DEVON ENERGY CORP /OK/

FORM 10-K
(Annual Report)

Filed 03/04/96 for the Period Ending 12/31/95

Address	20 N BROADWAY STE 1500
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SIC Code	1311 - Crude Petroleum and Natural Gas
Fiscal Year	12/31

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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, 1995 OR TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission File Number 1-10067

DEVON ENERGY CORPORATION

(Exact Name of Registrant as Specified in its Charter)

Oklahoma (State or Other Jurisdiction of Incorporation or Organization)	73-1474008 (I.R.S. Employer Identification No.)
20 North Broadway, Suite 1500 Oklahoma City, Oklahoma (Address of Principal Executive Offices)	73102-8260 (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

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 at least the past 90 days. Yes x 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

The aggregate market value of the voting stock held by non-affiliates of the Registrant as of February 28, 1996 was $459,567,965. At such date 22,111,896 shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy statement for the 1996 annual meeting of stockholders - Part III

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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
"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

FORWARD LOOKING STATEMENTS

This document contains "forward looking statements" as defined by the Securities Litigation Reform Act of 1995. Unless otherwise specifically identified, forward looking statements are identified by an asterisk (*) preceeding and following each such statement. Foward looking statements should be read in conjunction with the cautionary statements included in this document, including those found under "Item 2. Properties - Proved Reserves and Estimated Future Net Revenues" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Expenditures, Capital Resources and Liquidity - 1996 Estimates."

PART I

ITEM 1. BUSINESS

Devon Energy Corporation ("Devon" or the "Company") is an independent energy company engaged primarily in oil and gas exploration, development and production, and in the acquisition of producing properties. Through its predecessors, Devon began operations in 1971. In 1988 the Company's common stock began trading publicly on the American Stock Exchange under the symbol DVN. The principal and administrative offices of Devon are located at 20 North Broadway, Suite 1500, Oklahoma City, OK 73102-8260 (telephone 405/235-3611).

Devon's oil and gas properties are its primary assets and the source of its cash flow and earnings. Devon owns interests in 900 producing oil and gas properties in ten states. At December 31, 1995, Devon's estimated proved reserves were 363.8 Bcf of natural gas, 44.5 MMBbls of oil and 9.5 MMBoe of NGLs, or 114.6 MMBoe in total. Ninety-eight percent of such reserves are located in New Mexico, Wyoming, Texas, Oklahoma and Louisiana.

During 1988, Devon expanded its capital base with its first issuance of common stock to the public and began a substantial expansion program. Devon has utilized a two-pronged strategy of acquiring producing properties and engaging primarily in development drilling and limited exploration activities. During the eight years ended December 31, 1995, Devon has drilled 605 new wells, 581 of which were producers, and consummated 15 significant acquisitions. During this same period, total capital costs incurred (including acquisition and drilling costs) aggregated $535.0 million. Reserve additions were 538.1 Bcf of gas, 58.2 MMBbls of oil and 11.2 MMBoe of NGLs. These additions, minus production and property sales, resulted in reserves increasing by a factor of fourteen during the eight-year period.

Devon's single largest reserve position relates to its interests in two federal units in northwest New Mexico: the Northeast Blanco Unit ("NEBU") and the San Juan 32-9 Unit Fruitland Coal Participating Area (the "32-9 Unit"). These "state-of-the-art" projects produce natural gas from a nonconventional source: the Fruitland Coal formation. With NEBU, the 32-9 Unit and certain minor properties, Devon's property holdings in the San Juan Basin account for 29.4 MMBoe, or 26%, of Devon's total proved reserves. Devon's interest in coal seam production is part of a transaction the Company entered into effective January 1, 1995. See "- 1995 Transactions - San Juan Basin Transaction" below.

Devon's second largest reserve position is related to its 100% working interest in the Grayburg-Jackson field in the southeast New Mexico portion of the Permian Basin. Devon is in the second year of an extensive infill drilling program and waterflood project expected to be completed in 1997. *Total development costs for both the infill drilling and the waterflood projects are estimated to be approximately $60 million, $5.8 million of which was spent in 1994 and $30.1 million of which was spent in 1995.* As of December 31, 1995, the Grayburg-Jackson Field accounted for 26.4 MMBoe, or 23%, of Devon's total proved reserves. Approximately 52% of total proved reserves for this field are classified as proved undeveloped and are associated with the infill/waterflood program.

Devon also owns other significant interests in the Permian Basin of western Texas and southeastern New Mexico. These interests are in a number of different fields in the Basin, none of which, individually, accounts for more than 5% of total reserves. However, these holdings are highly concentrated in a relatively small geographic area and possess many operational and geologic similarities. Since 1987, Devon has made four separate acquisitions of properties in the Permian Basin. With these acquisitions, Devon gained significant developed and undeveloped leasehold acreage. The multi-objective nature (several potential producing zones) of the Permian Basin will continue to provide Devon with exploration and development opportunities which could further expand its reserves. As of year-end 1995, the Permian Basin properties other than the Grayburg-Jackson Field accounted for 28% of Devon's total proved reserves.

1995 Transactions

Worland Acquisition - In December, 1995, Devon completed the acquisition of a group of oil and natural gas properties and a gas processing plant located in north-central Wyoming (the "Worland Property"). Combined with the small interest Devon previously owned, this property is now Devon's third largest, accounting for about 14% of the Company's total proved reserves.

The properties acquired in 1995 were purchased from a major oil company for $50.3 million. All of the properties are located on a 25,000- acre federal unit in Big Horn and Washakie Counties, Wyoming. Of the $50.3 million total purchase price, $46.3 million was allocated to 38 producing wells, 16 proved undeveloped locations and a natural gas processing plant. The acquired assets had total estimated proved reserves of 15.3 MMBoe as of year-end 1995. The remaining $4 million purchase price was allocated to undeveloped leases on the unit. *Devon expects to invest an additional $9 million in 1996 to further develop the property, including drilling additional wells and upgrading the gas processing plant.*

In early 1996 Devon increased its interest in the Worland Property through several smaller acquisitions totaling $7 million. After these smaller acquisitions, the Company now owns an approximate 98% working interest in the proved properties and 100% of the gas processing plant and 15,500 acres of undeveloped leases. Because the Worland Field has many potentially productive producing zones, the acreage will provide the Company with many exploration and development opportunities which could increase reserves.

San Juan Basin Transaction - Effective January 1, 1995, Devon and an unrelated company entered into a transaction covering substantially all of Devon's San Juan Basin coal seam gas properties, i.e., NEBU and the 32-9 Unit, (the "San Juan Basin Transaction"). *The effect of the transaction is that the price the Company receives for its coal seam gas production has increased by $0.61 per Mcf from 1995 through the year 2002. Based on current estimates of coal seam gas production, the San Juan Basin Transaction will result in approximately $11 million of additional gas revenues in 1996 and a total of $71 million over the life of the transaction (including $12.8 million received in 1995).* See "Item 2. Properties. Significant Properties - San Juan Basin - San Juan Basin Transaction" for a more detailed description of this transaction.

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. The majority of Devon's drilling operations in 1996 will be concentrated in the Permian Basin, Rockies and Gulf Coast regions of the U.S.

The following tables set forth Devon's drilling results for 1988 through 1995.

Development Wells

	Gross (1)			Net (2)		
	Productive	Dry	Total	Productive	Dry	Total
1988	23	0	23	4.13	0	4.13
1989	32	1	33	7.02	0.01	7.03
1990	80	0	80	19.37	0	19.37
1991	22	1	23	1.62	0.11	1.73
1992	53	2	55	7.84	0.12	7.96
1993	92	4	96	43.39	1.40	44.79
1994	77	1	78	44.40	0.28	44.68
1995	184	3	187	143.87	0.29	144.16
	563	12	575	271.64	2.21	273.85

(1) A gross well is a well in which Devon owns an interest.
(2) Net wells are the sum of Devon's working interests in gross wells.

Exploratory Wells

	Gross (1)			Net (2)		
	Productive	Dry	Total	Productive	Dry	Total
1988	0	1	1	0	0.32	0.32
1989	0	1	1	0	0.69	0.69
1990	0	1	1	0	0.20	0.20
1991	0	0	0	0	0	0
1992	3	1	4	1.09	0.25	1.34
1993	4	2	6	2.05	0.49	2.54
1994	2	3	5	0.52	2.37	2.89
1995	9	3	12	2.53	1.18	3.71
	18	12	30	6.19	5.50	11.69

(1) A gross well is a well in which Devon owns an interest.
(2) Net wells are the sum of Devon's working interests in gross wells.

As of December 31, 1995, Devon was participating in the drilling of 16 gross (11.29 net) development wells which are not included in the table above. Through February 28, 1996, 11 gross (10.7 net) of these wells were completed as productive and the remaining wells were still in progress.

Customers

For the year ended December 31, 1995, two significant purchasers, Aquila Energy Marketing Corporation ("Aquila") and Enron Gas Marketing, Inc. ("Enron"), accounted for 31% and 16%, respectively, of Devon's gas sales. For the year ended December 31, 1994, Aquila, Enron and Meridian Oil Trading, Inc. ("MOTI") accounted for 21%, 19% and 18%, respectively, of Devon's gas sales. For the year ended December 31, 1993, there was one significant purchaser, MOTI, which accounted for approximately 39% of Devon's gas sales. Until September, 1995, MOTI was a significant purchaser of Devon's NEBU coal seam gas production at a market-sensitive price under the terms of a five-year contract entered into in May, 1990. Aquila and Enron purchase gas from numerous Devon properties, including NEBU and the 32-9 Unit. These purchases are primarily made at variable and market- sensitive prices.

Devon does not consider itself dependent upon any one of these purchasers, since other purchasers are willing to purchase this same gas production at competitive prices.

Devon sells its remaining 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.

Oil and Gas Marketing

Natural Gas Marketing. Virtually all of Devon's natural gas production is sold at variable, or "market-sensitive" prices. Though exact percentages vary daily, approximately 9% of such natural gas is sold under short-term contracts. The remaining 91% of Devon's natural gas is marketed under various long-term contracts (one year or more) which dedicate the natural gas to a purchaser for an extended period of time, but which still involve variable and market-sensitive pricing.

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 renegotiated from daily intervals up to 90 day intervals. These market-sensitive sales are referred to as "spot market" sales. The spot market has become progressively more competitive in recent years. As a result, prices on the spot market have been volatile. From time to time Devon has withheld gas from the market due to low prices.

Oil Marketing. Devon's oil production is sold under both long- and short-term agreements at prices in the range of field prices as posted by certain crude purchasers. Approximately 2% of Devon's 1995 oil production was purchased by its wholly-owned subsidiary, Devon Marketing Corporation, which also purchases oil from third parties and resells the purchased oil under contracts to refiners and others.

Competition

The oil and gas business is highly competitive. Devon encounters competition by major integrated and independent oil and gas companies in acquiring properties and drilling prospects, contracting for drilling equipment and securing trained personnel. Intense competition occurs with respect to marketing, particularly of natural gas. Certain competitors have resources which 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 have begun to more effectively utilize natural gas storage capacity by purchasing some of the winter load in the summer.

Government Regulation

The oil and gas industry is extensively regulated by federal, state and local authorities. 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 the 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.

Exploration and Production. Devon's 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; submitting and implementing spill prevention plans; submitting notification relating to the presence, use and release of certain contaminants 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 prohibit 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 most of its leases at NEBU, the 32-9 Unit, the Worland Property and many of the Company's leases in southeast New Mexico, including the Grayburg-Jackson Field, are granted by the federal government and administered by various federal agencies. 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 Mineral Lands Leasing Act of 1920 places limitations on the number of acres of federal lands that may be leased by any entity or person in any one state. Additionally, the Mineral Lands Leasing Act of 1920 and related regulations also restrict a corporation from holding federal onshore oil and gas leases if stock of such corporation is owned by citizens of foreign countries which are not deemed reciprocal under such Act. Reciprocity depends, in large part, on whether the laws of the foreign jurisdiction discriminate against a United States citizen's ownership of rights to minerals in such jurisdiction. The purchase of shares in Devon by citizens of foreign countries with laws which are not deemed to be reciprocal under such Act could have an impact on Devon's ownership of federal leases.

Environmental and Occupational Regulations. Various federal, state and local laws and regulations concerning the discharge of contaminants 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 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 and accidental discharges of oil, salt water or other deleterious substances. However, 100% coverage is not maintained concerning any environmental claim, and no coverage is maintained with respect to any award of punitive damages against Devon or any penalty or fine required to be paid by Devon because of its violation of any federal, state or local law. Devon's unreimbursed expenditures in 1995 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 the laws and regulations.

In 1992 Devon retained the services of an independent environmental engineering firm to provide a comprehensive evaluation of Devon's significant properties and to otherwise advise Devon concerning its compliance with various environmental laws. In 1993 Devon established its own internal Environmental Industrial Hygiene and Safety Department to perform these functions. 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 audits of Devon's compliance procedures.

No Price Controls on Liquid Hydrocarbons. There are currently no price controls on crude oil, condensate or NGLs.

Employees

As of December 31, 1995, Devon's staff consisted of 203 full-time employees, including 15 professionals in engineering, 6 in geology, 5 in the land department, 4 in oil and gas marketing, 30 in accounting and data processing, 7 in administration and other support positions. In addition, through its affiliate, Blackwood & Nichols Co. A Limited Partnership, Devon employs 21 people, including 3 operations engineers. The Company also engages independent consulting petroleum engineers, environmental professionals, geologists, geophysicists, landmen and attorneys on a fee basis.

ITEM 2. PROPERTIES

Substantially all of Devon's properties consist of interests in developed and undeveloped oil and gas leases located in New Mexico, Wyoming, Texas, Oklahoma and Louisiana. These interests entitle Devon to drill for and produce oil, natural gas and NGLs from a specific area. Devon's interests are mostly in the form of working interests and production payments, and, to a lesser extent, overriding royalty, royalty, mineral and net profits interests and other forms of direct and indirect ownership in oil and gas properties.

Proved Reserves and Estimated Future Net Revenue

"Proved Reserves" are those quantities of oil, natural gas and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known reservoirs under existing economic and operating conditions. Estimates of proved reserves are strictly technical judgments, and are not knowingly influenced by attitudes of conservatism or optimism. The following table sets forth Devon's estimated proved reserves, the estimated future net revenues therefrom and the present value thereof, discounted at 10% per annum ("10% Present

Value"), as of December 31, 1995. Approximately 92% of Devon's proved reserves were estimated by LaRoche & Associates, independent petroleum engineers ("LaRoche"). The remainder of such reserves were estimated by Devon's internal staff of engineers. In preparing their estimates, both LaRoche and Devon's staff used standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC guidelines (as described in the notes below). These estimates correspond with the method used in presenting the supplemental information on oil and gas operations in note 13 to Devon's consolidated financial statements included herein, except that federal income taxes otherwise attributable to such future net revenues have been disregarded in the presentation below.

	Total Proved Reserves	Proved Developed Reserves <F1>	Proved Undeveloped Reserves <F2>
Oil (MBBls)	44,466	28,703	15,763
Gas (MMcf)	363,846	311,664	52,182
NGLs (MBoe)	9,469	6,149	3,320
MBoe <F3>	114,576	86,797	27,779
Pre-tax Future Net Revenue ($ thousands)<F4>	927,812	667,994	259,818
Pre-tax 10% Present Value ($ thousands)<F4>	534,248	411,400	122,848

<F1> Proved developed reserves are proved reserves that are expected to be recovered from existing wells with existing equipment and operating methods.

<F2> Proved undeveloped reserves are proved reserves to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion, deepening or new fluid injection facilities.

<F3> Gas reserves are converted to MBoe at the rate of six MMcf per MBbl 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. The respective prices of gas and oil are affected by market and other factors in addition to relative energy content.

<F4> Estimated future net revenue represents estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs. The amounts shown do not give effect to non-property related expenses such as general and administrative expenses, 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, 1995. 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 $18.11 per Bbl of oil, $1.35 per Mcf of natural gas ($1.51 per Mcf including the effect of the San Juan Basin Transaction), and $12.73 per Boe of NGLs. These prices compare to benchmark prices of $18.00 for West Texas Intermediate crude oil and $2.10 for Texas Gulf Coast spot gas.

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 (ii) in filings with the Department of Energy ("DOE"). Reserve estimates filed by Devon with the SEC correspond with the estimates of Devon reserves contained herein. Reserve estimates filed with the DOE are based upon the same underlying assumptions as the estimates of Devon's reserves included herein. However, the DOE requires reports to include the interests of all owners in wells which Devon operates and to exclude all interests in wells which 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, 1995. 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 NGL 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.

The following table presents the net quantities of Devon's oil, natural gas and NGL reserves as of the end of the years indicated. Devon's total proved reserves for the years ended December 31, 1988 through 1991 were estimated by LaRoche. Approximately 88%, 95%, 91% and 92% of Devon's reserves as of the years ended December 31, 1992, 1993, 1994 and 1995, respectively, were estimated by LaRoche. The balance of the reserves were estimated by Devon's internal staff of engineers.

	Total Proved Reserves			Proved Developed Reserves		
As of December 31,	Oil (MBbls)	Gas (MMcf)	NGLs (MBoe)	Oil(MBbls)	Gas (MMcf)	NGLs(MBoe)
1988	5,590	98,388	- <F1>	4,203	65,503	- (1)
1989	4,800	149,761	- <F1>	3,688	82,086	- (1)
1990	4,058	169,473	- <F1>	3,456	163,364	- (1)
1991	3,798	191,642	- <F1>	3,179	191,360	- (1)
1992	16,349	263,598	1,011	13,823	249,154	797
1993	14,897	369,254	1,854	11,548	355,536	1,751
1994	42,165	347,560	5,442	18,718	324,302	3,123
1995	44,466	363,846	9,469	28,703	311,664	6,149

<F1> Minor quantities of NGLs are included in oil reserves.

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 five years ended December 31, 1995, is set forth in "Item 6. Selected Financial Data."

Well Statistics

As of December 31, 1995, Devon had interests in 4,024 producing wells, of which 2,903 gross (793 net) were oil wells and 1,121 gross (430 net) were natural gas wells. 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.

Leasehold

The following table sets forth Devon's developed and undeveloped oil and gas lease acreage as of December 31, 1995.

	Developed		Undeveloped	
	Gross<F1>	Net<F2>	Gross<F1>	Net<F2>
Arkansas	40	40	0	0
California	0	0	5,098	199
Colorado	1,279	121	8,382	5,725
Kansas	1,665	901	160	7
Louisiana	10,214	4,537	18,059	8,952
Montana	0	0	3,828	1,312
New Mexico	90,293	50,154	56,532	39,400
North Dakota	0	0	2,715	817
Oklahoma	68,789	32,271	24,992	11,176
Texas	145,582	76,274	111,014	70,369
Utah	277	134	680	453
West Virginia	4,991	3,737	609	144
Wyoming	43,437	36,392	33,855	23,530
	366,567	204,561	265,924	162,084

<F1> Gross acres are the total number of acres in which Devon owns a working interest.

<F2> Net refers to gross acres multiplied by Devon's fractional working interests therein.

Significant Properties

The following table sets forth information on the most significant geographic areas in which Devon's properties are located as of December 31, 1995.

	Oil(MBbls)	Gas(MMcf)	NGLs(MBoe)	MBoe<F1>	MBoe%<F2>	10% Present Value <F3> ($000)	10% Present Value% <F4>
San Juan Basin:							
Northwest New Mexico							
Northeast Blanco Unit	5	119,035	25	19,869	17.3%	$ 75,531<F5>	14.2%
32-9 Unit	0	56,741	0	9,457	8.3%	38,667<F6>	7.2%
Other	5	292	0	54	0	216	0
Total	10	176,068	25	29,380	25.6%	$114,414	21.4%
Permian Basin:							
West Texas and							
Southeast New Mexico							
Grayburg-Jackson Field	23,250	7,916	1,853	26,422	23.1%	$157,922	29.6%
Other	16,312	75,597	3,018	31,930	27.9%	161,184	30.1%
Total	39,562	83,513	4,871	58,352	51.0%	$319,106	59.7%
Rocky Mountains:							
Colorado and Wyoming							
Worland Unit	1,913	62,563	3,707	16,047	14.0%	$ 51,559	9.7%
Other	1,348	3,278	362	2,256	2.0%	9,113	1.7%
Total	3,261	65,841	4,069	18,303	16.0%	$ 60,672	11.4%
Mid-Continent:							
Oklahoma and							
Texas Panhandle	1,009	30,479	480	6,569	5.7%	$ 30,608	5.7%
All Other Properties	624	7,945	24	1,972	1.7%	9,448	1.8%
Grand Total	44,466	363,846	9,469	114,576	100.0%	$534,248	100.0%

<F1> Gas reserves are converted to MBoe at the rate of six MMcf of gas per MBbl 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. The respective prices of gas and oil are affected by market and other factors in addition to relative energy content.

<F2> Percentage which MBoe for the basin or region bears to total MBoe for all Proved Reserves.

<F3> Determined in accordance with SEC guidelines, except that no effect is given to future income taxes.

<F4> Percentage which present value for the basin or region bears to total present value for all Proved Reserves.

<F5> Includes $28.1 million of additional value attributable to San Juan Basin Transaction through the year 2002.

<F6> Includes $16.3 million of additional value attributable to San Juan Basin Transaction through the year 2002.

San Juan Basin. Devon's single largest reserve position relates to its interests in two federal units in the northwest New Mexico portion of the San Juan Basin: the 33,000 acre NEBU, in Rio Arriba and San Juan Counties, and the 22,400 acre 32-9 Unit in San Juan County. The San Juan Basin, a densely drilled area covering 3,700 square miles in central and northwestern New Mexico, has historically been considered the second largest gas producing basin in the United States. Prior to 1990, the Basin's gas production primarily came from conventional sandstone formations at a depth of about 5,500 feet. However, in the early 1980's, development of the shallower Fruitland Coal formation began. Coal seam gas production has increased total production so significantly that the San Juan Basin can now arguably be considered the largest gas producing basin in the U.S. Production from the coal seams constitutes almost all of Devon's reserves in these two units.

Substantially all of Devon's interests in both of these units are a part of a transaction into which the Company entered effective January 1, 1995. See " - San Juan Basin Transaction" below.

Northeast Blanco Unit. Approximately 96%, or 114.6 Bcf, of Devon's proved reserves attributable to NEBU are associated with the Fruitland coal seam formation. The potential for coal seam gas production varies depending upon the thickness of the coal formation, the type of coal in place, the depth at which it is found and other factors. NEBU is located in the central part of the San Juan Basin where each of the factors is at or near its optimum. NEBU is operated through a Devon affiliate, Blackwood & Nichols Co. A Limited Partnership. The Company initially began developing its coal seam interest during 1988, eventually drilling 102 wells, the maximum permitted under existing 320-acre spacing on NEBU's 33,000 acres.

By late 1990, the first NEBU coal seam wells were connected to pipelines and began producing. Additional wells were connected each year until project completion in late 1993. Production increased each year through 1994. The following table shows Devon's net production from NEBU:

Year	Gas Production
1990	1.0 Bcf
1991	8.7 Bcf
1992	17.5 Bcf
1993	18.2 Bcf
1994	18.7 Bcf
1995	16.2 Bcf
Total	**80.3 Bcf**

As the table above illustrates, NEBU production declined slightly, as expected, in 1995. About 1.2 Bcf of the reduction is due to the San Juan Basin Transaction described below. The remainder of the reduced production is due to natural decline. *It is likely that production will decrease to 13 to 15 Bcf in 1996 and continue a modest decline thereafter unless additional development or new technology is applied to the property.*

The current reserve estimates at NEBU assume that 55% to 65% of the coal seam gas in place can be economically recovered through the existing wells. *Additional production and recoverable reserves might be realized by continued reduction in operating pressure through compression and pipeline optimization, by use of subsurface pumping equipment to remove water, by drilling additional wells, or by using enhanced recovery techniques, such as injecting carbon dioxide or nitrogen into the coal formation, to force additional gas to the producing well bores.* Devon and other owners in the San Juan Basin are studying and experimenting with these various options to determine if additional recoveries are economically feasible. *If such development projects were to be undertaken by Devon, it would likely result in significant additional capital expenditures and gas reserves.* (As part of the San Juan Basin Transaction, Devon will be entitled to 75% of any reserves in excess of those estimated to be in place at the time of the transaction. The third party will pay 100% of the capital necessary to develop any such incremental reserves for its 25% interest in such reserves. See " - San Juan Basin Transaction" below.)

32-9 Unit. The 32-9 Unit, operated by Meridian Oil Production, Inc., is located approximately eight miles northwest of NEBU. Geologically and operationally this property is very similar to NEBU: the coal seams at the 32-9 Unit are about the same thickness as at NEBU, the type of coal and the depth at which it is found are similar, the gas content of the coal is estimated to be approximately the same. However, the 32-9 Unit is located in an area where the coal does not appear to be as permeable as it is at NEBU. The current reserve estimates assume that 20% to 30% of the coal seam gas in place can be economically recovered through the existing wells. *Thus, the 32-9 Unit wells tend to produce at lower rates but should produce for a longer period of time than the NEBU wells. There is the possibility that some infill wells may be drilled to accelerate production, if the State of New Mexico allows drilling on 160-acre spacing rather than the existing 320-acre spacing.* This unit is also being evaluated for possible improved recovery projects similar to those being studied at NEBU.

Although now largely complete, development of the 32-9 Unit began later and has proceeded more slowly than the development of NEBU. Production from the 32-9 Unit did not commence until March of 1992. Consequently, Devon believes the 32-9 Unit has not yet reached its peak production rate.

Devon also owns an interest in five wells on leases located immediately adjacent to the 32-9 Unit. These wells will not be committed to the 32-9 Unit. Unless otherwise indicated, all references herein to the 32-9 Unit include both the 33 wells expected to be included in the Unit and the five wells outside the Unit. Devon does not own any interest or reserves in the deeper, conventional sandstone reservoirs at the 32-9 Unit.

San Juan Basin Gas Price. The sales price for Devon's San Juan Basin coal seam gas production is a combination of the net wellhead price, plus additional revenue attributable to the San Juan Basin Transaction. The average net wellhead price for San Juan Basin coal seam production sold during 1995 (before the benefit of the San Juan Basin Transaction) was $0.71 per Mcf. This net realization is relatively low compared to conventional gas produced in other areas of the U.S. This occurred for two reasons:

First, during most of 1995, demand for natural gas in California (the primary market for San Juan Basin gas) was weak, causing San Juan Basin gas to sell at a larger discount than gas that could be delivered to higher demand areas of the U.S. *Devon believes that this supply/demand imbalance will persist throughout 1996, but should dissipate in future years.*

Second, the price for coal seam gas production was less than that for Devon's conventional gas in the San Juan Basin because (i) a relatively large portion (about 10%) of the produced gas is carbon dioxide which is removed, (ii) a fee must be paid to remove carbon dioxide and transport the gas from the field to transmission lines that carry the gas to market and (iii) a portion of the produced gas is used to fuel compressors and other field equipment. This is a permanent circumstance that will always affect the price of coal seam gas production from the San Juan Basin.

Offsetting the deductions from the wellhead price is an additional $0.61 per Mcf from the San Juan Basin Transaction. This increase, added to the net wellhead price of $0.71 per Mcf, resulted in a San Juan Basin coalseam gas price of $1.32 per Mcf in 1995. See " - San Juan Basin Transaction" below.

San Juan Basin Transaction. Effective January 1, 1995, Devon and an unrelated company entered into a transaction covering substantially all of Devon's San Juan Basin coal seam properties. *The effect of the transaction is that the price Devon receives for its coal seam gas production will be $0.61 per Mcf higher than the price the Company would otherwise receive from 1995 through the year 2002.*

The transaction is based on the fact that Devon's coal seam gas production qualifies as a "nonconventional fuel source" under Internal Revenue Service regulations. Consequently, gas produced from these properties through the year 2002 is eligible for the Section 29 Credit, which was equal to $1.01 per million Btu ("MMBtu") as of December 31,

1995. The transaction consists of four major elements. First, Devon conveyed about 179 Bcf, or 90%, of its year-end 1994 coal seam gas reserves to the unrelated party. However, for financial reporting purposes Devon retained all of these reserves and their future production and cash flow through a volumetric production payment and repurchase option. Second, Devon conveyed outright to the unrelated party 7.2 Bcf of reserves for a sales price of $5.2 million. The reserves and future cash flow associated with this conveyance were not retained by Devon. (However, Devon has an option to reacquire these reserves at their fair market value at the time the option is exercised.) Third, the unrelated party pays Devon an amount equal to 75% of the value of the Section 29 tax credits generated by the properties. Fourth, Devon retained a 75% reversionary interest in any reserves in excess of the
186.2 Bcf estimated to exist as of the date of the transaction. The transaction is described in more detail in note 3 to Devon's consolidated financial statements included elsewhere herein.

Permian Basin Properties. The Permian Basin covers approximately 66,000 square miles of western Texas and southeastern New Mexico. The area has more than 500 major fields which are grouped under the general designation of Permian Basin. Permian Basin acreage is largely "held by production" from existing wells, meaning that new leasehold positions are not readily attainable. Since 1987, Devon has made four separate acquisitions of properties in the Permian Basin. These acquisitions, especially the July, 1992 acquisition of certain Permian Basin properties, enabled Devon to obtain prospective acreage in areas in which leasehold positions could not otherwise be purchased. *The multi-objective nature (several potential producing zones) of the Permian Basin and Devon's large leasehold position there will continue to provide Devon with exploration and development opportunities. Enhanced oil recovery projects are also possible which could further expand Devon's reserves.*

Grayburg-Jackson Field. This field, which was acquired in the Alta Merger in May, 1994, is located in Eddy County, in the far southeastern New Mexico portion of the Permian Basin. It is the Company's single largest property in the Permian Basin, accounting for 23% of total oil and gas reserves. Its location within 35 miles of 26 other Devon properties makes it an ideal strategic fit for the Company's Permian Basin holdings.

Production from this field currently comes from the Grayburg-San Andres-Premier zones over a 400-foot interval to depths up to 4,000 feet. Although some of the oldest wells in the Field date back to the 1940's and 1950's, most of the currently producing wells were drilled in the early 1970's. Additional drilling over the years by previous owners left the field developed to an average of 40-acre spacing per well when Devon acquired it. However, similar properties in the immediate vicinity have been drilled on 20-acre spacing and successfully waterflooded. Based upon this information, in 1994 Devon initiated a $60 million capital development project which includes drilling about 150 wells over a two- to three- year period, converting producing wells to water injection wells and instituting a waterflood. As of year-end 1995, the project was about 50% completed.

From May through year-end 1994, the first seven months Devon owned the field, production from the Grayburg-Jackson Field was 234 MBoe. This was approximately 3% of Devon's total 1994 production. For 1995, production increased to 920 MBoe as additional drilling was completed and Devon owned the field for the full year. *For 1996 production is expected to again increase as development continues.* Currently about 50% of the Grayburg-Jackson Field reserves are classified as "proved developed." The remaining reserves are considered "proved undeveloped."

Worland Property. In December, 1995 Devon completed the acquisition of properties from a major oil company for approximately $50.3 million. All of the properties are located on a 25,000-acre federal unit in Big Horn and Washakie Counties, Wyoming. Of the $50.3 million purchase price, $46.3 million was allocated to 38 producing wells, 16 proved undeveloped locations and a natural gas processing plant. These acquired assets, combined with the small interest Devon previously owned, had total estimated proved reserves of 16.0 MMBoe as of year-end 1995. The remaining $4 million purchase price was allocated to undeveloped leasehold on the unit, which constitutes about 60%, or 15,500 acres, of the total acreage acquired.

In 1996 Devon expects to invest an additional $9 million to begin the exploitation of this property. Projects scheduled for 1996 include drilling development wells, optimization of the existing gas processing plant and gathering system, additional stimulation of existing wells and drilling wells to extend the productive limits of this property.

In early 1996 Devon increased its working interest in the proved property to 98% through several smaller acquisitions totaling $7 million. These acquisitions also increased the Company's interest in the gas processing plant and undeveloped leases to 100%.

The property consists of three separate fields located along a major geologic structure. It is the single largest gas producing feature in the Bighorn Basin. Seven separate horizons produce on the structure: the First, Second, Third and Fourth Frontier sandstones, the Muddy sandstone, the Phosphoria dolomite and the Tensleep sandstone, ranging in depths from 7,450 to 10,500 feet. The first production from this property was from the Phosphoria oil reservoir in the 1940s. Shallow gas production was established in the 1960s. The Tensleep, immediately below the Phosphoria zone, was developed in the 1970s. The original owner dedicated all gas production from the property, which they believed to be only a minor by-product of the oil production, under a long-term contract for $0.30 or less per Mcf. Because of this contract, full development of the gas reservoirs was not economically feasible until the price was renegotiated by the original owner in 1988.

Devon believes the major potential of this property is from the application of modern technology. Three-D seismic and new well completion techniques such as massive acid- fracturing, are proving successful in other parts of the Bighorn Basin and throughout the Rocky Mountain region, and may enhance reserves and recoveries at the Worland Property as well. In addition, both the Tensleep and Phosphoria are possible candidate zones for horizontal drilling technology.

Operation of Properties

The day-to-day operations of oil and gas properties is 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 1,372 of its 4,024 wells. As operator, Devon receives reimbursement of 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.

Title to Properties

Title to properties is subject to (i) royalty, overriding royalty, carried, net profits, working and other similar interests, (ii) contractual arrangements customary in the oil and gas industry, (iii) liens for current taxes not yet due and (iv) 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 production properties and before commencement of drilling operations on undeveloped properties.

ITEM 3. LEGAL PROCEEDINGS

Devon is involved in various routine legal proceedings incidental to its business. However, there are no material pending legal proceedings to which Devon is a party or of which any of its property is subject.

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

No matters were submitted to a vote of the Company's security holders during the fourth quarter of the year ended December 31, 1995.

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.

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

	High	Low	Average Daily Volume
1994:			
Quarter Ended March 31, 1994	22-7/8	17-1/2	55,131
Quarter Ended June 30, 1994	26-1/2	17-1/4	37,547
Quarter Ended September 30, 1994	23-1/4	19-3/4	26,344
Quarter Ended December 31, 1994	22-1/4	16	34,110
1995:			
Quarter Ended March 31, 1995	21-3/8	16-3/4	41,268
Quarter Ended June 30, 1995	23-1/4	20	41,437
Quarter Ended September 30, 1995	23-7/8	18	39,462
Quarter Ended December 31, 1995	26	21-1/2	22,333
1996:			

Quarter Ended March 31, 1996 (through February 28, 1996)	25-3/4	21-1/4	45,322

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. Total dividends for the years ended December 31, 1994 and 1995 were $0.12 per share. *Devon anticipates continuing to pay regular quarterly dividends in the foreseeable future.*

On February 27, 1996, there were approximately 1,200 Devon Common Stock shareholders of record.

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."

	Year Ended December 31,				
	1995	1994	1993	1992	1991
	(Thousands, Except Per Share Data)				
OPERATING RESULTS					
Oil sales	$ 55,290	38,086	38,395	27,329	9,436
Gas sales	50,732	56,372	54,876	39,973	19,091
NGL sales	6,404	4,908	4,544	1,370	--
Other revenue	877	1,407	942	2,892	1,815
Total revenues	$113,303	100,773	98,757	71,564	30,342
Lease operating expenses	$ 27,289	24,521	26,401	18,430	8,689
Gross production taxes	$ 6,832	6,899	6,924	4,600	1,912
Depreciation, depletion and amortization	$ 38,090	34,132	28,409	19,894	7,844
General and administrative expenses	$ 8,419	8,425	7,640	6,510	5,832
Interest expense	$ 7,051	5,439	3,422	2,644	2,209
Reduction of carrying value of oil and gas properties	$ --	--	--	--	25,000
<F1>					
Net earnings (loss)	$ 14,502	13,745	20,486 [1]	14,615	(15,024)
Net earnings (loss) per share:					
<F1>					
Assuming no dilution	$ 0.66	0.64	0.98 [1]	0.94	(1.99)
<F1>					
Assuming full dilution	$ 0.66	0.64	0.98 [1]	0.90	(1.99)
Cash dividends:					
Per preferred share	$ --	--	--	1.46	1.94
Per common share	$ 0.12	0.12	0.09	--	--
Weighted average common shares outstanding	22,074	21,552	20,822	13,802	8,687
BALANCE SHEET DATA					
Total assets	$421,564	351,448	285,553	225,972	102,107
Long-term debt	$143,000	98,000	80,000	54,450	32,000
Stockholders' equity	$219,041	206,406	172,900	153,267	53,015
PRODUCTION/PRICE DATA					
Production:					
Oil (MBbls)	3,300	2,467	2,337	1,446	484
Gas (MMcf)	36,886	39,335	35,598	28,374	15,398
NGLs (MBoe)	600	501	411	112	--
<F2>					
MBoe [2]	10,047	9,524	8,681	6,287	3,050
Average prices:					
Oil (Per Bbl)	$ 16.75	15.44	16.43	18.89	19.49
Gas (Per Mcf)	$ 1.38	1.43	1.54	1.41	1.24
NGLs (Per Boe)	$ 10.68	9.79	11.06	12.28	--
<F2>					
Per Boe [2]	$ 11.19	10.43	11.27	10.92	9.35

<F1>

1 Net earnings for 1993 include the cumulative effect of a required change in the method of accounting for income taxes in 1993 which provided earnings of $1.3 million, or $0.06 per share.

<F2>

2 Gas and NGLs are converted to Boe or MBoe at the rate of six Mcf of gas per barrel of oil and 42 gallons of NGLs per barrel of oil, based upon the approximate relative energy content of natural gas, oil and NGLs, which rate is not necessarily indicative of the relationship of oil, gas and NGL prices. 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 1993 through 1995. Reference is made to "Item 6. Selected Financial Data" and "Item 8. Financial Statements and Supplementary Data."

Overview

Many of the major trends for Devon have been positive in recent history. During the last three years:

the company's major assets, oil and gas reserves, have grown 87% to 115 million barrels of oil equivalent ("MMBoe"),

annual oil and gas production has risen 60% (from that of 1992) to 10 MMBoe,

total revenues for 1995 were 58% higher than those of 1992, and

cash margins (total revenues less cash expenses) have expanded to the $50 million to $60 million range.

However, non-cash expenses, such as higher depreciation, depletion and amortization and volatile oil and gas prices, have produced more variable results in net earnings. Net earnings were down in 1994 compared to 1993, but up in 1995. Even so, the net earnings of $14.5 million (1995), $13.7 million (1994), $19.2 million (1993) and $14.6 million (1992) were all substantially above the previous best year in Devon's history of $4.4 million in 1981.

Devon's liquidity and financial condition also have been strong during the last three years compared to historical levels. After the February 1996 annual review by its banks, Devon's credit lines have increased 117% since 1992 to $260 million. Of this, $110 million was unused as of the end of February 1996. Net cash provided by operating activities has been $61.3 million, $46.4 million and $64.0 million the last three years, compared to an average of $14 million for the years 1988 through 1992.

Devon has taken several actions in recent years to achieve its growth in operations and financial condition:

Devon acquired a substantial suite of properties primarily located in the Permian Basin in July, 1992. This $130 million acquisition caused significant improvement in both oil and gas production and in revenues from the second half of 1992 onward.

Devon acquired $54 million of coal seam gas properties in the San Juan Basin in June, 1993. These properties added to Devon's already significant coal seam gas properties and production in the San Juan Basin.

Devon acquired the properties of Alta Energy Corporation through a $72 million merger in May, 1994. The oil and gas properties acquired through the merger (the "Merger Properties") have added substantial oil and gas reserves, production and revenues to Devon's Permian Basin position.

Devon acquired certain Wyoming oil and natural gas properties and a gas processing plant (the "Worland Properties") for approximately $50 million in December, 1995.

In 1995, Devon entered into a transaction covering substantially all of its San Juan Basin coal seam gas properties (the "San Juan Basin Transaction"). In 1995, this transaction boosted Devon's revenues by $11.4 million. This transaction also added $44 million to Devon's pre-tax discounted present value of year-end oil and gas reserves.

Devon has been successful during the last three years in its drilling efforts. Devon has spent almost $125 million to drill 384 wells, of which 368 were completed as producers. Most of these efforts have been centered around the 1992 Permian Basin acquisition and the 1994 Merger. These properties, along with the Worland Properties, are expected to account for some 60% of Devon's 1996 drilling and development budget of $70 million to $80 million.

Devon's acquisition and drilling efforts during the last three years have added 74.5 MMBoe of proved reserves to its asset base. Combined with 13.7 MMBoe of upward revisions to its reserve estimates, Devon's total reserve additions of 88.2 MMBoe during the past three years were 312% of its production of 28.3 MMBoe.

Devon has sought to control its well operating expenses in part by selling marginal and non-strategic properties. Though the absolute dollar amount of well operating expenses increased by almost 50% since 1992 as Devon expanded its production and operations, Devon's sales of approximately 2,900 wells during the period helped to lower the expenses per unit of production by 7%. The combination of expanding its significant properties and selling the minor ones has increased Devon's economies of scale and overall efficiency.

Devon's reserve additions over the past three years have also increased capital resources via increases in Devon's lines of credit. Since the end of 1992, and including the banks' annual review completed in February, 1996, Devon's credit lines have increased by $140 million to a total of $260 million. Though total debt has increased, the unused portion of Devon's credit lines has increased some $50 million.

Results of Operations

Changes in oil, gas and NGL production, prices and revenues from 1993 to 1995 are shown in the table below.

	Ended December 31, 1995	1995 vs 1994	1994	1994 vs 1993	1993
Production					
Oil (MBbls)	3,300	+34%	2,467	+6%	2,337
Gas (MMcf)	36,886	-6%	39,335	+10%	35,598
NGLs (MBoe)	600	+20%	501	+22%	411
Oil, Gas and NGLs (MBoe)	10,047	+5%	9,524	+10%	8,681
Revenues					
Per Unit of Production:					
Oil (per Bbl)	$ 16.75	+8%	15.44	-6%	16.43
Gas (per Mcf)	$ 1.38	-3%	1.43	-7%	1.54
NGLs (per Boe)	$ 10.68	+9%	9.79	-11%	11.06
Oil, Gas and NGLs (per Boe)	$ 11.19	+7%	10.43	-7%	11.27
Absolute			(Thousands)		
Oil	$ 55,290	+45%	38,086	-1%	38,395
Gas	$ 50,732	-10%	56,372	+3%	54,876
NGLs	$ 6,404	+30%	4,908	+8%	4,544
Oil, Gas and NGLs	$112,426	+13%	99,366	+2%	97,815

Oil Revenues 1995 vs. 1994 Oil revenues rose $17.2 million in 1995. Substantial gains in production added $12.9 million to revenues in 1995, while higher average prices added the remaining $4.3 million.

The Merger Properties produced 843,000 barrels in 1995, a 239% increase from the 249,000 barrels which were produced during Devon's ownership for the last seven months of 1994. Production from Devon's other oil properties increased 11% in 1995, from 2,218,000 barrels in 1994 to 2,457,000 barrels in 1995.

1994 vs. 1993 Oil revenues were essentially unchanged from 1993 to 1994. A 130,000 barrel boost in production added $2.1 million to oil revenues. Unfortunately, a decrease in oil prices subtracted $2.4 million.

The Merger Properties added 249,000 barrels of additional production during the last seven months of 1994, while Devon's other properties accounted for a net decrease of approximately 119,000 barrels in 1994 due to the effect of property sales in 1993. Devon sold various minor, marginally profitable or non-strategic properties throughout 1993. These properties produced approximately 173,000 barrels of oil in 1993.

Gas Revenues 1995 vs. 1994 Gas revenues decreased $5.6 million, or 10%, in 1995, due to a combination of lower production and prices. Lower production accounted for $3.5 million of the revenue decrease, while lower gas prices accounted for the remaining $2.1 million.

Gas revenues in 1995 were down despite the positive effect of the 1995 San Juan Basin Transaction. Such transaction boosted 1995's gas revenues by $11.4 million, and raised the average prices for 1995 coal seam gas and total gas production by $0.61 and $0.35 per Mcf, respectively. See Note 3 to the consolidated financial statements included elsewhere in this Form 10-K for a detailed discussion of the San Juan Basin Transaction.

Coal seam gas production declined by 5%, from 22.0 Bcf in 1994 to 20.8 Bcf in 1995. This decline of 1.2 Bcf was due to the San Juan Basin Transaction which, among other things, included the sale of a small portion of Devon's coal seam gas properties.

The average realized coal seam gas price rose by 13%, from $1.17 per Mcf in 1994 to $1.32 per Mcf in 1995. The $0.61 per Mcf increase from the San Juan Basin Transaction more than offset a $0.46 per Mcf price drop at the wellhead. Total coal seam gas revenues were $27.5 million in 1995 versus $25.7 million in 1994. Coal seam gas revenues in 1995 included $14.7 million of wellhead sales and $12.8 million of revenues attributable to the San Juan Basin Transaction. The sale of the small portion of Devon's coal seam gas properties which was part of the San Juan Basin Transaction had the effect of reducing 1995's coal seam gas revenues by $1.4 million as compared to 1994's revenues. The $12.8 million of additional gas sales received pursuant to the terms of the San Juan Basin Transaction, less the $1.4 million of wellhead sales reduction as a result of the small sale, nets to the $11.4 million increase in coal seam gas sales from the San Juan Basin Transaction referred to in the second paragraph above.

Total conventional gas production and revenues for 1995 were 16.1 Bcf and $23.2 million, respectively, versus 17.4 Bcf and $30.7 million in 1994. Prices for conventional gas averaged $1.44 per Mcf in 1995 compared to 1994's average of $1.76 per Mcf.

Production for a full year from the Merger Properties contributed a 0.6 Bcf increase in gas production in 1995. However, this increase and others from wells drilled in 1994 and 1995 were more than offset by reduced production from other conventional gas wells. The primary areas where conventional production declined in 1995 were the Ozona field and NEBU. High pipeline pressure and down time for repairs contributed to a 0.6 Bcf reduction in Ozona production in 1995. Although Devon does not have a significant interest in conventional gas production in NEBU, it has been receiving more than its normal share of production through gas balancing and also received nonrecurring payments for inventory gas in 1994. In 1995, the amounts of imbalance makeup and inventory sales declined, thus leading to a 0.5 Bcf reduction in conventional NEBU production compared to 1994. Also, various marginal wells sold during 1994 and 1995 accounted for a 0.6 Bcf reduction in conventional production in 1995.

1994 vs. 1993 Gas revenues increased $1.5 million, or 3%, in 1994, as a 7% drop in prices dampened the effect of a 10% increase in production. Gas production increases boosted gas revenues by $5.8 million. Lower gas prices reduced gas revenues by $4.3 million.

Approximately 2.2 Bcf of the production increase was attributable to coal seam gas production from NEBU and the 32-9 Unit Properties. NEBU production increased from 18.2 Bcf in 1993 to 18.7 Bcf in 1994. Production from the 32-9 Unit Properties increased from 1.6 Bcf in 1993 to 3.3 Bcf in 1994 due to the fact that such properties were acquired by Devon in the middle of 1993, and therefore contributed only six months of production to Devon's 1993 totals.

Total coal seam gas production and revenues for 1994 were 21.9 Bcf and $25.7 million, respectively, versus 19.8 Bcf and $27.7 million for 1993. Prices for coal seam gas averaged $1.17 for 1994 versus $1.40 in 1993. The price per Mcf for coal seam gas is less than Devon's conventional gas (i.e., gas produced from other than coal formations) primarily due to the former's low Btu content and the costs of transportation and removing carbon dioxide. These adjustments have been taken into account in calculating the coal seam sales prices referred to in this discussion. Beginning in 1995, as discussed above, the San Juan Basin Transaction increased the coal seam price to a level much closer to Devon's conventional gas prices.

Total conventional gas production and revenues for 1994 were 17.4 Bcf and $30.7 million, respectively, versus 15.8 Bcf and $29.2 million in 1993. Prices for conventional gas averaged $1.76 per Mcf compared to $1.84 per Mcf in 1993.

Approximately 0.6 Bcf of conventional gas production was added during 1994 from the Merger Properties. Also, approximately 1.5 Bcf of additional 1994 production was contributed by the Ozona field and related properties in the Permian Basin. The Ozona properties were part of the Permian Basin Properties acquired in July 1992. However, prior to September 1993, substantially all of the gas produced from such properties was used to satisfy a recoupment obligation created by the prior owner of the properties. Therefore, Devon only began recognizing production and gas revenues from these properties in September 1993. More importantly, production from the Ozona properties more than doubled due to Devon's drilling efforts in this field.

Approximately 0.9 Bcf of gas was produced in 1993 from properties which were sold during 1993. Therefore, these properties contributed no production in 1994. Also, gas production declined 0.2 Bcf in 1994 due to properties which were sold in 1994 and therefore did not produce for a full year as they did in 1993.

NGL Revenues 1995 vs. 1994 NGL revenues increased by $1.5 million in 1995. Higher production contributed $1.0 million of the increase, while the remaining $0.5 of increased revenues was attributable to higher average prices in 1995.

The Merger Properties accounted for 52,000 Boe of the increased production. Such properties produced 84,000 Boe in 1995, compared to 32,000 Boe during the seven months Devon owned the properties in 1994.

1994 vs. 1993 A 90,000 Boe increase in NGL production raised revenues by $1.0 million. A decrease in prices subtracted $0.6 million.

Approximately 32,000 Boe of production was added during 1994 from the Merger Properties. The remaining increase was primarily attributable to Devon's drilling efforts in 1993 and 1994.

Expenses The details of the changes in pre-tax expenses between 1993 and 1995 are shown in the table below.

	Year Ended December 31,				
	1995	1995 vs 1994	1994	1994 vs 1993	1993
	(Absolute Amounts in Thousands)				
<F1>					
Absolute(1):					
Production and operating expenses:					
Lease operating expenses	$27,289	+11%	24,521	-7%	26,401
Production taxes	6,832	-1%	6,899	-	6,924
Depreciation, depletion and amortization attributable to:					
Oil and gas production	36,640	+11%	32,861	+20%	27,420
Non-oil and gas properties	1,450	+14%	1,271	+29%	989
General and administrative expenses . .	8,419	-	8,425	+10%	7,640
Interest expense	7,051	+30%	5,439	+59%	3,422
Total	$87,681	+10%	79,416	+9%	72,796
<F1>					
Per Boe(1):					
Production and operations expenses:					
Lease operating expenses	$ 2.72	+6%	2.57	-15%	3.04
Production taxes	0.68	-7%	0.73	-9%	0.80
Depreciation, depletion and amortization attributable to:					
Oil and gas production	3.65	+6%	3.45	+9%	3.16
Non-oil and gas properties	0.14	+8%	0.13	+18%	0.11
General and administrative expenses . .	0.84	-6%	0.89	+1%	0.88
Interest expense	0.70	+23%	0.57	+43%	0.40
Total	$ 8.73	+5%	8.34	-1%	8.39

<F1>
(1) Though per unit general and administrative expenses, interest expense and non-oil and gas property depreciation may be helpful for profitability trend analysis, these expenses are not directly attributable to production volumes. Rather they are an artifact of corporate structure, capitalization and financing, and non-oil and gas property fixed assets, respectively.

Production and Operating Expenses The details of the changes in production and operating expenses between 1993 and 1995 are shown in the table below.

	Year Ended December 31,				
	1995	1995 vs 1994	1994	1994 vs 1993	1993
	(Absolute Amounts in Thousands)				
Absolute:					
Recurring lease operating expenses . .	$23,842	+10%	21,583	-3%	22,317
Well workover expenses	3,447	+17%	2,938	-28%	4,084
Production taxes	6,832	-1%	6,899	-	6,924
Total production and operating expenses	$34,121	+9%	31,420	-6%	33,325
Per Boe:					
Recurring lease operating expenses . .	$ 2.37	+4%	2.27	-12%	2.57
Well workover expenses	0.35	+17%	0.30	-36%	0.47
Production taxes	0.68	-7%	0.73	-9%	0.80
Total production and operating expenses	$ 3.40	+3%	3.30	-14%	3.84

1995 vs. 1994 Recurring lease operating expenses increased by $2.2 million, or 10%, in 1995. Approximately $1.6 million of the increase was related to the Merger Properties, whose costs increased from $1.9 million in 1994 (for the last seven months of the year during which they were owned by Devon) to $3.5 million in 1995. However, on a cost per unit of production basis, the Merger Properties' recurring lease operating expenses dropped from $4.96 per Boe in 1994 to $3.16 per Boe in 1995. These per unit costs compare to the averages for Devon's other properties of $2.15 per Boe in 1994 and $2.28 per Boe in 1995.

1994 vs. 1993 Recurring lease operating expenses dropped by $0.7 million, or 3%, in 1994. The positive effect from the sale of over 2,000 wells in 1993 was partially offset by additional expenses related to the Merger Properties. The Merger Properties are primarily oil producing properties, which are traditionally more expensive to operate than gas producing properties. For the year 1994, the Merger Properties incurred $1.9 million of recurring lease operating expenses, or $4.96 per Boe, compared to $19.7 million of such costs, or $2.15 per Boe, incurred on Devon's other properties.

Workover expenses dropped by $1.1 million, or 28%, in 1994. Most of the reduction occurred in certain Permian Basin properties acquired in 1992. A substantial number of workover projects were completed on such properties in 1993 as Devon became more familiar with these properties following the acquisition. The need for workovers on these properties declined in 1994.

Depreciation, Depletion and Amortization Devon's largest non-cash expense is 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 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 capitalized costs change, 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.

1995 vs. 1994 Oil and gas property related DD&A increased by $3.8 million, or 11%, in 1995. Approximately $2.0 million of this increase was caused by an increase in the DD&A rate from $3.45 per Boe in 1994 to $3.65 per Boe in 1995. The increased DD&A rate was primarily caused by the inclusion of the Merger Properties for a full year in 1995, compared to only seven months in 1994. The remaining $1.8 million of the increase in oil and gas property related DD&A was caused by the increase in total production in 1995.

1994 vs. 1993 Oil and gas property related DD&A increased $5.4 million, or 20%, in 1994. Approximately 50% of this increase was related to the increase in combined oil, gas and NGL production in 1994. The other half of the increased expense was due to an increase in the DD&A rate from $3.16 per Boe in 1993 to $3.45 per Boe in 1994. The addition of the Merger Properties in 1994 was the primary cause for the increased DD&A rate. The DD&A rate for the seven months following the addition of the Merger Properties was $3.60 per Boe.

General and Administrative Expenses ("G&A") 1995 vs. 1994 G&A was constant between 1995 and 1994. Employee salaries and related overhead burdens increased by $0.3 million, legal fees increased by $0.3 million and abandoned acquisition costs rose by $0.1 million. These increases were offset by a $0.6 million increase in G&A reimbursements received from joint interest owners in Devon-operated properties and a $0.1 million reduction in franchise taxes. Approximately $0.2 million of the increase in G&A reimbursements related to a change in the method used to calculate the reimbursements on certain properties, and such change was retroactive to the prior two years. The reduction in franchise taxes resulted from Devon's reincorporation from Delaware to Oklahoma in June 1995.

1994 vs. 1993 G&A increased approximately $0.8 million, or 10%, in 1994. Employee salaries and related overhead burdens such as health insurance, payroll taxes and pension expenses rose by $1.4 million, or 16%. These increases were partially offset by a $0.3 million reduction in abandoned acquisition costs and a $0.3 million increase in overhead reimbursements received from joint interest owners in Devon-operated properties.

Interest Expense 1995 vs. 1994 Interest expense increased by $1.6 million, or 30%, in 1995. This increase was due almost exclusively to higher rates in 1995, which accounted for $1.3 million of the increased interest expense. The interest rate on the debt outstanding during 1995 was 6.5%, compared to 1994's rate of 5.2%. The overall interest rate (including the effect of various fees paid to the banks and the amortization of certain loan costs) averaged 7.3% in 1995, compared to the 1994 overall rate of 5.9%.

The remaining $0.3 million of interest expense increase in 1995 was caused by a higher average balance outstanding. The average debt balance during 1995 was $97.1 million, compared to 1994's average balance of $92.5 million.

Devon entered into an interest rate swap agreement in June, 1995, to hedge the impact of interest rate changes on a portion of its long-term debt. The principal amount of the swap agreement is $75 million, and the other party to the agreement is one of the lenders of Devon's credit lines (the "Lender"). The agreement terminates on June 16, 1998, unless the Lender exercises its right to extend the termination date to June 16, 2000. The terms of the agreement provide for quarterly payments either to or from Devon, determined by whether the three month London Interbank Offered Rate ("LIBOR") in effect at the beginning of each quarterly calculation period is greater or less than 5.6%. The calculation periods begin on the sixteenth day of each March, June, September and December during the term of the agreement. If, on the date of the beginning of the quarterly calculation period, the three month LIBOR exceeds 5.6%, the Lender will owe Devon the quarterly amount of the excess rate applied to the $75 million principal. Alternately, if the three month LIBOR on the applicable quarterly date is less than 5.6%, Devon will owe the Lender.

The swap agreement is accounted for as a hedge, with the amount which is either due to or from Devon recorded as a reduction or increase in interest expense. The three month LIBOR exceeded 5.6% at the beginning of each of the three quarterly calculation periods in 1995. Therefore, Devon recognized $0.1 million as a reduction to interest expense in 1995.

The swap agreement does not alter or affect any terms or conditions of Devon's credit lines.

1994 vs. 1993 Interest expense increased $2.0 million, or 59%, in 1994. The average long-term debt balance outstanding rose from $66.6 million during 1993 to $92.5 million during 1994. The borrowings used to fund a portion of the cash used in the Merger, along with the effect of borrowing $50.0 million at mid-year 1993 to acquire the 32-9 Unit Properties, accounted for the increased average debt during 1994. The interest rate on the debt outstanding increased from 4.2% in 1993 to 5.2% in 1994. The overall interest rate rose from 5.1% in 1993 to 5.9% in 1994.

Income Taxes 1995 vs 1994 Devon's effective financial tax rate in 1995 was 43%, compared to the statutory federal rate of 35%. State income taxes and certain tax aspects of the San Juan Basin Transaction were the primary factors which increased Devon's financial tax rate. The San Juan Basin Transaction also had a significant effect on the portion of income taxes which are current versus deferred.

1994 vs. 1993 Devon's effective financial tax rate in 1994 was 36% compared to the statutory federal rate of 35%. The effective financial rate rose above the federal statutory rate primarily due to the effect of state income taxes.

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 in "Item 8. Financial Statements and Supplementary Data."

Capital Expenditures Approximately $117.6 million of cash was spent in 1995 for capital expenditures, of which $114.9 million was related to the acquisition, drilling or development of oil and gas properties. Included in this total is $50.4 million spent in December to acquire the Worland Properties, including $0.1 million of third party costs which were capitalized as part of the transaction. Most of the drilling and development efforts in 1995 centered in the Permian Basin, which included 183 of the 199 wells which Devon drilled during 1995. Included in the Permian Basin activity was approximately $30.1 million spent in the Grayburg-Jackson Field acquired in the May 1994 Merger. Devon completed 88 infill wells in the Grayburg-Jackson Field, and an additional 9 such wells were in various stages of drilling or completion as of year-end 1995. Devon also began the initial stages of a waterflood program on this field. *Drilling of an additional 40 infill wells is expected to commence in 1996, along with the completion of the waterflood program.*

Other Cash Uses A $0.03 per common share dividend has been paid in each quarter since Devon paid its initial common stock dividend in the second quarter of 1993. This quarterly rate translates to a cash demand of $2.7 million annually. *Management expects the policy of paying a quarterly dividend to continue.*

Capital Resources and Liquidity Net cash provided by operating activities ("operating cash flow") was the primary source of capital and short-term liquidity in 1995. Operating cash flow in 1995 totaled $61.3 million, a 32% increase compared to the $46.4 million of operating cash flow generated in 1994.

In addition to operating cash flow, Devon's credit lines have been an important source of capital and liquidity. At year-end 1995, these credit lines totaled $205 million. Devon's December 31, 1995 borrowings from these credit lines were $143 million, leaving $62 million of credit available for future use. In 1996, the banks revised the credit line upward from $205 million to $260 million. (See Note 7 to the consolidated financial statements included elsewhere in this report for a detailed discussion of the credit lines.)

Devon's San Juan Basin coal seam gas production is subject to uncertainties regarding additional royalties and taxes. If such uncertainties are resolved in 1996, they are likely to require the use of operating cash flow, but Devon does not expect such amount to be material to its overall liquidity, capital resources or net earnings. For a complete discussion of these matters, see Note 11 to the consolidated financial statements contained elsewhere in this report.

1996 Estimates

The forward-looking statements provided in this discussion are based on management's examination of historical operating trends, the December 31, 1995 reserve report of LaRoche, data in Devon's files and other data available from third parties. The forward-looking statements were prepared assuming demand, curtailment, producibility and general market conditions for Devon's oil, natural gas and NGLs for 1996 will be substantially similar to those of 1995, unless otherwise noted. Devon cautions that its future oil and gas production and expenses are subject to all of the risks and uncertainties normally incident to the exploration for and development and production of oil and gas. These risks include, but are not limited to, environmental risks, drilling risks and the uncertainty inherent in estimating future oil and gas production or reserves.

Given the limitations expressed in the above paragraph, Devon's forward- looking statements for 1996 are set forth below.

Oil Revenues Devon expects its oil production in 1996 to total between 3.7 million barrels and 4.3 million barrels. Devon expects its net oil prices will average from between $0.10 below to $0.10 above West Texas Intermediate posted prices in 1996.

Gas Revenues Devon expects its total gas production in 1996 will be between 34.6 and 40.3 Bcf. It is expected that coal seam gas production will be 17.1 Bcf to 19.9 Bcf in 1996. Devon expects production from its conventional gas properties to total between 17.5 Bcf and 20.4 Bcf in

1996. Included in the 1996 conventional gas production estimates are 3.1 Bcf to
3.6 Bcf of estimated production from the Worland Properties which were acquired in mid-December 1995.

The incremental $0.61 per Mcf added to coal seam gas prices by the San Juan Basin Transaction should offset a substantial portion of the negative price effect from the low BTU content and the transportation and carbon dioxide removal costs previously discussed. Therefore, Devon expects its 1996 coal seam average price will be between $0.15 and $0.65 less than Texas Gulf Coast spot averages. Devon's conventional gas is expected to average $0.15 to $0.25 per Mcf less than Texas Gulf Coast spot prices during 1996. This conventional gas price differential is larger than in the last two years due to the inclusion of the Worland Properties in 1996. Gas production sold from the Worland Properties is expected to average $0.55 to $0.65 per Mcf less than Texas Gulf Coast spot prices during 1996.

From December of 1995 through February of 1996, the prices for Texas Gulf Coast and "Henry Hub" gas have been radically higher than those for virtually all other major basins in the U.S. Therefore, the basin differentials quoted above should be regarded as particularly volatile. The differentials quoted above are based more on historical levels than those of the last three or four months.

NGL Revenues Devon expects its production of NGLs in 1996 to total between 800,000 Boe and 950,000 Boe. Included in these estimates are 240,000 Boe to 280,000 Boe estimated to be produced in 1996 from the Worland Properties.

Production and Operating Expenses The addition of the Worland Properties and the higher number of wells producing at the Grayburg-Jackson Field should be the primary contributors to an expected increase in recurring lease operating expenses in 1996, and the resulting higher revenues should cause gross production taxes to also rise. Also, well workover expenses are anticipated to increase in 1996. Future oil, gas and NGL prices have a direct effect on gross production taxes to be incurred in 1996. Future prices could also have an effect on whether proposed workover projects are economically feasible. These factors contribute to the margin of error inherent in estimating future production and operating costs. Given these uncertainties, Devon estimates that 1996's total production and operating costs will be between $39 million and $45 million, or between $3.50 per Boe and $4.00 per Boe.

Depreciation, Depletion and Amortization The 1996 DD&A rate will depend on numerous factors which cannot be reasonably predicted at this time. Most notable among such factors are the amount of proved reserves which will be added from drilling efforts in 1996 compared to the costs incurred for such efforts, and the revisions to Devon's year-end 1995 reserve estimates which will be made during 1996. Assuming a 1996 rate constant with 1995's rate of $3.65 per Boe, and the estimated range from a 3% increase to a 19% increase in total oil, gas and NGL production discussed earlier in this section, 1996 DD&A expense (including non-oil and gas property related DD&A) is expected to increase to approximately $39 million to $45 million.

General and Administrative Expenses G&A is expected to be between $8.8 million and $9.4 million in 1996.

Interest Expense Future oil, gas and NGL prices and interest rates have a significant effect on Devon's interest expense. The interest rate swap entered into in 1995 removes the uncertainty of future interest rates from a portion, but not all of, Devon's long-term debt. Also, Devon can only marginally influence the prices it will receive in 1996 from sales of oil, gas and NGL. 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. Given the uncertainty of future prices and interest rates and their ultimate effect, Devon estimates that it will incur between $9 million and $11 million of interest expense in 1996.

Income Taxes Devon expects its financial income tax rate in 1996 to be between 41% and 46%. Regardless of the level of pre-tax earnings reported for financial purposes, approximately $2 million of Devon's financial income tax expense is "fixed" due to various aspects of the 1994 Merger and the San Juan Basin Transaction. Therefore, if the actual amount of 1996 pre-tax earnings differs materially from what Devon currently expects such amount to be, the actual financial income tax rate for 1996 could fall outside of the expected rate of 41% to 46%. Also, based on Devon's current expectations of 1996 taxable income, which are largely dependent on 1996 oil and gas prices, Devon anticipates its current portion of 1996 income taxes will be between $3 million and $5 million.

Capital Expenditures Devon expects its 1996 capital expenditures for drilling and development efforts will total between $70 and $80 million, including low risk development projects of approximately $21 million for the Grayburg-Jackson Field activities described above, and approximately $9 million on the Worland Properties. Devon also plans to spend another $20 million to $25 million on new, higher risk/reward projects in the Gulf Coast and Permian Basin areas. Devon has not given effect to any possible success associated with this $20 million to $25 million in its oil and gas reserve or production estimates.

In addition to these 1996 capital estimates, Devon also expects to incur an additional $6 million to $9 million in 1997 on certain of its proved undeveloped properties, with approximately half of such amount attributable to the Worland Properties.

Though Devon has completed at least one major acquisition in each of the last several 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.

The estimated future drilling and development activities are expected to be funded through a combination of working capital, cash flow from operations and borrowings from its credit lines. Devon considers these capital resources, which are discussed in detail below, to be more than adequate to fund these anticipated costs.

The above estimates of future capital expenditures could be significantly affected by dramatic swings in oil and gas prices, unanticipated delays in the initiation or completion of the projects, changes in governmental regulations which may affect permissible development, and possible acquisitions or mergers.

Capital Resources and Liquidity The above forward-looking statements generally estimate increases in 1996 for combined oil, gas and NGL production, and in those expenses which affect operating cash flow. However, the amount of net cash to be provided by operating activities in 1996 is uncertain due to the significant effect of future oil and gas prices. It is known, however, that such cash flow will continue to be the primary source of capital and liquidity in 1996. Operating cash flow, along with working capital and available credit, are more than adequate to meet known capital requirements for 1996.

Impact of Recently Issued Accounting Standards In 1995, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," and Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation." Both of these statements are effective beginning in 1996. With regard to oil and gas companies, Statement No. 121 will have a more significant impact on those companies following the successful efforts method of accounting, as Statement No. 121 revises the "ceiling test" for such companies. Statement No. 121 does not affect the ceiling test for companies such as Devon who follow the full cost method of accounting. Therefore, such statement is not expected to have a material impact on Devon's future operations.

With regard to Devon's stock options granted, no accounting is made until such time as the options are exercised. At that time, the proceeds are added to stockholders' equity, and no expense is recognized. Statement No. 123 provides companies with the option of expensing the "fair value" of stock options granted. Devon will not change its current accounting method regarding stock options, and therefore Statement No. 123 will not impact Devon's future operating results.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Notes to Consolidated Financial Statements December 31, 1995, 1994 and 1993

All financial statement schedules are omitted as they are inapplicable or the required information is immaterial.

INDEPENDENT AUDITORS' REPORT

The Board of Directors and Stockholders Devon Energy Corporation:

We have audited the consolidated financial statements of Devon Energy Corporation and subsidiaries as listed in the accompanying index. 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 generally accepted auditing standards. 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, 1995, 1994 and 1993, and the results of their operations and their cash flows for the years then ended, in conformity with generally accepted accounting principles.

As discussed in notes 1 and 8 to the consolidated financial statements, the Company changed its method of accounting for income taxes in 1993 to adopt the provisions of Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes."

KPMG Peat Marwick LLP

Oklahoma City, Oklahoma
February 12, 1996

DEVON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Balance Sheets

	December 31, 1995	1994	1993
Assets			
Current assets:			
Cash and cash equivalents	$ 8,897,891	8,336,371	19,550,288
Accounts receivable (Note 5)	14,400,295	15,626,799	15,356,653
Inventories	605,263	534,326	715,801
Prepaid expenses	222,135	564,371	543,166
Deferred income taxes (Note 8)	749,000	262,000	262,000
Total current assets	24,874,584	25,323,867	36,427,908
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties (Note 6)	631,437,904	523,941,141	414,073,372
Less accumulated depreciation, depletion and amortization	239,619,167	202,634,961	169,384,351
	391,818,737	321,306,180	244,689,021
Other assets	4,870,796	4,817,489	4,435,916
Total assets	$421,564,117	351,447,536	285,552,845
Liabilities and stockholders' equity			
Current liabilities:			
Accounts payable:			
Trade	3,868,458	6,394,897	3,883,775
Revenues and royalties due to others	7,322,418	7,398,199	14,679,455
Income taxes payable	1,364,070	-	467,962
Accrued expenses	3,003,943	3,225,493	2,256,583
Total current liabilities	15,558,889	17,018,589	21,287,775
Revenues and royalties due to others	816,412	1,383,135	1,445,883
Other liabilities (Notes 3 and 10)	8,623,057	-	-
Long-term debt (Note 7)	143,000,000	98,000,000	80,000,000
Deferred revenue	72,761	1,299,947	1,276,640
Deferred income taxes (Note 8)	34,452,000	27,340,000	8,643,000
Stockholders' equity (Note 9):			
Preferred stock of $1.00 par value. Authorized 3,000,000 shares; none issued	-	-	-
Common stock of $.10 par value. Authorized 120,000,000 shares; issued 22,111,896 in 1995, 22,050,996 in 1994, and 20,842,318 in 1993	2,211,190	2,205,100	2,084,232
Additional paid-in capital	167,430,347	166,654,305	144,403,743
Retained earnings	49,399,461	37,546,460	26,411,572
Total stockholders' equity	219,040,998	206,405,865	172,899,547
Commitments and contingencies (Notes 10 and 11)			
Total liabilities and stockholders' equity	$421,564,117	351,447,536	285,552,845

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Statements of Operations

	Year Ended December 31, 1995	1994	1993
Revenues			
Oil sales	$ 55,289,819	38,086,076	38,395,305
Gas sales	50,732,158	56,371,452	54,875,796
Natural gas liquids sales	6,403,663	4,908,126	4,543,625
Other	877,185	1,407,305	942,195
Total revenues	113,302,825	100,772,959	98,756,921
Costs and expenses			
Lease operating expenses	27,288,755	24,520,757	26,401,597
Gross production taxes	6,832,507	6,899,743	6,923,535
Depreciation, depletion and amortization (Note 6)	38,089,783	34,132,150	28,409,065
General and administrative expenses	8,418,739	8,424,687	7,640,210
Interest expense	7,051,142	5,438,911	3,421,742
Total costs and expenses	87,680,926	79,416,248	72,796,149
Earnings before income taxes and cumulative effect of change in accounting principle	25,621,899	21,356,711	25,960,772
Income tax expense (Note 8):			
Current	4,495,000	415,000	1,477,000
Deferred	6,625,000	7,197,000	5,298,000
Total income tax expense	11,120,000	7,612,000	6,775,000
Earnings before cumulative effect of change in accounting principle	14,501,899	13,744,711	19,185,772
Cumulative effect of change in accounting principle (Note 8)	-	-	1,300,000
Net earnings	$ 14,501,899	13,744,711	20,485,772
Net earnings per average common share outstanding (Note 1):			
Before cumulative effect of change in accounting principle	$0.66	0.64	0.92
Cumulative effect of change in accounting principle	-	-	0.06
Net earnings	$0.66	0.64	0.98
Weighted average common shares outstanding	22,073,550	21,551,581	20,822,029

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Statements of Stockholders' Equity

	Year Ended December 31, 1995	1994	1993
Common stock			
Balance, beginning of year	$ 2,205,100	2,084,232	2,073,298
Par value of common shares issued	6,090	120,868	10,934
Balance, end of year	2,211,190	2,205,100	2,084,232
Additional paid-in capital			
Balance, beginning of year	166,654,305	144,403,743	143,392,520
Common shares issued, net of issuance costs	776,042	22,250,562	1,011,223
Balance, end of year	167,430,347	166,654,305	144,403,743
Retained earnings			
Balance, beginning of year	37,546,460	26,411,572	7,801,189
Dividends	(2,648,898)	(2,609,823)	(1,875,389)
Net earnings	14,501,899	13,744,711	20,485,772
Balance, end of year	49,399,461	37,546,460	26,411,572
Total stockholders' equity, end of year	$219,040,998	206,405,865	172,899,547

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	1995	1994	1993
Cash flows from operating activities:			
Net earnings	$ 14,501,899	13,744,711	20,485,772
Adjustments to reconcile net earnings to net cash provided by operating activities:			
Depreciation, depletion and amortization	38,089,783	34,132,150	28,409,065
(Gain) loss on sale of assets	273,238	(27,086)	34,832
Deferred income taxes	6,625,000	7,197,000	5,298,000
Cumulative effect of change in accounting principle	-	-	(1,300,000)
Changes in assets and liabilities net of effects of acquisitions of businesses (Note 2):			
(Increase) decrease in:			
Accounts receivable	1,213,877	123,388	2,102,329
Inventories	(70,937)	181,475	(194,151)
Prepaid expenses	342,236	712	(127,430)
Other assets	677,238	(489,648)	(1,136,282)
Increase (decrease) in:			
Accounts payable	(430,736)	(8,896,674)	9,816,309
Income taxes payable	1,364,070	(467,962)	(718,038)
Accrued expenses	(221,550)	997,645	1,201,933
Revenues and royalties due to others	(566,723)	(62,748)	(69,763)
Long-term other liabilities	705,636	-	-
Deferred revenue	(1,227,186)	(49,127)	154,234
Net cash provided by operating activities	61,275,845	46,383,836	63,956,810
Cash flows from investing activities:			
Proceeds from sale of property and equipment	9,427,401	4,649,257	11,350,912
Capital expenditures	(117,593,897)	(35,619,968)	(85,565,098)
Payments made for acquisition of business (Note 2)	(2,391,484)	(42,397,463)	-
Net cash used in investing activities	(110,557,980)	(73,368,174)	(74,214,186)
Cash flows from financing activities:			
Proceeds from borrowings on revolving line of credit	52,000,000	32,500,000	60,000,000
Principal payments on revolving line of credit	(7,000,000)	(14,500,000)	(34,900,000)
Issuance of common stock, net of issuance costs	782,132	380,244	1,022,157
Dividends paid on common stock	(2,648,898)	(2,609,823)	(1,875,389)
Increase in long-term other liabilities (Note 3)	6,710,421	-	-
Net cash provided by financing activities	49,843,655	15,770,421	24,246,768
Net increase (decrease) in cash and cash equivalents	561,520	(11,213,917)	13,989,392
Cash and cash equivalents at beginning of year	8,336,371	19,550,288	5,560,896
Cash and cash equivalents at end of year	$ 8,897,891	8,336,371	19,550,288

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 generally accepted accounting principles. The more significant of such policies are briefly discussed below.

Basis of Presentation and Principles of Consolidation

Devon is a successor to several previous entities dating back to 1971. Devon's common stock trades on the American Stock Exchange under the symbol "DVN." Devon is engaged primarily in oil and gas exploration, development and production, and the acquisition of producing properties. Such activities are primarily in the states of New Mexico, Texas, Oklahoma, Wyoming and Louisiana.

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 generally accepted accounting principles 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. Actual amounts could differ from those estimates.

Inventories

Inventories, which consist primarily of tubular goods, parts and supplies, are stated at cost, determined principally by the average cost method, which is not in excess of net realizable value.

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. Net capitalized costs are limited to the estimated future net revenues, discounted

1. Summary of Significant Accounting Policies
(Continued)

Property and Equipment (Continued)

at 10% per annum, from proved oil, natural gas and natural gas liquids reserves. Such capitalized costs are depleted by an equivalent unit-of-production method, converting gas and natural gas liquids to oil at the ratio of one barrel ("Bbl") of oil to six thousand cubic feet ("Mcf") of natural gas and one barrel of oil to 42 gallons of natural gas liquids. 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.

Depreciation and amortization of other property and equipment, including leasehold improvements, is provided using the straight-line method based on estimated useful lives from 3 to 20 years.

Deferred Revenue

Deferred revenue includes funds received under take-or-pay provisions of certain gas contracts, which provide for recovery by the paying party of certain volumes of gas.

Gas Balancing

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, cash settlements are made among the joint interest owners under a variety of arrangements.

Devon follows the sales method of accounting for gas imbalances. A liability is recorded only if 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.

Stock Options

No accounting is made with respect to incentive stock options until such time as they are exercised, at which time the proceeds are added to stockholders' equity.

Major Purchasers

During 1995, there were two purchasers who accounted for over 10% of Devon's gas sales. These two purchasers and their respective share of gas sales were:
Aquila Energy Marketing Corporation ("Aquila") - 31%; and Enron Gas Marketing, Inc. ("Enron") - 16%. During 1994, there were three purchasers who accounted for over 10% of Devon's gas sales. These three purchasers and their respective share of gas sales were: Aquila - 21%; Enron - 19%; and Meridian Oil Trading, Inc. ("MOTI") - 18%. During 1993, MOTI accounted for 39% of Devon's gas sales.

Income Taxes

Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" ("Statement 109") was issued in February 1992. Under Statement 109's asset and liability method, 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 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. Under Statement 109, 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.

Devon adopted Statement 109 effective January 1, 1993, and has reported a benefit of $1.3 million in 1993 as a cumulative effect of a change in accounting principle.

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, net of amounts charged to affiliated partnerships for administrative and overhead costs, and net of amounts capitalized pursuant to the full cost method of accounting.

Net Earnings Per Common Share

Net earnings per common share are based upon the weighted average number of shares of common stock outstanding during the year. Stock options have been excluded since they would not have had a significant dilutive effect.

Dividends

Beginning with the second quarter of 1993, dividends on common stock were paid in 1993, 1994 and 1995 at a per share rate of $0.03 per quarter.

Fair Value of Financial Instruments

Devon's only financial instrument for which the fair value differs materially from the carrying value is the interest rate swap discussed in Note 7. The fair value and the carrying value for all other financial instruments (cash and equivalents, accounts receivable, accounts payable and long-term debt) are approximately equal due to the short-term nature of the current assets and liabilities and the fact that the interest rates paid on Devon's long-term debt are set for periods of three months or less.

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.

2. Acquisitions and Pro Forma Information

On December 18, 1995, Devon acquired certain Wyoming oil and natural gas properties and a gas processing plant (the "Worland Properties") for approximately $50.3 million. The acquisition was primarily funded with $46.0 million of borrowings from Devon's credit lines. Approximately $46.3 million of the purchase price was allocated to proved oil, gas and natural gas liquids reserves and the plant. The estimated reserve quantities acquired were 1.8 million barrels of oil, 59 billion cubic feet of natural gas and 3.7 million barrels of oil equivalent of natural gas liquids. Included in these reserves are certain proved undeveloped reserves, for which Devon expects to incur approximately $11.8 million of future capital costs. Approximately $4.0 million of the purchase price was allocated to undeveloped leasehold. (The quantities of proved reserves and the estimated future development costs stated in this paragraph are unaudited.)

On February 18, 1994, Devon and Alta Energy Corporation ("Alta") entered into an Agreement and Plan of Merger, as amended on April 13, 1994, whereby Alta was merged into a wholly-owned subsidiary of Devon (the "Merger"). The Merger was consummated on May 18, 1994, at which date the separate existence of Alta ceased. Alta's common stockholders received approximately 1,168,000 shares of Devon common stock and $1.5 million in cash upon consummation of the Merger. Subsequently, in February 1995, former Alta stockholders received an additional cash payment of $2.4 million based upon the evaluation of the Camille Adams #1 well in Louisiana which Alta completed during the first half of 1994. Devon also incurred $41.4 million of other costs related to the Merger. This included $31.7 million to

2. Acquisitions and Pro Forma Information (Continued)

acquire Alta's debt from its creditors; $3.0 million to acquire shares of Alta preferred and common stock; $3.8 million loaned to Alta for operating funds; $1.5 million to acquire certain net profits interests from Alta creditors; and $1.4 million for third party costs related to the Merger.

Devon recorded additional deferred tax liabilities of $11.5 million due to the substantially tax-free nature of the Merger to the former Alta stockholders. Excluding the $11.5 million of additional deferred tax liabilities, approximately $69.4 million of the total consideration involved in the Merger was allocated to proved oil and gas reserves. Including the deferred tax liabilities, $80.9 million was allocated to proved oil and gas reserves.

On June 28, 1993, Devon acquired certain coal seam natural gas properties in the San Juan Basin of New Mexico ("the Acquired San Juan Basin Properties") for approximately $53.3 million. Approximately $48.3 million of the purchase price was attributable to proved coal seam natural gas reserves. The remaining $5 million of the purchase price was allocated to unproved reserves associated with infill drilling and development rights. The acquisition was primarily funded with $50 million of borrowings from Devon's credit lines. The acquisition was accounted for by the purchase method of accounting for business combinations. Accordingly, the accompanying 1993 consolidated statement of operations does not include any revenues or expenses associated with the Acquired San Juan Basin Properties prior to July 1, 1993.

Pro Forma Information (Unaudited)

The 1995 acquisition of the Worland Properties as described above was accounted for by the purchase method of accounting for business combinations. Accordingly, the accompanying 1995 consolidated statement of operations does not include any revenues or expenses associated with the Worland Properties prior to the closing date of December 18, 1995. Following are Devon's pro forma results for 1995 assuming the acquisition occurred at the beginning of 1995:

1995

Total revenues	$118,652,000
Net earnings	$13,097,000
Net earnings per share	$0.59

The 1994 Merger described above was accounted for by the purchase method of accounting for business combinations. Accordingly, the accompanying consolidated statements of operations do not include any revenues or expenses related to Alta prior to the closing date of May 18, 1994. Following are Devon's pro forma 1994 results assuming the acquisition of the Worland Properties and the Merger both occurred on January 1, 1994:

2. Acquisitions and Pro Forma Information (Continued)

Pro Forma Information (Unaudited) (Continued)

	1994			
		Pro Forma Effect of		
	Devon Historical	Merger	Worland Properties	Devon Pro Forma
Total revenues	$100,773,000	4,329,000	6,297,000	111,399,000
Net earnings	$13,745,000	(329,000)	(387,000)	13,029,000
Net earnings per share	$0.64	(0.03)	(.02)	0.59

3. San Juan Basin Transaction

Effective January 1, 1995, Devon and an unrelated company entered into a transaction covering substantially all of Devon's San Juan Basin coal seam gas properties (the "San Juan Basin Transaction"). These coal seam gas properties represented Devon's largest oil and gas reserve position as of December 31, 1994. The properties' estimated reserves as of year-end 1994 were 199.2 billion cubic feet ("Bcf") of natural gas, or 31% of Devon's 633.2 equivalent Bcf of combined oil and natural gas reserves. In addition to the cash flow and earnings impact normally associated with oil and gas production, these properties also qualify as a "nonconventional fuel source" under Internal Revenue Service regulations. Consequently, gas produced from these properties through the year 2002 qualifies for Section 29 tax credits, which as of year-end 1995 were equal to approximately $1.01 per million Btu ("MMBtu").

The San Juan Basin Transaction involves approximately 186.2 Bcf, or 93%, of the year-end 1994 coal seam gas reserves, and has four major parts associated with it. First, Devon conveyed to the unrelated party 179 Bcf of the properties' reserves. However, for financial reporting purposes, Devon retained all of such reserves and their future production and cash flow through a volumetric production payment and a repurchase option. Second, Devon conveyed outright to the unrelated party 7.2 Bcf of reserves for a sales price of $5.2 million. The reserves and future cash flow associated with this conveyance were not retained by Devon. Third, and the source of the most significant impact of the transaction, Devon receives payments equal to 75% of the Section 29 tax credits generated by the properties. And fourth, Devon retained a 75% reversionary interest in any reserves in excess of the 186.2 Bcf estimated to exist as of December 31, 1994. Each of these parts of the San Juan Basin Transaction, and their effects on Devon's operations, are described in more detail in the following paragraphs.

3. San Juan Basin Transaction (Continued)

The production payment retained by Devon is equal to 94.05% of the first 143.4 Bcf of gas produced from the properties, or 134.9 Bcf. As such, Devon will continue to record gas sales and associated production and operating expenses and reserves associated with the production payment. Production from the retained production payment is currently estimated to occur over a period of 12 years.

The conveyance of the properties which are not subject to the retained production payment or the repurchase option was accounted for as a sale of oil and gas properties. Accordingly, 7.2 Bcf of gas reserves were removed from total proved reserves, and the $5.2 million of proceeds reduced the book value of oil and gas properties. The conveyance to the third party is limited exclusively to the existing wells drilled as of January 1, 1995. Wells to be drilled in the future, if any, are not included in this transaction.

In addition to receiving 94.05% of the properties' net cash flow through the retained production payment, Devon receives quarterly payments from the third party equal to 75% of the value of the Section 29 tax credits which are generated by production from such properties until the earlier of December 31, 2002, or until the option to repurchase is exercised. For the year ended December 31, 1995, Devon received $13.9 million related to the credits. Of this amount, $12.8 million was recorded as additional gas sales, and $1.1 million was recorded as an addition to liabilities as discussed in the following paragraph. *Based on the reserves estimated at December 31, 1995, and an assumed annual inflation factor of 2%, Devon estimates it will receive total tax credit payments of approximately $68 million from 1996 through 2002.*

Devon has an option to repurchase the properties at any time. The purchase price of such option is equal to the fair market value of the properties at the time the option is exercised, as defined in the transaction agreement, less the production payment balance. At closing, Devon received $5.6 million associated with reserves to be produced subsequent to the term of the production payment. Such amount is included in long-term "other liabilities" on the accompanying balance sheet. Since Devon expects to eventually exercise its option to repurchase the properties, the liability will be increased over time to reflect the option purchase price. As the purchase price increases, a portion of the tax credit payments received by Devon will be added to the liability. As stated above, for the year ended December 31, 1995, $1.1 million of the total amount received for tax credit payments was added to the liability, which raised the liability balance to $6.7 million.

3. San Juan Basin Transaction (Continued)

Devon has retained a 75% reversionary interest in the properties' reserves in excess, if any, of the 186.2 Bcf of reserves estimated to exist at December 31, 1994. The terms of the transaction provide that the third party will pay 100% of the capital necessary to develop any such incremental reserves for its 25% interest in such reserves. Devon's repurchase option also includes the right to purchase this incremental 25%. However, the $6.7 million of other liabilities recorded as of year-end 1995, does not include any amount related to such reserves.

4. Supplemental Cash Flow Information

Cash payments for interest in 1995, 1994, and 1993 were approximately $6.7 million, $5.1 million and $3.3 million, respectively. Cash payments for federal and state income taxes in 1995, 1994, and 1993 were approximately $2.2 million, $1.8 million and $2.3 million, respectively.

The Merger with Alta in 1994 involved cash and non-cash consideration as presented below:

	1994
Cash payments made	$42,915,845
Value of common stock issued	21,991,084
Liabilities assumed	7,192,671
Deferred tax liability created	11,500,000
Fair value of assets acquired	$83,599,600

The above cash payments of $42.9 million include approximately $1.4 million of direct costs paid to third parties which were capitalized and allocated to producing oil and gas properties. The cash payments made are reduced in the accompanying 1994 consolidated statement of cash flows by $518,382 of cash acquired in the Merger.

5. Accounts Receivable

The components of accounts receivable included the following:

	December 31,		
	1995	1994	1993
Oil, gas and natural gas liquids revenue accruals	$11,169,313	10,973,589	11,981,969
Joint interest billings	2,962,037	3,367,493	2,995,440
Income tax refunds due	-	959,085	-
Other	493,945	551,632	629,244
	14,625,295	15,851,799	15,606,653
Allowance for doubtful accounts	(225,000)	(225,000)	(250,000)
Net accounts receivable	$14,400,295	15,626,799	15,356,653

6. Property and Equipment

Property and equipment included the following:

	December 31, 1995	1994	1993
Oil and gas properties:			
Subject to amortization	$ 604,227,702	503,174,488	394,845,195
Not subject to amortization:			
Acquired in 1995	5,635,170	-	-
Acquired in 1994	1,001,427	1,451,109	-
Acquired in 1993	5,556,977	5,556,977	5,993,090
Acquired in 1992	8,257,985	8,561,031	8,650,308
Accumulated depreciation, depletion and amortization	(237,385,785)	(200,746,032)	(167,884,858)
Net oil and gas properties	387,293,476	317,997,573	241,603,735
Other property and equipment:			
Computers, office equipment, furniture and leasehold improvements	5,168,817	4,047,183	3,645,091
Automotive equipment	1,201,084	786,338	646,247
Other	388,742	364,015	293,441
	6,758,643	5,197,536	4,584,779
Accumulated depreciation and amortization	(2,233,382)	(1,888,929)	(1,499,493)
Net other property and equipment	4,525,261	3,308,607	3,085,286
Property and equipment, net of accumulated depreciation, depletion and amortization	$ 391,818,737	321,306,180	244,689,021

Depreciation, depletion and amortization expense consisted of the following components:

	Year Ended December 31, 1995	1994	1993
Depreciation, depletion and amortization of oil and gas properties	$36,639,753	32,861,174	27,419,640
Depreciation and amortization of other property and equipment	1,045,978	865,092	808,770
Amortization of other assets	404,052	405,884	180,655
Total expense	$38,089,783	34,132,150	28,409,065

DEVON ENERGY CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements December 31, 1995, 1994 and 1993

7. Long-term Debt

Devon has lines of credit pursuant to which it can borrow up to an amount determined by the banks based on their evaluation of the assets and cash flow (the "Borrowing Base") of Devon. The established Borrowing Base at December 31, 1995, was $205 million. In 1996, the banks revised the Borrowing Base upward to $260 million. Amounts borrowed under the credit lines bear interest at various fixed rate options which Devon may elect for periods up to 90 days. Such rates are generally less than the prime rate. Devon may also elect to borrow at the prime rate plus up to .75% depending on the percentage of the Borrowing Base that is borrowed. The average interest rates on the outstanding debt at the end of 1995, 1994 and 1993, were 6.64%, 6.83% and 4.16%, respectively. The loan agreements also provide for a quarterly commitment fee equal to .375% per annum.

Debt borrowed under the credit lines is unsecured. No principal payments are required until maturity unless the unpaid balance exceeds the Borrowing Base. As of December 31, 1995, $140 million of the outstanding balance matures on March 31, 1998, and the remaining $3 million matures on May 1, 1997. The loan agreements contain certain covenants and restrictions, among which are limitations on additional borrowings and sales of properties valued at more than $10 million, working capital and net worth maintenance requirements and a minimum debt to net worth ratio. At December 31, 1995, Devon was in compliance with such covenants and restrictions.

Assuming the Borrowing Base is not reduced below the current loan balance outstanding and the maturity dates of the loans are not extended, the debt outstanding at the end of 1995 is scheduled to be payable as follows:

Year ending December 31,	
1996	$ -
1997	3,000,000
1998	140,000,000
	$143,000,000

Devon entered into an interest rate swap agreement in June, 1995, to hedge the impact of interest rate changes on a portion of its long-term debt. The principal amount of the swap agreement is $75 million, and the other party to the agreement is one of the lenders of Devon's

7. Long-term Debt (Continued)

credit lines (the "Lender"). The agreement terminates on June 16, 1998, unless the Lender exercises its right to extend the termination date to June 16, 2000. The terms of the agreement provide for quarterly payments either to or from Devon, determined by whether the three month London Interbank Offered Rate ("LIBOR") in effect at the beginning of each quarterly calculation period is greater or less than 5.6%. The calculation periods begin on the sixteenth day of each March, June, September and December during the term of the agreement. If, on the date of the beginning of the quarterly calculation period, the three month LIBOR exceeds 5.6%, the Lender will owe Devon the quarterly amount of the excess rate applied to the $75 million principal. Alternately, if the three month LIBOR on the applicable quarterly date is less than 5.6%, Devon will owe the Lender.

The swap agreement is accounted for as a hedge, with the amount which is either due to or from Devon recorded as a reduction or increase in interest expense. The three month LIBOR exceeded 5.6% at the beginning of each of the three quarterly calculation periods in 1995. Therefore, Devon recognized $0.1 million as a reduction to interest expense in 1995. The fair value of the interest rate swap as of December 31, 1995 was a liability of approximately $1.4 million. The interest rate swap has no carrying value in the accompanying consolidated financial statements.

The swap agreement does not alter or affect any terms or conditions of Devon's credit lines.

8. Income Taxes

At December 31, 1995, Devon had the following carryforwards available to reduce future federal and state income taxes:

Types of Carryforward	Years of Expiration	Carryforward Amounts
Net operating loss - federal	1996-2008	$15,400,000
Net operating loss - various states	1996-2010	$18,100,000
Statutory depletion	N/A	$ 6,500,000
Minimum tax credit	N/A	$ 5,600,000
Investment tax credit	1996-1999	$ 100,000

8. Income Taxes (Continued)

All of the carryforward amounts shown above have been utilized for financial purposes to reduce deferred taxes. Substantially all of the federal net operating loss carryforwards shown above were acquired in the 1994 Merger.

Total income tax expense differed from the amounts computed by applying the federal income tax rate to net earnings before income taxes as a result of the following:

	Year Ended December 31,		
	1995	1994	1993
Federal statutory tax rate	35%	35%	35%
Nonconventional fuel source credits	(1)	-	(6)

Alternative minimum tax (credit)	-	-	(2)
State income taxes	4	3	1
Effect of San Juan Basin Transaction	4	-	-
Other	1	(2)	(2)
Effective income tax rate	43%	36%	26%

As discussed in Note 1, Devon adopted Statement 109 as of January 1, 1993. The $1.3 million cumulative benefit of this change is reported separately in the 1993 consolidated statement of operations.

The tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities at December 31, 1995, 1994 and 1993, as provided for under Statement 109, are presented below:

	December 31, 1995	1994	1993
Deferred tax assets:			
Net operating loss carryforwards	$ 6,082,000	6,127,000	1,609,000
Statutory depletion carryforwards	2,287,000	3,087,000	2,606,000
Investment tax credit carryforwards	85,000	813,000	894,000
Minimum tax credit carryforwards	5,576,000	2,195,000	1,860,000
Production payments	24,770,000	-	-
Other	1,966,000	897,000	629,000
Total gross deferred tax assets	40,766,000	13,119,000	7,598,000
Less valuation allowance	100,000	100,000	-
Net deferred tax assets	40,666,000	13,019,000	7,598,000
Deferred tax liabilities:			
Property and equipment, principally due to differences in depreciation, and the expensing of intangible drilling costs for tax purposes	(74,369,000)	(40,097,000)	(15,979,000)
Net deferred tax liability	$(33,703,000)	(27,078,000)	(8,381,000)

As shown in the above schedule, Devon has recognized $40.7 million of net deferred tax assets as of December 31, 1995. Such amount consists almost entirely of $14 million of various carryforwards available to offset future income taxes, and $24.8 million of net tax basis in production payments. The carryforwards include federal net operating loss carryforwards, the majority of which do not begin to expire until 2006, state net operating loss carryforwards which expire primarily between 1999 and 2003, investment tax credit carryforwards which expire between 1996 and 1999, and the statutory depletion and minimum tax credit carryforwards which have no expiration dates. Statement 109 requires that the tax benefit of carryforwards be 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", Statement 109 requires that a valuation allowance be 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 1996 and 2002. 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 federal 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. A $100,000 valuation allowance has been recorded at December 31, 1995, related to depletion carryforwards acquired in the Merger.

The $24.8 million of deferred tax assets related to production payments is offset by a portion of the deferred tax liability related to the excess financial basis of property and equipment. The income tax accounting for the San Juan Basin Transaction described in Note 3 differs from the financial accounting treatment which is described in such note. For income tax purposes, a gain from the conveyance of the properties was recognized, and the present value of the production payments to be received was recorded as a note receivable. For presentation purposes, the $24.8 million represents the tax effect of the difference in accounting for the production payment, less the effect of the taxable gain from the transaction which is being deferred and recognized on the installment basis for income tax purposes.

9. Stockholders' Equity

The authorized capital stock of Devon consists of 120 million shares of common stock, par value $.10 per share (the "Common Stock"), and three million shares of preferred stock, par value $1.00 per share (the "Preferred Stock"). 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.

Devon's Board of Directors has designated 150,000 shares of the Preferred Stock as Series A Junior Participating Preferred Stock (the "Series A Preferred Stock") in connection with the adoption of the share rights plan described later in this note. At December 31, 1995, there were no shares of Series A Preferred Stock issued or outstanding. The Series A 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 Preferred Stock. Holders of the Series A 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 Preferred Stock is neither redeemable nor convertible. The Series A Preferred Stock ranks prior to the Common Stock but junior to all other classes of Preferred Stock.

9. Stockholders' Equity (Continued)

Stock Option Plans

Prior to 1993, Devon had outstanding stock options issued to certain of its employees under two stock option plans adopted in 1987 and 1988 ("the 1987 Plan" and "the 1988 Plan"). During 1993, all remaining options outstanding under the 1987 Plan were exercised. Also during 1993, the 1988 Plan was cancelled. Options granted under the 1988 Plan remain exercisable by the employees owning such options, but no new options will be granted under the 1988 Plan. At December 31, 1995, 14 participants held the 368,600 options outstanding under the 1988 Plan.

Effective June 7, 1993, Devon adopted the Devon Energy Corporation 1993 Stock Option Plan ("the 1993 Plan") and reserved one million shares of Common Stock for issuance thereunder to key management and professional employees. Eighteen such employees were eligible to participate in the 1993 Plan at year-end 1995.

The exercise price of incentive stock options granted under the 1993 Plan may not be less than the estimated fair market value of the stock at the date of grant, plus 10% if the grantee owns or controls more than 10% of the total voting stock of Devon prior to the grant. The exercise price of nonqualified options granted under the 1993 Plan may not be less than 75% of the fair market value of the stock on 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 1993 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 1993 Plan is administered by a committee comprised of non-management members of the Board of Directors. The 1993 Plan expires on April 25, 2003. As of December 31, 1995, 18 participants held the 660,300 options outstanding under the 1993 Plan. There were 337,200 options available for future grants as of December 31, 1995.

9. Stockholders' Equity (Continued)

Stock Option Plans (Continued)

A summary of the status of Devon's stock option plans as of December 31, 1993, 1994 and 1995, and changes during each of the years then ended, is presented below:

	Options Outstanding		Options Exercisable	
	Number Outstanding	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
Balance at December 31, 1992	377,537	$10.146		

Options granted	214,500	$24.087		
Options exercised	(109,337)	$ 9.349		
Balance at December 31, 1993	482,700	$16.521	300,000	$14.848
Options granted	436,000	$20.736		
Options exercised	(40,800)	$ 9.355		
Balance at December 31, 1994	877,900	$18.947	485,000	$17.423
Options granted	219,000	$23.875		
Options exercised	(60,900)	$12.843		
Options forfeited	(7,100)	$20.105		
Balance at December 31, 1995	1,028,900	$20.349	688,800	$19.744

9. Stockholders' Equity (Continued)

Stock Option Plans (Continued)

The following table summarizes information about Devon's stock options which were outstanding, and those which were exercisable, as of December 31, 1995:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$8 to $14	168,600	5.3 years	$10.001	154,600	$10.148
$18 to $21	210,800	8.9 years	$18.088	121,600	$18.089
$23 to $25	649,500	8.7 years	$23.770	412,600	$23.827
$8 to $25	1,028,900	8.2 years	$20.349	688,800	$19.744

Share Rights Plan

Under Devon's share 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.

10. Retirement Plans

Devon has a defined benefit retirement plan (the "Basic Plan") which is non-contributory and includes substantially all employees meeting certain age and service requirements. The benefits are based on the employee's years of service and compensation. Devon's funding policy is to contribute annually the maximum amount that can be deducted for federal income tax purposes. Rights to amend or terminate the Basic Plan are retained by Devon.

Effective January 1, 1995, Devon has a separate defined benefit retirement plan (the "Supplementary Plan") which is non-contributory and includes only certain employees whose benefits under the Basic Plan are limited by federal income tax regulations. The Supplementary Plan's benefits are based on the employee's years of service and compensation. Devon's funding policy for the Supplementary Plan is to fund the benefits as they become payable. Rights to amend or terminate the Supplementary Plan are retained by Devon.

The following table sets forth the aggregate funded status of the Basic Plan and related amounts recognized in Devon's balance sheets:

		December 31,	
	1995	1994	1993
Actuarial present value of benefit obligations:			
Accumulated benefit obligation:			
Vested	$(3,500,000)	(2,648,000)	(2,737,000)
Nonvested	(654,000)	(282,000)	(394,000)
Total	$(4,154,000)	(2,930,000)	(3,131,000)
Projected benefit obligation for service rendered to date	(4,782,000)	(3,378,000)	(3,624,000)
Plan assets at fair value, primarily investments in corporate obligation and equity mutual funds	4,227,000	3,252,000	2,917,000
Plan assets less than projected benefit obligation	(555,000)	(126,000)	(707,000)
Unrecognized prior service cost (benefit)	(154,000)	(176,000)	(123,000)
Unrecognized net loss from past experience different from that assumed, and effects of changes in assumptions	921,000	225,000	683,000
Unrecognized net transitional asset	-	-	(35,000)
Prepaid (accrued) pension expense	$ 212,000	(77,000)	(182,000)

The following table sets forth the aggregate funded status of the Supplementary Plan and related amounts recognized in Devon's balance sheet as of December 31, 1995:

	December 31, 1995
Actuarial present value of benefit obligations:	
Accumulated benefit obligation:	
Vested	$(1,658,000)
Nonvested	(255,000)
Total	$(1,913,000)
Projected benefit obligation for service rendered to date	(2,245,000)
Plan assets at fair value	-
Projected benefit obligation in excess of plan assets	(2,245,000)
Unrecognized prior service cost	1,354,000
Unrecognized net loss from past experience different from that assumed, and effects of changes in assumptions	185,000
Accrued pension expense	(706,000)
Additional minimum liability	(1,207,000)
Total pension liability	$(1,913,000)

The $1.9 million total pension liability of the Supplementary Plan is included in long-term other liabilities on the accompanying consolidated balance sheet. The $1.2 million additional minimum liability is offset by a $1.2 million intangible asset included in other assets on the balance sheet.

Net pension expense for Devon's two defined benefit plans included the following components:

	Year Ended December 31, 1995	1994	1993
Service cost - benefits earned during the period	$ 362,000	277,000	183,000
Interest cost on projected benefit obligation	446,000	284,000	247,000
Actual return on plan assets	(536,000)	(20,000)	(254,000)
Net amortization and deferral	345,000	(231,000)	101,000
Net periodic pension expense	$ 617,000	310,000	277,000

10. Retirement Plans (Continued)

The weighted average discount rate used in determining the actuarial present value of the projected benefit obligation in 1995, 1994 and 1993 was 7.25%, 8.5% and 7.25%, respectively. The rate of increase in future compensation levels was 5% for all three years. The expected long-term rate of return on assets was 8.50% in 1995 and 8% in 1994 and 1993.

Devon has a 401(k) Incentive Savings Plan which covers all 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 $170,000, $158,000 and $147,000 for the years ended December 31, 1995, 1994 and 1993, 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 after consideration of recorded accruals.

The majority of Devon's sales of nonconventional gas from the San Juan Basin are subject to federal royalties administered and collected by the Minerals Management Service ("MMS"). In determining royalties payable to the MMS, Devon has followed the industry practice of reducing the gas sales price for certain permitted costs related to the transportation of gas produced and CO 2 removal. In 1995, the MMS issued new policies which would increase Devon's share of federal royalties for nonconventional gas produced and sold in the San Juan Basin for the years 1990 through 1995, and for future years as well. While the MMS has not asserted a claim for additional royalties, and while Devon intends to vigorously contest any claim for excessive additional federal royalties through available administrative and judicial processes, Devon has accrued an estimate of additional federal royalties related to its share of gas produced from 1990 through 1995. Devon's management, in consultation with legal counsel, believes adequate provision has been made for any additional federal royalties due and related interest. The amount accrued represents Devon's best estimate of the amount likely to be assessed by the MMS based on Devon's interpretation of the new policies issued and all other related information available to Devon. It is possible that a different interpretation of the policies and related facts could result in an assessment higher than what Devon has accrued. However, Devon's management does not believe that the amount of possible assessments above that already accrued would be material.

11. Commitments and Contingencies (Continued)

In a matter unrelated to the MMS issue discussed above, the State of New Mexico on December 29, 1995, assessed Devon and other producers of gas from the San Juan Basin a "natural gas processors tax." Devon's tax assessment for the years 1990 through 1995 was approximately $0.6 million, and the state also assessed another $0.3 million of penalties and interest. All of the assessment relates to nonconventional gas. Devon paid the assessment in January 1996 so that it could begin the necessary procedures of applying for a refund. This tax historically was paid by the owners of natural gas processing plants, not the gas producers, and was assessed for the privilege of processing natural gas. While Devon's nonconventional gas is purified through a plant prior to the actual sales point, such purification is only for the purpose of removing CO 2. Also, Devon does not own an interest in such plant. For these and other reasons, Devon does not believe the assessment of the additional tax and the related penalties and interest is valid. If the amount paid is not refunded through the normal administrative processes available, Devon intends to file a suit asking that the assessments be reversed. At this time, it is not possible to determine the eventual outcome of this matter. However, Devon's management and legal counsel believe that it is reasonably possible that the amount paid to the State of New Mexico will be refunded. Pending further developments on this matter, Devon will not expense in its financial statements the taxes, penalties and interest paid, but rather will record such amounts as receivables.

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, 1995:

Year ending December 31,	
1996	$543,000
1997	136,000
1998	83,000
1999	39,000
2000	26,000
Total minimum lease payments required	$827,000

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

1995	$546,388
1994	$521,769
1993	$487,554

DEVON ENERGY CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements December 31, 1995, 1994 and 1993

12. Oil and Gas Operations

Costs Incurred

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

	Year Ended December 31,		
	1995	1994	1993
Property acquisition costs:			
Proved, excluding deferred income taxes	$47,316,000	70,376,000	49,790,000
Deferred income taxes	-	11,500,000	-
Total proved, including deferred income taxes	$47,316,000	81,876,000	49,790,000
Unproved	$ 4,529,000	1,797,000	6,444,000
Exploration costs	$ 7,174,000	5,194,000	4,115,000
Development costs	$56,253,000	26,268,000	25,748,000

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 above table, were $2.7 million, $2.3 million and $2.2 million in the years 1995, 1994 and 1993, respectively.

Due to the substantially tax-free nature of the 1994 Merger to the former Alta stockholders, Devon recorded additional deferred tax liabilities of $11.5 million as of the effective date of the Merger. The deferred tax liabilities caused an additional $11.5 million to be allocated to proved oil and gas reserves in 1994 as shown in the above schedule.

Results of Operations for Oil and Gas Producing Activities

The following table includes revenues and expenses associated directly with Devon's oil and gas producing activities. It does not include any allocation of Devon's interest costs or general corporate overhead and, therefore, is 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 and gas sales after deducting costs, including depreciation, depletion and amortization and after giving effect to permanent differences:

	Year Ended December 31,		
	1995	1994	1993
Oil, gas and natural gas liquids sales	$112,425,000	99,366,000	97,815,000
Production and operating expenses	(34,121,000)	(31,421,000)	(33,325,000)

Depreciation, depletion and amortization	(36,640,000)	(32,861,000)	(27,420,000)
Income tax expense	(15,536,000)	(12,411,000)	(12,844,000)
Results of operations for oil and gas producing activities	$ 26,128,000	22,673,000	24,226,000
Depreciation, depletion and amortization per equivalent barrel of production	$3.65	3.45	3.16

DEVON ENERGY CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements December 31, 1995, 1994 and 1993

13. 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 Statement of Financial Accounting Standards No. 69, "Disclosures About Oil and Gas Producing Activities".

Quantities of Oil and Gas Reserves

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, 1995, as estimated by Devon's independent petroleum consultants LaRoche & Associates, and Devon's own petroleum engineers. Approximately 92%, 91%, and 95% of the respective year-end 1995, 1994 and 1993 proved reserves were calculated by LaRoche & Associates. The remaining percentage of reserves are based on Devon's own estimates. Natural gas liquids are denominated in barrels of oil equivalent ("Boe") and are converted to Boe using the ratio of 42 gallons to one barrel. All of Devon's reserves are located within the United States.

	Oil (Bbls)	Gas (Mcf)	Natural Gas Liquids (Boe)
Proved reserves as of December 31, 1992	16,349,000	263,598,000	1,011,000
Revisions of estimates	(995,000)	54,536,000	1,227,000
Extensions and discoveries	3,543,000	20,759,000	80,000
Purchase of reserves	363,000	75,168,000	20,000
Production	(2,337,000)	(35,598,000)	(411,000)
Sale of reserves	(2,026,000)	(9,209,000)	(73,000)
Proved reserves as of December 31, 1993	14,897,000	369,254,000	1,854,000
Revisions of estimates	3,157,000	(5,540,000)	1,733,000
Extensions and discoveries	2,008,000	13,206,000	183,000
Purchase of reserves	25,201,000	13,492,000	2,181,000
Production	(2,467,000)	(39,335,000)	(501,000)
Sale of reserves	(631,000)	(3,517,000)	(8,000)
Proved reserves as of December 31, 1994	42,165,000	347,560,000	5,442,000
Revisions of estimates	1,127,000	(7,431,000)	535,000
Extensions and discoveries	2,959,000	9,645,000	472,000
Purchase of reserves	1,852,000	59,585,000	3,665,000
Production	(3,300,000)	(36,886,000)	(600,000)
Sale of reserves	(337,000)	(8,627,000)	(45,000)
Proved reserves as of December 31, 1995	44,466,000	363,846,000	9,469,000
Proved developed reserves as of:			
December 31, 1992	13,823,000	249,154,000	797,000
December 31, 1993	11,548,000	355,536,000	1,751,000
December 31, 1994	18,718,000	324,302,000	3,123,000
December 31, 1995	28,703,000	311,664,000	6,149,000

DEVON ENERGY CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements December 31, 1995, 1994 and 1993

13. Supplemental Information on Oil and Gas Operations
(Unaudited) (Continued)

Standardized Measure of Discounted Future Net Cash Flows

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

	December 31, 1995	1994	1993
Future cash inflows	$1,476,418,000	1,186,845,000	913,931,000
Future costs:			
Development	(52,327,000)	(75,115,000)	(23,713,000)
Production	(496,279,000)	(400,676,000)	(256,658,000)
Future income tax expense	(153,431,000)	(71,427,000)	(61,480,000)
Future net cash flows	774,381,000	639,627,000	572,080,000
10% discount to reflect timing of cash flows	(328,481,000)	(281,421,000)	(228,530,000)
Standardized measure of discounted future net cash flows	$ 445,900,000	358,206,000	343,550,000
Discounted future net cash flows before income taxes	$ 534,248,000	398,206,000	380,471,000

Future cash inflows are computed by applying year-end prices (averaging $18.11 per barrel of oil, adjusted for transportation and other charges, $1.35 per Mcf of gas and $12.73 per Boe of natural gas liquids at December 31, 1995) 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. In addition to the future gas revenues calculated at $1.35 per Mcf, Devon's total future gas revenues also include the future tax credit payments to be received and recorded as gas revenues pursuant to the San Juan Basin Transaction described in Note 3. Devon's future cash inflows shown in the table above include $58.2 million related to these tax credit payments from 1996 through 2002. This amount has been calculated using the assumption that the year-end 1995 tax credit rate of $1.01 per MMBtu remains constant. 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.

Future income tax expenses are computed by applying the appropriate statutory tax rates to the future pretax 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. Prior to the San Juan Basin

Standardized Measure of Discounted Future Net Cash Flows
(Continued)

Transaction as described in Note 3, the future income tax expenses estimated at December 31, 1994 and 1993 were reduced by the estimated future Section 29 tax credits to be generated by the San Juan Basin coal seam gas properties. It was estimated at year-end 1994 and 1993 that undiscounted amounts of approximately $113 million and $137 million, respectively, of Section 29 tax credits could be generated in future years to Devon's interest. However, because of limitations on the amount of Section 29 tax credits which can actually be utilized for income tax purposes, the undiscounted amounts included as reductions to future income tax expense for purposes of calculating the standardized measure of discounted future net cash flows were only $41 million and $39 million at year-end 1994 and 1993, respectively. As a result of the San Juan Basin Transaction, substantially all of the value of the
Section 29 tax credits at year-end 1995 is now included in "future cash inflows," instead of a reduction to income tax expense, in Devon's standardized measure of discounted future net cash flows.

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,		
	1995	1994	1993
Beginning balance	$358,206,000	343,550,000	286,693,000
Sales of oil, gas and natural gas liquids, net of production costs	(78,304,000)	(67,945,000)	(64,490,000)
Net changes in prices and production costs	60,498,000	(107,210,000)	1,479,000
Extensions, discoveries, and improved recovery, net of future development costs	22,308,000	14,629,000	26,999,000
Purchase of reserves, net of future development costs	50,000,000	133,103,000	59,594,000
Development costs incurred during the period which reduced future development costs	43,810,000	16,519,000	11,580,000
Revisions of quantity estimates	7,397,000	26,167,000	47,798,000
Sales of reserves in place	(7,933,000)	(5,281,000)	(18,170,000)
Accretion of discount	39,821,000	38,047,000	31,457,000
Net change in income taxes	(48,347,000)	(3,080,000)	(9,048,000)
Other, primarily changes in timing	(1,556,000)	(30,293,000)	(30,342,000)
Ending balance	$445,900,000	358,206,000	343,550,000

Notes to Consolidated Financial Statements December 31, 1995, 1994 and 1993

14. Supplemental Quarterly Financial Information (Unaudited)

Following is a summary of the unaudited interim results of operations for the years ended December 31, 1995 and 1994:

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1995 - Actual Reported Results (a)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil, gas and natural gas liquids sales	$23,519,568	25,331,966	33,589,019	29,985,087	112,425,640
Total revenues	$23,762,327	25,650,334	33,770,864	30,119,300	113,302,825
Net earnings	$ 1,026,802	2,444,422	6,645,531	4,385,144	14,501,899
Net earnings per share	$0.05	0.11	0.30	0.20	0.66

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1995 - Adjusted Results (a)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil, gas and natural gas liquids sales	$26,478,770	28,293,715	27,668,068	29,985,087	112,425,640
Total revenues	$26,796,579	28,612,083	27,774,863	30,119,300	113,302,825
Net earnings	$ 2,864,127	4,181,531	3,071,097	4,385,114	14,501,899
Net earnings per share	$0.13	0.19	0.14	0.20	0.66

<F1>

(a) The San Juan Basin Transaction described in Note 3 was effective January 1, 1995. However, it was initially subject to a material contingency, and thus the transaction's impact on Devon's statement of operations was deferred pending the contingency's resolution. When the contingency was favorably resolved, the cumulative nine-month effect of the transaction was recorded in the third quarter. The first table above includes the 1995 quarterly results as reported, including the six-month out-of-period effect on the third quarter. The second table above presents the quarterly results as they would have been reported had the contingency not existed and had the San Juan Basin Transaction's effect on earnings been reported from the inception of the transaction on January 1, 1995.

1994

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil, gas and natural gas liquids sales	$25,778,304	24,953,045	25,054,238	23,580,067	99,365,654
Total revenues	$26,144,281	25,519,353	25,298,970	23,810,355	100,772,959
Net earnings	$ 4,876,974	4,053,853	3,055,972	1,757,912	13,744,711
Net earnings per share	$0.23	0.19	0.14	0.08	0.64

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

The information called for by this Item 10 is incorporated herein by reference to the definitive Proxy Statement to be filed by the Company pursuant to Regulation 14A of the General Rules and Regulations under the Securities and Exchange Act of 1934 not later than April 29, 1996.

ITEM 11. EXECUTIVE COMPENSATION

The information called for by this Item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by the Company pursuant to Regulation 14A of the General Rules and Regulations under the Securities and Exchange Act of 1934 not later than April 29, 1996.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by the Company pursuant to Regulation 14A of the General Rules and Regulations under the Securities and Exchange Act of 1934 not later than April 29, 1996.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information called for by this Item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by the Company pursuant to Regulation 14A of the General Rules and Regulations under the Securities and Exchange Act of 1934 not later than April 29,

PART IV

ITEM 14. 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 40 of this report.

2. Consolidated Financial Statement Schedules

All financial statement schedules are omitted as they are inapplicable, or the required information is immaterial.

3. Exhibits

2.1 - Agreement and Plan of Merger and Reorganization by and among Registrant and Devon Energy Corporation, a Delaware corporation, dated as of April 13, 1995 (incorporated by reference to Exhibit A to Registrant's definitive Proxy Statement for its 1995 Annual Meeting of Shareholders filed on April 21, 1995).

2.2 - Agreement and Plan of Merger by and among Devon Energy Corporation, Devon Acquisition Corp. and Alta Energy Corporation dated February 18, 1994
[incorporated by reference to Exhibit 2.1 to Registrant's Registration Statement on Form S-4 (No. 33-76524)].

2.3 - Amendment to Agreement and Plan of Merger by and among Devon Energy Corporation, Devon Acquisition Corp. and Alta Energy Corporation dated April 13, 1994
[incorporated by reference to Exhibit 2.2 to Amendment No. 1 to Registrant's Registration Statement on Form S-4 (No. 33-76524)].

3.1 - Registrant's Certificate of Incorporation (incorporated by reference to Exhibit B to Registrant's definitive Proxy Statement for its 1995 Annual Meeting of Shareholders filed on April 21, 1995).

3.2 - Registrant's Bylaws (incorporated by reference to Exhibit 3.2 to Registrant's Registration Statement on Form 8-B filed on June 7, 1995).

4.1 - Form of Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Registrant's Registration Statement on Form 8-B filed on June 7, 1995).

4.2 - Rights Agreement between Registrant and The First National Bank of Boston (incorporated by reference to Exhibit 4.2 to Registrant's Registration Statement on Form 8-B filed on June 7, 1995).

4.3 - Certificate of Designations of Series A Junior Participating Preferred Stock of Registrant (incorporated by reference to Exhibit 3.3 to Registrant's Registration Statement on Form 8-B filed on June 7, 1995).

10.1 - Credit Agreement dated October 7, 1994, among Devon Energy Corporation (Nevada), as Borrower, the Registrant and Devon Energy Operating Corporation, as Guarantors, NationsBank of Texas, N.A., as Agent, and NationsBank of Texas, N.A., Bank One, Texas, N.A., Bank of Montreal and First Union National Bank of North Carolina, as Lenders (incorporated by reference to Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1994).

10.2 - First Amendment, dated January 27, 1995, to Credit Agreement among Devon Energy Corporation (Nevada), as Borrower, the Registrant and Devon Energy Operating Corporation, as Guarantors, NationsBank of Texas, N.A., as Agent, and NationsBank of Texas, N.A., Bank One, Texas, N.A., Bank of Montreal and First Union National Bank of North Carolina, as Lenders (incorporated by reference to Exhibit 10.2 to Registrant's Annual Report on Form 10-K for the year ended December 31, 1994).

10.3 - Devon Energy Corporation 1988 Stock Option Plan
[incorporated by reference to Exhibit 10.4 to Registrant's Registration Statement on Form S-4 (No. 33-23564)].#

10.4 - 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).#

10.5 - Severance Agreement between Devon Energy Corporation (Nevada), Registrant and Mr. J. Larry Nichols, dated December 3, 1992 (incorporated by reference to Exhibit 10.10 to Registrant's Amendment No. 1 to Annual Report on Form 10-K for the year ended December 31, 1992).#

10.6 - Severance Agreement between Devon Energy Corporation (Nevada), Registrant and Mr. H. R. Sanders, Jr., dated December 3, 1992 (incorporated by reference to Exhibit 10.11 to Registrant's Amendment No. 1 to Annual Report on Form 10-K for the year ended December 31, 1992).#

10.7 - Severance Agreement between Devon Energy Corporation (Nevada), Registrant and Mr. J. Michael Lacey, dated December 3, 1992 (incorporated by reference to Exhibit 10.12 to Registrant's Amendment No. 1 to Annual Report on Form 10-K for the year ended December 31, 1992).#

10.8 - Severance Agreement between Devon Energy Corporation (Nevada), Registrant and Mr. H. Allen Turner, dated December 3, 1992 (incorporated by reference to Exhibit 10.13 to Registrant's Amendment No. 1 to Annual Report on Form 10-K for the year ended December 31, 1992).#

10.9 - Severance Agreement between Devon Energy Corporation (Nevada), Registrant and Mr. Darryl G. Smette, dated December 3, 1992 (incorporated by reference to Exhibit 10.14 to Registrant's Amendment No. 1 to Annual Report on Form 10-K for the year ended December 31, 1992).#

10.10 - Severance Agreement between Devon Energy Corporation (Nevada), Registrant and Mr. William T. Vaughn, dated December 3, 1992 (incorporated by reference to Exhibit 10.15 to Registrant's Amendment No. 1 to Annual Report on Form 10-K for the year ended December 31, 1992).#

10.11 - Stock Purchase Agreement dated January 14, 1994, between GSS Investments Corp. [a wholly-owned subsidiary of Registrant] and Princor Growth Fund, Inc. (incorporated by reference to Exhibit 3 to Amendment No. 2 to Registrant's Schedule 13D dated as of January 7, 1994).

10.12 - Stock Purchase Agreement dated January 14, 1994, between Registrant and Andrew P. Carstensen, Jr. (incorporated by reference to Exhibit 4 to Amendment No. 2 to Registrant's Schedule 13D dated as of January 7, 1994).

10.13 - Sale and Purchase Agreement relating to Registrant's San Juan Basin gas properties (incorporated by reference to Exhibit 10.15 to Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1995).

10.14 - Second Restatement of and Amendment to Sale and Purchase Agreement relating to Registrant's San Juan Basin gas properties (incorporated by reference to Exhibit 10.16 to Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1995).

10.15 - Purchase and Sale Agreement between Union Oil Company of California and Devon Energy Corporation (Nevada) (incorporated by reference to Exhibit 2 to Registrant's Current Report on Form 8-K dated December 18, 1995)

11 - Computation of earnings per share

21 - Subsidiaries of Registrant (incorporated by reference to Exhibit 21 to Registrant's Registration Statement on Form 8-B filed on June 7, 1995).

23.1 - Consent of LaRoche & Associates

23.2 - Consent of KPMG Peat Marwick LLP

Compensatory plans or arrangements.

(b) Reports on Form 8-K - A Current Report on Form 8-K dated December 18, 1995, was filed by the Registrant regarding the acquisition of certain Wyoming oil and natural gas properties and a gas processing plant for approximately $50.3 million.

FORM S-8 UNDERTAKING

For the purposes of complying with the amendments to the rules governing Form S-8 (effective July 13, 1990) under the Securities Act of 1933, the undersigned Registrant hereby undertakes as follows, which undertaking shall be incorporated by reference to the Registrant's Registration Statement on Form S-8 (No. 33-32378) and Registrant's Registration Statement on Form S-8 (No. 33-67924).

Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to directors, officers and controlling persons of the Registrant pursuant to the foregoing provisions, or otherwise, the Registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the Registrant of expenses incurred or paid by a director, officer or controlling person of the Registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the Registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the questions whether such indemnification by it is against public policy as expressed in the Act and will be governed by the final adjudication of such issue.

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

March 4, 1996 By J. Larry Nichols J. Larry Nichols, President

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.

March 4, 1996	By	John W. Nichols John W. Nichols Chairman of the Board and Director
March 4, 1996	By	J. Larry Nichols J. Larry Nichols President, Chief Executive Officer and Director
March 4, 1996	By	H. R. Sanders, Jr. H. R. Sanders, Jr. Executive Vice President and Director
March 4, 1996	By	William T. Vaughn William T. Vaughn Vice President - Finance
March 4, 1996	By	Danny J. Heatly Danny J. Heatly Controller
March 4, 1996	By	Thomas F. Ferguson Thomas F. Ferguson, Director

March, 4 1996 By David M. Gavrin David M. Gavrin, Director

March 4, 1996 By Michael E. Gellert Michael E. Gellert, Director

Exhibit 11

DEVON ENERGY CORPORATION
Computation of Earnings Per Share

	Year Ended December 31,		
	1995	1994	1993
PRIMARY EARNINGS PER SHARE			
Computation for Statement of Operations			
Net earnings per statement of operations	$14,501,899	13,744,711	20,485,772
Weighted average common shares outstanding	22,073,550	21,551,581	20,822,029
Primary earnings per share	$0.66	0.64	0.98
Additional Primary Computation (A)			
Net earnings per statement of operations	$14,501,899	13,744,711	20,485,772
Adjustment to weighted average common shares outstanding:			
Weighted average as shown above in primary computation	22,073,550	21,551,581	20,822,029
Add dilutive effect of outstanding stock options (as determined using the treasury stock method)	127,640	117,799	142,137
Weighted average common shares outstanding, as adjusted	22,201,190	21,669,380	20,964,166
Net earnings per common share, as adjusted	$0.65	0.63	0.98
FULLY DILUTED EARNINGS PER SHARE (A)			
Net earnings per statement of operations	$14,501,899	13,744,711	20,485,772
Weighted average common shares outstanding as shown in primary computation above	22,073,550	21,551,581	20,822,029
Add fully dilutive effect of outstanding stock options (as determined using the treasury stock method)	181,446	118,211	143,415
Weighted average common shares outstanding, as adjusted	22,254,996	21,669,792	20,965,444
Fully diluted earnings per common share	$0.65	0.63	0.98

(A) These calculations are submitted in accordance with Regulation S-K item 601(b)(11) although not required by footnote 2 to paragraph 14 of APB Opinion No. 15 because they result in dilution of less than 3%.

Exhibit 23.1

ENGINEER'S CONSENT

We consent to incorporation by reference in the Registration Statements (No. 33-32378 and No. 33-67924) on Form S-8 and the Registration Statement (No. 333-00815) on Form S-3 of Devon Energy Corporation the reference to our appraisal report for Devon Energy Corporation as of December 31, 1995, which appears in the December 31, 1995 annual report on Form 10-K of Devon Energy Corporation.

William E. LaRoche
LAROCHE & ASSOCIATES

March 4, 1996

Exhibit 23.2

INDEPENDENT AUDITORS' CONSENT

The Board of Directors and Stockholders Devon Energy Corporation:

We consent to incorporation by reference in the Registration Statements (No. 33-32378 and 33-67924) on Form S-8 and the Registration Statement (No. 333-00815) on Form S-3 of Devon Energy Corporation of our report dated February 12, 1996, relating to the consolidated balance sheets of Devon Energy Corporation and subsidiaries as of December 31, 1995, 1994 and 1993 and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years then ended, which report appears in the December 31, 1995 annual report on Form 10-K of Devon Energy Corporation.

Our report refers to a change in 1993 in the method of accounting for income taxes to adopt the provisions of Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes."

KPMG Peat Marwick LLP KPMG Peat Marwick LLP

Oklahoma City, Oklahoma
March 4, 1996

ARTICLE 5

PERIOD TYPE	YEAR
FISCAL YEAR END	DEC 31 1995
PERIOD END	DEC 31 1995
CASH	8897891
SECURITIES	0
RECEIVABLES	14400295
ALLOWANCES	0
INVENTORY	605263
CURRENT ASSETS	24874584
PP&E	631437904
DEPRECIATION	239619167
TOTAL ASSETS	421564117
CURRENT LIABILITIES	15558889
BONDS	143000000
COMMON	2211190
PREFERRED MANDATORY	0
PREFERRED	0
OTHER SE	216829808
TOTAL LIABILITY AND EQUITY	421564117
SALES	112425640
TOTAL REVENUES	113302825
CGS	0
TOTAL COSTS	0
OTHER EXPENSES	34121262
LOSS PROVISION	0
INTEREST EXPENSE	7051142
INCOME PRETAX	25621899
INCOME TAX	11120000
INCOME CONTINUING	14501899
DISCONTINUED	0
EXTRAORDINARY	0
CHANGES	0
NET INCOME	14501899
EPS PRIMARY	0.66
EPS DILUTED	0.66

End of Filing