolidated financial statements, on February 24, 2003, Devon announced its intention to merge with Ocean. The following forward-looking estimates do not include the additional capital expenditures that Devon will report in 2003 if this merger is consummated.

Devon's capital expenditures budget is based on an expected range of future oil, natural gas and NGL prices as well as the expected costs of the capital additions. Should actual prices received differ materially from Devon's price expectations for its future production, some projects may be accelerated or deferred and, consequently, may increase or decrease total 2003 capital expenditures. In addition, if the actual costs of the budgeted items vary significantly from the anticipated amounts, actual capital expenditures could vary materially from Devon's estimates.

Given the limitations discussed, Devon expects its 2003 capital expenditures for drilling and development efforts, plus related facilities, to total between $1.4 billion and $1.6 billion. These amounts include between $455 million and $525 million for drilling and facilities costs related to reserves classified as proved as of year-end 2002. In addition, these amounts include between $485 million and $555 million for other low risk/reward projects and between $435 million and $510 million for new, higher risk/reward projects. Low risk/reward projects include development drilling that does not offset currently productive units and for which there is not a certainty of continued production from a known productive formation. Higher risk/reward projects include exploratory drilling to find and produce oil or gas in previously untested fault blocks or new reservoirs.

The following table shows expected drilling and production facilities expenditures by geographic area.

	UNITED STATES	CANADA	INTERNATIONAL	TOTAL
		($ IN MILLIONS)		
Related to Proved Reserves........	$330-$370	$105-$125	$30-$ 40	$ 465-$ 535
Lower Risk/Reward Projects........	$335-$375	$150-$180	$ 0-$ 0	$ 485-$ 555
Higher Risk/Reward Projects.......	$180-$210	$205-$235	$50-$ 65	$ 435-$ 510
Total.............................	$845-$955	$460-$540	$80-$105	$1,385-$1,600

In addition to the above expenditures for drilling and development, Devon expects to spend between $150 million to $170 million on its marketing and midstream assets, which include its oil pipelines, gas processing plants, treating facilities and gas pipelines. Devon also expects to capitalize between $85 million and $95 million of G&A expenses in accordance with the full cost method of accounting. Devon also expects to pay between $30 million and $40 million for plugging and abandonment charges, and to spend between $50 million and $60 million for other non-oil and gas property fixed assets.

OTHER CASH USES

Devon's management expects the policy of paying a quarterly common stock dividend to continue. With the current $0.05 per share quarterly dividend rate and 157 million shares of common stock outstanding, 2003 dividends are expected to approximate $31 million. Also, Devon has $150 million of 6.49% cumulative preferred stock upon which it will pay $10 million of dividends in 2003.

CAPITAL RESOURCES AND LIQUIDITY

Devon's estimated 2003 cash uses, including its drilling and development activities, are expected to be funded primarily through a combination of working capital and operating cash flow. The amount of operating cash flow to be generated during 2003 is uncertain due to the factors affecting revenues and expenses as previously cited. However, based upon current oil and gas price expectations for 2003, Devon anticipates that its operating cash flow will exceed its planned capital expenditures and other cash requirements for the year. Devon currently intends to accumulate any excess cash to fund future years' debt maturities. Additional alternatives could be considered based upon the actual amount, if any, of such excess cash. If significant acquisitions or other unplanned capital requirements arise during the year, Devon could utilize its existing credit facilities and/or seek to establish and utilize other sources of financing. As of December 31, 2002, Devon had $975 million available under its $1 billion credit facilities, net of $25 million of outstanding letters of credit.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about Devon's potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil, gas and NGL prices, interest rates and foreign currency exchange rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how Devon views and manages its ongoing market risk exposures. All of Devon's market risk sensitive instruments were entered into for purposes other than speculative trading.

COMMODITY PRICE RISK

Devon's major market risk exposure is in the pricing applicable to its oil, gas and NGLs production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to its U.S. and Canadian natural gas and NGL production. Pricing for oil, gas and NGL production has been volatile and unpredictable for several years.

Devon periodically enters into financial hedging activities with respect to a portion of its projected oil and natural gas production through various financial transactions which hedge the future prices received. These transactions include financial price swaps whereby Devon will receive a fixed price for its production and pay a variable market price to the contract counterparty, and costless price collars that set a floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. These financial hedging activities are intended to support oil and natural gas prices at targeted levels and to manage Devon's exposure to oil and gas price fluctuations. Devon does not hold or issue derivative instruments for speculative trading purposes.

Devon's total hedged positions as of January 31, 2003 are set forth in the following tables.

PRICE SWAPS

Through various price swaps, Devon has fixed the price it will receive on a portion of its natural gas production in 2003. These swaps will result in a fixed price of $3.23 per Mcf on 97,148 Mcf per day of domestic production during 2003. Where necessary, the prices related to these swaps have been adjusted for certain transportation costs that are netted against the price recorded by Devon, and the price has also been adjusted for the Btu content of the gas production that has been hedged.

COSTLESS PRICE COLLARS

Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2003 and 2004 oil and natural gas production. The following tables include information on these collars for each geographic area. The floor and ceiling prices related to domestic oil production are based on NYMEX. The NYMEX price is the monthly average of settled prices on each trading day for West Texas Intermediate Crude oil delivered at Cushing, Oklahoma. The gas prices shown in the following table have been adjusted to a NYMEX-based price, using Devon's estimates of differentials between NYMEX and the specific regional indices upon which the collars are based. The floor and ceiling prices related to the domestic collars are based on various regional first-of-the-month price indices as published monthly by Inside FERC. The floor and ceiling prices related to the Canadian collars are based on the AECO index as published by the Canadian Gas Price Reporter.

If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. Any such settlements will either increase or decrease Devon's oil or gas revenues for the period. Because Devon's gas volumes are often sold at prices that differ from the related regional indices, and due to differing Btu content of gas production, the floor and ceiling prices of the various collars do not reflect actual limits of Devon's realized prices for the production volumes related to the collars.

The floor and ceiling prices in the following tables are weighted averages of all the various collars.

OIL PRODUCTION

	2003			
		WEIGHTED AVERAGE		
AREA (RANGE OF FLOOR PRICES/CEILING PRICES)	Bbls/DAY	Floor Price Per Bbl	Ceiling Price Per Bbl	MONTHS OF PRODUCTION
United States ($20.00 - $22.75/$27.05 - $28.65)............	18,000	$21.65	$27.91	Jan - Dec
United States ($23.25 - $23.50/$28.25 - $30.00)............	8,000	$23.38	$29.12	Jan - Dec
United States ($23.50 - $23.50/$28.25 - $30.75)............	6,000	$23.50	$29.31	Jul - Dec
Canada ($20.00 - $21.00/$26.60 - $28.15).......	5,000	$20.40	$27.37	Jan - Dec
Canada ($22.00 - $22.75/$27.00 - $28.40).......	13,000	$22.29	$27.52	Jan - Dec
Canada ($23.25 - $23.50/$28.35 - $29.25).......	5,000	$23.30	$28.79	Jan - Dec
Canada ($23.50 - $23.50/$28.80 - $29.75).......	3,000	$23.50	$29.18	Jul - Dec

	2004			
		WEIGHTED AVERAGE		
AREA (RANGE OF FLOOR PRICES/CEILING PRICES)	Bbls/Day	Floor Price Per Bbl	Ceiling Price Per Bbl	MONTHS OF PRODUCTION
United States ($20.00 - $20.00/$26.50 - $28.00)............	2,000	$20.00	$27.25	Jan - Dec
Canada ($20.00 - $20.00/$26.50 - $27.00).......	2,000	$20.00	$26.75	Jan - Dec

GAS PRODUCTION

AREA (RANGE OF FLOOR PRICES/CEILING PRICES)	2003 MMBtu/DAY	Weighted Average Floor Price Per MMBtu	Weighted Average Ceiling Price Per MMBtu	MONTHS OF PRODUCTION
United States ($3.28 - $3.28/$6.23 - $6.53)...........	40,000	$ 3.28	$6.38	Jan - Dec
United States ($3.28 - $3.28/$5.53 - $5.93)...........	55,000	$ 3.28	$5.74	Jan - Dec
United States ($3.25 - $3.28/$4.65 - $4.93)...........	70,000	$ 3.27	$4.80	Jan - Dec
United States ($3.00 - $3.28/$4.05 - $4.20)...........	130,000	$ 3.12	$4.11	Jan - Dec
United States ($3.28 - $3.45/$4.20 - $4.49)...........	110,000	$ 3.35	$4.37	Jan - Dec
United States ($3.44 - $3.44/$6.69 - $6.69)...........	5,000	$ 3.44	$6.69	Apr - Sep
Canada ($3.28 - $3.39/$6.85 - $7.13)......	20,000	$ 3.34	$6.99	Jan - Dec
Canada ($3.38 - $3.57/$6.10 - $6.89)......	80,000	$ 3.49	$6.52	Jan - Dec
Canada ($3.45 - $3.52/$4.27 - $4.89)......	90,000	$ 3.48	$4.34	Jan - Dec
Canada ($3.66 - $3.67/$7.24 - $7.68)......	30,000	$ 3.66	$7.44	Apr - Oct
Canada ($3.53 - $3.54/$5.27 - $5.96)......	40,000	$ 3.54	$5.60	Jan - Dec

AREA (RANGE OF FLOOR PRICES/CEILING PRICES)	2004 MMBtu/DAY	Weighted Average Floor Price Per MMBtu	Weighted Average Ceiling Price Per MMBtu	MONTHS OF PRODUCTION
United States ($3.28 - $3.28/$5.74 - $5.81)...........	30,000	$3.28	$5.79	Jan - Dec
United States ($3.28 - $3.28/$6.48 - $6.48)...........	10,000	$3.28	$6.48	Jan - Dec
Canada ($3.65 - $3.65/$5.67 - $5.80)......	20,000	$3.65	$5.73	Jan - Dec
Canada ($3.52 - $3.62/$6.55 - $6.70)......	20,000	$3.57	$6.62	Jan - Dec
Canada ($3.53 - $3.56/$6.05 - $6.30)......	20,000	$3.55	$6.18	Jan - Dec
Canada ($3.47 - $3.56/$7.42 - $7.70)......	30,000	$3.50	$7.59	Jan - Dec

Devon uses a sensitivity analysis technique to evaluate the hypothetical effect that changes in the market value of oil and gas may have on the fair value of its commodity hedging instruments. At January 31, 2003, a 10% increase in the underlying commodities' prices would have reduced the fair value of Devon's commodity hedging instruments by $135 million.

FIXED-PRICE PHYSICAL DELIVERY CONTRACTS

In addition to the commodity hedging instruments described above, Devon also manages its exposure to oil and gas price risks by periodically entering into fixed-price contracts.

Devon has fixed-price physical delivery contracts for the years 2003 through 2011 covering Canadian natural gas production ranging from 8 Bcf to 16 Bcf per year. From 2012 through 2016, Devon also has Canadian gas volumes subject to fixed-price contracts, but the yearly volumes are less than 1 Bcf.

INTEREST RATE RISK

At December 31, 2002, Devon had long-term debt outstanding of $7.6 billion. Of this amount, $6.5 billion, or 85%, bears interest at fixed rates averaging 7%. The remaining $1.1 billion of debt outstanding bears interest at floating rates which averaged 2.5%.

The terms of Devon's various floating rate debt facilities (revolving credit facilities, commercial paper and term loan credit facility) allow interest rates to be fixed at Devon's option for periods of between seven to 180 days. A 10% increase in short-term interest rates on the floating-rate debt outstanding as of

December 31, 2002 would equal approximately 25 basis points. Such an increase in interest rates would increase Devon's 2003 interest expense by approximately $3 million assuming borrowed amounts remain outstanding for all of 2003.

Devon assumed certain interest rate swaps as a result of the Anderson acquisition. Under these interest rate swaps, Devon has swapped a floating rate for a fixed rate. Under such swaps, Devon will record a fixed rate of 6.3% on $98 million of debt in 2003, 6.4% on $79 million of debt in 2004 through 2006 and 6.3% on $24 million of debt in 2007. The amount of gains or losses realized from such swaps are included as increases or decreases to interest expense.

Devon uses a sensitivity analysis technique to evaluate the hypothetical effect that changes in interest rates may have on the fair value of its interest rate swap instruments. At January 31, 2003, a 10% increase in the underlying interest rates would have increased the fair value of Devon's interest rate swaps by $2 million.

The above sensitivity analysis for interest rate risk excludes accounts receivable, accounts payable and accrued liabilities because of the short-term maturity of such instruments.

FOREIGN CURRENCY RISK

Devon's net assets, net earnings and cash flows from its Canadian subsidiaries are based on the U.S. dollar equivalent of such amounts measured in the Canadian dollar functional currency. Assets and liabilities of the Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period.

As a result of the Anderson acquisition, Devon's Canadian subsidiary, Devon Canada, assumed $400 million of fixed-rate long-term debt that is denominated in U.S. dollars. Changes in the currency conversion rate between the Canadian and U.S. dollars between the beginning and end of a reporting period increase or decrease the expected amount of Canadian dollars required to repay the notes. The amount of such increase or decrease is required to be included in determining net earnings for the period in which the exchange rate changes. A $0.03 decrease in the Canadian-to-U.S. dollar exchange rate would cause Devon to record a charge of approximately $20 million in 2003. The $400 million becomes due in March 2011. Until then, the gains or losses caused by the exchange rate fluctuations have no effect on cash flow.

Devon assumed certain foreign currency exchange rate swaps in the Anderson acquisition. A portion of Devon's Canadian gas sales are based on U.S. dollar prices. Therefore, currency fluctuations between the Canadian and U.S. dollars impacts the amount of Canadian dollars received by Devon's Canadian subsidiaries for this gas production. These foreign currency exchange rate swaps mitigate the effect of volatility in the Canadian-to-U.S. dollar exchange rate on Canadian gas revenues. Under these swap agreements, in 2003, Devon will sell $12 million at average Canadian-to-U.S. exchange rates of $0.676, and buy the same amount of dollars at the floating exchange rate. The amount of gains or losses realized from such swaps are included as increases or decreases to realized gas sales. At the December 31, 2002 exchange rate, these swaps would result in a decrease to gas sales during 2003 of approximately $1 million. A further $0.03 decrease in the Canadian-to-U.S. dollar exchange rate would result in an additional decrease to 2003 gas sales of approximately $1 million.

For purposes of the sensitivity analysis described above for changes in the Canadian dollar exchange rate, a change in the rate of $0.03 was used as opposed to a 10% change in the rate. During the last ten years, the Canadian-to-U.S. dollar exchange rate has fluctuated an average of approximately 4% per year, and no year's fluctuation was greater than 7%. The $0.03 change used in the above analysis represents an approximate 4% change in the year-end 2002 rate.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND CONSOLIDATED FINANCIAL STATEMENT SCHEDULES

All financial statement schedules are omitted as they are inapplicable or the required information has been included in the consolidated financial statements or notes thereto.

INDEPENDENT AUDITORS' REPORT

The Board of Directors and Stockholders
Devon Energy Corporation:

We have audited the accompanying consolidated balance sheets of Devon Energy Corporation and subsidiaries (the Company) as of December 31, 2002, 2001 and 2000, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years then ended. 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 Devon Energy Corporation and subsidiaries as of December 31, 2002, 2001 and 2000, and the results of their operations and their cash flows for each of the years then ended, in conformity with accounting principles generally accepted in the United States of America.

As described in Note 1 to the consolidated financial statements, as of January 1, 2001, the Company changed its method of accounting for derivative instruments and hedging activities; and, effective July 1, 2001, adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 141, Business Combinations, and certain provisions of SFAS No. 142, Goodwill and Other Intangible Assets; and effective January 1, 2002, adopted the remaining provisions of SFAS No. 142.

KPMG LLP

Oklahoma City, Oklahoma
February 4, 2003

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	DECEMBER 31, 2002	2001	2000
	(IN MILLIONS, EXCEPT SHARE DATA)		
ASSETS			
Current assets:			
Cash and cash equivalents	$ 292	183	194
Accounts receivable	639	489	562
Inventories	26	20	23
Deferred income taxes	--	--	9
Fair value of financial instruments	4	195	--
Income taxes receivable	56	68	--
Assets of discontinued operations	7	354	--
Investments and other current assets	40	45	40
Total current assets	1,064	1,354	828
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($2,289, $1,929 and $314 excluded from amortization in 2002, 2001 and 2000, respectively)	18,786	14,899	9,091
Less accumulated depreciation, depletion and amortization	7,934	6,137	4,429
	10,852	8,762	4,662
Investment in ChevronTexaco Corporation common stock, at fair value	472	636	599
Fair value of financial instruments	1	31	--
Goodwill	3,555	2,206	289
Assets of discontinued operations	--	--	361
Other assets	281	195	121
Total assets	$16,225	13,184	6,860
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable:			
Trade	$ 376	470	273
Revenues and royalties due to others	261	124	115
Income taxes payable	9	16	64
Accrued interest payable	119	102	23
Merger related expenses payable	12	7	52
Fair value of financial instruments	151	15	--
Liabilities of discontinued operations	--	56	--
Deferred income taxes	--	57	--
Accrued expenses	114	72	50
Total current liabilities	1,042	919	577
Other liabilities	323	172	158
Debentures exchangeable into shares of ChevronTexaco Corporation common stock	662	649	760
Other long-term debt	6,900	5,940	1,289
Deferred revenue	--	51	114
Fair value of financial instruments	18	45	--
Liabilities of discontinued operations	--	--	51
Deferred income taxes	2,627	2,149	634
Stockholders' equity:			
Preferred stock of $1.00 par value ($100 liquidation value) Authorized 4,500,000 shares; issued 1,500,000 in 2002, 2001 and 2000	1	1	1
Common stock of $.10 par value Authorized 400,000,000 shares; issued 160,461,000 in 2002, 129,886,000 in 2001 and 128,638,000 in 2000	16	13	13
Additional paid-in capital	5,178	3,610	3,564
Accumulated deficit	(84)	(147)	(215)
Accumulated other comprehensive loss	(267)	(28)	(85)
Unamortized restricted stock awards	(3)	--	(1)
Treasury stock, at cost: 3,704,000 shares in 2002 and 3,754,000 shares in 2001	(188)	(190)	--
Total stockholders' equity	4,653	3,259	3,277

Commitments and contingencies (Notes 11 and 12)

Total liabilities and stockholders' equity	$16,225	13,184	6,860

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)		
Revenues:			
Oil sales	$ 909	784	906
Gas sales	2,133	1,878	1,474
NGL sales	275	131	154
Marketing and midstream revenues	999	71	53
Total revenues	4,316	2,864	2,587
Operating Costs and Expenses:			
Lease operating expenses	621	467	388
Transportation costs	154	83	53
Production taxes	111	116	103
Marketing and midstream operating costs and expenses	808	47	28
Depreciation, depletion and amortization of property and equipment	1,211	831	662
Amortization of goodwill	--	34	41
General and administrative expenses	219	114	96
Expenses related to mergers	--	1	60
Reduction of carrying value of oil and gas properties	651	979	--
Total operating costs and expenses	3,775	2,672	1,431
Earnings from operations	541	192	1,156
Other Income (Expenses):			
Interest expense	(533)	(220)	(155)
Effects of changes in foreign currency exchange rates	1	(11)	(3)
Change in fair value of financial instruments	28	(2)	--
Impairment of ChevronTexaco Corporation common stock	(205)	--	--
Other income	34	69	40
Net other expenses	(675)	(164)	(118)
Earnings (loss) from continuing operations before income taxes and cumulative effect of change in accounting principle	(134)	28	1,038
Income Tax Expense (Benefit):			
Current	23	48	120
Deferred	(216)	(43)	257
Total income tax expense (benefit)	(193)	5	377
Earnings from continuing operations before cumulative effect of change in accounting principle	59	23	661
Discontinued Operations:			
Results of discontinued operations before income taxes (including net gain on disposal of $31 million in 2002)	54	56	104
Income tax expense	9	25	35
Net results of discontinued operations	45	31	69
Earnings before cumulative effect of change in accounting principle	104	54	730
Cumulative effect of change in accounting principle	--	49	--
Net earnings	104	103	730
Preferred stock dividends	10	10	10
Net earnings applicable to common shareholders	$ 94	93	720

CONSOLIDATED STATEMENTS OF OPERATIONS -- (CONTINUED)

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)		
Basic net earnings per share:			
Earnings from continuing operations	$ 0.32	0.09	5.13
Net results of discontinued operations	0.29	0.25	0.53
Cumulative effect of change in accounting principle	--	0.39	--
Net earnings	$ 0.61	0.73	5.66
Diluted net earnings per share:			
Earnings from continuing operations	0.32	0.09	4.97
Net results of discontinued operations	0.29	0.25	0.53
Cumulative effect of change in accounting principle	--	0.38	--
Net earnings	$ 0.61	0.72	5.50
Weighted average common shares outstanding:			
Basic	155	128	127
Diluted	156	130	132

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	PREFERRED STOCK	COMMON STOCK	ADDITIONAL PAID-IN CAPITAL	ACCUMULATED DEFICIT	ACCUMULATED OTHER COMPREHENSIVE LOSS	UNAMORTIZED RESTRICTED STOCK AWARDS
				(IN MILLIONS)		
Balance as of December 31, 1999	$1	13	3,492	(909)	(65)	--
Comprehensive earnings:						
Net earnings	--	--	--	730	--	--
Other comprehensive earnings (loss), net of tax:						
Foreign currency translation adjustments	--	--	--	--	(10)	--
Minimum pension liability adjustment	--	--	--	--	1	--
Unrealized loss on marketable securities	--	--	--	--	(11)	--
Other comprehensive loss	--	--	--	--	--	--
Comprehensive earnings						
Stock issued	--	--	69	(4)	--	--
Stock repurchased	--	--	--	--	--	--
Tax benefit related to employee stock options	--	--	3	--	--	--
Dividends on common stock	--	--	--	(22)	--	--
Dividends on preferred stock	--	--	--	(10)	--	--
Grant of restricted stock awards	--	--	--	--	--	(5)
Amortization of restricted stock awards	--	--	--	--	--	4
Balance as of December 31, 2000	1	13	3,564	(215)	(85)	(1)
Comprehensive earnings:						
Net earnings	--	--	--	103	--	--
Other comprehensive earnings (loss), net of tax:						
Foreign currency translation adjustments	--	--	--	--	(107)	--
Cumulative effect of change in accounting principle	--	--	--	--	(37)	--
Reclassification adjustment for derivative (gains) losses reclassified into oil and gas sales	--	--	--	--	(20)	--
Change in fair value of financial instruments	--	--	--	--	216	--
Minimum pension liability adjustment	--	--	--	--	(17)	--
Unrealized gain on marketable securities	--	--	--	--	22	--
Other comprehensive earnings	--	--	--	--	--	--
Comprehensive earnings						
Stock issued	--	--	48	--	--	--
Stock repurchased	--	--	(14)	--	--	--
Tax benefit related to employee stock options	--	--	12	--	--	--
Dividends on common stock	--	--	--	(25)	--	--
Dividends on preferred stock	--	--	--	(10)	--	--
Amortization of restricted stock awards	--	--	--	--	--	1
Balance as of December 31, 2001	1	13	3,610	(147)	(28)	--
Comprehensive loss:						
Net earnings	--	--	--	104	--	--
Other comprehensive earnings (loss), net of tax:						
Foreign currency translation adjustments	--	--	--	--	46	--
Reclassification adjustment for derivative losses reclassified into oil and gas sales	--	--	--	--	(39)	--
Change in fair value of financial instruments	--	--	--	--	(217)	--
Minimum pension liability adjustment	--	--	--	--	(54)	--
Unrealized loss on marketable securities	--	--	--	--	(103)	--
Impairment of marketable securities	--	--	--	--	128	--
Other comprehensive loss	--	--	--	--	--	--
Comprehensive loss						
Stock issued	--	3	1,562	--	--	--
Tax benefit related to employee stock options	--	--	6	--	--	--
Dividends on common stock	--	--	--	(31)	--	--

Dividends on preferred stock	--	--	--	(10)	--	--
Grant of restricted stock awards	--	--	--	--	--	(3)
Balance as of December 31, 2002	$1	16	5,178	(84)	(267)	(3)

	TREASURY STOCK	TOTAL STOCKHOLDERS' EQUITY
	(IN MILLIONS)	
Balance as of December 31, 1999	(11)	2,521
Comprehensive earnings:		
Net earnings	--	730
Other comprehensive earnings (loss), net of tax:		
Foreign currency translation adjustments	--	(10)
Minimum pension liability adjustment	--	1
Unrealized loss on marketable securities	--	(11)
Other comprehensive loss	--	(20)
Comprehensive earnings		710
Stock issued	21	86
Stock repurchased	(10)	(10)
Tax benefit related to employee stock options	--	3
Dividends on common stock	--	(22)
Dividends on preferred stock	--	(10)
Grant of restricted stock awards	--	(5)
Amortization of restricted stock awards	--	4
Balance as of December 31, 2000	--	3,277
Comprehensive earnings:		
Net earnings	--	103
Other comprehensive earnings (loss), net of tax:		
Foreign currency translation adjustments	--	(107)
Cumulative effect of change in accounting principle	--	(37)
Reclassification adjustment for derivative (gains) losses reclassified into oil and gas sales	--	(20)
Change in fair value of financial instruments	--	216
Minimum pension liability adjustment	--	(17)
Unrealized gain on marketable securities	--	22
Other comprehensive earnings	--	57
Comprehensive earnings		160
Stock issued	--	48
Stock repurchased	(190)	(204)
Tax benefit related to employee stock options	--	12
Dividends on common stock	--	(25)
Dividends on preferred stock	--	(10)
Amortization of restricted stock awards	--	1
Balance as of December 31, 2001	(190)	3,259
Comprehensive loss:		
Net earnings	--	104
Other comprehensive earnings (loss), net of tax:		
Foreign currency translation adjustments	--	46
Reclassification adjustment for derivative losses reclassified into oil and gas sales	--	(39)
Change in fair value of financial instruments	--	(217)
Minimum pension liability adjustment	--	(54)
Unrealized loss on marketable securities	--	(103)
Impairment of marketable securities	--	128
Other comprehensive loss	--	(239)
Comprehensive loss		(135)
Stock issued	2	1,567
Tax benefit related to employee stock options	--	6
Dividends on common stock	--	(31)

Dividends on preferred stock.................	--	(10)
Grant of restricted stock awards.............	--	(3)
	----	-----
Balance as of December 31, 2002..............	(188)	4,653
	====	=====

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS)		
CASH FLOWS FROM OPERATING ACTIVITIES			
Earnings from continuing operations	$ 59	23	661
Adjustments to reconcile earnings from continuing operations to net cash provided by operating activities:			
Depreciation, depletion and amortization of property and equipment	1,211	831	662
Amortization of goodwill	--	34	41
Accretion of discounts on long-term debt, net	33	26	3
Effects of changes in foreign currency exchange rates	(1)	11	3
Change in fair value of financial instruments	(28)	2	--
Reduction of carrying value of oil and gas properties	651	979	--
Impairment of ChevronTexaco Corporation common stock	205	--	--
Operating cash flows from discontinued operations	28	134	110
Loss (gain) on sale of assets	(2)	2	(1)
Deferred income tax expense (benefit)	(216)	(43)	257
Other	(9)	(3)	4
Changes in assets and liabilities, net of effects of acquisitions of businesses:			
(Increase) decrease in:			
Accounts receivable	(80)	203	(272)
Inventories	10	12	(5)
Income taxes receivable	--	(68)	--
Investments and other current assets	12	(8)	3
(Decrease) increase in:			
Accounts payable	(74)	37	78
Income taxes payable	21	(129)	61
Accrued interest and expenses	36	(46)	2
Deferred revenue	(46)	(63)	8
Long-term other liabilities	(56)	(24)	(26)
Net cash provided by operating activities	1,754	1,910	1,589
CASH FLOWS FROM INVESTING ACTIVITIES			
Proceeds from sale of property and equipment	1,067	41	101
Proceeds from sale of investments	--	--	13
Capital expenditures, including acquisitions of businesses	(3,426)	(5,235)	(1,148)
Discontinued operations (including net proceeds from sale of $336 million in 2002)	316	(91)	(132)
Increase in other assets	(3)	--	(7)
Net cash used in investing activities	(2,046)	(5,285)	(1,173)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from borrowings of long-term debt, net of issuance costs	6,067	6,199	2,580
Principal payments on long-term debt	(5,657)	(2,638)	(2,952)
Issuance of common stock, net of issuance costs	32	48	51
Repurchase of common stock	--	(204)	(10)
Issuance of treasury stock	--	--	25
Dividends paid on common stock	(31)	(25)	(22)
Dividends paid on preferred stock	(10)	(10)	(10)
Decrease in long-term other liabilities	--	--	(52)
Net cash provided by (used in) financing activities	401	3,370	(390)
Effect of exchange rate changes on cash	--	(6)	(1)
Net increase (decrease) in cash and cash equivalents	109	(11)	25
Cash and cash equivalents at beginning of year	183	194	169
Cash and cash equivalents at end of year	$ 292	183	194

See accompanying notes to consolidated financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Accounting policies used by Devon Energy Corporation and subsidiaries ("Devon") reflect industry practices and conform to accounting principles generally accepted in the United States of America. The more significant of such policies are briefly discussed below.

BASIS OF PRESENTATION AND PRINCIPLES OF CONSOLIDATION

Devon is engaged primarily in oil and gas exploration, development and production, and the acquisition of producing properties. Such activities domestically are concentrated in four geographic areas:

- the Permian Basin within Texas and New Mexico;

- the Rocky Mountains area of the United States stretching from the Canadian Border into northern New Mexico

- the Mid-Continent area of the central and southern United States; and

- the Gulf Coast, which includes properties located primarily in the onshore South Texas and South Louisiana areas and offshore in the Gulf of Mexico;

Devon's Canadian activities are located primarily in the Western Canadian Sedimentary Basin, and Devon's international activities -- outside of North America -- are located primarily in Azerbaijan, Brazil, China and West Africa.

Devon also has a marketing and midstream business which is responsible for marketing natural gas, crude oil and NGLs, and the construction and operation of pipelines, storage and treating facilities and gas processing plants. These services are performed for Devon as well as for unrelated third parties.

Devon's share of the assets, liabilities, revenues and expenses of affiliated partnerships and the accounts of its wholly-owned subsidiaries are included in the accompanying consolidated financial statements. All significant intercompany accounts and transactions have been eliminated in consolidation.

USE OF ESTIMATES IN THE PREPARATION OF FINANCIAL STATEMENTS

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Significant items subject to such estimates and assumptions include the carrying value of oil and gas properties, goodwill impairment assessment, deferred income taxes, valuation of derivative instruments, and obligations related to employee benefits. Actual amounts could differ from those estimates.

PROPERTY AND EQUIPMENT

Devon follows the full cost method of accounting for its oil and gas properties. Accordingly, all costs incidental to the acquisition, exploration and development of oil and gas properties, including costs of undeveloped leasehold, dry holes and leasehold equipment, are capitalized. Internal costs incurred that are directly identified with acquisition, exploration and development activities undertaken by Devon for its own account, and which are not related to production, general corporate overhead or similar activities, are also capitalized. For the years 2002, 2001 and 2000, such internal costs capitalized totaled $97 million, $77 million and $62 million, respectively.

Unproved properties are excluded from amortized capitalized costs until it is determined whether or not proved reserves can be assigned to such properties. Devon assesses its unproved properties for impairment at least annually.

Net capitalized costs are limited to the estimated future net revenues, discounted at 10% per annum, from proved oil, natural gas and natural gas liquids reserves plus the cost of properties not subject to amortization. Such limitations are imposed separately on a country-by-country basis and are tested quarterly. Capitalized costs are depleted by an equivalent unit-of-production method, converting gas to oil at the ratio of six thousand cubic feet of natural gas to one barrel of oil. Depletion is calculated using the capitalized costs plus the estimated future expenditures (based on current costs) to be incurred in developing proved reserves, and the estimated dismantlement and abandonment costs, net of estimated salvage values. No gain or loss is recognized upon disposal of oil and gas properties unless such disposal significantly alters the relationship between capitalized costs and proved reserves. All costs related to production activities, including workover costs incurred solely to maintain or increase levels of production from an existing completion interval, are charged to expense as incurred.

Depreciation and amortization of other property and equipment, including leasehold improvements, are provided using the straight-line method based on estimated useful lives from three to 39 years.

MARKETABLE SECURITIES AND OTHER INVESTMENTS

Devon accounts for certain investments in debt and equity securities by following the requirements of Statement of Financial Accounting Standards ("SFAS") No. 115, Accounting for Certain Investments in Debt and Equity Securities. This standard requires that, except for debt securities classified as "held-to-maturity," investments in debt and equity securities must be reported at fair value. As a result, Devon's investment in approximately 7.1 million shares of ChevronTexaco Corporation ("ChevronTexaco") common stock, which is classified as "available-for-sale," is reported at fair value. Except for unrealized losses that are determined to be "other than temporary", the tax effected unrealized gain or loss is recognized in other comprehensive loss and reported as a separate component of stockholders' equity. Devon's investments in other short-term securities are also classified as "available-for-sale."

The market value of Devon's investment in ChevronTexaco as of December 31, 2002, was approximately $472 million. Devon acquired these shares in its August 1999 acquisition of PennzEnergy Company. The shares are deposited with an exchange agent for possible exchange for $760 million of debentures that are exchangeable into the ChevronTexaco shares. The debentures, which mature in August 2008, were also assumed by Devon in the 1999 PennzEnergy acquisition.

Devon initially recorded the ChevronTexaco common shares at their market value at the closing date of the PennzEnergy acquisition, which was $95.38 per share, or an aggregate value of $677 million. Since then, as the ChevronTexaco shares have fluctuated in market value, the value of the shares on Devon's balance sheet has been adjusted to the applicable market value. Through September 30, 2002, any decreases in the value of the ChevronTexaco common shares were determined by Devon to be temporary in nature. Therefore, the changes in value were recorded directly to stockholders' equity and were not recorded in Devon's results of operations through September 30, 2002.

The determination that a decline in value of the ChevronTexaco shares is temporary or other than temporary is subjective and influenced by many factors. Among these factors are the significance of the decline as a percentage of the original cost, the length of time the stock price has been below original cost, the performance of the stock price in relation to the stock price of its competitors within the industry and the market in general, and whether the decline is attributable to specific adverse conditions affecting ChevronTexaco.

Beginning in July 2002, the market value of ChevronTexaco common stock began what has ultimately become a significant decline. The price per share decreased from $88.50 at June 30, 2002, to $69.25 per share at September 30, 2002, and to $66.48 per share at December 31, 2002. The year-end price of $66.48 represents a 25% decline since June 30, 2002, and a 30% decline from the original valuation in August 1999. As a result of the continuation of the decline in value during the fourth quarter of 2002, Devon determined that the decline is other than temporary, as that term is defined by accounting rules. Therefore, the $205 million cumulative decrease in the value of the ChevronTexaco common shares from the initial acquisition in August 1999 to December 31, 2002, was recorded as a noncash charge to Devon's results of operations in the fourth quarter of 2002. Net of the applicable tax benefit, the charge reduced net earnings by $128 million.

Depending on the future performance of ChevronTexaco's common stock, Devon may be required to record additional noncash charges in future periods if Devon determines that a decline in the value of such stock is other than temporary.

GOODWILL

Goodwill represents the excess of the purchase price of business combinations over the fair value of the net assets acquired.

Effective January 1, 2002, Devon adopted the remaining provisions of Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets (SFAS No. 142). Under SFAS No. 142, goodwill and intangible assets with indefinite useful lives are no longer amortized as they were prior to 2002, but are instead tested for impairment at least annually.

As of January 1, 2002, Devon had unamortized goodwill in the amount of $2.2 billion, which was subject to the transition goodwill impairment assessment provisions of SFAS No. 142. Devon has completed its assessment of the fair value of its reporting units and compared such fair value to each reporting unit's carrying value, including goodwill, as of January 1, 2002. Based on this assessment, no transitional impairment of the carrying value of goodwill was required.

As a result of the January 2002 Mitchell acquisition, goodwill increased to $3.6 billion at the end of 2002. Devon performed its annual assessment of goodwill in the fourth quarter of 2002. Based on this assessment, no impairment of goodwill was required.

Following is a reconciliation of reported net income and the related earnings per share amounts assuming the provisions of SFAS No. 142 had been adopted as of January 1, 2000.

	FOR THE YEAR ENDED DECEMBER 31, 2002	2001	2000
	(IN MILLIONS, EXCEPT PER SHARE DATA)		
Net earnings applicable to common shareholders, as reported	$ 94	93	720
Add back amortization of goodwill	--	34	41
Net earnings applicable to common shareholders, as adjusted	$ 94	127	761
Basic earnings per share:			
Net earnings applicable to common shareholders, as reported	$0.61	0.73	5.66
Amortization of goodwill	--	0.26	0.32
Net earnings applicable to common shareholders, as adjusted	$0.61	0.99	5.98
Diluted earnings per share:			
Net earnings applicable to common shareholders, as reported	$0.61	0.72	5.50
Amortization of goodwill	--	0.26	0.31
Net earnings applicable to common shareholders, as adjusted	$0.61	0.98	5.81

REVENUE RECOGNITION AND GAS BALANCING

Oil and gas revenues are recognized when sold. During the course of normal operations, Devon and other joint interest owners of natural gas reservoirs will take more or less than their respective ownership share of the natural gas volumes produced. These volumetric imbalances are monitored over the lives of the wells' production capability. If an imbalance exists at the time the wells' reserves are depleted, settlements are made among the joint interest owners under a variety of arrangements.

Devon follows the sales method of accounting for gas production imbalances. A liability is recorded when Devon's excess takes of natural gas volumes exceed its estimated remaining recoverable reserves. No receivables are recorded for those wells where Devon has taken less than its ownership share of gas production.

Marketing and midstream revenues are recorded on the sales method at the time products are sold or services are provided to third parties. Revenues and expenses attributable to Devon's NGL purchase and processing contracts are reported on a gross basis since Devon takes title to the products and has risks and rewards of ownership.

HEDGING ACTIVITIES

Devon has periodically entered into oil and gas financial instruments and foreign exchange rate swaps to manage its exposure to oil and gas price volatility. The foreign exchange rate swaps mitigate the effect of volatility in the Canadian-to-U.S. dollar exchange rate on certain Canadian gas revenues that are based on U.S. dollar prices.

As of January 1, 2001, Devon adopted the provisions of SFAS No. 133, Accounting for Derivative Instruments and Certain Hedging Activities and SFAS No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activities, an Amendment of SFAS No. 133. SFAS Nos. 133 and 138 require that all derivative instruments be recorded on the balance sheet at their respective fair values. In accordance with the transition provisions of SFAS No. 133, Devon recorded a net-of-tax cumulative-effect-type adjustment of $37 million loss in accumulated other comprehensive loss ("AOCL") to recognize the fair value of all derivatives that were designated as cash-flow hedging instruments. Additionally, Devon recorded a net-of-tax cumulative-effect-type adjustment to net earnings of $49 million gain ($0.39 per basic share and $0.38 per diluted share) related to the fair value of derivative instruments that did not qualify as hedges. This gain related principally to the option embedded in Devon's debentures that are exchangeable into shares of ChevronTexaco common stock.

All derivatives are recognized on the balance sheet at their fair value. The majority of Devon's derivatives that qualify for hedge accounting treatment are either "cash flow" hedges or "foreign currency cash flow" hedges (collectively, "cash flow hedges"). Devon designates its cash flow hedge derivatives as such on the date the derivative contract is entered into or the date of a business combination which includes cash flow hedges. Devon formally documents all relationships between hedging instruments and hedged items, as well as its risk-management objective and strategy for undertaking various hedge transactions. Devon also assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items.

During 2002 and 2001, there were no gains or losses reclassified into earnings as a result of the discontinuance of hedge accounting treatment for any of Devon's derivatives.

By using derivative instruments to hedge exposures to changes in commodity prices and exchange rates, Devon exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. To mitigate this risk, the hedging instruments are usually placed with counterparties that Devon believes are minimal credit risks. It is Devon's policy to only enter into derivative contracts with investment grade rated counterparties deemed by management to be competent and competitive market makers.

Market risk is the adverse effect on the value of a derivative instrument that results from a change in interest rates, commodity prices, or currency exchange rates. The market risk associated with commodity price and foreign exchange contracts is managed by establishing and monitoring parameters that limit the types and degree of market risk that may be undertaken. The oil and gas reference prices upon which the hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by Devon.

Devon does not hold or issue derivative instruments for speculative trading purposes. Substantially all of Devon's commodity price swaps and costless price collars, interest rate swaps, and foreign exchange rate swaps have been designated as cash flow hedges. Changes in the fair value of these derivatives are reported on the balance sheet in AOCL. These amounts are reclassified to oil and gas sales or interest expense when the forecasted transaction takes place.

During the third quarter of 2001, Devon entered into foreign exchange forward contracts to mitigate the effect of volatility in the Canadian-to-U.S. dollar exchange rate on the Anderson acquisition. Under SFAS No. 133, these derivative instruments were not considered hedges and, as such, the realized gain of $30 million from settling these contracts is included in the 2001 consolidated statement of operations as other income.

Also, during the third quarter of 2001, Devon entered into interest rate locks to reduce exposure to the variability in market interest rates, specifically U.S. Treasury rates, in anticipation of the sale of the debt securities discussed in Note 6. These derivative instruments were designated as cash flow hedges. A $28 million loss was incurred on these interest rate locks. This loss will be amortized into interest expense using the effective interest method over the life of the debt securities.

Devon recorded in its statements of operations a gain of $28 million and a loss of $2 million for the years ended December 31, 2002 and 2001, respectively, for the change in fair value of derivative instruments that do not qualify for hedge accounting treatment, as well as the ineffectiveness of derivatives that do qualify as hedges.

As of December 31, 2002, $147 million of net deferred losses on derivative instruments accumulated in AOCL are expected to be reclassified to earnings during the next 12 months. Transactions and events expected to occur over the next 12 months that will necessitate reclassifying these derivatives' losses to earnings are primarily the production and sale of oil and gas which includes the production hedged under the various derivative instruments. The maximum term over which Devon is hedging exposures to the variability of cash flows for commodity price risk is 24 months.

STOCK OPTIONS

Devon applies the intrinsic value-based method of accounting prescribed by Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations, in accounting for its fixed plan stock options. As such, compensation expense would be recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price. SFAS No. 123, Accounting for Stock-Based Compensation, established accounting and disclosure requirements using a fair value-based method of accounting for stock-based employee compensation plans. As allowed by SFAS No. 123, Devon has elected to continue to apply the intrinsic value-based method of accounting described above, and has adopted the disclosure requirements of SFAS No. 123.

Had Devon elected the fair value provisions of SFAS No. 123 and recognized compensation expense over the vesting period based on the fair value of the stock options granted as of their grant date, Devon's 2002, 2001 and 2000 pro forma net earnings and pro forma net earnings per share would have differed from the amounts actually reported as shown in the following table.

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)		
Net earnings available to common shareholders:			
As reported	$ 94	93	720
Pro forma	$ 78	79	702
Net earnings per share available to common shareholders:			
As reported:			
Basic	$0.61	0.73	5.66
Diluted	$0.61	0.72	5.50
Pro forma:			
Basic	$0.51	0.62	5.51
Diluted	$0.50	0.61	5.36

MAJOR PURCHASERS

No purchaser accounted for over 10% of revenues in 2002. In 2001 and 2000, Enron Capital and Trade Resource Corporation accounted for 16% and 21%, respectively, of Devon's combined oil, gas and natural gas liquids sales.

On December 2, 2001, Enron Corp. and certain of its subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code. Prior to this date, Devon had terminated substantially all of its agreements to sell oil, gas or NGLs to Enron related entities. Devon incurred $3 million of losses in 2001 for sales to Enron related subsidiaries which were not collected prior to the bankruptcy filing.

INCOME TAXES

Devon accounts for income taxes using the asset and liability method, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases, as well as the future tax consequences attributable to the future utilization of existing tax net operating loss and other types of carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. U.S. deferred income taxes have not been provided on undistributed earnings of foreign operations which are being permanently reinvested.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses are reported net of amounts allocated to working interest owners of the oil and gas properties operated by Devon and net of amounts capitalized pursuant to the full cost method of accounting.

DISCONTINUED OPERATIONS

Effective January 1, 2002, Devon was required to adopt SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, which supersedes both SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of and the accounting and reporting provisions of APB Opinion No. 30, Reporting the Results of Operations-Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions, for the disposal of a segment of a business (as previously defined in that Opinion).

On April 18, 2002, Devon sold its Indonesian operations to PetroChina Company Limited for total cash consideration of $250 million. On October 25, 2002, Devon sold its Argentine operations to Petroleo Brasileiro S.A. for total cash consideration of $90 million. On January 27, 2003, Devon sold its Egyptian operations to IPR Transoil Corporation for total cash consideration of $7 million.

Under the provisions of SFAS No. 144, Devon has reclassified its Indonesian, Argentine and Egyptian activities as discontinued operations. This reclassification affects not only the 2002 presentation of financial results, but also the presentation of all prior periods' results.

The major classes of assets and liabilities of these discontinued operations as of December 31, 2002, 2001 and 2000 and revenues from these discontinued operations in 2002, 2001 and 2000 are presented below:

	AS OF DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS)		
MAJOR CLASSES OF ASSETS AND LIABILITIES			
Cash	$--	10	34
Accounts receivable	7	48	36
Inventories	--	21	24
Other current assets	--	2	12
Property and equipment, net of accumulated depreciation, depletion and amortization	--	266	248
Other assets	--	7	7
Total assets	$ 7	354	361
Accounts payable -- trade	$--	41	49
Income taxes payable	--	14	2
Accrued expense	--	1	1
Other liabilities	--	7	6
Deferred income taxes	--	(7)	(7)
Total liabilities	$--	56	51

	FOR THE YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS)		
REVENUES			
Oil sales	$72	174	173
Gas sales	7	12	11
NGL sales	1	1	--
Total revenues	$80	187	184

NET EARNINGS PER COMMON SHARE

Basic earnings per share is computed by dividing income available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted earnings per share reflects the potential dilution that could occur if Devon's dilutive outstanding stock options were exercised (calculated using the treasury stock method) and if Devon's zero coupon convertible senior debentures were converted to common stock.

The following table reconciles the net earnings and common shares outstanding used in the calculations of basic and diluted earnings per share for 2002, 2001 and 2000.

	NET EARNINGS APPLICABLE TO COMMON STOCKHOLDERS	WEIGHTED AVERAGE COMMON SHARES OUTSTANDING	NET EARNINGS PER SHARE
		(IN MILLIONS)	
YEAR ENDED DECEMBER 31, 2002:			
Basic earnings per share	$ 94	155	0.61
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	--	1	
Diluted earnings per share	$ 94	156	0.61
YEAR ENDED DECEMBER 31, 2001:			
Basic earnings per share	$ 93	128	0.73
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	--	2	
Diluted earnings per share	$ 93	130	0.72
YEAR ENDED DECEMBER 31, 2000:			
Basic earnings per share	$720	127	5.66
Dilutive effect of:			
Potential common shares issuable upon conversion of senior convertible debentures (the increase in net earnings is net of income tax expense of $3)	5	3	
Potential common shares issuable upon the exercise of outstanding stock options	--	2	
Diluted earnings per share	$725	132	5.50

The senior convertible debentures included in the 2000 dilution calculations were not included in the 2002 and 2001 dilution calculations because the inclusion was anti-dilutive.

Certain options to purchase shares of Devon's common stock have been excluded from the dilution calculations because the options' exercise price exceeded the average market price of Devon's common stock during the applicable year. The following information relates to these options.

	2002	2001	2000
Options excluded from dilution calculation (in millions)	5	3	1
Range of exercise prices	$45.49 - $89.66	$48.13 - $89.66	$55.54 - $89.66
Weighted average exercise price	$ 50.85	$ 56.11	$ 66.64

The excluded options for 2002 expire between January 24, 2003 and December 2, 2012.

COMPREHENSIVE EARNINGS OR LOSS

Devon's comprehensive earnings or loss information is included in the accompanying consolidated statements of stockholders' equity. A summary of accumulated other comprehensive earnings or loss as of

December 31, 2002, 2001 and 2000, and changes during each of the years then ended, is presented in the following table.

	FOREIGN CURRENCY TRANSLATION ADJUSTMENTS	CHANGE IN FAIR VALUE OF FINANCIAL INSTRUMENTS	MINIMUM PENSION LIABILITY ADJUSTMENTS	UNREALIZED GAIN (LOSS) ON MARKETABLE SECURITIES	TOTAL
			(IN MILLIONS)		
Balance as of December 31, 1999	$ (28)	--	(1)	(36)	(65)
2000 activity	(10)	--	1	(18)	(27)
Deferred taxes	--	--	--	7	7
2000 activity, net of deferred taxes	(10)	--	1	(11)	(20)
Balance as of December 31, 2000	(38)	--	--	(47)	(85)
2001 activity	(107)	243	(28)	36	144
Deferred taxes	--	(84)	11	(14)	(87)
2001 activity, net of deferred taxes	(107)	159	(17)	22	57
Balance as of December 31, 2001	(145)	159	(17)	(25)	(28)
2002 activity	46	(379)	(85)	41	(377)
Deferred taxes	--	123	31	(16)	138
2002 activity, net of deferred taxes	46	(256)	(54)	25	(239)
Balance as of December 31, 2002	$ (99)	(97)	(71)	--	(267)

The 2002 activity for unrealized gain (loss) on marketable securities includes additional unrealized losses of $164 million ($103 million net of taxes), offset by the recognition of a $205 million loss ($128 million net of taxes) in the statement of operations during 2002. The recognized loss was due to the impairment of the ChevronTexaco common stock owned by Devon.

FOREIGN CURRENCY TRANSLATION ADJUSTMENTS

The assets and liabilities of certain foreign subsidiaries are prepared in their respective local currencies and translated into U.S. dollars based on the current exchange rate in effect at the balance sheet dates, while income and expenses are translated at average rates for the periods presented. Translation adjustments have no effect on net income and are included in accumulated other comprehensive loss.

DIVIDENDS

Dividends on Devon's common stock were paid in 2002, 2001 and 2000 at a per share rate of $0.05 per quarter. As adjusted for the pooling-of-interests method of accounting followed for the 2000 Santa Fe Snyder merger, annual dividends per share for 2002, 2001 and 2000 were $0.20, $0.20 and $0.17, respectively.

STATEMENTS OF CASH FLOWS

For purposes of the consolidated statements of cash flows, Devon considers all highly liquid investments with original maturities of three months or less to be cash equivalents.

COMMITMENTS AND CONTINGENCIES

Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

Environmental expenditures are expensed or capitalized in accordance with accounting principles generally accepted in the United States of America. Liabilities for these expenditures are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. Reference is made to Note 11 for a discussion of amounts recorded for these liabilities.

IMPACT OF RECENTLY ISSUED ACCOUNTING STANDARDS NOT YET ADOPTED

In June 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. SFAS No. 143 requires liability recognition for retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms, and natural gas processing plants. The obligations included within the scope of SFAS No. 143 are those for which a company faces a legal obligation for settlement. The initial measurement of the asset retirement obligation is to be the discounted present fair value, defined as "the price that an entity would have to pay a willing third party of comparable credit standing to assume the liability in a current transaction other than in a forced or liquidation sale."

The asset retirement cost equal to the discounted fair value of the retirement obligation is to be capitalized as part of the cost of the related long-lived asset and allocated to expense using a systematic and rational method.

Devon will adopt SFAS No. 143 effective January 1, 2003 using a cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation.

Devon previously estimated costs of dismantlement, removal, site reclamation, and other similar activities in the total costs that are subject to depreciation, depletion, and amortization. However, Devon did not record a separate asset or liability for such amounts. Upon adoption of SFAS No. 143 on January 1, 2003, Devon expects to record a cumulative-effect-type adjustment for an increase to net earnings of between $10 million and $30 million, net of deferred tax expense of between $5 million and $15 million. Additionally, Devon expects to establish an asset retirement obligation of between $425 million and $475 million, an increase to property and equipment of between $375 million and $425 million and a decrease in accumulated DD&A of between $65 million and $95 million.

The FASB issued Statement No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections, on April 30, 2002. SFAS No. 145 will be effective for fiscal years beginning after May 15, 2002. This statement rescinds SFAS No. 4, Reporting Gains and Losses From Extinguishment of Debt, and requires that all gains and losses from extinguishment of debt should be classified as extraordinary items only if they meet the criteria in APB No. 30. Applying APB No. 30 will distinguish transactions that are part of an entity's recurring operations from those that are unusual or infrequent or that meet the criteria for classification as an extraordinary item. Any gain or loss on extinguishment of debt that was classified as an extraordinary item in prior periods presented that does not meet the criteria in APB No. 30 for classification as an extraordinary item must be reclassified. Devon early adopted the provisions related to SFAS No. 145 during the fourth quarter 2002. With the adoption of SFAS No. 145, a loss of $6 million resulting from extinguishment of debt in 1999 was reclassified from extraordinary loss to interest expense, and 1999's current income tax expense was reduced by the $2 million tax benefit related to the loss from early extinguishment.

The FASB issued Statement No. 146, Accounting for Costs Associated with Exit or Disposal Activities, in June 2002. SFAS No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force Issue No. 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs incurred in a Restructuring). SFAS No. 146 applies to costs incurred in an "exit activity", which includes, but is not limited to, a restructuring, or a "disposal activity" covered by SFAS No. 144.

SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred. Previously, under Issue 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. Statement No. 146 also establishes that fair value is the objective for initial measurement of the liability.

The provisions of SFAS No. 146 are effective for exit or disposal activities that are initiated after December 31, 2002. Devon currently has no such exit or disposal activities planned.

In November 2002, the FASB issued Interpretation No. 45, Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others, an interpretation of FASB Statements No. 5, 57 and 107 and a rescission of FASB Interpretation No. 34. This Interpretation elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees issued. The Interpretation also clarifies that a guarantor is required to recognize, at inception of a guarantee, a liability for the fair value of the obligation undertaken. The initial recognition and measurement provisions of the Interpretation are applicable to guarantees issued or modified after December 31, 2002 and are not expected to have a material effect on Devon's financial statements. The disclosure requirements are effective for financial statements of interim and annual periods ending after December 31, 2002.

In December 2002, the FASB issued SFAS No. 148, Accounting for Stock-Based Compensation -- Transition and Disclosure, an amendment of FASB Statement No.
123. This Statement amends FASB Statement No. 123, Accounting for Stock-Based Compensation, to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, this Statement amends the disclosure requirements of Statement No. 123 to require prominent disclosures in both annual and interim financial statements. Certain of the disclosure modifications are required for fiscal years ending after December 15, 2002 and are included in the notes to these consolidated financial statements.

In January 2003, the FASB issued Interpretation No. 46, Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51. Interpretation No. 46 requires a company to consolidate a variable interest entity if the company has a variable interest (or combination of variable interests) that will absorb a majority of the entity's expected losses if they occur, receive a majority of the entity's expected residual returns if they occur, or both. A direct or indirect ability to make decisions that significantly affect the results of the activities of a variable interest entity is a strong indication that a company has one or both of the characteristics that would require consolidation of the variable interest entity. Interpretation No. 46 also requires additional disclosures regarding variable interest entities. The new interpretation is effective immediately for variable interest entities created after January 31, 2003, and is effective in the first interim or annual period beginning after June 15, 2003, for variable interest entities in which a company holds a variable interest that it acquired before February 1, 2003. Devon owns no interests in variable interest entities, and therefore this new interpretation will not affect Devon's consolidated financial statements.

RECLASSIFICATION

Certain of the 2001 and 2000 amounts in the accompanying consolidated financial statements have been reclassified to conform to the 2002 presentation.

2. BUSINESS COMBINATIONS AND PRO FORMA INFORMATION

MITCHELL ENERGY & DEVELOPMENT CORP. MERGER

On January 24, 2002, Devon completed its acquisition of Mitchell Energy & Development Corp. ("Mitchell"). Under the terms of this merger, Devon issued approximately 30 million shares of Devon common stock and paid $1.6 billion in cash to the Mitchell stockholders. The cash portion of the acquisition was funded from borrowings under a $3.0 billion senior unsecured term loan credit facility (see Note 6).

Devon acquired Mitchell for the significant development and exploitation projects in each of Mitchell's core areas, increased marketing and midstream operations and increased exposure to the North American natural gas market.

The calculation of the purchase price and the allocation to assets and liabilities as of January 24, 2002, are shown below.

	(IN MILLIONS, EXCEPT SHARE PRICE)
Calculation and allocation of purchase price:	
Shares of Devon common stock issued to Mitchell stockholders	30
Average Devon stock price	$50.95
Fair value of common stock issued	$1,512
Cash paid to Mitchell stockholders, calculated at $31 per outstanding common share of Mitchell	1,573
Fair value of Devon common stock and cash to be issued to Mitchell stockholders	3,085
Plus estimated acquisition costs incurred	84
Plus fair value of Mitchell employee stock options assumed by Devon	27
Total purchase price	3,196
Plus fair value of liabilities assumed by Devon:	
Current liabilities	190
Long-term debt	506
Other long-term liabilities	128
Deferred income taxes	796
Total purchase price plus liabilities assumed	$4,816
Fair value of assets acquired by Devon:	
Current assets	$ 169
Proved oil and gas properties	1,535
Unproved oil and gas properties	639
Marketing and midstream facilities and equipment	1,000
Other property and equipment	15
Other assets	103
Goodwill (none deductible for income taxes)	1,355
Total fair value of assets acquired	$4,816

ANDERSON EXPLORATION LTD. ACQUISITION

On October 15, 2001, Devon accepted all of the Anderson common shares tendered by Anderson stockholders in the tender offer, which represented approximately 97% of the outstanding Anderson common shares. On October 17, 2001, Devon completed its acquisition of Anderson by a compulsory acquisition under the Canada Business Corporations Act of the remaining 3% of Anderson common shares. The cost to Devon of acquiring Anderson's outstanding common shares and paying for the intrinsic value of Anderson's outstanding options and appreciation rights was approximately $3.5 billion, which was funded from the sale of $3.0 billion of debt securities and borrowings under the $3.0 billion senior unsecured term loan credit facility (see Note 6).

Devon acquired Anderson to increase the scope of its Canadian operations, for the exposure to north Canada's exploratory areas and to increase exposure to the North American natural gas market.

The calculation of the purchase price and the allocation to assets and liabilities as of October 15, 2001, are shown below.

	(IN MILLIONS, EXCEPT SHARE PRICE)
Calculation and allocation of purchase price:	
Number of Anderson common shares outstanding	132
Acquisition price per share	$25.68
Cash paid to Anderson stockholders	$3,386
Cash paid to settle Anderson employees' stock options and appreciation rights	92
	3,478
Plus estimated acquisition costs incurred	35
Total purchase price	3,513
Plus fair value of liabilities assumed by Devon:	
Current liabilities	251
Long-term debt	1,017
Other long-term liabilities	3
Fair value of financial instruments	30
Deferred income taxes	1,407
Total purchase price plus liabilities assumed	$6,221
Fair value of assets acquired by Devon:	
Current assets	$ 214
Proved oil and gas properties	2,605
Unproved oil and gas properties	1,432
Other property and equipment	21
Goodwill (none deductible for income tax purposes)	1,949
Total fair value of assets acquired	$6,221

PRO FORMA INFORMATION

Set forth in the following table is certain unaudited pro forma financial information for the years ended December 31, 2002 and 2001. The information has been prepared assuming the Anderson acquisition and the Mitchell merger were consummated on January 1, 2001. All pro forma information is based on estimates and assumptions deemed appropriate by Devon. The pro forma information is presented for illustrative purposes only. If the transactions had occurred in the past, Devon's operating results might have been different from those presented in the following table. The pro forma information should not be relied upon as an indication of the operating results that Devon would have achieved if the transactions had occurred on January 1, 2001. The pro forma information also should not be used as an indication of the future results that Devon will achieve after the transactions.

The following should be considered in connection with the pro forma financial information presented:

- On February 12, 2001, Anderson acquired all of the outstanding shares of Numac Energy Inc. The summary unaudited pro forma combined statements of operations do not include any results from Numac's operations prior to February 12, 2001.

- Devon's historical results of operations for the year ended December 31, 2001 include $34 million of amortization expense for goodwill related to previous mergers. As of January 1, 2002, in accordance with new accounting pronouncements, such goodwill is no longer amortized, but instead is tested for impairment at least annually. No goodwill amortization expense has been recognized in the pro forma statements of operations for the goodwill related to the Anderson acquisition or the Mitchell merger.

	PRO FORMA INFORMATION YEAR ENDED DECEMBER 31	
	2002	2001
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS AND PRODUCTION VOLUMES) (UNAUDITED)	
REVENUES		
Oil sales	$ 911	1,059
Gas sales	2,155	3,133
Natural gas liquids sales	280	306
Marketing and midstream revenues	1,069	1,238
Total revenues	4,415	5,736
OPERATING COSTS AND EXPENSES		
Lease operating expenses	625	705
Transportation costs	157	155
Production taxes	112	148
Marketing and midstream operating costs and expenses	873	1,085
Depreciation, depletion and amortization of property and equipment	1,230	1,358
Amortization of goodwill	--	34
General and administrative expenses	224	205
Expenses related to mergers	--	1
Reduction of carrying value of oil and gas properties	651	1,136
Total operating costs and expenses	3,872	4,827
Earnings from operations	543	909
OTHER INCOME (EXPENSES)		
Interest expense	(534)	(507)
Effects of changes in foreign currency exchange rates	1	(19)
Change in fair value of financial instruments	28	(15)
Impairment of ChevronTexaco Corporation common stock	(205)	--
Other income	34	68
Net other expenses	(676)	(473)
Earnings (loss) from continuing operations before income tax expense (benefit) and cumulative effect of change in accounting principle	$ (133)	436
INCOME TAX EXPENSE (BENEFIT)		
Current	23	55
Deferred	(215)	96
Total income tax expense (benefit)	(192)	151
Earnings from continuing operations before cumulative effect of change in accounting principle	59	285
DISCONTINUED OPERATIONS		
Results of discontinued operations before income taxes (including net gain on disposal of $31 million in 2002)	54	56
Total income tax expense	9	25
Net results of discontinued operations	45	31
Earnings before cumulative effect of change in accounting principle	104	316
Cumulative effect of change in accounting principle	--	49
Net earnings	104	365
Preferred stock dividends	10	10
Net earnings applicable to common stockholders	$ 94	355

	PRO FORMA INFORMATION YEAR ENDED DECEMBER 31	
	2002	2001
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS AND PRODUCTION VOLUMES) (UNAUDITED)	
Basic earnings per average common share outstanding:		
Earnings from continuing operations	$ 0.31	1.75
Net results of discontinued operations	0.29	0.21
Cumulative effect of change in accounting principle	--	0.31
Net earnings	$ 0.60	2.27
Diluted earnings per average common share outstanding:		
Earnings from continuing operations	$ 0.31	1.73
Net results of discontinued operations	0.29	0.20
Cumulative effect of change in accounting principle	--	0.30
Net earnings	$ 0.60	2.23
Weighted average common shares outstanding -- basic	157	157
Weighted average common shares outstanding -- diluted	158	164
Production volumes:		
Oil (MMBbls)	42	50
Gas (Bcf)	771	802
NGLs (MMBbls)	20	17
MMBoe	191	201

SANTA FE SNYDER MERGER

Devon closed its merger with Santa Fe Snyder Corporation ("Santa Fe Snyder") on August 29, 2000. The merger was accounted for using the pooling-of-interests method of accounting for business combinations. Accordingly, all operational and financial information contained herein includes the combined amounts for Devon and Santa Fe Snyder for all periods presented.

Devon issued approximately 41 million shares of its common stock to the former stockholders of Santa Fe Snyder based on an exchange ratio of 0.22 shares of Devon common stock for each share of Santa Fe Snyder common stock. Because the merger was accounted for using the pooling-of-interests method, all combined share information has been retroactively restated to reflect the exchange ratio.

During 2000, Devon recorded a pre-tax charge of $60 million ($37 million net of tax) for direct costs related to the Santa Fe Snyder merger.

3. SUPPLEMENTAL CASH FLOW INFORMATION

Cash payments (refunds) for interest and income taxes in 2002, 2001 and 2000 are presented below:

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS)		
Interest paid	$248	118	155
Income taxes paid (refunded)	$(12)	185	80

The 2002 Mitchell acquisition and the 2001 Anderson acquisition involved non-cash consideration as presented below:

	2002	2001
	(IN MILLIONS)	
Value of common stock issued	$1,512	--
Employee stock options assumed	27	--
Liabilities assumed	824	1,301
Deferred tax liability created	796	1,407
Fair value of assets acquired with non-cash consideration	$3,159	2,708

4. ACCOUNTS RECEIVABLE

The components of accounts receivable included the following:

	DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS)		
Oil, gas and natural gas liquids revenue accruals	$422	275	402
Joint interest billings	102	145	123
Marketing and midstream revenues	73	1	--
Other	52	72	41
	649	493	566
Allowance for doubtful accounts	(10)	(4)	(4)
Net accounts receivable	$639	489	562

5. PROPERTY AND EQUIPMENT

Property and equipment included the following:

	DECEMBER 31, 2002	2001	2000
	(IN MILLIONS)		
Oil and gas properties:			
Subject to amortization	$15,020	12,580	8,555
Not subject to amortization:			
Acquired in 2002	730	--	--
Acquired in 2001	1,338	1,638	--
Acquired in 2000	52	65	74
Acquired prior to 2000	169	226	240
Accumulated depreciation, depletion and amortization	(7,796)	(6,048)	(4,382)
Net oil and gas properties	9,513	8,461	4,487
Other property and equipment	1,477	390	222
Accumulated depreciation and amortization	(138)	(89)	(47)
Net other property and equipment	1,339	301	175
Property and equipment, net of accumulated depreciation, depletion and amortization	$10,852	8,762	4,662

The costs not subject to amortization relate to unproved properties which are excluded from amortized capital costs until it is determined whether or not proved reserves can be assigned to such properties. The excluded properties are assessed for impairment at least annually. Subject to industry conditions, evaluation of most of these properties, and the inclusion of their costs in the amortized capital costs is expected to be completed within five years.

Depreciation, depletion and amortization of property and equipment consisted of the following components:

	YEAR ENDED DECEMBER 31, 2002	2001	2000
	(IN MILLIONS)		
Depreciation, depletion and amortization of oil and gas properties	$1,106	793	632
Depreciation and amortization of other property and equipment	97	30	23
Amortization of other assets	8	8	7
Total	$1,211	831	662

6. LONG-TERM DEBT AND RELATED EXPENSES

A summary of Devon's long-term debt is as follows:

	DECEMBER 31, 2002	DECEMBER 31, 2001	DECEMBER 31, 2000
	(IN MILLIONS)		
Borrowings under credit facilities with banks	$ --	50	147
Commercial paper borrowings	--	75	--
$3 billion term loan credit facility	1,135	1,046	--
Debentures exchangeable into shares of ChevronTexaco Corporation common stock:			
4.90% due August 15, 2008	444	444	444
4.95% due August 15, 2008	316	316	316
Discount on exchangeable debentures	(98)	(111)	--
Zero coupon convertible senior debentures exchangeable into shares of Devon Energy Corp. common stock, 3.875% due June 27, 2020	388	374	360
Other debentures and notes:			
6.75% due February 15, 2004	211	--	--
8.05% due June 15, 2004	125	125	125
7.25% due July 18, 2005	111	110	--
7.42% due October 1, 2005	--	23	--
7.57% due October 4, 2005	--	31	--
10.25% due November 1, 2005	236	236	250
6.55% due August 2, 2006	127	126	--
8.75% due June 15, 2007	--	175	175
10.125% due November 15, 2009	177	177	200
6.75% due March 15, 2011	400	400	--
6.875% due September 30, 2011	1,750	1,750	--
7.875% due September 30, 2031	1,250	1,250	--
7.95% due April 15, 2032	1,000	--	--
Fair value adjustment on 8.05% notes related to interest rate swap	5	--	--
Net (discount) premium on other debentures and notes	(15)	(8)	32
	7,562	6,589	2,049
Less amount classified as current	--	--	--
Long-term debt	$7,562	6,589	2,049

Maturities of long-term debt as of December 31, 2002, excluding the $113 million of discounts net of premiums and the $5 million fair value adjustment, are as follows (in millions):

2003	$ --
2004	336
2005	347
2006	1,262
2007	--
2008 and thereafter	5,725
Total	$7,670

CREDIT FACILITIES WITH BANKS

Devon has $1 billion of unsecured long-term credit facilities (the "Credit Facilities"). The Credit Facilities include a U.S. facility of $725 million (the "U.S. Facility") and a Canadian facility of $275 million (the "Canadian Facility"). The $725 million U.S. Facility consists of a Tranche A facility of $200 million and a Tranche B facility of $525 million. On June 7, 2002, Devon renewed the $525 million Tranche B facility and its $275 million Canadian facility.

The Tranche A facility matures on October 15, 2004. Devon may borrow funds under the Tranche B facility until June 5, 2003 (the "Tranche B Revolving Period"). Devon may request that the Tranche B Revolving Period be extended an additional 364 days by notifying the agent bank of such request between 30 and 60 days prior to the end of the Tranche B Revolving Period. On June 6, 2003, at the end of the Tranche B Revolving Period, Devon may convert the then outstanding balance under the Tranche B facility to a two-year term loan by paying the Agent a fee of 12.5 basis points. The applicable borrowing rate would be at LIBOR plus 125 basis points. On December 31, 2002, there were no borrowings outstanding under the $725 million U.S. Facility. The available capacity under the U.S. Facility as of December 31, 2002, net of $25 million of outstanding letters of credit, was $700 million.

Devon may borrow funds under the $275 million Canadian Facility until June 5, 2003 (the "Canadian Facility Revolving Period"). Devon may request that the Canadian Facility Revolving Period be extended an additional 364 days by notifying the agent bank of such request between 30 and 60 days prior to the end of the Canadian Facility Revolving Period. Debt outstanding as of the end of the Canadian Facility Revolving Period is payable in semiannual installments of 2.5% each for the following five years, with the final installment due five years and one day following the end of the Canadian Facility Revolving Period. On December 31, 2002, there were no borrowings under the $275 million Canadian facility.

Under the terms of the Credit Facilities, Devon has the right to reallocate up to $100 million of the unused Tranche B facility maximum credit amount to the Canadian Facility. Conversely, Devon also has the right to reallocate up to $100 million of unused Canadian Facility maximum credit amount to the Tranche B Facility.

Amounts borrowed under the Credit Facilities bear interest at various fixed rate options that Devon may elect for periods up to six months. Such rates are generally less than the prime rate. Devon may also elect to borrow at the prime rate. The Credit Facilities provide for an annual facility fee of $1.4 million that is payable quarterly. The weighted average interest rate on the $50 million and $147 million outstanding under the previous facilities at December 31, 2001 and 2000, was 4.8% and 6.1%, respectively.

The agreements governing the Credit Facilities contain certain covenants and restrictions, including a maximum debt-to-capitalization ratio. At December 31, 2002, Devon was in compliance with such covenants and restrictions.

LETTER OF CREDIT FACILITY

On July 25, 2002, Devon renewed and increased its letter of credit and revolving bank facility ("LOC Facility") for its Canadian operations. This C$150 million LOC Facility will be used primarily by Devon's wholly-owned subsidiaries, Devon Canada Corporation and Northstar Energy Corporation, to issue letters of credit. As of December 31, 2002, C$109 million ($69 million converted to U.S. dollars using the December 31, 2002 exchange rate) of letters of credit were issued under the LOC Facility primarily for Canadian drilling commitments.

COMMERCIAL PAPER

On August 29, 2000, Devon entered into a commercial paper program. Devon may borrow up to $725 million under the commercial paper program. Total borrowings under the U.S. Facility and the commercial paper program may not exceed $725 million. The commercial paper borrowings may have terms of up to 365 days and bear interest at rates agreed to at the time of the borrowing. The interest rate is based on a standard index such as the Federal Funds Rate, London Interbank Offered Rate (LIBOR), or the money market rate as found on the commercial paper market. As of December 31, 2002, Devon had no commercial paper debt outstanding. As of December 31, 2001, Devon had $75 million of borrowings under its commercial paper program at an average rate of 3.5%. Because Devon had the intent and ability to refinance the balance due with borrowings under its U.S. Facility, the $75 million outstanding under the commercial paper program was classified as long-term debt on the December 31, 2001 consolidated balance sheet.

$3 BILLION TERM LOAN CREDIT FACILITY

On October 12, 2001, Devon and its wholly-owned financing subsidiary Devon Financing Corporation, U.L.C. ("Devon Financing") entered into a new $3 billion senior unsecured term loan credit facility. The facility has a term of five years. Devon and Devon Financing may borrow funds under this facility subject to conditions usual in commercial transactions of this nature, including the absence of any default under this facility. Interest on borrowings under this facility may be based, at the borrower's option, on LIBOR or on UBS Warburg LLC's base rate (which is the higher of UBS Warburg's prime commercial lending rate and the weighted average of rates on overnight Federal funds transactions with members of the Federal Reserve System plus 0.50%).

This $3 billion facility includes various rate options which can be elected by Devon, including a rate based on LIBOR plus a margin. Through June 17, 2002, this margin was fixed at 100 basis points. Thereafter, the margin is based on Devon's debt rating. Based on Devon's current debt rating, the margin after June 17, 2002, is 100 basis points. As of December 31, 2002, the average interest rate on this facility was 2.5%.

Prior to December 31, 2001, Devon borrowed $1 billion under this term loan credit facility to partially fund the Anderson acquisition. The remaining $2 billion of availability was utilized upon the closing of the Mitchell acquisition on January 24, 2002. As of December 31, 2002, $1.9 billion of the original $3 billion balance had been retired. The primary sources of the repayments were the issuance of $1 billion of debt securities, of which $0.8 billion was used to pay down debt, and $1.4 billion from the sale of certain oil and gas properties, of which $1.1 billion was used to pay down debt.

The terms of this facility require repayment of the debt during the following periods:

	(IN MILLIONS)
April 15, 2006	$ 335
October 15, 2006	800
Total	$1,135

This credit facility contains certain covenants and restrictions, including a maximum allowed debt-to-capitalization ratio as defined in the credit facility. At December 31, 2002, Devon was in compliance with such covenants and restrictions.

EXCHANGEABLE DEBENTURES

The exchangeable debentures consist of $444 million of 4.90% debentures and $316 million of 4.95% debentures. The exchangeable debentures were issued on August 3, 1998 and mature August 15, 2008. The exchangeable debentures were callable beginning August 15, 2000, initially at 104.0% of principal and at prices declining to 100.5% of principal on or after August 15, 2007. The exchangeable debentures are exchangeable at the option of the holders at any time prior to maturity, unless previously redeemed, for shares of ChevronTexaco common stock. In lieu of delivering ChevronTexaco common stock, Devon may, at its option, pay to any holder an amount of cash equal to the market value of the ChevronTexaco common stock to satisfy the exchange request. However, at maturity, the holders will receive an amount at least equal to the face value of the debt outstanding. Such amount will either be in cash or in a combination of cash and ChevronTexaco common stock.

As of December 31, 2002, Devon beneficially owned approximately 7.1 million shares of ChevronTexaco common stock. These shares have been deposited with an exchange agent for possible exchange for the exchangeable debentures. Each $1,000 principal amount of the exchangeable debentures is exchangeable into 9.3283 shares of ChevronTexaco common stock, an exchange rate equivalent to $107 7/32 per share of ChevronTexaco stock.

The exchangeable debentures were assumed as part of the PennzEnergy merger. The fair values of the exchangeable debentures were determined as of August 17, 1999, based on market quotations. The fair value approximated the face value of the exchangeable debentures. As a result, no premium or discount was recorded on these exchangeable debentures. However, pursuant to the adoption of SFAS No. 133 effective January 1, 2001, these debentures were revalued as of August 17, 1999. Under SFAS No. 133, the total fair value of the debentures was allocated between the interest-bearing debt and the option to exchange ChevronTexaco common stock that is embedded in the debentures. Accordingly, the debt portion of the debentures was reduced by $140 million as of August 17, 1999. This discount is being accreted using the effective interest method, and has raised the effective interest rate on the debentures to 7.76% in 2001 compared to 4.92% prior to 2001.

ZERO COUPON CONVERTIBLE DEBENTURES

In June 2000, Devon privately sold zero coupon convertible senior debentures. The debentures were sold at a price of $464.13 per debenture with a yield to maturity of 3.875% per annum. Each of the 760,000 debentures is convertible into 5.7593 shares of Devon common stock. Devon may call the debentures at any time after five years, and a debenture holder has the right to require Devon to repurchase the debentures after five, 10 and 15 years, at the issue price plus accrued original issue discount and interest. The first put date is June 26, 2005, at an accreted value of $427 million. Devon has the right to satisfy its obligation by paying cash or issuing shares of Devon common stock with a value equal to its obligation. Devon's proceeds were approximately $346 million, net of debt issuance costs of approximately

$7 million. Devon used the proceeds from the sale of these debentures to pay down other domestic long-term debt.

OTHER DEBENTURES AND NOTES

In connection with the Mitchell acquisition, Devon assumed $211 million of 6.75% senior notes due 2004. The fair value of these senior notes approximated the face value. As a result, no premium or discount was recorded on these senior notes.

In June 1999, Devon issued $125 million of 8.05% notes due 2004. The notes were issued for 98.758% of face value and Devon received total proceeds of $122 million after deducting related costs and expenses of $2 million. The notes, which mature June 15, 2004, are redeemable, upon not less than thirty nor more than sixty days notice, as a whole or in part, at the option of Devon. The notes are general unsecured obligations of Devon.

In connection with the Anderson acquisition, Devon assumed $702 million of senior notes. The table below summarizes the debt assumed, the fair value of the debt at October 15, 2001, and the effective interest rate of the debt assumed after determining the fair values of the respective notes using October 15, 2001, market interest rates. The premiums and discounts are being amortized or accreted using the effective interest method. All of the notes are general unsecured obligations of Devon.

DEBT ASSUMED	FAIR VALUE OF DEBT ASSUMED	EFFECTIVE RATE OF DEBT ASSUMED
	(IN MILLIONS)	
7.25% senior notes due 2005	$116	6.3%
7.42% senior notes due 2005	$ 24	5.7%
7.57% senior notes due 2005	$ 33	5.7%
6.55% senior notes due 2006	$129	6.5%
6.75% senior notes due 2011	$400	6.8%

Devon recorded a $2 million early retirement premium in 2001 related to the early retirement of the above 7.57% and 7.42% senior notes.

The 10.25% and 10.125% debentures were assumed as part of the PennzEnergy merger. The fair values of the respective debentures were determined using August 17, 1999, market interest rates. As a result, premiums were recorded on these debentures which lowered their effective interest rates to 8.3% and 8.9% on the $236 million of 10.25% debentures and $177 million of 10.125% debentures, respectively. The premiums are being amortized using the effective interest method.

During October 2001, Devon repurchased $14 million and $23 million of its 10.25% debentures and 10.125% debentures, respectively. Devon recorded an early retirement premium of $5 million related to this repurchase.

On October 3, 2001, Devon, through Devon Financing, sold $1.75 billion of 6.875% notes due September 30, 2011 and $1.25 billion of 7.875% debentures due September 30, 2031. The debt securities are unsecured and unsubordinated obligations of Devon Financing. Devon has fully and unconditionally guaranteed on an unsecured and unsubordinated basis the obligations of Devon Financing under the debt securities. The proceeds from the issuance of these debt securities were used to fund a portion of the Anderson acquisition.

The $3 billion of debt securities were structured in a manner that results in an expected weighted average after-tax borrowing rate of approximately 1.65%.

Interest on the debt securities is payable by Devon Financing semiannually on March 30 and September 30 of each year. The indenture governing the debt securities limits both Devon Financing's and Devon's ability to incur debt secured by liens or enter into mergers or consolidations, or transfer all or substantially all of their respective assets, unless the successor company assumes Devon Financing's or Devon's obligations under the indenture.

On March 25, 2002, Devon sold $1 billion of 7.95% notes due April 15, 2032. The net proceeds received, after discounts and issuance costs, were $986 million. The debt securities are unsecured and unsubordinated obligations of Devon. The net proceeds were partially used to pay down $820 million on Devon's $3 billion term loan credit facility. The remaining $166 million of net proceeds was used in June 2002 to partially fund the early extinguishment of $175 million of 8.75% senior subordinated notes due June 15, 2007. The notes were redeemed at 104.375% of principal, or approximately $183 million.

INTEREST EXPENSE

Following are the components of interest expense for the years 2002, 2001 and 2000:

	YEAR ENDED DECEMBER 31, 2002	2001	2000
	(IN MILLIONS)		
Interest based on debt outstanding	$499	200	157
Accretion (amortization) of debt discount (premium), net	13	10	(4)
Facility and agency fees	2	1	3
Amortization of capitalized loan costs	8	3	2
Capitalized interest	(4)	(3)	(3)
Early retirement premiums	8	7	--
Other	7	2	--
Total interest expense	$533	220	155

EFFECTS OF CHANGES IN FOREIGN CURRENCY EXCHANGE RATES

The $400 million of 6.75% fixed-rate senior notes referred to in the first table of this note are payable by a Canadian subsidiary of Devon. However, the notes are denominated in U.S. dollars. Until their retirement in mid-January 2000, $225 million of additional notes denominated in U.S. dollars were owed by another Canadian subsidiary. Changes in the exchange rate between the U.S. dollar and the Canadian dollar from the dates the notes were issued or assumed as part of an acquisition to the dates of repayment increase or decrease the expected amount of Canadian dollars eventually required to repay the notes. Such changes in the Canadian dollar equivalent of the debt are required to be included in determining net earnings for the period in which the exchange rate changed. The rate of conversion of Canadian dollars to U.S. dollars increased in 2002 and declined in 2001 and 2000. Therefore, $1 million of reduced expense was recorded in 2002 and $11 million and $3 million of increased expense was recorded in 2001 and 2000, respectively.

7. INCOME TAXES

At December 31, 2002, Devon had the following carryforwards available to reduce future income taxes:

TYPES OF CARRYFORWARD	YEARS OF EXPIRATION	CARRYFORWARD AMOUNTS
		(IN MILLIONS)
Net operating loss - U.S. federal	2008 - 2021	$ 10
Net operating loss - various states	2003 - 2016	$119
Net operating loss - Canada	2005 - 2009	$119
Net operating loss - International	Indefinite	$ 63
Minimum tax credits	Indefinite	$164

All of the carryforward amounts shown above have been utilized for financial purposes to reduce the deferred tax liability.

The earnings (loss) before income taxes and the components of income tax expense (benefit) for the years 2002, 2001 and 2000 were as follows:

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS)		
Earnings (loss) from continuing operations before income taxes:			
U.S.	$ 354	458	872
Canada	(515)	(357)	156
International	27	(73)	10
Total	$(134)	28	1,038
Current income tax expense (benefit):			
U.S. federal	$ (34)	23	107
Various states	11	6	6
Canada	28	8	2
International	18	11	5
Total current tax expense	23	48	120
Deferred income tax expense (benefit):			
U.S. federal	56	124	152
Various states	(14)	(32)	33
Canada	(253)	(145)	67
International	(5)	10	5
Total deferred tax expense (benefit)	(216)	(43)	257
Total income tax expense (benefit)	$(193)	5	377

The taxes on the results of discontinued operations presented in the accompanying statements of operations were all related to foreign operations.

Total income tax expense (benefit) differed from the amounts computed by applying the U.S. federal income tax rate to earnings (loss) before income taxes as a result of the following:

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS)		
Expected income tax (benefit) based on U.S. statutory tax rate of 35%	$ (47)	10	363
Benefit from disposition of certain foreign assets	--	--	(46)
Financial expenses not deductible for income tax purposes	--	12	15
Dividends received deduction	(5)	(5)	(5)
Nonconventional fuel source credits	(19)	(19)	(8)
State income taxes	7	4	15
Taxation on foreign operations	(121)	5	22
Other	(8)	(2)	21
Total income tax expense (benefit)	$(193)	5	377

The tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities at December 31, 2002, 2001 and 2000 are presented below:

	DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS)		
Deferred tax assets:			
Net operating loss carryforwards	$ 78	39	123
Minimum tax credit carryforwards	164	118	85
Long-term debt	--	6	17
Fair value of financial instruments	46	7	--
Pension benefit obligation	42	11	--
Other	53	26	95
Total deferred tax assets	383	207	320
Deferred tax liabilities:			
Property and equipment, principally due to nontaxable business combinations, differences in depreciation, and the expensing of intangible drilling costs for tax purposes	(2,863)	(2,189)	(694)
ChevronTexaco Corporation common stock	(147)	(213)	(167)
Other	--	(11)	(84)
Total deferred tax liabilities	(3,010)	(2,413)	(945)
Net deferred tax liability	$(2,627)	(2,206)	(625)

As shown in the above table, Devon has recognized $383 million of deferred tax assets as of December 31, 2002. Such amount consists primarily of $242 million of various carryforwards available to offset future income taxes. The carryforwards include federal net operating loss carryforwards, the majority of which do not begin to expire until 2008, state net operating loss carryforwards which expire primarily between 2003 and 2016, Canadian carryforwards which expire primarily in 2008, International carryforwards which have no expiration and minimum tax credit carryforwards which have no expiration. The tax benefits of carryforwards are recorded as an asset to the extent that management assesses the utilization of such carryforwards to be "more likely than not." When the future utilization of some portion of the carryforwards is determined not to be "more likely than not," a valuation allowance is provided to reduce the recorded tax benefits from such assets.

Devon expects the tax benefits from the net operating loss carryforwards to be utilized between 2003 and 2008. Such expectation is based upon current estimates of taxable income during this period, considering limitations on the annual utilization of these benefits as set forth by tax regulations. Significant changes in such estimates caused by variables such as future oil and gas prices or capital expenditures could alter the timing of the eventual utilization of such carryforwards. There can be no assurance that Devon will generate any specific level of continuing taxable earnings. However, management believes that Devon's future taxable income will more likely than not be sufficient to utilize substantially all its tax carryforwards prior to their expiration.

8. STOCKHOLDERS' EQUITY

The authorized capital stock of Devon consists of 400 million shares of common stock, par value $.10 per share (the "Common Stock"), and 4.5 million shares of preferred stock, par value $1.00 per share. The preferred stock may be issued in one or more series, and the terms and rights of such stock will be determined by the Board of Directors.

There were 16 million Exchangeable Shares issued on December 10, 1998, in connection with the Northstar Energy Corporation combination. As of year-end 2002, 14 million of the Exchangeable Shares had been exchanged for shares of Devon's common stock. The Exchangeable Shares have rights identical to those of Devon's common stock and are exchangeable at any time into Devon's common stock on a one-for-one basis.

Effective August 17, 1999, Devon issued 1.5 million shares of 6.49% cumulative preferred stock, Series A, to holders of PennzEnergy 6.49% cumulative preferred stock, Series A. Dividends on the preferred stock are cumulative from the date of original issue and are payable quarterly, in cash, when declared by the Board of Directors. The preferred stock is redeemable at the option of Devon at any time on or after June 2, 2008, in whole or in part, at a redemption price of $100 per share, plus accrued and unpaid dividends to the redemption date.

As discussed in Note 2, there were approximately 30 million shares of Devon common stock issued on January 24, 2002, in connection with the Mitchell acquisition. Also, Devon's Board of Directors has designated a certain number of shares of the preferred stock as Series A Junior Participating Preferred Stock (the "Series A Junior Preferred Stock") in connection with the adoption of the shareholder rights plan described later in this note. Effective January 22, 2002, the Board voted to increase the designated shares from one million to two million. At December 31, 2002, there were no shares of Series A Junior Preferred Stock issued or outstanding. The Series A Junior Preferred Stock is entitled to receive cumulative quarterly dividends per share equal to the greater of $10 or 100 times the aggregate per share amount of all dividends (other than stock dividends) declared on Common Stock since the immediately preceding quarterly dividend payment date or, with respect to the first payment date, since the first issuance of Series A Junior Preferred Stock. Holders of the Series A Junior Preferred Stock are entitled to 100 votes per share (subject to adjustment to prevent dilution) on all matters submitted to a vote of the stockholders. The Series A Junior Preferred Stock is neither redeemable nor convertible. The Series A Junior Preferred Stock ranks prior to the Common Stock but junior to all other classes of Preferred Stock.

STOCK OPTION PLANS

Devon has outstanding stock options issued to key management and professional employees under three stock option plans adopted in 1988, 1993 and 1997 (the "1988 Plan," the "1993 Plan" and the

"1997 Plan"). Options granted under the 1988 Plan and 1993 Plan remain exercisable by the employees owning such options, but no new options will be granted under these plans. At December 31, 2002, there were 13,000 and 309,000 options outstanding under the 1988 Plan and the 1993 Plan, respectively.

On May 21, 1997, Devon's stockholders adopted the 1997 Plan and reserved two million shares of Common Stock for issuance thereunder. On December 9, 1998, Devon's stockholders voted to increase the reserved number of shares to three million. On August 17, 1999, Devon's stockholders voted to increase the reserved number of shares to six million. On August 29, 2000, Devon's stockholders voted to increase the reserved number of shares to 10 million.

The exercise price of stock options granted under the 1997 Plan may not be less than the estimated fair market value of the stock at the date of grant. Options granted are exercisable during a period established for each grant, which period may not exceed 10 years from the date of grant. Under the 1997 Plan, the grantee must pay the exercise price in cash or in Common Stock, or a combination thereof, at the time that the option is exercised. The 1997 Plan is administered by a committee comprised of non-management members of the Board of Directors. The 1997 Plan expires on April 25, 2007. As of December 31, 2002, there were 7,477,000 options outstanding under the 1997 Plan. There were 1,237,000 options available for future grants as of December 31, 2002.

In addition to the stock options outstanding under the 1988 Plan, 1993 Plan and 1997 Plan, there were approximately 1,327,000, 774,000, 1,314,000 and 17,000 stock options outstanding at the end of 2002 that were assumed as part of the Mitchell acquisition, the Santa Fe Snyder merger, the PennzEnergy merger and the Northstar combination, respectively.

A summary of the status of Devon's stock option plans as of December 31, 2000, 2001 and 2002, and changes during each of the years then ended, is presented below.

	OPTIONS OUTSTANDING		OPTIONS EXERCISABLE	
	NUMBER OUTSTANDING (IN THOUSANDS)	WEIGHTED AVERAGE EXERCISE PRICE	NUMBER EXERCISABLE (IN THOUSANDS)	WEIGHTED AVERAGE EXERCISE PRICE
Balance at December 31, 1999	8,554	$38.20	7,064	$39.55
Options granted	1,625	$51.43		
Options exercised	(2,489)	$33.11		
Options forfeited	(334)	$60.35		
Balance at December 31, 2000	7,356	$41.84	6,025	$40.72
Options granted	2,601	$35.43		
Options exercised	(1,505)	$31.13		
Options forfeited	(268)	$62.77		
Balance at December 31, 2001	8,184	$41.09	5,516	$41.93
Options granted	2,807	$45.77		
Options assumed in the Mitchell acquisition	1,554	$26.82		
Options exercised	(899)	$29.33		
Options forfeited	(415)	$47.12		
Balance at December 31, 2002	11,231	$41.00	6,991	$40.05

The weighted average fair values of options granted during 2002, 2001 and 2000 were $15.25, $13.17 and $28.73, respectively. The fair value of each option grant was estimated for disclosure purposes on the date of grant using the Black-Scholes Option Pricing Model with the following assumptions for 2002, 2001 and 2000, respectively: risk-free interest rates of 3.2%, 3.8% and 5.5%; dividend yields of 0.4%, 0.6% and 0.4%; expected lives of five, five and five years; and volatility of the price of the underlying common stock of 41.8%, 42.2% and 40.0%.

The following table summarizes information about Devon's stock options which were outstanding, and those which were exercisable, as of December 31, 2002:

	OPTIONS OUTSTANDING			OPTIONS EXERCISABLE	
RANGE OF EXERCISE PRICES	NUMBER OUTSTANDING	WEIGHTED AVERAGE REMAINING LIFE	WEIGHTED AVERAGE EXERCISE PRICE	NUMBER EXERCISABLE	WEIGHTED AVERAGE EXERCISE PRICE
	(IN THOUSANDS)			(IN THOUSANDS)	
$10.270 - $25.667	1,157	2.70 Years	$ 18.63	1,157	$18.63
$29.125 - $33.381	956	6.12 Years	$ 30.87	956	$30.87
$34.375 - $39.773	3,281	6.74 Years	$ 35.40	1,735	$35.72
$40.483 - $49.950	3,566	6.99 Years	$ 46.00	1,244	$45.82
$50.142 - $59.813	1,772	5.88 Years	$ 53.04	1,404	$53.36
$60.150 - $89.660	499	4.36 Years	$ 70.79	495	$70.87
	11,231	6.11 Years	$ 41.00	6,991	$40.05

SHAREHOLDER RIGHTS PLAN

Under Devon's shareholder rights plan, stockholders have one right for each share of Common Stock held. The rights become exercisable and separately transferable ten business days after a) an announcement that a person has acquired, or obtained the right to acquire, 15% or more of the voting shares outstanding, or b) commencement of a tender or exchange offer that could result in a person owning 15% or more of the voting shares outstanding.

Each right entitles its holder (except a holder who is the acquiring person) to purchase either (a) 1/100 of a share of Series A Preferred Stock for $75.00, subject to adjustment or, (b) Devon Common Stock with a value equal to twice the exercise price of the right, subject to adjustment to prevent dilution. In the event of certain merger or asset sale transactions with another party or transactions which would increase the equity ownership of a shareholder who then owned 15% or more of Devon, each Devon right will entitle its holder to purchase securities of the merging or acquiring party with a value equal to twice the exercise price of the right.

The rights, which have no voting power, expire on April 16, 2005. The rights may be redeemed by Devon for $.01 per right until the rights become exercisable.

9. FINANCIAL INSTRUMENTS

The following table presents the carrying amounts and estimated fair values of Devon's financial instruments at December 31, 2002, 2001 and 2000.

	2002		2001		2000	
	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
			(IN MILLIONS)			
Investments	$ 479	479	644	644	606	606
Oil and gas price hedge agreements	$ (144)	(144)	225	225	--	(58)
Interest rate swap agreements	$ (5)	(5)	(9)	(9)	--	--
Electricity hedge agreements	$ (2)	(2)	(12)	(12)	--	--
Foreign exchange hedge agreements	$ (1)	(1)	(4)	(4)	--	(1)
Embedded option in exchangeable debentures	$ (12)	(12)	(34)	(34)	--	--
Long-term debt	$(7,562)	(8,425)	(6,589)	(6,699)	(2,049)	(2,050)

The following methods and assumptions were used to estimate the fair values of the financial instruments in the above table. The carrying values of cash and cash equivalents, accounts receivable and accounts payable (including income taxes payable and accrued expenses) included in the accompanying consolidated balance sheets approximated fair value at December 31, 2002, 2001 and 2000.

Investments -- The fair values of investments are primarily based on quoted market prices.

Oil and Gas Price Hedge Agreements -- The fair values of the oil and gas price hedges are based on either (a) an internal discounted cash flow calculation, (b) quotes obtained from the counterparty to the hedge agreement or
(c) quotes provided by brokers.

Interest Rate Swap Agreements -- The fair values of the interest rate swaps are based on quotes obtained from the counterparty to the swap agreement.

Electricity Hedge Agreements -- The fair values of the electricity hedges are based on an internal discounted cash flow calculation.

Foreign Exchange Hedge Agreements -- The fair values of the foreign exchange agreements are based on either (a) an internal discounted cash flow calculation or (b) quotes obtained from brokers.

Embedded Option in Exchangeable Debentures -- The fair values of the embedded options are based on quotes obtained from brokers.

Long-term Debt -- The fair values of the fixed-rate long-term debt have been estimated based on quotes obtained from brokers or by discounting the principal and interest payments at rates available for debt of similar terms and maturity. The fair values of the floating-rate long-term debt are estimated to approximate the carrying amounts due to the fact that the interest rates paid on such debt are generally set for periods of three months or less.

Devon's total hedged positions as of January 31, 2003 are set forth in the following tables.

PRICE SWAPS

Through various price swaps, Devon has fixed the price it will receive on a portion of its natural gas production in 2003. These swaps will result in a fixed price of $3.23 per Mcf on 97,148 Mcf per day of domestic production during 2003. Where necessary, the prices related to these swaps have been adjusted for certain transportation costs that are netted against the price recorded by Devon, and the price has also been adjusted for the Btu content of the gas production that has been hedged.

COSTLESS PRICE COLLARS

Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2003 and 2004 oil and natural gas production. The following tables include information on these collars. The floor and ceiling prices related to domestic oil production are based on NYMEX. The NYMEX price is the monthly average of settled prices on each trading day for West Texas Intermediate Crude oil delivered at Cushing, Oklahoma. The gas prices shown in the following table have been adjusted to a NYMEX-based price, using Devon's estimates of differentials between NYMEX and the specific regional indices upon which the collars are based. The floor and ceiling prices related to the domestic collars are based on various regional first-of-the-month price indices as published monthly by Inside FERC. The floor and ceiling prices related to the Canadian collars are based on the AECO index as published by the Canadian Gas Price Reporter.

If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. Any such settlements will either increase or decrease Devon's oil or gas revenues for the period. Because Devon's gas volumes are often sold at prices that differ from the related regional indices, and due to differing Btu content of gas production, the floor and ceiling prices of the various collars do not reflect actual limits of Devon's realized prices for the production volumes related to the collars.

The floor and ceiling prices in the following tables are weighted averages of all the various collars.

OIL PRODUCTION

		WEIGHTED AVERAGE	
YEAR	BBLS/DAY	FLOOR PRICE PER PER BBL	CEILING PRICE PER PER BBL
2003	53,537	$22.26	$28.14
2004	4,000	$20.00	$27.00

GAS PRODUCTION

		WEIGHTED AVERAGE	
YEAR	MMBTU/DAY	FLOOR PRICE PER PER MMBTU	CEILING PRICE PER PER MMBTU
2003	655,096	$3.34	$5.11
2004	130,000	$3.47	$6.44

INTEREST RATE SWAPS

Devon assumed certain interest rate swaps as a result of the Anderson acquisition. Under these interest rate swaps, Devon has swapped a floating rate for a fixed rate. Under such swaps, Devon will record a fixed rate of 6.3% on $98 million of debt in 2003, 6.4% on $79 million of debt in 2004 through

2006 and 6.3% on $24 million of debt in 2007. The amount of gains or losses realized from such swaps are included as increases or decreases to interest expense.

Devon has also entered into an interest rate swap on its $125 million 8.05% senior notes due in 2004 to swap a fixed interest rate for a variable interest rate. The variable interest rate on this instrument is based on LIBOR plus a margin of 336 basis points.

FOREIGN CURRENCY EXCHANGE RATE SWAPS

Devon assumed certain foreign currency exchange rate swaps in the Anderson acquisition. These swaps require Devon to sell $12 million at average Canadian-to-U.S. exchange rates of $0.676, and buy the same amount of dollars at the floating exchange rate, in 2003.

10. RETIREMENT PLANS

Devon has non-contributory defined benefit retirement plans (the "Basic Plans") which include U.S. and Canadian employees meeting certain age and service requirements. The benefits are based on the employee's years of service and compensation. During 2002, Devon established a funding policy regarding the Basic Plans such that it would contribute the amount of funds necessary so that the Basic Plans' assets would be equal to the related accumulated benefit obligation by the end of 2004. As of December 31, 2002, the Basic Plans' accumulated benefit obligation totaled $363 million, which was $82 million more than the related assets. Devon's intentions are to fund this deficit over the two-year period ending December 31, 2004. The actual amount of contributions required during this period will depend on investment returns from the plan assets during the same period.

Devon also has separate defined benefit retirement plans (the "Supplementary Plans") which are non-contributory and include only certain employees whose benefits under the Basic Plans are limited by income tax regulations. The Supplementary Plans' benefits are based on the employee's years of service and compensation. Devon's funding policy for the Supplementary Plans is to fund the benefits as they become payable. Rights to amend or terminate the Supplementary Plans are retained by Devon.

Devon has defined benefit postretirement plans, which are unfunded, and cover substantially all employees. The plans provide medical and, in some cases, life insurance benefits and are, depending on the type of plan, either contributory or non-contributory. The accounting for the health care plan anticipates future cost-sharing changes that are consistent with Devon's expressed intent to increase, where possible, contributions from future retirees.

The following table sets forth the plans' benefit obligations, plan assets, reconciliation of funded status, amounts recognized in the consolidated balance sheets and the actuarial assumptions used as of December 31, 2002, 2001 and 2000.

	PENSION BENEFITS			OTHER POSTRETIREMENT BENEFITS		
	2002	2001	2000	2002	2001	2000
	(IN MILLIONS)					
Change in benefit obligation:						
Benefit obligation at beginning of year	$210	165	156	33	32	38
Service cost	9	5	7	1	--	1
Interest cost	28	13	11	4	2	2
Participant contributions	--	--	--	1	1	--
Amendments	--	5	4	--	(1)	(2)
Mergers and acquisitions	208	16	--	30	--	--
Special termination benefits	--	3	--	--	--	--
Settlement payments	(15)	(4)	--	--	--	--
Curtailment loss (gain)	2	(1)	(3)	--	--	--
Actuarial loss (gain)	42	17	(3)	6	4	(3)
Benefits paid	(24)	(9)	(7)	(7)	(5)	(4)
Benefit obligation at end of year	460	210	165	68	33	32
Change in plan assets:						
Fair value of plan assets at beginning of year	156	155	158	--	--	--
Actual return on plan assets	(47)	(9)	3	--	--	--
Mergers and acquisitions	145	17	--	--	--	--
Employer contributions	66	6	1	6	4	4
Participant contributions	--	--	--	1	1	--
Settlement payments	(15)	(4)	--	--	--	--
Administrative expenses	--	--	--	--	--	--
Benefits paid	(24)	(9)	(7)	(7)	(5)	(4)
Fair value of plan assets at end of year	281	156	155	--	--	--
Funded status	(179)	(54)	(10)	(68)	(33)	(32)
Unrecognized net actuarial (gain) loss	152	35	10	8	2	(2)
Unrecognized prior service cost	5	6	1	(1)	(1)	(1)
Unrecognized net transition (asset) obligation	--	--	(6)	--	--	1
Net amount recognized	$(22)	(13)	(5)	(61)	(32)	(34)
The net amounts recognized in the consolidated balance sheets consist of:						
(Accrued) prepaid benefit cost	$(22)	(13)	(5)	(61)	(32)	(34)
Additional minimum liability	(118)	(33)	(1)	--	--	--
Intangible asset	5	5	1	--	--	--
Accumulated other comprehensive loss	113	28	--	--	--	--
Net amount recognized	$(22)	(13)	(5)	(61)	(32)	(34)

	PENSION BENEFITS			OTHER POSTRETIREMENT BENEFITS		
	2002	2001	2000	2002	2001	2000
	(IN MILLIONS)					
Assumptions:						
Discount rate	6.72%	7.10%	7.65%	6.75%	7.15%	7.65%
Expected return on plan assets	8.27%	8.27%	8.50%	N/A	N/A	N/A
Rate of compensation increase	4.88%	4.88%	5.00%	5.00%	5.00%	5.00%

As indicated in the prior table, Devon's defined benefit plans had a combined underfunded status of $179 million as of December 31, 2002. Of this $179 million total, $75 million is attributable to the Supplementary Plans which have no plan assets. However, certain trusts have been established to assist Devon in funding the benefit obligations of such Supplementary Plans. At December 31, 2002, these trusts had investments with a market value of approximately $53 million. This total is included in noncurrent other assets in the accompanying consolidated balance sheets.

The accumulated benefit obligation was in excess of plan assets for each of the defined benefit pension plans as of December 31, 2002.

Net periodic benefit cost included the following components:

	PENSION BENEFITS			OTHER POSTRETIREMENT BENEFITS		
	2002	2001	2000	2002	2001	2000
	(IN MILLIONS)					
Service cost	$ 9	5	7	1	--	1
Interest cost	28	13	11	4	2	2
Expected return on plan assets	(24)	(13)	(13)	--	--	--
Amortization of prior service cost	1	1	--	--	--	--
Recognized net actuarial (gain) loss	2	1	--	--	--	--
Net periodic benefit cost	$ 16	7	5	5	2	3

For measurement purposes, a 10% annual rate of increase in the per capita cost of covered health care benefits was assumed in 2002. The rate was assumed to decrease on a pro-rata basis annually to 5% in the year 2008 and remain at that level thereafter. Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plan. A one percentage-point change in assumed health care cost trend rates would have the following effects:

	ONE-PERCENTAGE POINT INCREASE	ONE-PERCENTAGE POINT DECREASE
	(IN MILLIONS)	
Effect on total of service and interest cost components for 2002	$--	$--
Effect on year-end 2002 postretirement benefit obligation	$ 3	$(4)

Devon has incurred certain postemployment benefits to former or inactive employees who are not retirees. These benefits include salary continuance, severance and disability health care and life insurance which are accounted for under SFAS No. 112, Employer's Accounting for Postemployment Benefits. The accrued postemployment benefit liability was approximately $6 million, $7 million and $13 million at the end of 2002, 2001 and 2000, respectively.

Devon has a 401(k) Incentive Savings Plan which covers all domestic employees. At its discretion, Devon may match a certain percentage of the employees' contributions to the plan. The matching percentage is determined annually by the Board of Directors. Devon's matching contributions to the plan were $8 million, $5 million and $5 million for the years ended December 31, 2002, 2001 and 2000, respectively.

Devon has defined contribution pension plans for its Canadian employees. Devon makes a contribution to each employee which is based upon the employee's base compensation and classification. Such contributions are subject to maximum amounts allowed under the Income Tax Act (Canada).

Devon also has a savings plan for its Canadian employees. Under the savings plan, Devon contributes a base percentage amount to all employees and the employee may elect to contribute an additional percentage amount (up to a maximum amount) which is matched by additional Devon contributions.

During the years 2002, 2001 and 2000, Devon's combined contributions to the Canadian defined contribution plan and the Canadian savings plan were $8 million, $3 million and $2 million, respectively.

11. COMMITMENTS AND CONTINGENCIES

Devon is party to various legal actions arising in the normal course of business. Matters that are probable of unfavorable outcome to Devon and which can be reasonably estimated are accrued. Such accruals are based on information known about the matters, Devon's estimates of the outcomes of such matters and its experience in contesting, litigating and settling similar matters. None of the actions are believed by management to involve future amounts that would be material to Devon's financial position or results of operations in excess of recorded accruals.

ENVIRONMENTAL MATTERS

Devon is subject to certain laws and regulations relating to environmental remediation activities associated with past operations, such as the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") and similar state statutes. In response to liabilities associated with these activities, accruals have been established when reasonable estimates are possible. Such accruals primarily include estimated costs associated with remediation. Devon has not used discounting in determining its accrued liabilities for environmental remediation, and no material claims for possible recovery from third party insurers or other parties related to environmental costs have been recognized in Devon's consolidated financial statements. Devon adjusts the accruals when new remediation responsibilities are discovered and probable costs become estimable, or when current remediation estimates must be adjusted to reflect new information.

Certain of Devon's subsidiaries acquired in past mergers are involved in matters in which it has been alleged that such subsidiaries are potentially responsible parties ("PRPs") under CERCLA or similar state legislation with respect to various waste disposal areas owned or operated by third parties. As of December 31, 2002, Devon's consolidated balance sheet included $8 million of non-current accrued liabilities, reflected in "Other liabilities," related to these and other environmental remediation liabilities. Devon does not currently believe there is a reasonable possibility of incurring additional material costs in excess of the current accruals recognized for such environmental remediation activities. With respect to the sites in which Devon subsidiaries are PRPs, Devon's conclusion is based in large part on (i) Devon's participation in consent decrees with both other PRPs and the Environmental Protection Agency, which provide for performing the scope of work required for remediation and contain covenants not to sue as protection to the PRPs, (ii) participation in groups as a de minimis PRP, and (iii) the availability of other defenses to liability. As a result, Devon's monetary exposure is not expected to be material.

ROYALTY MATTERS

Numerous gas producers and related parties, including Devon, have been named in various lawsuits filed by private litigants alleging violation of the federal False Claims Act. The suits allege that the producers and related parties used below-market prices, improper deductions, improper measurement techniques and transactions with affiliates which resulted in underpayment of royalties in connection with natural gas and natural gas liquids produced and sold from federal and Indian owned or controlled lands. The various suits have been consolidated by the United States Judicial Panel on Multidistrict Litigation for pre-trial proceedings in the matter of In re Natural Gas Royalties Qui Tam Litigation, MDL-1293, United States District Court for the District of Wyoming. Devon believes that it has acted reasonably, has legitimate and strong defenses to all allegations in the suits, and has paid royalties in good faith. Devon does not currently believe that it is subject to material exposure in association with these lawsuits and no liability has been recorded in connection therewith.

Also, pending in federal court in Texas is a similar suit alleging underpaid royalties to the United States in connection with natural gas and natural gas liquids produced and sold from United States owned and/or controlled lands. The claims were filed by private litigants against Devon and numerous other producers, under the federal False Claims Act. The United States served notice of its intent to intervene as to certain defendants, but not Devon. Devon and certain other defendants are challenging the constitutionality of whether a claim under the federal False Claims Act can be maintained absent government intervention. Devon believes that it has acted reasonably and paid royalties in good faith. Devon does not currently believe that it is subject to material exposure in association with this litigation. As a result, Devon's monetary exposure in this suit is not expected to be material.

Devon is a defendant in certain private royalty owner litigation filed in Wyoming regarding deductibility of certain post production costs from royalties payable by Devon. The plaintiffs in these lawsuits propose to expand them into county or state-wide class actions relating specifically to transportation and related costs associated with Devon's Wyoming gas production. A significant portion of such production is, or will be, transported through facilities owned by Thunder Creek Gas Services, L.L.C., of which Devon owns a 75% interest. Devon believes that it has acted reasonably and paid royalties in good faith and in accordance with its obligations under its oil and gas leases and applicable law, and Devon does not believe that it is subject to material exposure in association with this litigation.

OTHER MATTERS

Devon is involved in other various routine legal proceedings incidental to its business. However, to Devon's knowledge as of the date of this report, there were no other material pending legal proceedings to which Devon is a party or to which any of its property is subject.

OPERATING LEASES

The following is a schedule by year of future minimum rental payments required under operating leases that have initial or remaining noncancelable lease terms in excess of one year as of December 31, 2002:

YEAR ENDING DECEMBER 31,	(IN MILLIONS)
2003	$ 30
2004	33
2005	28
2006	24
2007	20
Thereafter	86
Total minimum lease payments required	$221

Total rental expense for all operating leases is as follows for the years ended December 31:

	(IN MILLIONS)
2002	$37
2001	$17
2000	$19

The 2002 rent expense includes $13 million for the abandonment of certain office space obtained in the Santa Fe Snyder merger.

12. REDUCTION OF CARRYING VALUE OF OIL AND GAS PROPERTIES

Under the full cost method of accounting, the net book value of oil and gas properties, less related deferred income taxes, may not exceed a calculated "ceiling." The ceiling limitation is the discounted estimated after-tax future net revenues from proved oil and gas properties plus the cost of properties not subject to amortization. The ceiling is determined separately by country. In calculating future net revenues, current prices and costs are generally held constant indefinitely. The net book value, less deferred tax liabilities, is compared to the ceiling on a quarterly and annual basis. Any excess of the net book value, less related deferred taxes, is written off as an expense. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

During 2002 and 2001, Devon reduced the carrying value of its oil and gas properties by $651 and $883 million, respectively, due to the full cost ceiling limitations. The after-tax effect of these reductions in 2002 and 2001 were $371 million and $533 million, respectively. The following table summarizes these reductions by country.

	YEAR ENDED DECEMBER 31,			
	2002		2001	
	GROSS	NET OF TAXES	GROSS	NET OF TAXES
	(IN MILLIONS)			
United States	$ --	--	449	281
Canada	651	371	434	252
Total	$651	371	883	533

The 2002 Canadian reduction was primarily the result of lower prices. Under the purchase method of accounting for business combinations, acquired oil and gas properties are recorded at fair value as of the date of purchase. Devon estimates such fair value using its estimates of future oil and gas prices. In contrast, the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely. Accordingly, the resulting value is not necessarily indicative of the fair value of the reserves. The recorded values of oil and gas properties added from the Anderson acquisition in 2001 were based on expected future oil and gas prices that were higher than the June 30, 2002, prices used to calculate the Canadian ceiling.

The 2001 domestic and Canadian reductions were also primarily the result of lower prices. The oil and gas properties added from the Anderson acquisition and other smaller acquisitions in 2001 were recorded at fair values that were based on expected future oil and gas prices higher than the December 31, 2001 prices used to calculate the ceiling.

Additionally, during 2001, Devon elected to abandon operations in Thailand, Malaysia, Qatar and on certain properties in Brazil. After meeting the drilling and capital commitments on these properties, Devon determined that these properties did not meet Devon's internal criteria to justify further investment.

Accordingly, Devon recorded an $96 million charge associated with the impairment of these properties. The after-tax effect of this reduction was $78 million.

The provisions of SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, which Devon was required to adopt effective January 1, 2002, are only required to be applied prospectively. As a result, these impairment charges have not been reclassified as part of the Discontinued Operations on the consolidated statements of operations.

13. SEGMENT INFORMATION

Devon manages its business by country. As such, Devon identifies its segments based on geographic areas. Devon has three reportable segments: its operations in the U.S., its operations in Canada, and its international operations outside of North America. Substantially all of these segments' operations involve oil and gas producing activities. Certain information regarding such activities for each segment is included in Note 14.

Following is certain financial information regarding Devon's segments for 2002, 2001 and 2000. The revenues reported are all from external customers.

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
AS OF DECEMBER 31, 2002:				
Current assets	$ 603	366	95	1,064
Property and equipment, net of accumulated depreciation, depletion and amortization	6,838	3,497	517	10,852
Goodwill, net of amortization	1,565	1,921	69	3,555
Other assets	723	31	--	754
Total assets	$9,729	5,815	681	16,225
Current liabilities	$ 626	344	72	1,042
Long-term debt	3,545	4,017	--	7,562
Deferred tax liabilities	1,520	1,062	45	2,627
Other liabilities	333	7	1	341
Stockholders' equity	3,705	385	563	4,653
Total liabilities and stockholders' equity	$9,729	5,815	681	16,225

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
YEAR ENDED DECEMBER 31, 2002:				
Revenues:				
Oil sales	$ 524	331	54	909
Gas sales	1,403	730	--	2,133
Natural gas liquids sales	192	83	--	275
Marketing and midstream revenues	985	14	--	999
Total revenues	3,104	1,158	54	4,316
Operating Costs And Expenses:				
Lease operating expenses	354	255	12	621
Transportation costs	99	55	--	154
Production taxes	104	7	--	111
Marketing and midstream operating costs and expenses	800	8	--	808
Depreciation, depletion and amortization of property and equipment	834	371	6	1,211
General and administrative expenses	166	40	13	219
Reduction in carrying value of oil and gas properties	--	651	--	651
Total operating costs and expenses	2,357	1,387	31	3,775
Earnings (loss) from operations	747	(229)	23	541
Other Income (Expenses):				
Interest expense	(235)	(295)	(3)	(533)
Effects of changes in foreign currency exchange rates	--	1	--	1
Change in fair value of financial instruments	31	(3)	--	28
Impairment of ChevronTexaco Corporation common stock	(205)	--	--	(205)
Other income	16	11	7	34
Net other income (expenses)	(393)	(286)	4	(675)
Earnings (loss) from continuing operations before income taxes	354	(515)	27	(134)
Income Tax Expense (Benefit):				
Current	(23)	28	18	23
Deferred	42	(253)	(5)	(216)
Total income tax expense (benefit)	19	(225)	13	(193)
Earnings (loss) from continuing operations	335	(290)	14	59
Discontinued Operations:				
Results of discontinued operations before income taxes	--	--	54	54
Income tax expense	--	--	9	9
Net results of discontinued operations	--	--	45	45
Net earnings (loss)	$ 335	(290)	59	104
Capital expenditures	$2,797	532	97	3,426

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
AS OF DECEMBER 31, 2001:				
Current assets	$ 661	192	501	1,354
Property and equipment, net of accumulated depreciation, depletion and amortization	4,051	4,248	463	8,762
Goodwill, net of amortization	209	1,928	69	2,206
Other assets	826	33	3	862
Total assets	$5,747	6,401	1,036	13,184
Current liabilities	$ 407	367	145	919
Long-term debt	1,987	4,602	--	6,589
Deferred tax liabilities	775	1,316	58	2,149
Other liabilities	224	20	24	268
Stockholders' equity	2,354	96	809	3,259
Total liabilities and stockholders' equity	$5,747	6,401	1,036	13,184

	U.S.	CANADA	INTERNATIONAL	TOTAL
			(IN MILLIONS)	
YEAR ENDED DECEMBER 31, 2001:				
Revenues:				
Oil sales	$ 586	146	52	784
Gas sales	1,571	307	--	1,878
Natural gas liquids sales	103	28	--	131
Marketing and midstream revenues	64	7	--	71
Total revenues	2,324	488	52	2,864
Operating Costs And Expenses:				
Lease operating expenses	340	110	17	467
Transportation costs	59	24	--	83
Production taxes	113	3	--	116
Marketing and midstream operating costs and expenses	43	4	--	47
Depreciation, depletion and amortization of property and equipment	647	166	18	831
Amortization of goodwill	34	--	--	34
General and administrative expenses	98	15	1	114
Expenses related to mergers	--	1	--	1
Reduction in carrying value of oil and gas properties	449	434	96	979
Total operating costs and expenses	1,783	757	132	2,672
Earnings (loss) from operations	541	(269)	(80)	192
Other Income (Expenses):				
Interest expense	(139)	(81)	--	(220)
Effects of changes in foreign currency exchange rates	--	(11)	--	(11)
Change in fair value of financial instruments	(1)	(1)	--	(2)
Other income	57	5	7	69
Net other income (expenses)	(83)	(88)	7	(164)
Earnings (loss) from continuing operations before income taxes and cumulative effect of change in accounting principle	$ 458	$(357)	$ (73)	$ 28
Income Tax Expense (Benefit):				
Current	29	8	11	48
Deferred	92	(145)	10	(43)
Total income tax expense (benefit)	121	(137)	21	5
Earnings (loss) from continuing operations before cumulative effect of change in accounting principle	337	(220)	(94)	23
Discontinued Operations:				
Results of discontinued operations before income taxes	--	--	56	56
Income tax expense	--	--	25	25
Net results of discontinued operations	--	--	31	31
Earnings (loss) before cumulative effect of change in accounting principle	337	(220)	(63)	54
Cumulative effect of change in accounting principle	49	--	--	49
Net earnings (loss)	$ 386	(220)	(63)	103
Capital expenditures	$1,356	3,774	105	5,235

	U.S.	CANADA	INTERNATIONAL	TOTAL
			(IN MILLIONS)	
AS OF DECEMBER 31, 2000:				
Current assets	$ 645	79	104	828
Property and equipment, net of accumulated depreciation, depletion and amortization	3,640	586	436	4,662
Goodwill, net of amortization	244	--	45	289
Assets of discontinued operations	--	--	361	361
Other assets	720	--	--	720
Total assets	$5,249	665	946	6,860
Current liabilities	$ 449	74	54	577
Long-term debt	1,902	147	--	2,049
Deferred tax liabilities	537	69	28	634
Liabilities of discontinued operations	--	--	51	51
Other liabilities	259	1	12	272
Stockholders' equity	2,102	374	801	3,277
Total liabilities and stockholders' equity	$5,249	665	946	6,860

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
YEAR ENDED DECEMBER 31, 2000:				
Revenues:				
Oil sales	$ 727	116	63	906
Gas sales	1,305	169	--	1,474
Natural gas liquids sales	136	18	--	154
Marketing and midstream revenues	47	6	--	53
Total revenues	2,215	309	63	2,587
Operating Costs And Expenses:				
Lease operating expenses	319	52	17	388
Transportation costs	42	11	--	53
Production taxes	102	1	--	103
Marketing and midstream operating costs and expenses	25	3	--	28
Depreciation, depletion and amortization of property and equipment	565	65	32	662
Amortization of goodwill	41	--	--	41
General and administrative expenses	81	10	5	96
Expenses related to mergers	60	--	--	60
Total operating costs and expenses	1,235	142	54	1,431
Earnings from operations	980	167	9	1,156
Other Income (Expenses):				
Interest expense	(144)	(10)	(1)	(155)
Effects of changes in foreign currency exchange rates	--	(3)	--	(3)
Other income	36	2	2	40
Net other income (expenses)	(108)	(11)	1	(118)
Earnings from continuing operations before income taxes	872	156	10	1,038
Income Tax Expense:				
Current	113	2	5	120
Deferred	185	67	5	257
Total income tax expense	298	69	10	377
Earnings from continuing operations	574	87	--	661
Discontinued Operations:				
Results of discontinued operations before income taxes	--	--	104	104
Income tax expense	--	--	35	35
Net results of discontinued operations	--	--	69	69
Net earnings	$ 574	87	69	730
Capital expenditures	$ 893	203	52	1,148

14. SUPPLEMENTAL INFORMATION ON OIL AND GAS OPERATIONS (UNAUDITED)

The following supplemental unaudited information regarding the oil and gas activities of Devon is presented pursuant to the disclosure requirements promulgated by the Securities and Exchange Commission and SFAS No. 69, "Disclosures About Oil and Gas Producing Activities."

COSTS INCURRED

The following tables reflect the costs incurred in oil and gas property acquisition, exploration, and development activities:

	TOTAL YEAR ENDED DECEMBER 31, 2002	2001	2000
	(IN MILLIONS)		
Property acquisition costs:			
Proved, excluding deferred income taxes	$1,538	2,971	247
Deferred income taxes	--	84	--
Total proved, including deferred income taxes	$1,538	3,055	247
Unproved, excluding deferred income taxes:			
Business combinations	$ 639	1,433	--
Other acquisitions	64	183	54
Deferred income taxes	--	27	--
Total unproved, including deferred income taxes	$ 703	1,643	54
Exploration costs	$ 383	337	197
Development costs	$1,140	916	562

	DOMESTIC YEAR ENDED DECEMBER 31, 2002	2001	2000
	(IN MILLIONS)		
Property acquisition costs:			
Proved, excluding deferred income taxes	$1,536	292	177
Deferred income taxes	--	79	--
Total proved, including deferred income taxes	$1,536	371	177
Unproved, excluding deferred income taxes:			
Business combinations	$ 639	--	--
Other acquisitions	27	158	35
Deferred income taxes	--	27	--
Total unproved, including deferred income taxes	$ 666	185	35
Exploration costs	$ 161	166	117
Development costs	$ 808	726	466

	CANADA		
	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS)		
Property acquisition costs:			
Proved, excluding deferred income taxes	$ 2	2,621	70
Deferred income taxes	--	5	--
Total proved, including deferred income taxes	$ 2	2,626	70
Unproved, excluding deferred income taxes:			
Business combinations	$ --	1,433	--
Other acquisitions	28	24	17
Deferred income taxes	--	--	--
Total unproved, including deferred income taxes	$ 28	1,457	17
Exploration costs	$207	126	55
Development costs	$299	168	57

	INTERNATIONAL		
	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS)		
Property acquisition costs:			
Proved, excluding deferred income taxes	$--	58	--
Deferred income taxes	--	--	--
Total proved, including deferred income taxes	$--	58	--
Unproved, excluding deferred income taxes:			
Business combinations	$--	--	--
Other acquisitions	9	1	2
Deferred income taxes	--	--	--
Total unproved, including deferred income taxes	$ 9	1	2
Exploration costs	$15	45	25
Development costs	$33	22	39

The preceding Total and International cost incurred tables exclude $16 million, $85 million and $135 million in 2002, 2001 and 2000, respectively, related to discontinued operations.

Pursuant to the full cost method of accounting, Devon capitalizes certain of its general and administrative expenses which are related to property acquisition, exploration and development activities. Such capitalized expenses, which are included in the costs shown in the preceding tables, were $97 million, $77 million and $62 million in the years 2002, 2001 and 2000, respectively.

RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES

The following tables include revenues and expenses associated directly with Devon's oil and gas producing activities, including general and administrative expenses directly related to such producing activities. They do not include any allocation of Devon's interest costs or general corporate overhead and, therefore, are not necessarily indicative of the contribution to net earnings of Devon's oil and gas operations. Income tax expense has been calculated by applying statutory income tax rates to oil, gas and NGL sales after deducting costs, including depreciation, depletion and amortization and after giving effect to permanent differences.

	TOTAL		
	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and natural gas liquids sales	$ 3,317	2,793	2,534
Production and operating expenses	(886)	(666)	(544)
Depreciation, depletion and amortization	(1,106)	(793)	(632)
Amortization of goodwill	--	(34)	(41)
General and administrative expenses directly related to oil and gas producing activities	(29)	(17)	(14)
Reduction of carrying value of oil and gas properties	(651)	(979)	--
Income tax expense	(234)	(126)	(533)
Results of operations for oil and gas producing activities	$ 411	178	770
Depreciation, depletion and amortization per equivalent barrel of production	$ 5.88	6.30	5.58

	DOMESTIC		
	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and natural gas liquids sales	$2,119	2,260	2,168
Production and operating expenses	(557)	(512)	(463)
Depreciation, depletion and amortization	(737)	(615)	(541)
Amortization of goodwill	--	(34)	(41)
General and administrative expenses directly related to oil and gas producing activities	(14)	(9)	(10)
Reduction of carrying value of oil and gas properties	--	(449)	--
Income tax (expense) benefit	(295)	(263)	(442)
Results of operations for oil and gas producing activities	$ 516	378	671
Depreciation, depletion and amortization per equivalent barrel of production	$ 6.22	6.48	5.73

	CANADA		
	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and natural gas liquids sales	$1,144	481	303
Production and operating expenses	(317)	(137)	(64)
Depreciation, depletion and amortization	(364)	(164)	(64)
General and administrative expenses directly related to oil and gas producing activities	(14)	(6)	(3)
Reduction of carrying value of oil and gas properties	(651)	(434)	--
Income tax benefit (expense)	74	102	(79)
Results of operations for oil and gas producing activities	$ (128)	(158)	93
Depreciation, depletion and amortization per equivalent barrel of production	$ 5.39	5.74	4.05

	INTERNATIONAL		
	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and natural gas liquids sales	$ 54	52	63
Production and operating expenses	(12)	(17)	(17)
Depreciation, depletion and amortization	(5)	(14)	(27)
General and administrative expenses directly related to oil and gas producing activities	(1)	(2)	(1)
Reduction of carrying value of oil and gas properties	--	(96)	--
Income tax benefit (expense)	(13)	35	(12)
Results of operations for oil and gas producing activities	$ 23	(42)	6
Depreciation, depletion and amortization per equivalent barrel of production	$2.40	6.20	9.04

The preceding Total and International results of oil and gas producing activities tables exclude $19 million, $28 million and $66 million in 2002, 2001 and 2000, respectively, related to discontinued operations.

QUANTITIES OF OIL AND GAS RESERVES

Set forth below is a summary of the reserves which were evaluated by independent petroleum consultants for each of the years ended 2002, 2001 and 2000.

	2002		2001		2000	
	ESTIMATED	AUDITED	ESTIMATED	AUDITED	ESTIMATED	AUDITED
Domestic	12%	61%	67%	9%	80%	17%
Canada	31%	--%	43%	--%	100%	--%
International	100%	--%	100%	--%	100%	--%

Estimated reserves are those quantities of reserves which were estimated by an independent petroleum consultant. Audited reserves are those quantities of revenues which were estimated by Devon employees and audited by an independent petroleum consultant.

The domestic reserves were evaluated by the independent petroleum consultants of LaRoche Petroleum Consultants, Ltd. and Ryder Scott Company, L.P. in each of the years presented. The Canadian reserves were evaluated by the independent petroleum consultants of AJM Petroleum Consultants in 2002; Paddock Lindstrom & Associates and Gilbert Laustsen Jung Associates, Ltd. in 2001; and Paddock Lindstrom & Associates in 2000. The International reserves were evaluated by the independent petroleum consultants of Ryder Scott Company Petroleum Consultants in each of the years presented.

Set forth below is a summary of the changes in the net quantities of crude oil, natural gas and natural gas liquids reserves for each of the three years ended December 31, 2002.

	TOTAL			
	Oil (MMBbls)	Gas (Bcf)	Natural Gas Liquids (MMBbls)	Total (MMBoe)
Proved reserves as of December 31, 1999	439	2,785	55	958
Revisions of estimates	(3)	95	4	17
Extensions and discoveries	31	569	6	132
Purchase of reserves	24	80	--	37
Production	(37)	(417)	(7)	(113)
Sale of reserves	(48)	(67)	(8)	(68)
Proved reserves as of December 31, 2000	406	3,045	50	963
Revisions of estimates	(14)	(284)	7	(54)
Extensions and discoveries	17	499	7	107
Purchase of reserves	166	2,267	52	596
Production	(36)	(489)	(8)	(126)
Sale of reserves	(12)	(14)	--	(14)
Proved reserves as of December 31, 2001	527	5,024	108	1,472
Revisions of estimates	(10)	(81)	--	(23)
Extensions and discoveries	36	570	11	142
Purchase of reserves	13	1,723	105	405
Production	(42)	(761)	(19)	(188)
Sale of reserves	(80)	(639)	(13)	(199)
Proved reserves as of December 31, 2002	444	5,836	192	1,609
Proved developed reserves as of:				
December 31, 1999	264	2,465	52	728
December 31, 2000	232	2,595	46	711
December 31, 2001	298	3,911	88	1,038
December 31, 2002	260	4,618	150	1,180

	DOMESTIC			
	Oil (MMBbls)	Gas (Bcf)	Natural Gas Liquids (MMBbls)	Total (MMBoe)
Proved reserves as of December 31, 1999	249	2,275	51	679
Revisions of estimates	(3)	101	4	18
Extensions and discoveries	21	504	5	110
Purchase of reserves	21	53	--	30
Production	(29)	(355)	(6)	(94)
Sale of reserves	(33)	(57)	(8)	(51)
Proved reserves as of December 31, 2000	226	2,521	46	692
Revisions of estimates	(25)	(262)	7	(62)
Extensions and discoveries	12	360	5	77
Purchase of reserves	15	170	--	43
Production	(26)	(376)	(6)	(95)
Sale of reserves	(11)	(14)	--	(13)
Proved reserves as of December 31, 2001	191	2,399	52	642
Revisions of estimates	8	26	2	15
Extensions and discoveries	10	344	6	73
Purchase of reserves	12	1,722	105	404
Production	(24)	(482)	(14)	(118)
Sale of reserves	(50)	(457)	(5)	(131)
Proved reserves as of December 31, 2002	147	3,552	146	885
Proved developed reserves as of:				
December 31, 1999	214	1,960	48	589
December 31, 2000	192	2,087	42	582
December 31, 2001	167	1,988	48	546
December 31, 2002	135	2,802	117	719

	CANADA			
	Oil (MMBbls)	Gas (Bcf)	Natural Gas Liquids (MMBbls)	Total (MMBoe)
Proved reserves as of December 31, 1999	32	506	4	120
Revisions of estimates	3	(6)	--	2
Extensions and discoveries	3	65	1	15
Purchase of reserves	3	27	--	7
Production	(5)	(62)	(1)	(16)
Sale of reserves	--	(6)	--	(1)
Proved reserves as of December 31, 2000	36	524	4	127
Revisions of estimates	--	(22)	--	(3)
Extensions and discoveries	5	139	2	30
Purchase of reserves	133	2,097	52	535
Production	(8)	(113)	(2)	(29)
Sale of reserves	--	--	--	--
Proved reserves as of December 31, 2001	166	2,625	56	660
Revisions of estimates	2	(107)	(2)	(18)
Extensions and discoveries	26	226	5	69
Purchase of reserves	1	1	--	1
Production	(16)	(279)	(5)	(68)
Sale of reserves	(30)	(182)	(8)	(68)
Proved reserves as of December 31, 2002	149	2,284	46	576
Proved developed reserves as of:				
December 31, 1999	29	501	4	117
December 31, 2000	30	508	4	119
December 31, 2001	124	1,923	40	485
December 31, 2002	119	1,816	33	455

	INTERNATIONAL			
	Oil (MMBbls)	Gas (Bcf)	Natural Gas Liquids (MMBbls)	Total (MMBoe)
Proved reserves as of December 31, 1999	158	4	--	159
Revisions of estimates	(3)	--	--	(3)
Extensions and discoveries	7	--	--	7
Purchase of reserves	--	--	--	--
Production	(3)	--	--	(3)
Sale of reserves	(15)	(4)	--	(16)
Proved reserves as of December 31, 2000	144	--	--	144
Revisions of estimates	11	--	--	11
Extensions and discoveries	--	--	--	--
Purchase of reserves	18	--	--	18
Production	(2)	--	--	(2)
Sale of reserves	(1)	--	--	(1)
Proved reserves as of December 31, 2001	170	--	--	170
Revisions of estimates	(20)	--	--	(20)
Extensions and discoveries	--	--	--	--
Purchase of reserves	--	--	--	--
Production	(2)	--	--	(2)
Sale of reserves	--	--	--	--
Proved reserves as of December 31, 2002	148	--	--	148
Proved developed reserves as of:				
December 31, 1999	21	4	--	22
December 31, 2000	10	--	--	10
December 31, 2001	7	--	--	7
December 31, 2002	6	--	--	6

The preceding International quantities of reserves are attributable to production sharing contracts with various foreign governments.

The preceding Total and International quantities of oil and gas reserves tables exclude the following proved reserves and proved developed reserves related to discontinued operations.

	OIL (MMBbls)	GAS (Bcf)	NATURAL GAS LIQUIDS (MMBbls)	TOTAL (MMBoe)
Proved reserves as of:				
December 31, 1999	57	165	13	97
December 31, 2000	53	413	12	134
December 31, 2001	59	453	13	147
December 31, 2002	1	--	--	1
Proved developed reserves as of:				
December 31, 1999	37	36	--	43
December 31, 2000	29	35	--	35
December 31, 2001	26	37	--	32
December 31, 2002	--	--	--	--

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

The accompanying tables reflect the standardized measure of discounted future net cash flows relating to Devon's interest in proved reserves:

	TOTAL		
	DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS)		
Future cash inflows	$38,399	21,769	37,974
Future costs:			
Development	(2,053)	(1,860)	(1,267)
Production	(9,076)	(7,682)	(7,329)
Future income tax expense	(8,737)	(3,050)	(8,553)
Future net cash flows	18,533	9,177	20,825
10% discount to reflect timing of cash flows	(8,168)	(4,162)	(8,760)
Standardized measure of discounted future net cash flows	$10,365	5,015	12,065

	DOMESTIC		
	DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS)		
Future cash inflows	$20,571	9,861	29,144
Future costs:			
Development	(1,122)	(793)	(916)
Production	(5,871)	(3,774)	(5,661)
Future income tax expense	(3,911)	(759)	(6,346)
Future net cash flows	9,667	4,535	16,221
10% discount to reflect timing of cash flows	(4,157)	(1,734)	(6,592)
Standardized measure of discounted future net cash flows	$ 5,510	2,801	9,629

	CANADA		
	DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS)		
Future cash inflows	$13,799	9,011	5,686
Future costs:			
Development	(633)	(922)	(85)
Production	(2,600)	(3,292)	(616)
Future income tax expense	(3,999)	(2,006)	(1,967)
Future net cash flows	6,567	2,791	3,018
10% discount to reflect timing of cash flows	(2,677)	(1,195)	(1,241)
Standardized measure of discounted future net cash flows	$ 3,890	1,596	1,777

	INTERNATIONAL		
	DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS)		
Future cash inflows	$ 4,029	2,897	3,144
Future costs:			
Development	(298)	(145)	(266)
Production	(605)	(616)	(1,052)
Future income tax expense	(827)	(285)	(240)
Future net cash flows	2,299	1,851	1,586
10% discount to reflect timing of cash flows	(1,334)	(1,233)	(927)
Standardized measure of discounted future net cash flows	$ 965	618	659

Future cash inflows are computed by applying year-end prices (averaging $27.99 per barrel of oil, adjusted for transportation and other charges, $3.88 per Mcf of gas and $17.07 per barrel of natural gas liquids at December 31, 2002) to the year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements in existence at year-end.

Future development and production costs are computed by estimating the expenditures to be incurred in developing and producing proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. Of the $2.1 billion of future development costs, $547 million, $410 million and $128 million are estimated to be spent in 2003, 2004 and 2005, respectively.

Future development costs include not only development costs, but also future dismantlement, abandonment and rehabilitation costs. Included as part of the $2.1 billion of future development costs are $535 million of future dismantlement, abandonment and rehabilitation costs.

Future production costs include general and administrative expenses directly related to oil and gas producing activities. Future income tax expenses are computed by applying the appropriate statutory tax rates to the future pre-tax net cash flows relating to proved reserves, net of the tax basis of the properties involved. The future income tax expenses give effect to permanent differences and tax credits, but do not reflect the impact of future operations.

The preceding Total and International standardized measure of discounted future net cash flows tables exclude $21 million, $299 million and $407 million in 2002, 2001 and 2000, respectively, related to discontinued operations.

CHANGES RELATING TO THE STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

Principal changes in the standardized measure of discounted future net cash flows attributable to Devon's proved reserves are as follows:

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS)		
Beginning balance	$ 5,015	12,065	4,465
Sales of oil, gas and natural gas liquids, net of production costs	(2,402)	(2,126)	(1,989)
Net changes in prices and production costs	9,122	(11,878)	9,582
Extensions, discoveries, and improved recovery, net of future development costs	1,471	582	2,702
Purchase of reserves, net of future development costs	888	2,480	512
Development costs incurred during the period which reduced future development costs	175	314	113
Revisions of quantity estimates	(61)	(316)	457
Sales of reserves in place	(1,879)	(84)	(818)
Accretion of discount	692	1,708	532
Net change in income taxes	(2,673)	3,340	(4,152)
Other, primarily changes in timing	17	(1,070)	661
Ending balance	$10,365	5,015	12,065

The preceding table excludes $21 million, $299 million, $407 million and $303 million as of December 31, 2002, 2001, 2000 and 1999, respectively, related to discontinued operations.

15. SUPPLEMENTAL QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Following is a summary of the unaudited interim results of operations for the years ended December 31, 2002 and 2001.

	2002				
	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	FULL YEAR
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)				
Oil, gas and natural gas liquids sales	$ 743	882	766	926	3,317
Total revenues	$ 903	1,149	1,031	1,233	4,316
Net earnings (loss)	$ 62	(104)	62	84	104
Net earnings (loss) per common share:					
Basic	$0.41	(0.68)	0.38	0.52	0.61
Diluted	$0.40	(0.68)	0.37	0.52	0.61

	2001				
	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	FULL YEAR
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)				
Oil, gas and natural gas liquids sales	$ 961	665	521	646	2,793
Total revenues	$ 981	680	533	670	2,864
Net earnings (loss) before cumulative effect of change in accounting principle	$ 351	136	85	(518)	54
Net earnings (loss)	$ 400	136	85	(518)	103
Net earnings (loss) per common share:					
Basic					
Net earnings (loss) before cumulative effect of change in accounting principle	$2.70	1.03	0.65	(4.13)	0.34
Cumulative effect of change in accounting principle	0.38	--	--	--	0.39
Total basic	$3.08	1.03	0.65	(4.13)	0.73
Diluted					
Net earnings (loss) before cumulative effect of change in accounting principle	$2.59	1.01	0.64	(4.13)	0.34
Cumulative effect of change in accounting principle	0.37	--	--	--	0.38
Total diluted	$2.96	1.01	0.64	(4.13)	0.72

The second quarter of 2002 includes $651 million of reduction of carrying value of oil and gas properties. The fourth quarter of 2002 includes $205 million for the impairment of ChevronTexaco Corporation common stock. The after-tax effect of these expenses was $371 million and $128 million, respectively. The per share effects of these quarterly reductions was $2.37 and $0.82, respectively.

The second, third and fourth quarters of 2001 include $77 million, $10 million and $892 million, respectively, of reductions of carrying value of oil and gas properties. The after-tax effect of these expenses was $62 million, $7 million and $542 million, respectively. The per share effect of these quarterly reductions was $0.48, $0.05 and $4.30, respectively.

Oil, gas and natural gas liquids sales for the first, second, third and fourth quarters of 2002 exclude $35 million, $21 million, $17 million and $7 million, respectively, related to discontinued operations. Oil, gas and natural gas liquids sales for the first, second, third and fourth quarters of 2001 exclude $50 million, $45 million, $50 million and $42 million, respectively, related to discontinued operations.

16. PENDING MERGER (UNAUDITED)

On February 24, 2003, Devon and Ocean Energy Inc. ("Ocean") announced their intention to merge. In the transaction, Devon will issue 0.414 of a share of its common stock for each outstanding share of Ocean common stock. Also, Devon will assume approximately $1.8 billion of debt from Ocean. The transaction is subject to approval by the stockholders of both companies, as well as certain regulatory approvals. If approved, the transaction is expected to be consummated shortly after the stockholder meetings.

Ocean's December 31, 2002 proved oil and gas reserves totaled 593 million barrels of oil equivalent located in the United States, West Africa and other International locations.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not Applicable.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

INFORMATION ABOUT DIRECTORS

Pursuant to provisions of our certificate of incorporation and bylaws, the board of directors has fixed the number of directors at 10. Our certificate of incorporation and bylaws provide for three classes of directors serving staggered three-year terms, with Class I having three directors, Class II having four directors and Class III having three directors.

DIRECTORS WHOSE TERMS EXPIRE IN 2003

J. TODD MITCHELL 44 years old Director since 2002	J. Todd Mitchell served on the Board of Directors of Mitchell Energy & Development Corp. from 1993 to 2002. Mr. Mitchell has served as president of GPM, Inc., a family-owned investment company, since 1998. He has also served as President of Dolomite Resources, Inc., a privately owned mineral exploration and investments company, since 1987 and as Chairman of Rock Solid Images, a privately owned seismic data analysis software company, since 1998.
J. LARRY NICHOLS 60 years old Director since 1971	J. Larry Nichols is a co-founder of Devon. He was named Chairman of the Board of Directors in 2000. He has been President since 1976 and Chief Executive Officer since 1980. Mr. Nichols serves on the Board of Governors of the American Stock Exchange. He serves as a Director of BOK Financial Corporation, Smedvig ASA and Baker Hughes Incorporated. Mr. Nichols serves as a director of several trade associations that are relevant to the conduct of the Company's business.
ROBERT B. WEAVER 64 years old Director since 1999	Robert B. Weaver was an energy finance specialist for Chase Manhattan Bank, N.A., where he was in charge of the worldwide energy group from 1981 until his retirement in 1994. From 1998 to 1999, Mr. Weaver served as a Director, Chairman of the Audit Committee and member of the Compensation Committee of PennzEnergy Company and its predecessor Pennzoil Company.

DIRECTORS WHOSE TERMS EXPIRE IN 2004

THOMAS F. FERGUSON 66 years old Director since 1982	Thomas F. Ferguson is the Chairman of the Audit Committee. He is the Managing Director of United Gulf Management Ltd., a wholly- owned subsidiary of Kuwait Investment Projects Company KSC. Mr. Ferguson represents Kuwait Investment Projects Company on the boards of various companies in which it invests, including Baltic Transit Bank in Latvia and Tunis International Bank in Tunisia. Mr. Ferguson is a Canadian qualified Certified General Accountant and was formerly employed by the Economist Intelligence Unit of London as a financial consultant.

DAVID M. GAVRIN
68 years old
Director since 1979

David M. Gavrin serves as the Chairman of the Compensation Committee. Mr. Gavrin has been a private investor since 1989 and is currently a Director of MetBank Holding Corporation and United American Energy Corp., an independent power producer. From 1978 to 1988, he was a General Partner of Windcrest Partners, and for 14 years prior to that he was an officer of Drexel Burnham Lambert Incorporated.

MICHAEL E. GELLERT
71 years old
Director since 1971

Michael E. Gellert is Chairman of the Nominating Committee. Since 1967, Mr. Gellert has been a General Partner of Windcrest Partners, a private investment partnership in New York City. From January 1958 until his retirement in October 1989, Mr. Gellert served in executive capacities with Drexel Burnham Lambert Incorporated and its predecessors in New York City. In addition to serving as a Director of Devon, Mr. Gellert serves on the boards of High Speed Access Corporation, Humana Inc., Seacor Smit Inc., Six Flags Inc., Travelers Series Fund, Inc., Dalet Technologies and Smith Barney World Funds.

DIRECTORS WHOSE TERMS EXPIRE IN 2005

JOHN A. HILL
61 years old
Director since 2000

John A. Hill has been with First Reserve Corporation, an oil and gas investment management company, since 1983 and is currently the Vice Chairman and Managing Director. Prior to joining First Reserve, Mr. Hill was President, Chief Executive Officer and Director of Marsh & McLennan Asset Management Company and served as the Deputy Administrator of the Federal Energy Administration during the Ford administration. Mr. Hill is Chairman of the Board of Trustees of the Putnam Funds in Boston, a Trustee of Sarah Lawrence College, and a Director of TransMontaigne Inc., various companies controlled by First Reserve Corporation and Continuum Health Partners.

WILLIAM J. JOHNSON
68 years old
Director since 1999

William J. Johnson has been a private consultant for the oil and gas industry for more than five years. He is President and a Director of JonLoc Inc., an oil and gas company of which he and his family are sole shareholders. Mr. Johnson has served as a Director of Tesoro Petroleum Corp. since 1996. From 1991 to 1994, Mr. Johnson was President, Chief Operating Officer and a Director of Apache Corporation.

MICHAEL M. KANOVSKY
54 years old
Director since 1998

Michael M. Kanovsky was a co-founder of Northstar Energy Corporation, Devon's Canadian subsidiary, and served on the board of directors since 1982. Mr. Kanovsky is President of Sky Energy Corporation, a privately held energy corporation. He continues to be active in the Canadian energy industry and is currently a Director of ARC Resources Ltd. and Bonavista Petroleum Ltd.

ROBERT A. MOSBACHER
51 years old
Director since 1999

Robert A. Mosbacher, Jr. has served as President and CEO of Mosbacher Energy Company since 1986, and has been Vice Chairman of Mosbacher Power Group since 1995. Mr. Mosbacher was previously a Director of PennzEnergy Company and served on the Executive Committee. He is currently a Director of JPMorgan Chase and Company, Houston Regional Board, and is on the Executive Committee of the U.S. Oil & Gas Association.

CHAIRMAN EMERITUS

JOHN W. NICHOLS 88 years old Director since 1971	John W. Nichols, one of our co-founders, was named Chairman Emeritus in 1999. He was Chairman of our board of directors since we began operations in 1971 and continued in this capacity until 1999. He is a founding partner of Blackwood & Nichols Co., which developed the conventional reserves in the Northeast Blanco Unit of the San Juan Basin. Mr. Nichols is a non-practicing Certified Public Accountant.

INFORMATION ABOUT EXECUTIVE OFFICERS

BRIAN J. JENNINGS 42 years old Senior Vice President -- Corporate Development	Brian James Jennings was elected to the position of Senior Vice President -- Corporate Development in July 2001. Mr. Jennings joined Devon in March 2000 as Vice President -- Corporate Finance. Prior to joining Devon, Mr. Jennings was a Managing Director in the Energy Investment Banking Group of PaineWebber, Inc. He began his banking career at Kidder, Peabody in 1989 before moving to Lehman Brothers in 1992 and later to PaineWebber in 1997. Mr. Jennings specialized in providing strategic advisory and corporate finance services to public and private companies in the E&P and oilfield service sectors. He began his energy career with ARCO International Oil & Gas, a subsidiary of Atlantic Richfield Company. Mr. Jennings received his Bachelor of Science in Petroleum Engineering from the University of Texas at Austin and his Master of Business Administration from the University of Chicago's Graduate School of Business.
J. MICHAEL LACEY 57 years old Senior Vice President -- Exploration and Production	J. Michael Lacey was elected to the position of Senior Vice President -- Exploration and Production in 1999. Mr. Lacey joined Devon in 1989 as Vice President of Operations and Exploration. Prior to his employment with Devon, Mr. Lacey served as General Manager for Tenneco Oil Company's Mid-Continent and Rocky Mountain Divisions. He is a registered professional engineer, and a member of the Society of Petroleum Engineers and the American Association of Petroleum Geologists. Mr. Lacey holds undergraduate and graduate degrees in petroleum engineering from the Colorado School of Mines.
DUKE R. LIGON 61 years old Senior Vice President & General Counsel	Duke R. Ligon was elected to the position of Senior Vice President & General Counsel in 1999. Mr. Ligon had previously joined Devon as Vice President & General Counsel in 1997. Prior to joining Devon, Mr. Ligon practiced energy law for 12 years, most recently as a partner at the law firm of Mayer, Brown & Platt in New York City. He has also served as Senior Vice President and Managing Director for Investment Banking at Bankers Trust Company in New York City for 10 years. Additionally, Mr. Ligon served for three years in various positions with the U.S. Departments of the Interior and Treasury, as well as the Department of Energy. Mr. Ligon holds an undergraduate degree in chemistry from Westminister College and a law degree from the University of Texas School of Law.
MARIAN J. MOON 52 years old Senior Vice President -- Administration	Marian J. Moon was elected to the position of Senior Vice President - Administration in 1999. Ms. Moon has been with Devon for 19 years, serving in various capacities, including Manager of Corporate Finance. Prior to joining Devon, Ms. Moon was employed for 11 years by Amarex, Inc., an Oklahoma City based oil and natural gas production and exploration firm, where she served most recently as Treasurer. Ms. Moon is a member of the American Society of Corporate Secretaries. She is a graduate of Valparaiso University.

JOHN RICHELS 51 years old Senior Vice President -- Canadian Division	John Richel was elected to the position of Senior Vice President - Canadian Division in 2001. Prior to his election to Senior Vice President, Mr. Richels held the position of Chief Executive Officer of Northstar Energy Corporation, Devon's Canadian subsidiary. Mr. Richels served as Northstar's Executive Vice President and Chief Financial Officer from 1996 to 1998 and was on its Board of Directors from 1993 to 1996. Prior to joining Northstar, Mr. Richels was Managing Partner, Chief Operating Partner and a member of the Executive Committee of the Canadian based national law firm, Bennett Jones. Mr. Richels has previously served as a Director of a number of publicly traded companies and is Vice-Chairman of the Board of Governors of the Canadian Association of Petroleum Producers. He holds a bachelor's degree in economics from York University and a law degree from the University of Windsor.
DARRYL G. SMETTE 55 years old Senior Vice President -- Marketing	Darryl G. Smette was elected to the position of Senior Vice President -- Marketing in 1999. Mr. Smette previously held the position of Vice President -- Marketing and Administrative Planning since 1989. He joined Devon in 1986 as Manager of Gas Marketing. His marketing background includes 15 years with Energy Reserves Group, Inc./BHP Petroleum (Americas), Inc., most recently as Director of Marketing. Mr. Smette is an oil and gas industry instructor, approved by the University of Texas Department of Continuing Education. He is a member of the Oklahoma Independent Producers Association, Natural Gas Association of Oklahoma and the American Gas Association. Mr. Smette holds an undergraduate degree from Minot State College and a master's degree from Wichita State University.
WILLIAM T. VAUGHN 56 years old Senior Vice President -- Finance	William T. Vaughn was elected to the position of Senior Vice President -- Finance in 1999. Mr. Vaughn previously served as Devon's Vice President of Finance in charge of commercial banking functions, accounting, tax and information services since 1987. Prior to that, he was Controller of Devon from 1983 to 1987. Mr. Vaughn's previous experience includes employment with Marion Corporation for two years, most recently as Controller, and employment with Arthur Young & Co. for seven years, most recently as Audit Manager. He is a Certified Public Accountant and a Member of the American Institute of Certified Public Accountants. He is a graduate of the University of Arkansas with a Bachelor of Science degree.

OTHER OFFICERS

RICK D. CLARK 55 years old Vice President and General Manager -- Central Division	Rick D. Clark was elected to the position of Vice President and General Manager -- Central Division in 2002. Since joining Devon in 1995, Mr. Clark has also served as Vice President and General Manager of the Permian/Mid-Continent Division and Production/ Operations Manager. Prior to joining Devon, Mr. Clark was employed by Patrick Petroleum Company where he served since 1988 as Executive Vice President, Operations and Corporate Development. Mr. Clark has also worked in various production engineering, reservoir engineering, financial and managerial capacities for Ladd Petroleum Corporation and Conoco Inc. He is a member of the Society of Petroleum Engineers. Mr. Clark holds a professional degree in Petroleum Engineering from the Colorado School of Mines.

DON D. DECARLO 46 years old Vice President and General Manager -- Western Division	Don D. DeCarlo was elected to the position of Vice President and General Manager -- Western Division in 2002. Mr. DeCarlo has also served as Vice President and General Manager, Rocky Mountain Division, for Devon and Santa Fe Snyder Corporation. Mr. DeCarlo began his professional career in 1978 with Tenneco Oil Company in Oklahoma City. In 1989 he joined Santa Fe Energy Resources as an Engineering Manager in Tulsa, Oklahoma. During his 11-year tenure with Santa Fe, Mr. DeCarlo held management positions of increasing responsibility in Bakersfield, California; Midland, Texas and most recently in Denver, Colorado. He received a Bachelor of Science degree in Petroleum Engineering from West Virginia University. He is a member of the Society of Petroleum Engineers and currently holds the position of Vice President for the Independent Petroleum Association of the Mountain States.
JANICE A. DOBBS 54 years old Corporate Secretary and Manager of Corporate Governance	Janice A. Dobbs was elected to the position of Corporate Secretary in 2001. Ms. Dobbs joined Devon in 1999 as the Manager of Corporate Governance and Assistant Corporate Secretary. From 1993 to 1999 Ms. Dobbs served as the Corporate Secretary and Compliance Manager of Chesapeake Energy Corporation. From 1975 until her association with Chesapeake, Ms. Dobbs was the corporate/securities legal assistant with the law firm of Andrews Davis Legg Bixler Milsten & Price, Inc. in Oklahoma City. Prior to that she was the corporate/securities legal assistant with Texas International Petroleum Company. Ms. Dobbs is a Certified Legal Assistant, an associate member of the American Bar Association and a member of the American Society of Corporate Secretaries.
DANNY J. HEATLY 47 years old Vice President -- Accounting	Danny J. Heatly was elected to the position of Vice President -- Accounting in 1999. Mr. Heatly had previously served as Devon's Controller since 1989. Prior to joining Devon, Mr. Heatly was associated with Peat Marwick Main & Co. (now KPMG LLP) in Oklahoma City for 10 years with various duties, including Senior Audit Manager. He is a Certified Public Accountant and a member of the American Institute of Certified Public Accountants and the Oklahoma Society of Certified Public Accountants. He graduated with a Bachelor of Accountancy degree from the University of Oklahoma.
RICHARD E. MANNER 56 years old Vice President -- Information Services	Richard E. Manner was elected to the position of Vice President -- Information Services in 2000. Mr. Manner has been an information technology professional for 28 years. Prior to joining Devon, he was employed by Unisys in Houston, Texas. There he served for 14 years in various positions including Director of Information Systems. Prior to his tenure with Unisys, Mr. Manner spent two years with a National Aeronautics and Space Administration contractor as a software engineer, and eight years with AMF Tuboscope where he supervised the design of oilfield inspection instrumentation and facilities. He is a registered professional engineer and a member of the Society of Professional Engineers. Mr. Manner received his electrical engineering degree from the University of Oklahoma.

R. ALAN MARCUM
36 years old
Controller

R. Alan Marcum was elected to the position of Controller in 1999. Mr. Marcum has been with Devon since 1995, most recently as Assistant Controller. Prior to joining Devon, Mr. Marcum was employed by KPMG Peat Marwick (now KPMG LLP) as a senior auditor, with responsibilities including special engagements involving due diligence work, agreed upon procedures and SEC filings. He holds a Bachelor of Science degree from East Central University, majoring in Accounting and Finance. He is a Certified Public Accountant and a member of the Oklahoma State Society of Certified Public Accountants.

PAUL R. POLEY
49 years old
Vice President -- Human Resources

Paul R. Poley was elected to the position of Vice President -- Human Resources in 2000. Mr. Poley was previously employed by Fleming Companies in Oklahoma City most recently as Director of Human Resources Planning and Development. At Fleming, his responsibilities included human resources development, management succession, strategic planning, performance management and training. Prior to his 11 years at Fleming, Mr. Poley was Regional Personnel Manager for International Mill Service, Inc. He received his Bachelor of Arts degree in Sociology from Bucknell University.

TERRENCE L. RUDER
50 years old
Vice President & General Manager -- Marketing & Midstream Division

Terrence L. Ruder was elected to the position of Vice President & General Manager -- Marketing & Midstream Division in 2001. Mr. Ruder has been with Devon since 1999, most recently as President of Thunder Creek Gas Services, a gas pipeline subsidiary located in Wyoming. He has over 25 years of energy industry experience in both domestic and international capacities. Prior to joining Devon, Mr. Ruder held a variety of marketing and business development positions with BHP Petroleum and BHP Power, most recently as Senior Vice President & General Manager of BHP Power in Brazil. Mr. Ruder graduated with a Bachelor of Business Administration degree in Finance from Wichita State University.

DAVID J. SAMBROOKS
44 years old
Vice President and General Manager -- International Division

David J. Sambrooks was elected to the position of Vice President and General Manager -- International Division in 2001. From 2000 to 2001, Mr. Sambrooks served as Production Manager, South America. Prior to joining Devon, Mr. Sambrooks was General Manager of International Business Development and Western Hemisphere Production for Santa Fe Snyder Corporation. Mr. Sambrooks began his professional career in 1980 with Sun Exploration and Production Company (later Oryx Energy) and held positions of increasing responsibility in Houston, Corpus Christi and Midland before joining Santa Fe Energy Resources in 1990. During his 10-year tenure with Santa Fe, Mr. Sambrooks held progressive positions in engineering and management covering South Texas, offshore Gulf of Mexico, and beginning in 1993, international. Mr. Sambrooks received a Bachelor of Science degree in Mechanical Engineering from the University of Texas, Austin and a M.B.A. from the Executive Program at the University of Houston.

WILLIAM A. VAN WIE
57 years old
Vice President and General Manager -- Gulf Division

William A. Van Wie was elected to the position of Vice President and General Manager -- Gulf Division in 1999. Mr. Van Wie previously served as Senior Vice President and General Manager -- Offshore for PennzEnergy Company. Mr. Van Wie began his career as a geologist for Tenneco Oil Company's Frontier Projects Group in 1974. Following the sale of Tenneco's Gulf of Mexico properties to Chevron in 1988, he joined that company as Division Geologist. In 1992, he moved to Pennzoil Exploration and Production Company as Vice President/Exploitation Manager. He then served as Manager of Offshore Exploration for Amerada Hess Corporation, before he rejoined Pennzoil in 1997. He is an active member of the American Association of Petroleum Geologists, serves as a trustee for the American Geological Institute Foundation, is a Vice Chairman of Independent Petroleum Association of America's Offshore Committee and is also a member of the National Ocean Industries Association. Mr. Van Wie received his Bachelor of Science degree in Geology from St. Lawrence University in Canton, New York and a Master's degree and Ph.D. in geology from the University of Cincinnati.

VINCENT W. WHITE
45 years old
Vice President -- Communications and Investor Relations

Vincent W. White was elected to the position of Vice President -- Communications and Investor Relations in 1999. Mr. White previously served as Devon's Director of Investor Relations since 1993. Prior to joining Devon, he served as Controller of Arch Petroleum Inc. and was an auditor with KPMG Peat Marwick (now KPMG LLP). Mr. White is a Certified Public Accountant and a member of the Petroleum Investor Relations Association, the National Investor Relations Institute and the American Institute of Certified Public Accountants. Mr. White received his Bachelor of Accounting degree from the University of Texas at Arlington.

DALE T. WILSON
43 years old
Treasurer

Dale T. Wilson was elected to the position of Treasurer in 1999. Prior to joining Devon, Mr. Wilson was employed in the banking industry for 17 years, most recently by Bank of America as a Managing Director of the Energy Finance Group. Mr. Wilson has been active in oil and gas trade associations and is currently a member of the Association for Financial Professionals. He is a graduate of Baylor University with a Bachelor's degree in finance and accounting.

ITEM 11. EXECUTIVE COMPENSATION

SUMMARY COMPENSATION TABLE

The following table sets forth information regarding annual and long-term compensation during 2000, 2001 and 2002 for the CEO and the four most highly compensated executive officers, other than the CEO, who were serving as executive officers of the company on December 31, 2002.

			ANNUAL COMPENSATION		LONG-TERM COMPENSATION(1)	
NAME	PRINCIPAL POSITION	YEAR	SALARY	BONUS	AWARDS OF OPTIONS (# OF SHARES)	ALL OTHER COMPENSATION
J. Larry Nichols.....	Chairman, President and CEO	2002	$715,000	$1,500,000	105,000	$11,000(2)
		2001	650,000	1,000,000	105,000	10,200(2)
		2000	600,000	1,000,000	70,000	10,200(2)
Brian J. Jennings....	Senior Vice President	2002	$325,000	400,000	53,000	$16,000(3)
		2001	275,000	275,000	53,000	10,729(3)
		2000	225,000	112,500	50,000(4)	9,029(2)

NAME	PRINCIPAL POSITION	YEAR	ANNUAL COMPENSATION SALARY	BONUS	LONG-TERM COMPENSATION(1) AWARDS OF OPTIONS (# OF SHARES)	ALL OTHER COMPENSATION
J. Michael Lacey.....	Senior Vice President	2002	$400,000	$487,500	53,000	$11,000(2)
		2001	$350,000	325,000	53,000	10,200(2)
		2000	325,000	300,000	35,000	10,200(2)
Darryl G. Smette.....	Senior Vice President	2002	$400,000	$487,500	53,000	$43,385(3)
		2001	$350,000	325,000	53,000	14,238(3)
		2000	300,000	300,000	35,000	10,200(2)
William T. Vaughn....	Senior Vice President	2002	$325,000	$400,000	53,000	$35,838(3)
		2001	290,000	275,000	53,000	13,546(3)
		2000	275,000	250,000	35,000	10,200(2)

(1) No awards of restricted stock or payments under long-term incentive plans were made by the company to any of the named executives in any periods covered by the table.

(2) Consists of company matching contributions to the Devon Energy Incentive Savings Plan.

(3) Consists of company matching contributions to the Devon Energy Incentive Savings Plan and the Devon Energy Deferred Compensation Savings Plan.

(4) Mr. Jennings received a one-time stock option award of 25,000 shares when he joined the Company in March 2000 in addition to his annual grant in November 2000.

OPTION GRANTS IN 2002

The following table sets forth information concerning options to purchase common stock granted in 2002 to the five individuals named in the Summary Compensation Table. The material terms of such options appear in the following table and the footnotes thereto.

INDIVIDUAL GRANTS					
NAME	OPTIONS GRANTED	PERCENT OF TOTAL OPTIONS GRANTED IN 2002	EXERCISE PRICE PER SHARE(1)	EXPIRATION DATE	GRANT DATE PRESENT VALUE(2)
J. Larry Nichols...........	105,000(3)	3.7%	$46.09	12/2/2012	$1,716,750
Brian J. Jennings..........	53,000(3)	1.9%	$46.09	12/2/2012	$ 866,550
J. Michael Lacey...........	53,000(3)	1.9%	$46.09	12/2/2012	$ 866,550
Darryl G. Smette...........	53,000(3)	1.9%	$46.09	12/2/2012	$ 866,550
William T. Vaughn..........	53,000(3)	1.9%	$46.09	12/2/2012	$ 866,550

(1) Exercise Price is the closing price of common stock as reported by the American Stock Exchange or "AMEX" on the date of grant.

(2) The Grant Date Present Value is an estimation of the possible future value of the option based upon the Black-Scholes Option Pricing Model. The following assumptions were used in the model: volatility (a measure of the historic variability of a stock price) -- 41.1%; risk-free interest rate (the interest paid by zero-coupon U.S. government issues with a remaining term equal to the expected life of the options) -- 3.1% per annum; annual dividend yield -- 0.4%; and expected life of the options -- five years from grant date. The option value estimated using this model does not necessarily represent the value to be realized by the named officers.

(3) These options were granted as of December 2, 2002. 20% of such grant was immediately vested and exercisable. An additional 20% of such grant becomes vested and exercisable on each of the next four anniversary dates of the original grant.

AGGREGATE OPTION EXERCISES IN 2002 AND YEAR-END OPTION VALUES

The following table sets forth information for the five individuals named in the Summary Compensation Table concerning the exercise of options to purchase common stock in 2002 and unexercised options to purchase common stock held at December 31, 2002.

NAME	NUMBER OF SHARES ACQUIRED UPON EXERCISE	VALUE REALIZED(2)	NUMBER OF UNEXERCISED OPTIONS AT 12/31/02		VALUE OF UNEXERCISED IN-THE-MONEY OPTIONS AT 12/31/02(1)	
			EXERCISABLE	UNEXERCISABLE	EXERCISABLE	UNEXERCISABLE
J. Larry Nichols.........	40,000	$531,400	431,000	147,000	$5,692,675	$696,150
J. Michael Lacey.........	--	--	107,036	74,200	$ 737,047	$351,390
Darryl G. Smette.........	--	--	197,900	74,200	$2,408,006	$351,390
William T. Vaughn........	10,000	$403,950	196,400	74,200	$2,305,288	$351,390
Brian J. Jennings........	--	--	71,800	84,200	$ 297,385	$351,390

(1) The value is based on the aggregate amount of the excess of $45.90 (the closing price as reported by the AMEX for December 31, 2002) over the relevant exercise price for outstanding options that were exercisable and in-the-money at year-end.

(2) The value is based on the excess of the market price over the relevant exercise price for the options exercised.

EMPLOYMENT AGREEMENTS

A small number of senior executives, including the five individuals named in the Summary Compensation Table, are entitled to certain additional compensation under the following events:

(1) employment with the company is involuntarily terminated other than for "Cause;" or

(2) employee voluntarily terminates for "Good Reason", as those terms are defined in each of the officers' employment agreements.

In either case the payment due to the officer would be equal to three times their annual compensation. In addition, the Employment Agreement provides for the officer to receive the same basic health and welfare benefits that he or she would otherwise be entitled to receive if he or she were an employee of the company for three years after termination. If the executive is terminated within two years of a "change in control," he or she is also entitled to an additional three years of service credit and age in determining eligibility for retiree medical and supplemental retirement benefits. "Change of control" is defined in the Employment Agreements the same as in the Retirement Plans described below.

RETIREMENT PLANS

We have three employee retirement plans, as follows:

Basic Plan........	The Basic Plan is a qualified defined benefit retirement plan which provides benefits based upon employment service with Devon. Each eligible employee who retires is entitled to receive annual retirement income, computed as a percentage of "final average compensation" (which consists of the average of the highest three consecutive years' salaries, wages, and bonuses out of the last ten years), and credited years of service up to 25 years. Contributions by employees are neither required nor permitted under the Basic Plan. Benefits are computed based on straight-life annuity amounts and are reduced by Social Security benefits. Benefits under the Basic Plan are reduced for certain highly compensated employees in order to comply with certain

requirements of the Employment Retirement Income Security Act of 1974 and the Internal Revenue Code.

The following table sets forth the credited years of service as of December 31, 2002 under Devon's Basic Plan for each of the five individuals named in the Summary Compensation Table.

NAME OF INDIVIDUAL	CREDITED YEARS OF SERVICE
J. Larry Nichols....................	25
J. Michael Lacey....................	14
Brian J. Jennings...................	3
Darryl G. Smette....................	16
William T. Vaughn...................	19

Benefit Restoration Plan.......................... The Benefit Restoration Plan is a non-qualified retirement benefit plan, the purpose of which is to restore retirement benefits for certain selected key management and highly compensated employees because their annual compensation is greater than the maximum annual compensation that can be considered in computing their benefits under the Basic Plan. An employee must be selected by the Compensation and Stock Option Committee in order to be eligible for participation in the Benefit Restoration Plan. All other provisions of the Benefit Restoration Plan mirror those of the Basic Plan. All of the five individuals named in the Summary Compensation Table have been selected to participate in the Benefit Restoration Plan. The Benefit Restoration Plan has been informally funded through a rabbi trust arrangement.

Supplemental Retirement Plan... The Supplemental Retirement Plan is another non-qualified retirement plan for a small group of executives, the purpose of which is to provide additional retirement benefits for long-service executives. The plan vests after 10 years of service, and provides retirement income equal to 65% of the executive's final average compensation, multiplied by a fraction, the numerator of which is his credited years of service (not to exceed 20) and the denominator of which is 20 (or less, if so determined by the Compensation and Stock Option Committee), less any offset amounts. Offset amounts are (i) benefits payable under the Basic Plan, (ii) benefits payable under the Benefit Restoration Plan, (iii) benefits due to the participant under Social Security, and (iii) any benefits paid to the participant under the company's long-term disability plan.

In general, benefits will be paid under the Supplemental Retirement Plan when the participant retires from the company. However, in the event that the executive's employment with the company is terminated under conditions that qualify him or her to a severance benefit under the Employment Agreement (see above), then the executive will be 100% vested in his or her benefit and entitled to receive the actuarial equivalent of such benefit earned as of the date of termination of employment. If the executive is terminated within two years following a "change of control," his or her benefit will be paid in a single lump sum payment. Otherwise, the benefit will be paid monthly for the life of the executive. "Change of control" is defined as the date on which one of the following occurs: (i) an entity or group acquires 30% or more of the company's outstanding voting securities, (ii) the incumbent board ceases to constitute at least a majority of the company's board, or (iii) a merger, reorganization or consolidation is consummated, after shareholder approval, unless (a) substantially all of the shareholders prior to the transaction continue to own more than 50% of the voting power after the transaction, (b) no person owns 30% or more of the combined voting securities, and (c) the incumbent board constitutes at least a majority of the board after the transaction. The Supplemental Retirement Plan is also informally funded through a rabbi trust arrangement.

The following table shows the estimated aggregate annual retirement benefits payable under the Basic Plan, the Benefit Restoration Plan and the Supplemental Retirement Plan to the participants therein, including the five individuals named in the Summary Compensation Table. The amount presented assumes a normal retirement in 2002 at age 65.

FINAL AVERAGE COMPENSATION	YEARS OF SERVICE			
	5	10	15	20 OR MORE
$ 500,000	$76,642	$153,284	$229,926	$ 306,568
600,000	92,892	185,784	278,676	371,568
700,000	109,142	218,284	327,426	436,568
800,000	125,392	250,784	376,176	501,568
900,000	141,642	283,284	424,926	566,568
1,000,000	157,892	315,784	473,676	631,568
1,500,000	239,142	478,284	717,426	956,568
2,000,000	320,392	640,784	961,176	1,281,568

DIRECTOR COMPENSATION

Non-management directors of Devon receive:

- an annual retainer of $40,000, payable quarterly.

- $2,000 for each Board meeting attended. Directors participating in a telephonic meeting receive a fee of $1,000;

- an additional $3,000 per year for serving as chairmen of a standing committee of the Board.

- $2,000 for each committee meeting attended that requires separate travel.

- $1,000 for each committee meeting that does not require separate travel.

Non-management directors are eligible to receive stock options in addition to their cash remuneration. Such directors are eligible to receive stock option grants of up to 3,000 shares immediately after each annual meeting of stockholders at an exercise price equal to the fair market value of the common stock on that date. Any unexercised options will expire ten years after the date of grant. The Compensation and Stock Option Committee, which awards options to non-management directors, may elect to grant awards that are less than the 3,000 shares maximum. However, the Compensation and Stock Option Committee has no other discretion regarding the award of stock options to non-management directors. The directors were eligible to receive stock options beginning in 1997. The following table sets forth information concerning options granted to non-management directors in 2002:

INDIVIDUAL GRANTS IN 2002

NAME	OPTIONS GRANTED(1)	PERCENT OF TOTAL OPTIONS GRANTED IN 2002	EXERCISE PRICE PER SHARE(2)	EXPIRATION DATE	GRANT DATE PRESENT VALUE(3)
Thomas F. Ferguson..........	3,000	0.1%	$49.91	5/16/2012	$60,759
David M. Gavrin.............	3,000	0.1%	$49.91	5/16/2012	$60,759
Michael E. Gellert..........	3,000	0.1%	$49.91	5/16/2012	$60,759
John A. Hill................	3,000	0.1%	$49.91	5/16/2012	$60,759
William J. Johnson..........	3,000	0.1%	$49.91	5/16/2012	$60,759
Michael M. Kanovsky.........	3,000	0.1%	$49.91	5/16/2012	$60,759
Robert A. Mosbacher, Jr. ...	3,000	0.1%	$49.91	5/16/2012	$60,759
J. Todd Mitchell............	3,000	0.1%	$49.91	5/16/2012	$60,759
Robert B. Weaver............	3,000	0.1%	$49.91	5/16/2012	$60,759

(1) The options were granted on May 16, 2002, and immediately became vested and exercisable.

(2) Exercise price is the fair market value on the date of grant, which is the closing price of common stock on the AMEX.

(3) The grant date present value is an estimation of the possible future value of the option grant based upon the Black-Scholes Option Pricing Model. The following assumptions were used in the model: volatility (a measure of the historic variability of a stock price) -- 40.0%; risk-free interest rate (the interest paid by zero-coupon U.S. government issues with a remaining term equal to the expected life of the options) -- 4.2% per annum; annual dividend yield -- 0.4%; and expected life of the options -- five years from grant date. The option value estimated using this model does not necessarily represent the value to be realized by the named directors.

COMPENSATION COMMITTEE INTERLOCKS

The compensation committee is composed of four independent, non-employee directors, Messrs. Gavrin, Gellert, Hill and Johnson. These directors have no interlocking relationships as defined by the Securities and Exchange Commission.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

EQUITY COMPENSATION PLAN INFORMATION

The following table sets forth information as of December 31, 2002 about Devon's common stock that may be issued under Devon's equity compensation plans.

PLAN CATEGORY	COLUMN a NUMBER OF SECURITIES TO BE ISSUED UPON EXERCISE OF OUTSTANDING OPTIONS, WARRANTS AND RIGHTS	COLUMN b WEIGHTED-AVERAGE EXERCISE PRICE OF OUTSTANDING OPTIONS, WARRANTS AND RIGHTS	COLUMN c NUMBER OF SECURITIES REMAINING AVAILABLE FOR FUTURE ISSUANCE UNDER EQUITY COMPENSATION PLANS (EXCLUDING SECURITIES REFLECTED IN COLUMN (A))
Equity compensation plans approved by security holders........................	7,799,000	$41.01	1,285,000(1)
Equity compensation plans not approved by security holders........................	--	--	--
Total(2)..................................	7,799,000	$41.01	1,285,000

(1) Of these shares, a maximum of 48,000 may be issued in the form of restricted stock.

(2) As of December 31, 2002, options to purchase an aggregate of 3,432,000 shares of Devon's common stock at a weighted average exercise price of $41.00 were outstanding under the following equity

compensation plans, which options were assumed in connection with merger and acquisition transactions: Santa Fe Energy Resources Incentive Compensation Plan 2000, Pennzoil Company 1997 Incentive Plan, Pennzoil Company 1997 Stock Option Plan, Mitchell Energy & Development Corp. 1995 Stock Option Plan, Santa Fe Energy Resources, Inc. 1995 Incentive Stock Compensation Plan, Pennzoil Company 1990 Stock Option Plan, Santa Fe Energy Resources 1990 Incentive Stock Compensation Plan, Snyder Oil Corporation 1990 Stock Plan for non-Employee Directors, Pennzoil Company 1995 Stock Option Plan, Pennzoil Company 1992 Stock Option Plan, Mitchell Energy & Development Corp. 1999 Stock Option Plan, Santa Fe Snyder Corporation 1999 Stock Compensation Retention Plan, PennzEnergy Company 1998 Incentive Plan, and Pennzoil Company 1998 Stock Option Plan. No further grants or awards will be made under the assumed equity compensation plans and the options under these equity compensation plans are not reflected in the table above.

PRINCIPAL SECURITY OWNERSHIP

The table below sets forth, as of February 24, 2002, the names and addresses of each person known by management to own beneficially more than 5% of our outstanding voting shares, the number of voting shares beneficially owned by each such stockholder and the percentage of outstanding voting shares owned. The table also sets forth the number and percentage of outstanding voting shares beneficially owned by our Chief Executive Officer, or CEO, each of our directors, the four most highly compensated executive officers other than the CEO and by all of our executive officers and directors as a group.

NAME AND ADDRESS OF BENEFICIAL OWNER	NUMBER OF SHARES(1)	PERCENT OF CLASS
Davis Selected Advisors, L.P. .... 2949 East Elvira Road, Suite 101 Tucson, AZ 85706	13,763,095(3)	8.48%
George P. Mitchell................................. 2001 Timberloch Place The Woodlands, TX 77380	13,305,393(2)	8.20%
KM Investment Corporation & Kerr-McGee Worldwide Corporation..................................... 123 Robert S. Kerr Avenue Oklahoma City, OK 73102	9,954,000(4)	6.13%
J. Larry Nichols*..................................	960,201(5)	**
J. Todd Mitchell*..................................	354,000(6)	**
Michael E. Gellert*................................	329,720(7)	**
Darryl G. Smette...................................	211,500(8)	**
William T. Vaughn..................................	210,342(9)	**
J. Michael Lacey...................................	112,201(10)	**
David M. Gavrin*...................................	90,181(11)	**
Brian J. Jennings..................................	78,951(12)	**
John A. Hill*......................................	60,264(13)	**
Michael M. Kanovsky*...............................	49,526(14)	**
Thomas F. Ferguson*................................	18,000(15)	**
William J. Johnson*................................	17,533(16)	**
Robert B. Weaver*..................................	9,523(17)	**
Robert A. Mosbacher, Jr.*..........................	9,223(18)	**
All of our directors and executive officers as a group (17 persons)...............................	2,845,193(19)	1.75%

* Director. The business address of each director is 20 North Broadway, Oklahoma City, Oklahoma 73102.

** Less than 1%.

(1) Shares beneficially owned includes shares of common stock, exchangeable shares and shares of common stock issuable within 60 days of February 24, 2003.

(2) George P. Mitchell has reported ownership on Schedule 13G filed on January 28, 2002. Mr. Mitchell disclaims beneficial ownership of 598,166 of these shares which are deemed beneficially owned by Mr. Mitchell's wife.

(3) Davis Selected Advisors, L.P. has reported ownership on Schedule 13G filed on February 14, 2002.

(4) KM Investment Corporation, a wholly owned subsidiary of Kerr-McGee Worldwide Corporation has reported beneficial ownership of these shares on Schedule 13G filed on January 13, 2003. Kerr-McGee acquired these shares on December 31, 1996, in connection with a transaction whereby Devon acquired the North American onshore oil and gas exploration and production properties and businesses of Kerr-McGee in exchange for 9,954,000 shares of common stock. On August 2, 1999, Kerr-McGee completed an offering of exchangeable notes which are due on August 2, 2004. These notes are exchangeable into our common stock owned by Kerr-McGee or, at Kerr-McGee's option, the cash equivalent of the value of that common stock. Kerr-McGee reports sole voting and investment power with respect to these shares.

(5) Includes 42,965 shares owned of record by Mr. Nichols as trustee of a family trust, 78,624 shares owned by Mr. Nichols' wife, and 431,000 shares which are deemed beneficially owned pursuant to stock options held by Mr. Nichols.

(6) Includes 351,000 shares acquired as a result of the merger of Mitchell Energy & Development Corp. (MND) into Devon at a conversion rate of .585 shares of DVN common stock for each share of MND Class A common stock. These shares are held by a family limited partnership, the general partner of which is a limited liability company that is owned in equal shares by the 10 adult children of George P. Mitchell and Cynthia Woods Mitchell and for which J. Todd Mitchell acts as the sole manager. The limited liability company owns a 0.1% general partnership interest in the partnership. Mr. & Mrs. Mitchell own a 5% limited partnership interest in the partnership, and the trusts for the 10 adult children of Mr. & Mrs. Mitchell (including J. Todd Mitchell) each owns a 9.49% limited partnership interest in the partnership. J. Todd Mitchell is the sole trustee of each of the trusts. J. Todd Mitchell disclaims beneficial ownership of the shares of common stock referred to in this footnote except to the extent of his pecuniary interest therein. The remaining 3,000 shares are deemed beneficially owned pursuant to stock options held by Mr. Mitchell.

(7) Includes 309,149 shares owned by Windcrest Partners, a limited partnership, in which Mr. Gellert shares investment and voting power and 18,000 shares which are deemed beneficially owned pursuant to stock options held by Mr. Gellert.

(8) Includes 197,900 shares that are deemed beneficially owned pursuant to stock options held by Mr. Smette.

(9) Includes 196,400 shares that are deemed beneficially owned pursuant to stock options held by Mr. Vaughn.

(10) Includes 107,036 shares that are deemed beneficially owned pursuant to stock options held by Mr. Lacey.

(11) Includes 10,320 shares owned by Mr. Gavrin's wife and 18,000 shares that are deemed beneficially owned pursuant to stock options held by Mr. Gavrin.

(12) Includes 78,951 shares that are deemed beneficially owned pursuant to stock options held by Mr. Jennings.

(13) Includes 11,942 shares owned by a partnership in which Mr. Hill shares voting and investment power, 4,727 shares owned by Mr. Hill's immediate family and 9,656 shares that are deemed beneficially owned pursuant to stock options held by Mr. Hill.

(14) Includes exchangeable shares that are convertible into 36,116 shares of common stock and 12,705 shares that are deemed beneficially owned pursuant to stock options held by Mr. Kanovsky.

(15) Includes 18,000 shares that are deemed beneficially owned pursuant to stock options held by Mr. Ferguson.

(16) Includes 10,128 shares that are deemed beneficially owned pursuant to stock options held by Mr. Johnson.

(17) Includes 9,000 shares that are deemed beneficially owned pursuant to stock options held by Mr. Weaver.

(18) Includes 9,000 shares that are deemed beneficially owned pursuant to stock options held by Mr. Mosbacher.

(19) Includes exchangeable shares that are convertible into 37,496 shares of common stock and 1,436,126 shares that are deemed beneficially owned pursuant to stock options held by officers and directors.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Not Applicable.

ITEM 14. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures and internal controls designed to ensure that information required to be disclosed in our filings under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Our principal executive and financial officers have evaluated our disclosure controls and procedures within 90 days prior to the filing of this Annual Report on Form 10-K and have determined that such disclosure controls and procedures are effective.

Subsequent to their evaluation, there were no significant changes in internal controls or other factors that could significantly affect internal controls, including any corrective actions with regard to significant deficiencies and material weaknesses.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENTS AND SCHEDULES, AND REPORTS ON FORM 8-K

(a) The following documents are filed as part of this report:

1. Consolidated Financial Statements

Reference is made to the Index to Consolidated Financial Statements and Consolidated Financial Statement Schedules appearing at Item 8 on Page of this report.

2. Consolidated Financial Statement Schedules

All financial statement schedules are omitted as they are inapplicable, or the required information has been included in the consolidated financial statements or notes thereto.

3. Exhibits

2002 10-K EXHIBIT NUMBER	DESCRIPTION
2.1	Agreement and Plan of Merger, dated as of February 23, 2003, by and among Devon Energy Corporation, Devon NewCo Corporation, and Ocean Energy, Inc. (incorporated by reference to Exhibit 99.2 to Registrant's Current Report on Form 8-K filed February 24, 2003)
2.2	Amended and Restated Agreement and Plan of Merger, dated as of August 13, 2001, by and among Devon Energy Corporation, Devon NewCo Corporation, Devon Holdco Corporation, Devon Merger Corporation, Mitchell Merger Corporation and Mitchell Energy & Development Corp. (incorporated by reference to Annex A to Registrant's Joint Proxy Statement/Prospectus of Form S-4 Registration Statement No. 333-68694 as filed August 30, 2001)
2.3	Offer to Purchase for Cash and Directors' Circular dated September 6, 2001 (incorporated by reference to Registrant's and Devon Acquisition Corporation's Schedule 14D-1F filing, filed September 6, 2001)
2.4	Pre-Acquisition Agreement, dated as of August 31, 2001, between Devon Energy Corporation and Anderson Exploration Ltd. (incorporated by reference to Exhibit 2.2 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed September 14, 2001)
2.5	Agreement and Plan of Merger by and among Registrant, Devon Merger Co. and Santa Fe Snyder Corporation dated as of May 25, 2000 (incorporated by reference to Registrant's Registration Statement on Form S-4, File No. 333-39908).
2.6	Amendment No. One, dated as of July 11, 2000, to Agreement and Plan of Merger by and among Registrant, Devon Merger Co. and Santa Fe Snyder Corporation dated as of May 25, 2000 (incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on July 12, 2000).
2.7	Amended and Restated Agreement and Plan of Merger among Registrant, Devon Energy Corporation (Oklahoma), Devon Oklahoma Corporation and PennzEnergy Company dated as of May 19, 1999 (incorporated by reference to Exhibit 2.1 to Registrant's Form S-4, File No. 333-82903).
2.8	Amended and Restated Combination Agreement between Registrant and Northstar Energy Corporation dated as of June 29, 1998 (incorporated by reference to Annex B to Registrant's definitive proxy statement for a special meeting of shareholders, filed November 6, 1998).
3.1	Registrant's Restated Certificate of Incorporation (incorporated by reference to Exhibit 3 to Registrant's Form 8-K filed August 18, 1999).
3.2	Registrant's Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to Registrant's definitive proxy statement for a special meeting of shareholders filed July 21, 2000).
4.1	Rights Agreement dated as of August 17, 1999 between Registrant and BankBoston, N.A. (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed on August 18, 1999).
4.2	Amendment to Rights Agreement, dated as of May 25, 2000, by and between Devon Energy Corporation and Fleet National Bank (f/k/a BankBoston, N.A.) (incorporated by reference to Exhibit 4.2 to Devon Energy Corporation's definitive proxy statement for a special meeting of shareholders filed on July 21, 2000)
4.3	Amendment to Rights Agreement, dated as of October 4, 2001, by and between Devon Energy Corporation and Fleet National Bank (f/k/a Bank Boston, N.A.) (incorporated by reference to Exhibit 99.1 to Devon Energy Corporation's Form 8-K filed on October 11, 2001)
4.4	Amendment to Rights Agreement, dated September 13, 2002, between Devon and Wachovia Bank, N.A (incorporated by reference to Exhibit 4.9 to Registrant's Registration Statement on Form S-3 File Nos. 333-83156, 333-83156-1, and 333-83156-2 as filed on October 4, 2002).
4.5	Registration Rights Agreement dated December 31, 1996, by and between Registrant and Kerr-McGee Corporation (incorporated by reference to Exhibit 4.4 to Registrant's Form 8-K filed on January 14, 1997).
4.6	Certificate of Designations of Series A Junior Participating Preferred Stock of Registrant (incorporated by reference to Exhibit 4.3 to Registrant's Form 8-K filed on August 18, 1999).

2002 10-K EXHIBIT NUMBER	DESCRIPTION
4.7	Certificate of Designations of the 6.49% Cumulative Preferred Stock, Series A of Registrant (incorporated by reference to Exhibit 4(g) to Registrant's Form 8-K filed on August 18, 1999).
4.8	Indenture, dated as of March 1, 2002, between Devon and The Bank of New York, as Trustee, relating to senior debt securities issuable by Devon (the "Senior Indenture")(incorporated by reference to Exhibit 4.1 of Registrant's Form 8-K filed April 9, 2002).
4.9	Supplemental Indenture No. 1, dated as of March 25, 2002, between Devon and The Bank of New York, as Trustee, establishing $1,000,000,000 principal amount of 7.95% Senior Debentures due April 15, 2032 as a series of debt securities under the Senior Indenture (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed on April 9, 2002).
4.10	Indenture, dated as of October 3, 2001, by and among Devon Financing Corporation, U.L.C. (as issuer), Devon Energy Corporation (as guarantor) and The Chase Manhattan Bank (as trustee) (incorporated by reference to Exhibit 4.7 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001)
4.11	Indenture dated as of June 27, 2000 between Registrant and The Bank of New York, setting forth the terms of the Zero Coupon Convertible Senior Debentures due 2020 (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed July 12, 2000).
4.12	Senior Indenture dated as of June 1, 1999 between Santa Fe Snyder and The Bank of New York, as Trustee, relating to Santa Fe Snyder Corporation's 8.05% Senior Notes due 2004 (incorporated by reference to Exhibit 4.1 to Santa Fe Snyder Corporation's Form 8-K filed on June 15, 1999).
4.13	First Supplemental Indenture dated as of June 14, 1999 to Senior Indenture dated June 1, 1999 between Santa Fe Snyder and The Bank of New York, as Trustee, relating to Santa Fe Snyder's 8.05% Senior Notes due 2004 (incorporated by reference to Exhibit 4.2 to Santa Fe Snyder Corporation's Form 8-K filed on June 15, 1999).
4.14	Second Supplemental Indenture, dated as of October 31, 2002, by and between Devon Energy Production Company, L.P., as Successor to the Issuer, and the Bank of New York, as Trustee, supplementing the Indenture dated as of June 1, 1999, as supplemented by the First Supplemental Indenture, dated as of June 14, 1999, by and between Devon SFS Operating, Inc. and the Trustee relating to Santa Fe Snyder Corporation's 8.05% Senior Notes due 2004 (incorporated by reference to Exhibit 4.1 of Registrant's Form 10-Q filed November 14, 2002).
4.15	Indenture dated as of December 15, 1992 between Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Texas Commerce Bank National Association, Trustee setting forth the terms of the 4.90% Exchangeable Senior Debentures due 2008 and the 4.95% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4(o) to Pennzoil Company's Form 10-K filed March 10, 1993 (SEC File No. 1-5591)).
4.16	First Supplemental Indenture dated as of January 13, 1993 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association (incorporated by reference to Exhibit 4(p) to Pennzoil Company's Form 10-K for the year ended December 31, 1992).
4.17	Second Supplemental Indenture dated as of October 12, 1993 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association (incorporated by reference to Exhibit 4(i) to Pennzoil Company's Form 10-K for the year ended December 31, 1993).
4.18	Third Supplemental Indenture dated as of August 3, 1998 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association, supplements the terms of the 4.90% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4(g) to PennzEnergy Company's Form 10-K for the year ended December 31, 1998).

2002 10-K EXHIBIT NUMBER	DESCRIPTION
4.19	Fourth Supplemental Indenture dated as of August 3, 1998 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association, supplements the terms of the 4.95% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4(h) to PennzEnergy Company's Form 10-K for the year ended December 31, 1998).
4.20	Fifth Supplemental Indenture dated as of August 17, 1999 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association supplements the terms of the 4.90% Exchangeable Senior Debentures due 2008 and the 4.95% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4.7 to Registrant's Form 8-K filed on August 18, 1999).
4.21	Indenture dated as of February 15, 1986 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Mellon Bank, N.A. (incorporated by reference to Exhibit 4(a) to Pennzoil Company's Form 10-Q for the quarter ended June 30, 1986 (SEC File No. 1-5591).
4.22	First Supplemental Indenture dated as of August 17, 1999 to Indenture dated as of February 15, 1986 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association supplementing the terms of the 10.625% Debentures due 2001, 10.125% Debentures due 2009, 9.625% Notes due 1999 and 10.25% Debentures due 2005 (incorporated by reference to Exhibit 4.8 to Registrant's Form 8-K filed on August 18, 1999).
4.23	Support Agreement, dated December 10, 1998, between the Registrant and Northstar Energy Corporation (incorporated by reference to Exhibit 4.1 to Devon Energy Corporation (Oklahoma)'s (predecessor to Registrant) Form 8-K dated as of December 11, 1998).
4.24	Amending Support Agreement dated August 17, 1999, between the Registrant and Northstar Energy Corporation (incorporated by reference to Exhibit 4.5 to Registrant's Form 8-K filed on August 18, 1999).
4.25	Exchangeable Share Provisions (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed December 23, 1998).
4.26	Amended Exchangeable Share Provisions dated as of August 17, 1999 (incorporated by reference to Exhibit 4.17 to Registrant's Form 10-K for the year ended December 31, 1999).
9.1	Voting and Exchange Trust Agreement, dated December 10, 1998, by and between the Registrant, Northstar Energy Corporation and CIBC Mellon Trust Company (incorporated by reference to Exhibit 9 to Registrant's Form 8-K filed on December 23, 1998).
9.2	Amending Voting and Exchange Trust Agreement, dated as of August 17, 1999, by and between Registrant, Northstar Energy Corporation and CIBC Mellon Trust Company (incorporated by reference to Exhibit 9 to Registrant's Form 8-K filed on August 18, 1999).
10.1	Amended and Restated Investor Rights Agreement, dated as of August 13, 2001, by and among Devon Energy Corporation, Devon Holdco Corporation, George P. Mitchell and Cynthia Woods Mitchell (attached as Annex C to the Joint Proxy Statement/Prospectus of Form S-4 Registration Statement No. 333-68694 as filed August 30, 2001)
10.2	Credit Agreement dated July 25, 2002, by and among Northstar Energy Corporation and Devon Canada Corporation, as Borrowers and RBC Capital Markets, as Arranger and Royal Bank of Canada, as Administrative Agent and Certain Financial Institutions, as Lenders for the Cdn. $140 million credit facility (incorporated by reference to Exhibit 10.3 to Registrant's Form 10-Q filed on August 13, 2002).
10.3	Letter Agreement dated July 25, 2002, by and among Northstar Energy Corporation and Devon Canada Corporation, as Borrowers and Royal Bank of Canada acting through its Canadian Branch , as Lender for the Cdn. $10 million credit facility (incorporated by reference to Exhibit 10.4 to Registrant's Form 10-Q filed August 13, 2002).

2002 10-K EXHIBIT NUMBER	DESCRIPTION
10.4	Amended and Restated Canadian Credit Agreement dated June 7, 2002 among Northstar Energy Corporation and Devon Canada Corporation, as Canadian Borrowers, Bank of America, N.A. acting through its Canadian Branch, as Administrative Agent, and Certain Financial Institutions, as Lenders (incorporated by reference to Registrant's Form 10-Q filed on August 13, 2002).
10.5	Canadian Credit Agreement dated August 29, 2000, among Northstar Energy Corporation and Devon Energy Canada Corporation, as Canadian Borrowers, Bank of America Canada, as Administrative Agent, Banc of America Securities, LLC, as Lead Arranger, BancOne Capital Markets, Inc., as Syndication Agent, The Chase Manhattan Bank, as Documentation Agent, First Union National Bank, as Co-Documentation Agent, and Certain Financial Institutions, as Lenders for the $275 million credit facility (incorporated by reference to Exhibit 10.2 to Registrant's Form 10-K filed on March 15, 2001).
10.6	First Amendment to Canadian Credit Agreement dated March 1, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.2.1 to Registrant's Form 10-Q filed on May 14, 2001).
10.7	Second Amendment to Canadian Credit Agreement dated as of June 27, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent, and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.2.2 to Registrant's Form 10-Q filed on August 14, 2001).
10.8	Third Amendment to Canadian Credit Agreement dated as of July 31, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent, and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.8 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001)
10.9	Fourth Amendment to Canadian Credit Agreement dated as of August 13, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent, and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.9 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001)
10.10	Fifth Amendment to Canadian Credit Agreement dated as of September 21, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent, and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.10 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001)
10.11	Sixth Amendment to Canadian Credit Agreement dated as of October 5, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent, and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.11 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001)
10.12	U.S. Credit Agreement, dated August 29, 2000 among the Registrant, as U.S. Borrower, Bank of America, N.A., as Administrative Agent, Banc of America Securities, LLC, as Lead Arranger, Banc One Capital Markets, Inc., as Syndication Agent, The Chase Manhattan Bank, as Documentation Agent, First Union National Bank, as Co-Documentation Agent, and Certain Financial Institutions, as Lenders for the $725 million credit facility (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-K filed on March 15, 2001).
10.13	First Amendment to U.S. Credit Agreement dated March 1, 2001, among Registrant, Bank of America N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.1.1 to Registrant's Form 10-Q filed on May 14, 2001).

2002 10-K EXHIBIT NUMBER	DESCRIPTION
10.14	Second Amendment to U.S. Credit Agreement dated as of June 27, 2001, among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.1.2 to Registrant's Form 10-Q filed on August 14, 2001).
10.15	Third Amendment to U.S. Credit Agreement dated as of July 31, 2001, among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.4 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001)
10.16	Fourth Amendment to U.S. Credit Agreement dated as of August 13, 2001, among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.5 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001)
10.17	Fifth Amendment to U.S. Credit Agreement dated as of September 21, 2001, among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.6 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001)
10.18	Sixth Amendment to U.S. Credit Agreement dated as of October 5, 2001, among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.7 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001)
10.19	Seventh Amendment to U.S. Credit Agreement dated June 7, 2002 by and among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to this Amendment (incorporated by reference to Registrant's Form 10-Q filed on August 13, 2002).
10.20	Credit Agreement, dated as of October 12, 2001, by and among Devon Energy Corporation, Devon Financing Corporation, U.L.C., UBS AG, Stamford Branch (as Administrative Agent), and the lenders signatory thereto (incorporated by reference to Exhibit 10.3 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001)
10.21	Devon Energy Corporation Restricted Stock Bonus Plan (incorporated by reference to Registrant's Form S-8 filed on August 29, 2000, File No. 333-44702).*
10.22	Mitchell Energy & Development Corp. 1997 Bonus Unit Plan (incorporated by reference to Exhibit 10(e) to Mitchell Energy & Development Corp.'s Annual Report on Form 10-K for the year ended January 31, 1998).*
10.23	First Amendment to Mitchell Energy & Development Corp. 1997 Bonus Unit Plan (incorporated by reference to exhibit 10(c) of the Mitchell Energy & Development Corp. annual report on Form 10-K dated January 31, 1999).*
10.24	Mitchell Energy & Development Corp. 1999 Stock Option Plan (incorporated by reference to exhibit 10(d) of the annual report on Form 10-K dated January 31, 2000).*
10.25	Santa Fe Snyder Corporation 1999 Stock Compensation Retention Plan (incorporated by reference to Exhibit 10(a) to Santa Fe Snyder Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 1999).*
10.26	PennzEnergy Company 1998 Incentive Plan (incorporated by reference to Exhibit 4.3 to Pennzoil Company's Form S-8 filed on December 29, 1998 SEC No. 333-69845).*
10.27	Pennzoil Company 1998 Stock Option Plan (incorporated by reference to SEC File No. 333-59011).*
10.28	Santa Fe Energy Resources Incentive Compensation Plan, as amended (incorporated by reference to exhibit 10(a) to Santa Fe Energy Resources, Inc.'s Annual Report on Form 10-K for the year ended December 31, 1998).*

2002 10-K EXHIBIT NUMBER	DESCRIPTION
10.29	Devon Energy Corporation 1997 Stock Option Plan (incorporated by reference to Exhibit A to Registrant's Proxy Statement for the 1997 Annual Meeting of Shareholders filed on April 3, 1997).*
10.30	Pennzoil Company 1997 Incentive Plan (incorporated by reference to Exhibit A to Pennzoil Company definitive proxy material filed on March 21, 1997, SEC File No. 1-5591).*
10.31	Pennzoil Company 1997 Stock Option Plan (incorporated by reference to SEC File No. 333-26021).*
10.32	Santa Fee Energy Resources, Inc. 1995 Incentive Stock Compensation Plan for Nonexecutive Officers (incorporated by reference to SEC File No. 033-59255).*
10.33	Santa Fe Energy Resources, Inc. 1995 Incentive Stock Compensation Plan for Nonexecutive Officers (incorporated by reference to SEC File No. 033-59255).*
10.34	Devon Energy Corporation 1993 Stock Option Plan (incorporated by reference to Exhibit A to Registrant's Proxy Statement for the 1993 Annual Meeting of Shareholders filed on May 6, 1993).*
10.35	Pennzoil Company 1993 Conditional Stock Award Program (incorporated by reference to Exhibit B to Pennzoil Company's definitive proxy material filed on April 13, 1993, File No. 1-5591).*
10.36	Santa Fe Energy Resources Deferred Compensation Plan, effective as of January 1, 1991, as amended and restated, effective February 1, 1994 (incorporated by reference to Exhibit 10(p) to Santa Fe Energy Resources, Inc.'s Annual Report on Form 10-K for the year ended December 31, 1993).*
10.37	Pennzoil Company 1990 Stock Option Plan (incorporated by reference to Pennzoil Company's definitive proxy material filed on April 26, 1990, File No. 1-5591).*
10.38	Santa Fe Energy Resources 1990 Incentive Stock Compensation Plan, Third Amendment and Restatement (incorporated by reference to Exhibit 10(a) to Santa Fe Energy Resources, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 1996).*
10.39	Santa Fe Energy Resources, Inc. Supplemental Retirement Plan effective as of December 4, 1990 (incorporated by reference to Exhibit 10(h) to Santa Fe Energy Resources, Inc.'s Annual Report on Form 10-K for the year ended December 31, 1996).*
10.40	Snyder Oil Corporation 1990 Stock Plan for non-Employee Directors (incorporated by reference to Exhibit 10.4 to SEC File No. 33-33455).*
10.41	Devon Energy Corporation 1988 Stock Option Plan (incorporated by reference to Exhibit 10.4 to Registrant's Registration Statement on Form S-8 filed on August 19, 1999, SEC File No. 333-85553).*
10.42	Supplemental Retirement Income Agreement among Devon Energy Corporation (Nevada), Registrant and John W. Nichols, dated March 26, 1997 (incorporated by reference to Exhibit 10.13 to Registrant's Form 10-Q for the quarter ended June 30, 1997).*
10.43	Severance Agreement between Devon Energy Corporation (Nevada), Devon Energy Corporation, Devon Delaware Corporation and J. Larry Nichols, dated May 19, 1999 (incorporated by reference to Exhibit 10.3 to Registrant's Form 10-Q for the quarter ended September 30, 1999).*
10.44	Form of Employment Agreement between Registrant and Brian J. Jennings, J. Michael Lacey, Duke R. Ligon, Marian J. Moon, John Richels, Darryl G. Smette and William T. Vaughn, dated January 1, 2002. (incorporated by reference to Exhibit 10.26 of Registrant's Form 10-K for the year ended December 31, 2001).*
12	Statement of computations of ratios of earnings to fixed charges and to combined fixed charges and preferred stock dividends.
21	List of Significant Subsidiaries of Registrant.

2002 10-K EXHIBIT NUMBER	DESCRIPTION
23.1	Consent of KPMG LLP
23.2	Consent of LaRoche Petroleum Consultants
23.3	Consent of Paddock Lindstrom & Associates Ltd.
23.4	Consent of Ryder Scott Company, L.P.
23.5	Consent of Gilbert Laustsen Jung Associates Ltd.
23.6	Consent of AJM Petroleum Consultants
99.1	Certification of J. Larry Nichols, Chief Executive Officer
99.2	Certification of William T. Vaughn, Chief Financial Officer

* Compensatory plans or arrangements

(b) Reports on Form 8-K:

On October 3, 2002, the Company filed updated financial statements, which take into effect the reclassification of Devon's Indonesia activities as discontinued operations following the sale of Indonesia.

On December 11, 2002, the Company filed forward-looking statements in connection with its December 31, 2002 reserve reports of independent petroleum engineers.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

DEVON ENERGY CORPORATION

By /s/ J. LARRY NICHOLS
J. Larry Nichols,
Chairman of the Board, President and Chief Executive Officer

March 5, 2003

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 and in the capacities and on the dates indicated.

/s/ J. LARRY NICHOLS J. Larry Nichols	Chairman of the Board, President and Chief Executive Officer	March 5, 2003
/s/ WILLIAM T. VAUGHN William T. Vaughn	Senior Vice President -- Finance and Chief Financial Officer	March 5, 2003
/s/ DANNY J. HEATLY Danny J. Heatly	Vice President -- Accounting	March 5, 2003
/s/ THOMAS F. FERGUSON Thomas F. Ferguson	Director	March 5, 2003
/s/ DAVID M. GAVRIN David M. Gavrin	Director	March 5, 2003
/s/ MICHAEL E. GELLERT Michael E. Gellert	Director	March 5, 2003
/s/ JOHN A. HILL John A. Hill	Director	March 5, 2003
/s/ WILLIAM J. JOHNSON William J. Johnson	Director	March 5, 2003
/s/ MICHAEL M. KANOVSKY Michael M. Kanovsky	Director	March 5, 2003
/s/ J. TODD MITCHELL J. Todd Mitchell	Director	March 5, 2003

/s/ ROBERT MOSBACHER, JR. -- Robert A. Mosbacher, Jr.	Director	March 5, 2003
/s/ ROBERT B. WEAVER -- Robert B. Weaver	Director	March 5, 2003

CERTIFICATION

I, J. Larry Nichols, certify that:

1. I have reviewed this annual report on Form 10-K of Devon Energy Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

/s/ J. LARRY NICHOLS

J. Larry Nichols
Chief Executive Officer

Date: March 5, 2003

CERTIFICATION

I, William T. Vaughn, certify that:

1. I have reviewed this annual report on Form 10-K of Devon Energy Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

/s/ WILLIAM T. VAUGHN

William T. Vaughn
Chief Financial Officer

Date: March 5, 2003

INDEX TO EXHIBITS

2002 10-K EXHIBIT NUMBER	DESCRIPTION
2.1	Agreement and Plan of Merger, dated as of February 23, 2003, by and among Devon Energy Corporation, Devon NewCo Corporation, and Ocean Energy, Inc. (incorporated by reference to Exhibit 99.2 to Registrant's Current Report on Form 8-K filed February 24, 2003)
2.2	Amended and Restated Agreement and Plan of Merger, dated as of August 13, 2001, by and among Devon Energy Corporation, Devon NewCo Corporation, Devon Holdco Corporation, Devon Merger Corporation, Mitchell Merger Corporation and Mitchell Energy & Development Corp. (incorporated by reference to Annex A to Registrant's Joint Proxy Statement/Prospectus of Form S-4 Registration Statement No. 333-68694 as filed August 30, 2001)
2.3	Offer to Purchase for Cash and Directors' Circular dated September 6, 2001 (incorporated by reference to Registrant's and Devon Acquisition Corporation's Schedule 14D-1F filing, filed September 6, 2001)
2.4	Pre-Acquisition Agreement, dated as of August 31, 2001, between Devon Energy Corporation and Anderson Exploration Ltd. (incorporated by reference to Exhibit 2.2 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed September 14, 2001)
2.5	Agreement and Plan of Merger by and among Registrant, Devon Merger Co. and Santa Fe Snyder Corporation dated as of May 25, 2000 (incorporated by reference to Registrant's Registration Statement on Form S-4, File No. 333-39908).
2.6	Amendment No. One, dated as of July 11, 2000, to Agreement and Plan of Merger by and among Registrant, Devon Merger Co. and Santa Fe Snyder Corporation dated as of May 25, 2000 (incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on July 12, 2000).
2.7	Amended and Restated Agreement and Plan of Merger among Registrant, Devon Energy Corporation (Oklahoma), Devon Oklahoma Corporation and PennzEnergy Company dated as of May 19, 1999 (incorporated by reference to Exhibit 2.1 to Registrant's Form S-4, File No. 333-82903).
2.8	Amended and Restated Combination Agreement between Registrant and Northstar Energy Corporation dated as of June 29, 1998 (incorporated by reference to Annex B to Registrant's definitive proxy statement for a special meeting of shareholders, filed November 6, 1998).
3.1	Registrant's Restated Certificate of Incorporation (incorporated by reference to Exhibit 3 to Registrant's Form 8-K filed August 18, 1999).
3.2	Registrant's Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to Registrant's definitive proxy statement for a special meeting of shareholders filed July 21, 2000).
4.1	Rights Agreement dated as of August 17, 1999 between Registrant and BankBoston, N.A. (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed on August 18, 1999).
4.2	Amendment to Rights Agreement, dated as of May 25, 2000, by and between Devon Energy Corporation and Fleet National Bank (f/k/a BankBoston, N.A.) (incorporated by reference to Exhibit 4.2 to Devon Energy Corporation's definitive proxy statement for a special meeting of shareholders filed on July 21, 2000)
4.3	Amendment to Rights Agreement, dated as of October 4, 2001, by and between Devon Energy Corporation and Fleet National Bank (f/k/a Bank Boston, N.A.) (incorporated by reference to Exhibit 99.1 to Devon Energy Corporation's Form 8-K filed on October 11, 2001)
4.4	Amendment to Rights Agreement, dated September 13, 2002, between Devon and Wachovia Bank, N.A (incorporated by reference to Exhibit 4.9 to Registrant's Registration Statement on Form S-3 File Nos. 333-83156, 333-83156-1, and 333-83156-2 as filed on October 4, 2002).
4.5	Registration Rights Agreement dated December 31, 1996, by and between Registrant and Kerr-McGee Corporation (incorporated by reference to Exhibit 4.4 to Registrant's Form 8-K filed on January 14, 1997).

2002 10-K EXHIBIT NUMBER	DESCRIPTION
4.6	Certificate of Designations of Series A Junior Participating Preferred Stock of Registrant (incorporated by reference to Exhibit 4.3 to Registrant's Form 8-K filed on August 18, 1999).
4.7	Certificate of Designations of the 6.49% Cumulative Preferred Stock, Series A of Registrant (incorporated by reference to Exhibit 4(g) to Registrant's Form 8-K filed on August 18, 1999).
4.8	Indenture, dated as of March 1, 2002, between Devon and The Bank of New York, as Trustee, relating to senior debt securities issuable by Devon (the "Senior Indenture")(incorporated by reference to Exhibit 4.1 of Registrant's Form 8-K filed April 9, 2002).
4.9	Supplemental Indenture No. 1, dated as of March 25, 2002, between Devon and The Bank of New York, as Trustee, establishing $1,000,000,000 principal amount of 7.95% Senior Debentures due April 15, 2032 as a series of debt securities under the Senior Indenture (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed on April 9, 2002).
4.10	Indenture, dated as of October 3, 2001, by and among Devon Financing Corporation, U.L.C. (as issuer), Devon Energy Corporation (as guarantor) and The Chase Manhattan Bank (as trustee) (incorporated by reference to Exhibit 4.7 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001)
4.11	Indenture dated as of June 27, 2000 between Registrant and The Bank of New York, setting forth the terms of the Zero Coupon Convertible Senior Debentures due 2020 (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed July 12, 2000).
4.12	Senior Indenture dated as of June 1, 1999 between Santa Fe Snyder and The Bank of New York, as Trustee, relating to Santa Fe Snyder Corporation's 8.05% Senior Notes due 2004 (incorporated by reference to Exhibit 4.1 to Santa Fe Snyder Corporation's Form 8-K filed on June 15, 1999).
4.13	First Supplemental Indenture dated as of June 14, 1999 to Senior Indenture dated June 1, 1999 between Santa Fe Snyder and The Bank of New York, as Trustee, relating to Santa Fe Snyder's 8.05% Senior Notes due 2004 (incorporated by reference to Exhibit 4.2 to Santa Fe Snyder Corporation's Form 8-K filed on June 15, 1999).
4.14	Second Supplemental Indenture, dated as of October 31, 2002, by and between Devon Energy Production Company, L.P., as Successor to the Issuer, and the Bank of New York, as Trustee, supplementing the Indenture dated as of June 1, 1999, as supplemented by the First Supplemental Indenture, dated as of June 14, 1999, by and between Devon SFS Operating, Inc. and the Trustee relating to Santa Fe Snyder Corporation's 8.05% Senior Notes due 2004 (incorporated by reference to Exhibit 4.1 of Registrant's Form 10-Q filed November 14, 2002).
4.15	Indenture dated as of December 15, 1992 between Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Texas Commerce Bank National Association, Trustee setting forth the terms of the 4.90% Exchangeable Senior Debentures due 2008 and the 4.95% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4(o) to Pennzoil Company's Form 10-K filed March 10, 1993 (SEC File No. 1-5591)).
4.16	First Supplemental Indenture dated as of January 13, 1993 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association (incorporated by reference to Exhibit 4(p) to Pennzoil Company's Form 10-K for the year ended December 31, 1992).
4.17	Second Supplemental Indenture dated as of October 12, 1993 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association (incorporated by reference to Exhibit 4(i) to Pennzoil Company's Form 10-K for the year ended December 31, 1993).

2002 10-K EXHIBIT NUMBER	DESCRIPTION
4.18	Third Supplemental Indenture dated as of August 3, 1998 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association, supplements the terms of the 4.90% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4(g) to PennzEnergy Company's Form 10-K for the year ended December 31, 1998).
4.19	Fourth Supplemental Indenture dated as of August 3, 1998 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association, supplements the terms of the 4.95% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4(h) to PennzEnergy Company's Form 10-K for the year ended December 31, 1998).
4.20	Fifth Supplemental Indenture dated as of August 17, 1999 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association supplements the terms of the 4.90% Exchangeable Senior Debentures due 2008 and the 4.95% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4.7 to Registrant's Form 8-K filed on August 18, 1999).
4.21	Indenture dated as of February 15, 1986 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Mellon Bank, N.A. (incorporated by reference to Exhibit 4(a) to Pennzoil Company's Form 10-Q for the quarter ended June 30, 1986 (SEC File No. 1-5591).
4.22	First Supplemental Indenture dated as of August 17, 1999 to Indenture dated as of February 15, 1986 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association supplementing the terms of the 10.625% Debentures due 2001, 10.125% Debentures due 2009, 9.625% Notes due 1999 and 10.25% Debentures due 2005 (incorporated by reference to Exhibit 4.8 to Registrant's Form 8-K filed on August 18, 1999).
4.23	Support Agreement, dated December 10, 1998, between the Registrant and Northstar Energy Corporation (incorporated by reference to Exhibit 4.1 to Devon Energy Corporation (Oklahoma)'s (predecessor to Registrant) Form 8-K dated as of December 11, 1998).
4.24	Amending Support Agreement dated August 17, 1999, between the Registrant and Northstar Energy Corporation (incorporated by reference to Exhibit 4.5 to Registrant's Form 8-K filed on August 18, 1999).
4.25	Exchangeable Share Provisions (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed December 23, 1998).
4.26	Amended Exchangeable Share Provisions dated as of August 17, 1999 (incorporated by reference to Exhibit 4.17 to Registrant's Form 10-K for the year ended December 31, 1999).
9.1	Voting and Exchange Trust Agreement, dated December 10, 1998, by and between the Registrant, Northstar Energy Corporation and CIBC Mellon Trust Company (incorporated by reference to Exhibit 9 to Registrant's Form 8-K filed on December 23, 1998).
9.2	Amending Voting and Exchange Trust Agreement, dated as of August 17, 1999, by and between Registrant, Northstar Energy Corporation and CIBC Mellon Trust Company (incorporated by reference to Exhibit 9 to Registrant's Form 8-K filed on August 18, 1999).
10.1	Amended and Restated Investor Rights Agreement, dated as of August 13, 2001, by and among Devon Energy Corporation, Devon Holdco Corporation, George P. Mitchell and Cynthia Woods Mitchell (attached as Annex C to the Joint Proxy Statement/Prospectus of Form S-4 Registration Statement No. 333-68694 as filed August 30, 2001)
10.2	Credit Agreement dated July 25, 2002, by and among Northstar Energy Corporation and Devon Canada Corporation, as Borrowers and RBC Capital Markets, as Arranger and Royal Bank of Canada, as Administrative Agent and Certain Financial Institutions, as Lenders for the Cdn. $140 million credit facility (incorporated by reference to Exhibit 10.3 to Registrant's Form 10-Q filed on August 13, 2002).

2002 10-K EXHIBIT NUMBER	DESCRIPTION
10.3	Letter Agreement dated July 25, 2002, by and among Northstar Energy Corporation and Devon Canada Corporation, as Borrowers and Royal Bank of Canada acting through its Canadian Branch , as Lender for the Cdn. $10 million credit facility (incorporated by reference to Exhibit 10.4 to Registrant's Form 10-Q filed August 13, 2002).
10.4	Amended and Restated Canadian Credit Agreement dated June 7, 2002 among Northstar Energy Corporation and Devon Canada Corporation, as Canadian Borrowers, Bank of America, N.A. acting through its Canadian Branch, as Administrative Agent, and Certain Financial Institutions, as Lenders (incorporated by reference to Registrant's Form 10-Q filed on August 13, 2002).
10.5	Canadian Credit Agreement dated August 29, 2000, among Northstar Energy Corporation and Devon Energy Canada Corporation, as Canadian Borrowers, Bank of America Canada, as Administrative Agent, Banc of America Securities, LLC, as Lead Arranger, BancOne Capital Markets, Inc., as Syndication Agent, The Chase Manhattan Bank, as Documentation Agent, First Union National Bank, as Co-Documentation Agent, and Certain Financial Institutions, as Lenders for the $275 million credit facility (incorporated by reference to Exhibit 10.2 to Registrant's Form 10-K filed on March 15, 2001).
10.6	First Amendment to Canadian Credit Agreement dated March 1, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.2.1 to Registrant's Form 10-Q filed on May 14, 2001).
10.7	Second Amendment to Canadian Credit Agreement dated as of June 27, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent, and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.2.2 to Registrant's Form 10-Q filed on August 14, 2001).
10.8	Third Amendment to Canadian Credit Agreement dated as of July 31, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent, and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.8 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001)
10.9	Fourth Amendment to Canadian Credit Agreement dated as of August 13, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent, and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.9 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001)
10.10	Fifth Amendment to Canadian Credit Agreement dated as of September 21, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent, and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.10 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001)
10.11	Sixth Amendment to Canadian Credit Agreement dated as of October 5, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent, and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.11 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001)
10.12	U.S. Credit Agreement, dated August 29, 2000 among the Registrant, as U.S. Borrower, Bank of America, N.A., as Administrative Agent, Banc of America Securities, LLC, as Lead Arranger, Banc One Capital Markets, Inc., as Syndication Agent, The Chase Manhattan Bank, as Documentation Agent, First Union National Bank, as Co-Documentation Agent, and Certain Financial Institutions, as Lenders for the $725 million credit facility (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-K filed on March 15, 2001).

2002 10-K EXHIBIT NUMBER	DESCRIPTION
10.13	First Amendment to U.S. Credit Agreement dated March 1, 2001, among Registrant, Bank of America N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.1.1 to Registrant's Form 10-Q filed on May 14, 2001).
10.14	Second Amendment to U.S. Credit Agreement dated as of June 27, 2001, among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.1.2 to Registrant's Form 10-Q filed on August 14, 2001).
10.15	Third Amendment to U.S. Credit Agreement dated as of July 31, 2001, among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.4 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001)
10.16	Fourth Amendment to U.S. Credit Agreement dated as of August 13, 2001, among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.5 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001)
10.17	Fifth Amendment to U.S. Credit Agreement dated as of September 21, 2001, among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.6 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001)
10.18	Sixth Amendment to U.S. Credit Agreement dated as of October 5, 2001, among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.7 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001)
10.19	Seventh Amendment to U.S. Credit Agreement dated June 7, 2002 by and among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to this Amendment (incorporated by reference to Registrant's Form 10-Q filed on August 13, 2002).
10.20	Credit Agreement, dated as of October 12, 2001, by and among Devon Energy Corporation, Devon Financing Corporation, U.L.C., UBS AG, Stamford Branch (as Administrative Agent), and the lenders signatory thereto (incorporated by reference to Exhibit 10.3 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001)
10.21	Devon Energy Corporation Restricted Stock Bonus Plan (incorporated by reference to Registrant's Form S-8 filed on August 29, 2000, File No. 333-44702).*
10.22	Mitchell Energy & Development Corp. 1997 Bonus Unit Plan (incorporated by reference to Exhibit 10(e) to Mitchell Energy & Development Corp.'s Annual Report on Form 10-K for the year ended January 31, 1998).*
10.23	First Amendment to Mitchell Energy & Development Corp. 1997 Bonus Unit Plan (incorporated by reference to exhibit 10(c) of the Mitchell Energy & Development Corp. annual report on Form 10-K dated January 31, 1999).*
10.24	Mitchell Energy & Development Corp. 1999 Stock Option Plan (incorporated by reference to exhibit 10(d) of the annual report on Form 10-K dated January 31, 2000).*
10.25	Santa Fe Snyder Corporation 1999 Stock Compensation Retention Plan (incorporated by reference to Exhibit 10(a) to Santa Fe Snyder Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 1999).*
10.26	PennzEnergy Company 1998 Incentive Plan (incorporated by reference to Exhibit 4.3 to Pennzoil Company's Form S-8 filed on December 29, 1998 SEC No. 333-69845).*
10.27	Pennzoil Company 1998 Stock Option Plan (incorporated by reference to SEC File No. 333-59011).*

2002 10-K EXHIBIT NUMBER	DESCRIPTION
10.28	Santa Fe Energy Resources Incentive Compensation Plan, as amended (incorporated by reference to exhibit 10(a) to Santa Fe Energy Resources, Inc.'s Annual Report on Form 10-K for the year ended December 31, 1998).*
10.29	Devon Energy Corporation 1997 Stock Option Plan (incorporated by reference to Exhibit A to Registrant's Proxy Statement for the 1997 Annual Meeting of Shareholders filed on April 3, 1997).*
10.30	Pennzoil Company 1997 Incentive Plan (incorporated by reference to Exhibit A to Pennzoil Company definitive proxy material filed on March 21, 1997, SEC File No. 1-5591).*
10.31	Pennzoil Company 1997 Stock Option Plan (incorporated by reference to SEC File No. 333-26021).*
10.32	Mitchell Energy & Development Corp. 1995 Stock Option Plan (incorporated by reference to SEC File No. 333-06981)*
10.33	Santa Fe Energy Resources, Inc. 1995 Incentive Stock Compensation Plan for Nonexecutive Officers (incorporated by reference to SEC File No. 033-59255).*
10.34	Devon Energy Corporation 1993 Stock Option Plan (incorporated by reference to Exhibit A to Registrant's Proxy Statement for the 1993 Annual Meeting of Shareholders filed on May 6, 1993).*
10.35	Pennzoil Company 1993 Conditional Stock Award Program (incorporated by reference to Exhibit B to Pennzoil Company's definitive proxy material filed on April 13, 1993, File No. 1-5591).*
10.36	Santa Fe Energy Resources Deferred Compensation Plan, effective as of January 1, 1991, as amended and restated, effective February 1, 1994 (incorporated by reference to Exhibit 10(p) to Santa Fe Energy Resources, Inc.'s Annual Report on Form 10-K for the year ended December 31, 1993).*
10.37	Pennzoil Company 1990 Stock Option Plan (incorporated by reference to Pennzoil Company's definitive proxy material filed on April 26, 1990, File No. 1-5591).*
10.38	Santa Fe Energy Resources 1990 Incentive Stock Compensation Plan, Third Amendment and Restatement (incorporated by reference to Exhibit 10(a) to Santa Fe Energy Resources, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 1996).*
10.39	Santa Fe Energy Resources, Inc. Supplemental Retirement Plan effective as of December 4, 1990 (incorporated by reference to Exhibit 10(h) to Santa Fe Energy Resources, Inc.'s Annual Report on Form 10-K for the year ended December 31, 1996).*
10.40	Snyder Oil Corporation 1990 Stock Plan for non-Employee Directors (incorporated by reference to Exhibit 10.4 to SEC File No. 33-33455).*
10.41	Devon Energy Corporation 1988 Stock Option Plan (incorporated by reference to Exhibit 10.4 to Registrant's Registration Statement on Form S-8 filed on August 19, 1999, SEC File No. 333-85553).*
10.42	Supplemental Retirement Income Agreement among Devon Energy Corporation (Nevada), Registrant and John W. Nichols, dated March 26, 1997 (incorporated by reference to Exhibit 10.13 to Registrant's Form 10-Q for the quarter ended June 30, 1997).*
10.43	Severance Agreement between Devon Energy Corporation (Nevada), Devon Energy Corporation, Devon Delaware Corporation and J. Larry Nichols, dated May 19, 1999 (incorporated by reference to Exhibit 10.3 to Registrant's Form 10-Q for the quarter ended September 30, 1999).*
10.44	Form of Employment Agreement between Registrant and Brian J. Jennings, J. Michael Lacey, Duke R. Ligon, Marian J. Moon, John Richels, Darryl G. Smette and William T. Vaughn, dated January 1, 2002. (incorporated by reference to Exhibit 10.26 of Registrant's Form 10-K for the year ended December 31, 2001).*
12	Statement of computations of ratios of earnings to fixed charges and to combined fixed charges and preferred stock dividends.

2002 10-K EXHIBIT NUMBER	DESCRIPTION
21	List of Significant Subsidiaries of Registrant.
23.1	Consent of KPMG LLP
23.2	Consent of LaRoche Petroleum Consultants
23.3	Consent of Paddock Lindstrom & Associates Ltd.
23.4	Consent of Ryder Scott Company, L.P.
23.5	Consent of Gilbert Laustsen Jung Associates Ltd.
23.6	Consent of AJM Petroleum Consultants
99.1	Certification of J. Larry Nichols, Chief Executive Officer
99.2	Certification of William T. Vaughn, Chief Financial Officer

* Compensatory plans or arrangements

EXHIBIT 12

DEVON ENERGY CORPORATION

STATEMENT OF COMPUTATIONS OF RATIOS OF EARNINGS TO FIXED CHARGES AND TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

	YEARS ENDED DECEMBER 31, 2002	2001	2000	1999	1998
EARNINGS:					
Adjusted earnings (loss) from continuing operations before income taxes	$ (135)	27	1,036	(264)	(305)
Add fixed charges (see below)	549	229	164	126	60
Adjusted earnings (loss)	414	256	1,200	(138)	(245)
FIXED CHARGES AND PREFERRED STOCK DIVIDENDS:					
Gross interest expense	537	223	158	111	44
Distributions on preferred securities of subsidiary trust	--	--	--	7	10
Estimated interest component of operating lease payments	12	6	6	8	6
Fixed charges	549	229	164	126	60
Preferred stock requirements, pre-tax	16	16	16	6	--
Combined fixed charges and preferred stock dividends	$ 565	245	180	132	60
Ratios of earnings to fixed charges	NA	1.12	7.34	NA	NA
Ratio of earnings to combined fixed charges preferred stock dividends	NA	1.05	6.70	NA	NA
Insufficiency of earnings to cover fixed charges and combined fixed charges	$ 135	NA	NA	264	305
Insufficiency of earnings to cover fixed charges and combined fixed charges and preferred stock dividends	$ 151	NA	NA	270	305

EXHIBIT 21

DEVON ENERGY CORPORATION

Significant Subsidiaries

1. Devon Energy Corporation (Oklahoma), an Oklahoma corporation;

2. Devon Energy Production Company, L.P., an Oklahoma limited partnership;

3. Northstar Energy Corporation, an Alberta corporation;

4. Devon MND Operating, Inc., a Delaware corporation;

5. Devon Canada Corporation, an Alberta corporation;

6. Devon Canada, a general partnership registered in Alberta;

7. Devon AXL, a general partnership registered in Alberta;

8. Devon Energy Operating Company, L.P., a Delaware limited partnership; and

9. Devon Gas Services, L.P., a Delaware limited partnership.

EXHIBIT 23.1

INDEPENDENT AUDITORS' CONSENT

The Board of Directors
Devon Energy Corporation:

We consent to incorporation by reference in the Registration Statements (File Nos. 333-68694, 333-32214, 333-47672, 333-44702, 333-39908 and 333-85553) on Form S-8 and the Registration Statements (File Nos. 333-85211, 333-50036, 333-50034 and 333-100308) on Form S-3 of Devon Energy Corporation of our report dated February 4, 2003, relating to the consolidated balance sheets of Devon Energy Corporation and subsidiaries as of December 31, 2002, 2001 and 2000 and the related consolidated statements of operations, stockholders' equity, and cash flows for the years then ended, which report appears in the December 31, 2002 Annual Report on Form 10-K of Devon Energy Corporation.

The audit report covering the December 31, 2002 consolidated financial statements refers to changes in the methods of accounting for derivative instruments and hedging activities, business combinations and goodwill.

KPMG LLP

Oklahoma City, Oklahoma
March 6, 2003

EXHIBIT 23.2

ENGINEER'S CONSENT

We consent to incorporation by reference in the Registration Statements (File Nos. 333-68694, 333-32214, 333-47672, 333-44702, 333-39908 and 333-85553) on Form S-8, the Registration Statement (File No. 333-75206) on Form S-4, and the Registration Statements (File Nos. 333-85211, 333-50036, 333-50034 and 333-100308) on Form S-3 of Devon Energy Corporation of the reference to our reports for Devon Energy Corporation, which appears in the December 31, 2002 annual report on Form 10-K of Devon Energy Corporation.

LAROCHE PETROLEUM CONSULTANTS, LTD.

By: /s/ William M. Kazmann

William M. Kazmann
Partner

March 6, 2003

EXHIBIT 23.3

ENGINEER'S CONSENT

We consent to incorporation by reference in the Registration Statements (File Nos. 333-68694, 333-32214, 333-47672, 333-44702, 333-39908 and 333-85553) on Form S-8, the Registration Statement (File No. 333-75206) on Form S-4, and the Registration Statements (File Nos. 333-85211, 333-50036, 333-50034 and 333-100308) on Form S-3 of Devon Energy Corporation of the reference to our reports for Devon Energy Corporation, which appears in the December 31, 2002 annual report on Form 10-K of Devon Energy Corporation.

PADDOCK LINDSTROM & ASSOCIATES LTD.

/s/ L.K. Lindstrom

L.K. Lindstrom, P. Eng.
President

March 5, 2003

EXHIBIT 23.4

CONSENT OF RYDER SCOTT COMPANY, L.P.

We consent to incorporation by reference in the Registration Statements (File Nos. 333-68694, 333-32214, 333-47672, 333-44702, 333-39908 and 333-85553) on Form S-8, the Registration Statement (File No. 333-75206) on Form S-4, and the Registration Statements (File Nos. 333-85211, 333-50036, 333-50034 and 333-100308) on Form S-3 of Devon Energy Corporation of the reference to our reserve reports for Devon Energy Corporation, which appears in the December 31, 2002 annual report on Form 10-K of Devon Energy Corporation.

/s/ Ryder Scott Company, L.P.
RYDER SCOTT COMPANY, L.P.

Houston, Texas
March 5, 2003

EXHIBIT 23.5

LETTER OF CONSENT

We consent to incorporation by reference in the Registration Statements (File Nos. 333-68694, 333-32214, 333-47672, 333-44702, 333-39908 and 333-85553) on Form S-8, the Registration Statement (File No. 333-75206) on Form S-4, and the Registration Statements (File Nos. 333-85211, 333-50036, 333-50034 and 333-100308) on Form S-3 of Devon Energy Corporation of the reference to our firm name and our reports providing estimates of a portion of the natural gas, natural gas liquids and conventional oil reserves of Anderson Exploration Ltd. as of March 31, 2000, September 30, 2000, and March 31, 2001, which appears in the December 31, 2002 annual report on Form 10-K of Devon Energy Corporation.

GILBERT LAUSTSEN JUNG
ASSOCIATES LTD.

/s/ Dana B. Laustsen

Dana B. Laustsen, P. Eng.
Executive Vice-President

Calgary, Alberta
March 6, 2003

EXHIBIT 23.6

ENGINEER'S CONSENT

We consent to incorporation by reference in the Registration Statements (File Nos. 333-68694, 333-32214, 333-47672, 333-44702, 333-39908 and 333-85553) on Form S-8, the Registration Statement (File No. 333-75206) on Form S-4, and the Registration Statements (File Nos. 333-85211, 333-50036, 333-50034 and 333-100308) on Form S-3 of Devon Energy Corporation of the reference to our reports for Devon Energy Corporation, which appears in the December 31, 2002 annual report on Form 10-K of Devon Energy Corporation.

AJM PETROLEUM CONSULTANTS

/s/ Robin G. Bertram

Name: Robin G. Bertram, P. Eng.
Title: Vice President, Engineering

March 5, 2003

EXHIBIT 99.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Devon Energy Corporation ("Devon") on Form 10-K for the period ended December 31, 2002 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, J. Larry Nichols, Chief Executive Officer of Devon, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Devon.

Date: March 6, 2003

/s/ J. Larry Nichols

J. Larry Nichols
Chief Executive Officer

EXHIBIT 99.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO**

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Devon Energy Corporation ("Devon") on Form 10-K for the period ended December 31, 2002 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, William T. Vaughn, Chief Financial Officer of Devon, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(3) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(4) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Devon.

Date: March 6, 2003

/s/ William T. Vaughn

William T. Vaughn
Chief Financial Officer