SOUTHWESTERN ENERGY CO
Form 10-K405
March 30, 2001

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, 2000

or

( ) Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from ____________ to _________________

Commission file number 1-8246

Southwestern Energy Company
(Exact name of Registrant as specified in its charter)

ARKANSAS	71-0205415
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

2350 N. Sam Houston Parkway East, Suite 300, Houston, Texas 77032
(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code: (281) 618-4700

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	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. 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 was $271,006,029 based on the New York Stock Exchange -- Composite Transactions closing price on March 8, 2001, of $10.95.

The number of shares outstanding as of March 8, 2001, of the Registrant's Common Stock, par value $.10, was 25,188,574.

DOCUMENTS INCORPORATED BY REFERENCE

Document incorporated by reference and the Part of the Form 10-K into which the document is incorporated: Definitive Proxy Statement to holders of the Registrant's Common Stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Shareholders on May 17, 2001 - PART III.

SOUTHWESTERN ENERGY COMPANY
ANNUAL REPORT on FORM 10-K
For the Year Ended December 31, 2000

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Part I

ITEM 1. BUSINESS

Southwestern Energy Company (the "Company" or "Southwestern") is an energy company primarily focused on natural gas. The Company was incorporated in Arkansas in 1929 as a local gas distribution company. Today, Southwestern is an exempt holding company under the Public Utility Holding Company Act of 1935 and derives the vast majority of its operating income and cash flow from its oil and gas exploration and production business. The Company is involved in the following business segments:

1. Exploration and Production - Engaged in natural gas and oil exploration, development and production, with operations principally located in Arkansas, Oklahoma, Texas, New Mexico, and Louisiana. This represents the Company's primary business.
2. Natural Gas Distribution - Engaged in the gathering, distribution and transmission of natural gas to approximately 136,000 customers in Arkansas.
3. Marketing and Transportation - Provides marketing and transportation services in the Company's core areas of operation and owns a 25% interest in the NOARK Pipeline System, Limited Partnership (NOARK).

This Report on Form 10-K includes certain statements that may be deemed to be "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of this Report for a discussion of factors that could cause actual results to differ materially from any such forward-looking statements.

Business Strategy

The Company's business strategy is to provide long-term growth through focused exploration and production of oil and natural gas. The Company seeks to maximize cash flow and earnings and provide consistent growth in oil and gas production and reserves through the discovery, production and marketing of high margin reserves from a balanced portfolio of drilling opportunities. This balanced portfolio includes low risk development drilling in the Arkoma Basin, moderate risk exploration and exploitation in the Permian Basin and east Texas, and high potential exploration opportunities in the onshore Gulf Coast.

Additionally, the Company creates additional value through its natural gas distribution, marketing and transportation activities. During 2000, Southwestern announced its intent to sell its gas distribution business. However, the Company has not received an offer that it believes reflects the true value of the utility system. Accordingly, Southwestern will continue to hold and operate these assets. The Company further enhances shareholder value by creating and capturing additional value beyond the wellhead through its marketing and transportation activities.

EXPLORATION AND PRODUCTION

In 1943, the Company commenced a program of exploration and development of natural gas reserves in Arkansas for supply to its utility customers. In 1971, the Company initiated an exploration and development program outside Arkansas, unrelated to the utility's requirements. Since that time, the Company's exploration and development activities outside Arkansas have expanded substantially.

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During 1998, Southwestern brought in new senior operating management and replaced over 50% of its professional technical staff to refocus its exploration and production segment. Additionally in 1998, the Company closed its Oklahoma City office and moved these operations to its Houston office in an effort to increase future profitability. The segment was also reorganized into asset management teams to provide an area specific focus in exploration and development projects and a new incentive compensation system was put in place to more closely align its employees' efforts with the interests of its shareholders. As a result of these changes, the operating results of this business segment have improved substantially, with results in 2000 some of the best in the Company's history.

At December 31, 2000, the Company had proved oil and gas reserves of 380.5 billion cubic feet (Bcf) equivalent, including proved natural gas reserves of 331.8 Bcf and proved oil reserves of 8,130 thousand barrels (MBbls). The Company's reserve life index approximated 10.7 years at year-end 2000, with 82% of total reserves classified as proved developed. All of the Company's reserves are located entirely within the United States. Revenues of the exploration and production subsidiaries are predominately generated from production of natural gas. Sales of gas production accounted for 82% of total operating revenues for this segment in 2000, 87% in 1999 and 89% in 1998.

Areas of Operation

Southwestern engages in gas and oil exploration and production through its subsidiaries, SEECO, Inc. (SEECO), Southwestern Energy Production Company (SEPCO), and Diamond "M" Production Company (Diamond M). SEECO operates exclusively in the state of Arkansas and holds a large base of both developed and undeveloped gas reserves and conducts an ongoing drilling program in the historically productive Arkansas part of the Arkoma Basin. SEPCO conducts development drilling and exploration programs in the Oklahoma portion of the Arkoma Basin, the Permian Basin of Texas and New Mexico, the Anadarko Basin of Oklahoma, Louisiana, and Texas. Diamond M operates properties in the Permian Basin of Texas.

The following table provides December 31, 2000 information as to proved reserves, well count, and gross and net acreage, and 2000 annual information as to production, capital expenditures and reserve additions for each of the Company's core operating areas.

	Arkoma	Mid-Continent	Texas/ New Mexico	Louisiana	Total
Proved Reserves:					
Gas (Bcf)	200.3	24.4	82.2	24.9	331.8
Oil (MBbls)	-	1,759	5,176	1,195	8,130
Total Reserves (Bcfe)	200.3	34.9	113.2	32.1	380.5
Capital Expenditures (in millions)	$17.6	-	$27.7	$23.9	$69.2
Production (Bcfe)	19.9	3.5	9.9	2.4	35.7
Reserve Additions (Bcfe)	18.4	1.2	30.6	19.9	70.1
Total Gross Wells	808	564	401	32	1,805
Percent Operated	44%	28%	37%	44%	37%
Gross Acreage	387,633	164,455	436,519	102,027	1,090,634
Net Acreage	249,267	57,699	136,125	31,836	474,927

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Arkoma Basin. The Arkoma Basin provides a solid foundation for the Company's exploration and production program and represents the primary source of production and reserves for the Company. At December 31, 2000, the Company had approximately 200.3 Bcf of natural gas reserves in the Arkoma Basin, representing 60% of the Company's natural gas reserves and 53% of total reserves on a Bcf equivalent (Bcfe) basis. The Company participated in 42 wells during 2000 with a 76% success ratio and an average working interest of 47%. The Company's Arkoma drilling program added 18.4 Bcf of gas reserves at a finding and development cost of $0.97 per thousand cubic feet (Mcf). Average net daily production in 2000 was 54.6 million cubic feet (MMcf).

The Company's strategy in the Arkoma is to annually replace production from the basin with new reserves at a finding cost of under $1.00 per Mcf. The Company intends to continue that strategy by investing approximately $21 million and drilling approximately 50 wells in the basin in 2001.

Southwestern's Arkoma Basin operations continue to generate a significant amount of the Company's cash flow. Production, or lifting, costs in the basin continued to be extremely low during 2000 at $.24 per Mcf (including production taxes). After direct general and administrative expenses of $.14 per Mcf, Southwestern's netback per Mcf after cash operating expenses was 88% of the average price it received for its Arkoma production in 2000.

Southwestern's traditional operating area over the years has been in the "fairway" portion of the basin, which is primarily within the boundaries of the Company's utility gathering system. The Company's strategy in this core producing area is to delineate new geologic plays and extend previously identified trends using Southwestern's extensive databank of regional structural and stratigraphic maps. Southwestern completed five wells out of seven drilled in the fairway in 2000 that added 6.1 Bcf of new reserves. The largest success in this area was the Sexton #1-20 well in Johnson County, Arkansas. This well was placed on production in February 2000 at 3.6 MMcf of gas per day (MMcfd) and added 3.3 Bcf of new reserves in 2000. Southwestern plans to drill up to 13 wells in the fairway portion of the basin in 2001.

In recent years, Southwestern has extended its development program outside of the traditional fairway area to continue its growth. In 1998, Southwestern drilled its first exploratory well at its Ranger Anticline prospect area, located in the southern edge of the Arkansas portion of the basin. This prospect area features a complex series of thrusted anticlinal folds containing deepwater Pennsylvanian sands. To date, the Company has successfully drilled six out of nine wells in this prospect, adding 9.9 Bcf of reserves net to Southwestern's interest at a finding cost of $.56 per Mcf. In December 2000, the Company secured 20,200 net federal acres with a 10-year lease term to further develop this play. Southwestern plans to drill up to six wells here in 2001.

In 2000, Southwestern built on its initial drilling success in new discovery areas such as Cherokee and Haileyville in eastern Oklahoma. In the Cherokee prospect area in LeFlore County, the Company successfully drilled eight wells out of nine in 2000. At Haileyville, three wells out of the four drilled were completed, including the Collins #1-13 well, which is currently producing over 7.2 million cubic feet of gas per day (MMcfd). The Company believes there is significant potential that is currently untapped in this area of the basin, and these prospects will be focus areas in 2001.

Mid-Continent. The Company's activities in this region are primarily focused on the Anadarko Basin of Oklahoma. At December 31, 2000, the Company had approximately 24.4 Bcf of natural gas reserves and 1,759 MBbls of oil reserves in the region, representing 7% and 22%, respectively, of the Company's total gas and oil reserves. Average net daily production in 2000 for this region was 9.6 MMcf equivalent (MMcfe). Southwestern does not expect its

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Mid-Continent operations to be a primary area of future growth, due to its efforts to concentrate on those areas where it has a competitive advantage. The Company intends to produce these properties to depletion, sell them or trade them for properties in the Company's core areas of operation. During 2000, the Company sold at auction a portion of its properties in the Mid-Continent area with proved reserves of 13.8 Bcfe for approximately $13.1 million.

Texas/New Mexico. The Company has key operations in the states of Texas and New Mexico, and is primarily focused here on the Permian Basin in west Texas and southeast New Mexico, the onshore Texas Gulf Coast and a newly acquired producing field in east Texas. At December 31, 2000, Southwestern had proved reserves of 82.2 Bcf of gas and 5,176 MBbls of oil in the region, representing 25% and 64%, respectively, of the Company's total gas and oil reserves.

Over the past three years, Southwestern has made meaningful strides in establishing itself as a significant player in the Permian Basin. At December 31, 2000, Southwestern had proved reserves of 38.2 Bcf of gas and 4,670 MBbls of oil in the basin, or 66.2 Bcfe. The Company successfully completed 43 out of 57 wells drilled in the Permian in 2000, resulting in a success rate of 75%. Southwestern's average working interest in the Permian during 2000 was 27%. Average net daily production in the basin was 27.1 MMcfe and production costs, including production taxes, averaged $.77 per Mcf equivalent (Mcfe) during 2000.

Southwestern continued to develop its Logan Draw prospect area in Eddy County, New Mexico, successfully completing 10 out of 13 wells there in 2000. Southwestern has an average working interest of 32% in the Logan Draw development area, which is the combination of the Company's Top Dog, Amber, and Freight Train prospects. To date, the Company has drilled 21 successful wells out of 26 and has added 8.1 Bcfe of reserves at a finding cost of $.84 per Mcfe.

In late 1999, the Company entered into a joint exploration agreement with Phillips Petroleum to explore for deeper formations under acreage that is held-by-production in southeast New Mexico. This initial joint venture agreement spawned the development of two more joint exploration agreements that were consummated in late 2000, one with Energen Resources and a second agreement with Phillips. In total, these agreements provide the Company access to an additional 98,700 gross acres to pursue drilling opportunities. Under each agreement, Southwestern's partners have a deferred election clause at casing point, allowing them to retain a pre-specified working interest share. Southwestern is the operator of all wells under the agreements. These agreements have terms ranging from 12 to 21 months, and each has continuous drilling options thereafter. To date, the Company has drilled nine out of eleven successful wells under these joint ventures, and plans to drill at least six wells under these agreements in 2001.

One meaningful discovery resulting from the first Phillips joint venture is the Company's oil discovery at its Bimini prospect in Lea County, New Mexico. The Company was successful on five wells out of five drilled, and together the wells are currently producing 450 barrels of oil per day (Bopd) and 480 MMcfd from the Blinebry formation. The discovery at Bimini has set up two additional prospect areas with similar Blinebry potential that will be tested during 2001. The Company also had discoveries in 2000 at its Heisman and Outland prospects under this agreement with follow-up drilling planned for these areas.

The Company entered the prolific gas-producing area of east Texas with the acquisition of producing properties in the Overton Field in Smith County, Texas in April 2000. This transaction creates an additional low-risk multi-year development drilling program for the Company and is discussed more fully below under "Acquisitions."

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Louisiana. Southwestern began its drilling program in south Louisiana in 1996 and this area continues to be the main focus area of the Company's high-impact exploration activities. At December 31, 2000, Southwestern had proved reserves of 24.9 Bcf of gas and 1,195 MBbls of oil in the state, representing 8% of the Company's total reserves on a gas equivalent basis. Average net daily production in this area was 6.6 MMcfe and production costs (including production taxes) averaged $.87 per Mcfe during 2000.

The Company has an extensive inventory of 3-D seismic data covering over 1,230 miles in Louisiana. From this extensive 3-D database, Southwestern has internally generated a multi-year inventory of exploration prospects to be drilled in 2001 and beyond. The Company also continues to gain exposure to additional 3-D seismic data for future drilling opportunities.

Southwestern has been successful in four out of its last five exploration wells in this area, beginning with its first internally-generated discovery in December 1999 at its Gloria prospect in Assumption Parish. The Dugas & LeBlanc #1 well was placed on production in February 2000 and is currently producing 9.6 MMcfd and 310 barrels of condensate per day (Bcpd). Southwestern is the operator of the well and holds a 50% working interest.

The Company announced in February 2000 that it had made a significant discovery at its North Grosbec prospect, also in Assumption Parish, which has resulted in one of the largest discoveries in the Company's history. The Brownell-Kidd #1 well was placed on production in May 2000 and is currently producing 16.2 MMcfd and 575 Bcpd. The Company holds a 25% working interest in this well which is operated by Petro-Hunt, L.L.C. Southwestern plans to drill up to two additional development wells at North Grosbec in 2001 to facilitate efficient depletion of the reservoir.

After drilling a dry hole at its Brigadoon prospect, the Company made another gas discovery in its Eden 3-D project area. The Eden 3-D project was an alliance formed with industry partners to jointly explore a 146-mile proprietary 3-D seismic survey in the Nodosaria Embayment area of Lafayette, St. Landry and Acadia Parishes. The Company's first well drilled in the project, the Robertson #1, was placed on production in late-December 2000 and is currently producing at 6.8 MMcfd and 317 Bcpd. Southwestern operates the well with a 27.5% working interest. The Company plans to drill two additional exploratory tests in its Eden 3-D project area in 2001 and has identified several additional prospect leads for 2002.

In January 2001, Southwestern announced a discovery at its Malone prospect, located south of the Company's Gloria discovery in Assumption Parish. The SL 16626 #1 well encountered approximately 260 feet of gas pay in five separate productive sands within the Miocene formation. Southwestern is currently completing this well and plans to have it placed on production in March. After drilling the initial discovery well, an offset development well was immediately drilled and reached total depth in February. Logs indicate favorable pay development and the Company expects this well to be placed on production by May. Southwestern has a 33 percent working interest in this prospect and believes that it represents a significant gas accumulation.

Acquisitions

In April 2000, the Company purchased the Overton Field in Smith County, Texas, from Total Fina Elf for $6.1 million. Proved developed producing reserves associated with the purchase were 7.5 Bcfe, for a purchase price of $.81 per Mcfe. The purchase included 16 active gas wells in 13 spacing units, 8,800 contiguous acres in established units and 2,000 additional undeveloped acres outside the units. The Overton Field represents a significant low-risk development opportunity for Southwestern, as it is one of the last Cotton Valley Sand fields in east Texas that has not been downspaced from original 640-acre units. Currently, adjacent gas-producing fields in the area are spaced at 80-acre to 160-acre units.

Southwestern plans to drill between 8 and 14 wells in the field in 2001, primarily targeting the Cotton Valley Taylor Sand formation above 12,000 feet. Based on the well performance of the initial development phase, there is the potential for 22 to 38 additional development locations to be drilled over the next few years based upon 160-acre unit spacing.

In 1999, the Company purchased producing properties in the Permian Basin with estimated proved reserves of 9.4 Bcf of gas and 576 MBbls, or 12.9 Bcfe. The properties were purchased from Petro-Quest Exploration, a privately held company headquartered in Midland, Texas, for $9.4 million. The Company did not make any producing property acquisitions in 1998 or 1997. In 1996, the Company acquired approximately 32.7 Bcf of gas and 6,350 MBbls of oil located in Texas and Oklahoma for $45.8 million. The Company's current strategy is to pursue selective acquisitions that would complement its existing operations.

Capital Spending

The Company invested a total of $69.2 million in its exploration and production program during 2000, and participated in a total of 105 wells, of which 78 were successful. The Company's investments were balanced between the Company's core areas of operations, with approximately $17.6 million invested in the Arkoma Basin, $27.7 million in the Texas/ New Mexico region and $23.9 million for exploration, primarily in south Louisiana. Of these expenditures, approximately $19.3 million was invested in exploration wells, $23.8 million in development drilling and workovers, $5.1 million for land and leasehold acquisition, $4.1 million in seismic expenditures, $6.7 million for producing property acquisitions and $10.2 million in capitalized interest, expenses and other technology-related expenditures.

In 2001, the Company's capital budget for exploration and production is $75.0 million, with approximately 75% of this capital dedicated to drilling. As in 2000, the Company's investments will again be balanced between the Company's core areas of operations, with approximately $20.5 million allocated to the Company's low-risk development activities in the Arkoma Basin, $30.3 million allocated to medium-risk exploration and exploitation in the Texas/New Mexico area, and $24.2 million allocated to high-potential exploration in south Louisiana. Of the $75.0 million capital budget, approximately $23.7 million is allocated to exploration wells, $32.3 million to development drilling, $4.7 million for land and leasehold acquisition, $3.3 million for seismic expenditures, and $11.0 million in capitalized interest, expenses and technology-related items. Although no capital was budgeted for acquisitions in 2001, the Company will continue to seek producing property acquisitions in its core producing areas that would complement its overall strategy. The Company expects to maintain its capital investments within the limits of internally generated cash flow, and will adjust its capital program accordingly.

Sales and Major Customers

Natural gas equivalent production averaged 97.7 million cubic feet equivalent per day (MMcfed) in 2000, compared to 90.2 MMcfed in 1999 and 101.1 MMcfed in 1998. The Company's gas production was 31.6 Bcf in 2000, compared to 29.4 Bcf in 1999, and 32.7 Bcf in 1998. The Company also produced 676,000 barrels of oil in 2000, compared to 578,000 barrels in 1999, and 703,000 barrels in 1998. The decreases in production in 1999 were the result of lower non-operated production due to the industry slowdown during late 1998 and early 1999, the decline in production from certain wells in the Gulf Coast area and production losses from marginal properties that were sold during the year. The Company expects its equivalent production in 2001 to increase approximately 7% over the level in 2000.

The Company's natural gas production realized an average wellhead price of $2.88 per Mcf in 2000, compared to $2.21 per Mcf in 1999 and $2.34 per Mcf in 1998. The Company's average oil price realized was $22.99 per barrel in 2000, compared to $17.11 per barrel in 1999 and $13.60 per barrel in 1998.

Southwestern's largest single customer for sales of its gas production is the Company's utility subsidiary, Arkansas Western Gas Company (Arkansas Western). Sales from SEECO to Arkansas Western accounted for approximately 24% of total exploration and production revenues in 2000, 31% in 1999 and 38% in 1998. All of the Company's remaining sales are to unaffiliated purchasers. SEECO's sales to Arkansas Western were 7.8 Bcf in 2000, compared to 8.2 Bcf in 1999 and 11.3 Bcf in 1998. The decrease in affiliated gas sales in 1999 was the result of warmer weather in the utility's service territory combined with the loss of certain intercompany gas supply contracts.

Gas volumes sold by SEECO to Arkansas Western for its northwest Arkansas division (AWG) were 5.1 Bcf in 2000 and 1999, and 7.7 Bcf in 1998. Through these sales, SEECO furnished 36% of the northwest Arkansas system's requirements in 2000, 38% in 1999 and 55% in 1998. SEECO also delivered approximately 2.8 Bcf in 2000, 2.6 Bcf in 1999 and 2.0 Bcf in 1998, directly to certain large business customers of AWG through a transportation service of the utility subsidiary.

Prior to 1999, most of the sales to AWG were pursuant to a twenty-year contract between SEECO and AWG, entered into in July 1978, under which the price was frozen between 1984 and 1994. This contract was amended in 1994 as a result of a settlement reached to resolve certain gas cost issues before the Arkansas Public Service Commission. This contract expired July 24, 1998 but continued on a month-to-month basis through November 1998.

In March 1997, AWG filed a gas supply plan with the Arkansas Public Service Commission (APSC) which projected system load growth patterns and long-range gas supply needs for the utility's northwest Arkansas system. The gas supply plan also addressed replacement supplies for AWG's long-term contract with SEECO. After discussions with the APSC it was determined that the majority of the utility's future gas supply needs should be provided through a competitive bidding process. On October 1, 1998, AWG sent requests for proposals to various suppliers requesting bids on seven different packages of gas supply to be effective December 1, 1998. These bid requests included replacement of the gas supply and no-notice service previously provided by the long-term gas supply contract between AWG and SEECO. Eleven potential suppliers returned bids in late October.

SEECO along with the Company's marketing subsidiary successfully bid on five of the original seven packages with prices based on the NorAm East Index plus a demand charge. The volumes of gas projected to be sold under these contracts in their first year were approximately equal to the historical annual volumes sold under the expired long-term contracts, assuming normal weather patterns. However, the volumes to be sold under these contracts are not fixed and will fluctuate with the weather-related requirements of AWG. These contracts provide more of the gas needed during periods of colder weather, and less of AWG's base system needs. As a result, periods of abnormally warmer weather, such as in 1999 and 1998, result in lower deliveries to AWG by SEECO. However, charges for no-notice service associated with these contracts are approximately $6.0 million per year and are received by SEECO regardless of weather patterns. Other sales to AWG are made under long-term contracts with flexible pricing provisions. Two of the five original gas supplying packages have come up for rebid since 1998 and were not awarded to SEECO. These packages provide approximately 2.5 Bcf of AWG's annual gas supply. There were no demand fees associated with the two contracts not renewed. In 2001, AWG will again perform a competitive bidding process for its primary gas supply needs and the Company expects its subsidiaries to aggressively bid to retain the contracts currently in place.

SEECO's sales to Associated Natural Gas Company (Associated), a division of Arkansas Western which operates a natural gas distribution system in northeast Arkansas, were 2.7 Bcf in 2000, 3.1 Bcf in 1999 and 3.6 Bcf in 1998.

These deliveries accounted for approximately 51% of Associated's total requirements in 2000, 42% in 1999 and 46% in 1998. The decrease in 2000 volumes delivered was due to Southwestern's sale of its Missouri utility assets in May 2000, as discussed below in "Natural Gas Distribution," somewhat offset by colder than normal weather in November and December 2000. The decrease in 1999 was due to record warm weather. Effective October 1990, SEECO entered into a ten-year contract with Associated to supply a portion of its system requirements at a price to be redetermined annually. For the contract period beginning October 1, 1997, the contract was revised to redetermine the sales price monthly based on an index

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posting plus a reservation fee. Effective October 2000, Associated placed its gas supply out for competitive bids. SEECO was successful in obtaining a one-year bid to supply approximately 1.0 Bcf of gas, or approximately 40% of Associated's annual requirement assuming normal weather patterns.

At present, SEECO's contracts for sales of gas to unaffiliated customers consist of short-term sales made to customers of the utility subsidiary's transportation program and spot sales into markets away from the utility's distribution system. These sales are subject to seasonal price swings. SEECO's sales to unaffiliated customers are also affected by the demand of the utility for production on its gathering system. SEECO's sales to unaffiliated purchasers accounted for approximately 29% of total exploration and production revenues in 2000, 28% in 1999 and 19% in 1998.

The combined gas production of SEPCO and Diamond M was 13.8 Bcf in 2000, compared to 10.5 Bcf in 1999 and 13.2 Bcf in 1998. Oil production was 676 MBbls in 2000, compared to 578 MBbls in 1999 and 703 MBbls in 1998. SEPCO's and Diamond M's gas and oil production is sold under contracts with unaffiliated purchasers which reflect current short-term prices and which are subject to seasonal price swings. SEPCO's and Diamond M's combined gas and oil sales accounted for 47% of total exploration and production revenues in 2000, 41% in 1999 and 43% in 1998.

The Company periodically enters into hedging activities with respect to a portion of its projected crude oil and natural gas production through a variety of financial arrangements intended to support oil and gas prices at targeted levels and to minimize the impact of price fluctuations. The Company's policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings. At December 31, 2000, the Company had hedges in place on 34.7 Bcf of future gas production and 697,000 barrels of future oil production. Subsequent to December 31, 2000, the Company closed its position on 298,000 barrels of 2001 oil production with a floor price of $18.00. The Company currently has hedges in place on approximately 80% of its 2001 anticipated gas production and approximately 50% of its 2001 anticipated oil production. See Item 7.A. of this Form 10-K, "Quantitative and Qualitative Disclosures About Market Risk," for further information regarding the Company's hedge position at December 31, 2000.

Competition

All phases of the gas and oil industry are highly competitive. Southwestern competes in the acquisition of properties, the search for and development of reserves, the production and sale of gas and oil and the securing of the labor and equipment required to conduct operations. Southwestern's competitors include major gas and oil companies, other independent gas and oil concerns and individual producers and operators. Many of these competitors have financial and other resources that substantially exceed those available to Southwestern. Gas and oil producers also compete with other industries that supply energy and fuel. During 2000 the impact of inflation and competition intensified as shortages in drilling rigs, third party services and qualified labor developed due to an overall increase in the activity level of the domestic oil and gas industry. The Company anticipates that inflationary pressures and industry competition will continue to increase for the foreseeable future.

Competition in the state of Arkansas has increased in recent years, due largely to the development of improved access to interstate pipelines. Due to the Company's significant leasehold acreage position in Arkansas and its long-time presence and reputation in this area, the Company believes it will continue to be successful in acquiring new leases in Arkansas. While improved intrastate and interstate pipeline transportation in Arkansas should increase the Company's access to markets for its gas production, these markets will generally be served by a number of other suppliers. Thus, the Company will encounter competition that may affect both the price it receives and contract terms it must offer. Outside Arkansas, the Company is less established and faces competition from a larger number of other producers. The Company has in recent years been successful in building its inventory of undeveloped leases and obtaining participating interests in drilling prospects in its core areas of operations.

NATURAL GAS DISTRIBUTION

The Company's subsidiary Arkansas Western Gas Company operates integrated natural gas distribution systems concentrated primarily in northern Arkansas. The APSC regulates the Company's utility rates and operations. The Company serves approximately 136,000 customers and obtains a substantial portion of the gas they consume through its Arkoma Basin gathering facilities.

On May 31, 2000, the Company completed the sale of its Missouri gas distribution assets for $32.0 million. The sale resulted in a pre-tax gain of approximately $3.2 million and proceeds from the sale were used to pay down debt. The gas distribution statistics discussed below include the results from the Company's Missouri utility operations through May 2000.

In June 2000, Southwestern announced its intent to sell its remaining utility operations in Arkansas to fund a $109.3 million judgment against the Company (Hales judgment). The Company hired Morgan Stanley Dean Witter as its investment advisor to manage the auction process and the Company received several serious expressions of interest from bona fide parties. However, to date, the Company has not received an offer that it believes reflects the true value of the utility system. Accordingly, Southwestern will continue to hold and operate these assets. Absent a sale of its utility assets, the Company's strategy is to utilize cash flow in excess of its capital requirements to reduce the debt incurred as a result of the Hales judgment. As part of this strategy, the Company has hedged approximately 80% of its 2001 anticipated gas production and 50% of its 2001 anticipated oil production at attractive prices (as discussed previously under "Exploration and Production") to ensure that it will have cash flow available to reduce the debt level.

Arkansas Western consists of two operating divisions. The AWG division gathers natural gas in the Arkansas River Valley of western Arkansas and transports the gas through its own transmission and distribution systems, ultimately delivering it at retail to approximately 115,000 customers in northwest Arkansas. The Associated division receives its gas from transportation pipelines and delivers the gas through its own transmission and distribution systems, ultimately delivering it at retail to approximately 21,000 customers in northeast Arkansas. Associated, formerly a wholly-owned subsidiary of Arkansas Power and Light Company, was acquired and merged into Arkansas Western effective June 1, 1988.

Gas Purchases and Supply

AWG purchases its system gas supply through a competitive bidding process implemented in late 1998, as discussed above, and directly at the wellhead under long-term contracts. SEECO furnished approximately 36% of AWG's system requirements in 2000, 38% in 1999 and 55% in 1998. AWG also purchases gas from unaffiliated producers under take-or-pay contracts. Currently, the Company believes that it does not have a significant exposure to take-or-pay liabilities resulting from these contracts. The Company expects to be able to continue to satisfactorily manage its exposure to take-or-pay liabilities.

Associated purchases gas for its system supply from unaffiliated suppliers accessed by interstate pipelines and from affiliates. Purchases from unaffiliated suppliers are under firm contracts with terms between one and three years. The rates charged by most suppliers include demand components to ensure availability of gas supply, administrative fees, and a commodity component which is based on monthly indexed market prices. Associated's gas purchases are transported through four pipelines. The pipeline transportation rates include demand charges to reserve pipeline capacity and commodity charges based on volumes transported. Associated has also contracted with an interstate pipeline for storage capacity to meet its peak seasonal demands. These contracts involve demand charges based on the maximum deliverability, capacity charges based on the maximum storage quantity, and charges for the quantities injected and withdrawn.

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AWG has no restriction on adding new residential or commercial customers and will supply new industrial customers that are compatible with the scale of its facilities. AWG has never denied service to new customers within its service area or experienced curtailments because of supply constraints. In addition, Associated has never denied service to new customers within its service area or experienced curtailments because of supply constraints since the acquisition date. Curtailment of large industrial customers of AWG and Associated occurs only infrequently when extremely cold weather requires that systems be dedicated exclusively to human needs customers.

The gas distribution subsidiary's rate schedules include purchased gas adjustment clauses whereby the actual cost of purchased gas above or below the level included in the base rates is permitted to be billed or is required to be credited to customers. Each month, the difference between actual costs of purchased gas and gas costs recovered from customers is deferred. The deferred differences are billed or credited, as appropriate, to customers in subsequent months.

Markets and Customers

The utility continues to capitalize on the healthy economies and sustained customer growth found in its service territory. AWG and Associated provide natural gas to approximately 119,000 residential, 16,300 commercial, and 225 industrial customers, while also providing gas transportation services to approximately 40 end-use and off-system customers. Total gas throughput in 2000 was 33.5 Bcf, compared to 36.4 Bcf in 1999 and 32.8 Bcf in 1998. In 2000, the loss of throughput associated with the sale of the utility's Missouri assets was partially offset by colder weather. The increase in 1999 was the result of higher off-system transportation volumes. Off-system transportation volumes were 3.1 Bcf in 2000, compared to 4.8 Bcf in 1999 and 1.1 Bcf transported in 1998.

Residential and Commercial. Approximately 85% of the utility's revenues are from residential and commercial markets. Residential and commercial customers combined accounted for 55% of total gas throughput for the gas distribution segment in 2000, compared to 51% in 1999 and 57% in 1998. Gas volumes sold to residential customers were 10.9 Bcf in 2000, compared to 10.8 Bcf in 1999 and 11.1 Bcf in 1998. Gas sold to commercial customers totaled 7.6 Bcf in 2000, 1999 and 1998. Weather during the calendar year 2000 was normal as measured by degree days, however, deliveries were negatively impacted by the sale of the Company's Missouri properties. The decrease in residential gas volumes sold in 1999 was due to record warm weather. Weather during 1999 was 21% warmer than normal and 8% warmer than in 1998.

The gas heating load is one of the most significant uses of natural gas and is sensitive to outside temperatures. Sales, therefore, vary throughout the year. Profits, however, have become less sensitive to fluctuations in temperature recently as tariffs implemented in Arkansas contain a weather normalization clause to lessen the impact of revenue increases and decreases which might result from weather variations during the winter heating season.

Industrial and End-use Transportation. Deliveries to industrial customers, which are generally smaller concerns using gas for plant heating or product processing, accounted for 11.8 Bcf in gas deliveries in 2000, 13.1 Bcf in 1999 and 13.0 Bcf in 1998. No industrial customer accounts for more than 8% of Arkansas Western's total throughput. The decline in deliveries in 2000 was primarily the result of the sale of the utility's Missouri operations.

Both AWG and Associated offer a transportation service that allows larger business customers to obtain their own gas supplies directly from other suppliers. A total of 39 customers are currently using the transportation service, including AWG's 17 largest customers in northwest Arkansas and Associated's 3 largest customers in northeast Arkansas.

Competition

AWG and Associated have experienced a general trend in recent years toward lower rates of usage among their customers, largely as a result of conservation efforts that the Company encourages. Competition is increasingly being experienced from alternative fuels, primarily electricity, fuel oil, and propane. A significant amount of fuel switching has not been experienced, though, as natural gas has generally been the least expensive, most readily available fuel in the service territories of AWG and Associated. This could change, however, if natural gas prices continue to remain at their current high levels.

The competition from alternative fuels and, in a limited number of cases, alternative sources of natural gas have intensified in recent years. Industrial customers are most likely to consider utilization of these alternatives, as they are less readily available to commercial and residential customers. In an effort to provide some pricing alternatives to its large industrial customers with relatively stable loads, AWG offers an optional tariff to its larger business customers and to any other large business customer which shows that it has an alternate source of fuel at a lower price or that one of its direct competitors has access to cheaper sources of energy. This optional tariff enables those customers willing to accept the risk of price and supply volatility to direct AWG to obtain a certain percentage of their gas requirements in the spot market. Participating customers continue to pay the non-gas cost of service included in AWG's present tariff for large business customers and agree to reimburse AWG for any take-or-pay liability caused by spot market purchases on the customer's behalf.

Regulation

The Company's utility rates and operations are regulated by the APSC. The Company operates through municipal franchises that are perpetual by state law. These franchises, however, are not exclusive within a geographic area.

As the regulatory focus of the natural gas industry shifts from the federal level to the state level, utilities across the nation are being required to unbundle their sales services from transportation services in an effort to promote greater competition. Although no such legislation or regulatory directives related to natural gas are presently pending in Arkansas, the Company is aggressively controlling costs and constantly reviewing issues such as system capacity and reliability, obligation to serve, rate design and stranded or transition costs.

In Arkansas, the state legislature is now considering legislation that would deregulate the retail sale of electricity in Arkansas as soon as 2002. At this time, it is unknown whether or not such legislation will be adopted or if it is adopted, what its final form will be. The Company is also unable to predict the precise impact of any such legislation on its utility operations. The Company's utility subsidiary has historically maintained a substantial price advantage over electricity for most applications. However, if gas prices are at high levels or if retail electric competition is implemented in Arkansas, it is possible that some portion of this price advantage may be lost in some markets. As described in the paragraph above, the Company is taking steps to preserve its competitive advantage over alternative energy sources, including electricity. If electric deregulation occurs in Arkansas, legislative or regulatory precedents may be set that would also affect natural gas utilities in the future. These issues may include further unbundling of services and the regulatory treatment of stranded costs.

Gas distribution revenues in future years will be impacted by customer growth and rate increases allowed by the APSC. In recent years, AWG has experienced customer growth of approximately 2% to 3% annually, while Associated has experienced customer growth of approximately 1% or less annually. Based on current economic conditions in the Company's service territories, the Company expects this trend in customer growth to continue.

In December 1996, AWG received approval from the APSC for a rate increase of $5.1 million annually. The December 1996 rate increase order issued by the APSC also provided that AWG cause to be filed with the APSC an independent study of its procedures for allocating costs between regulated and non-regulated operations, its staffing levels and executive compensation. The independent study was ordered by the APSC to address issues raised by the Office of the Attorney General of the State of Arkansas. The study was conducted in 1999 with a final report issued in December 1999. The report found the Company's costs to be reasonable in all categories and did not recommend any changes in rates currently in effect.

The Company received approvals in December 1997 from the APSC and the Missouri Public Service Commission for rate increases and tariff changes for Associated which allowed the utility to collect an additional $3.0 million annually. Of the $3.0 million increase, approximately $2.0 million was in the form of base rate increases and $1.0 million was related to the increased cost of service of the Company's gathering plant which is recovered through either the purchased gas adjustment clause or through direct charges to transportation customers. Rate increase requests that may be filed in the future will depend on customer growth, increases in operating expenses, and additional investments in property, plant and equipment. AWG's rates for gas delivered to its retail customers are not regulated by the Federal Energy Regulatory Commission (FERC), but its transmission and gathering pipeline systems are subject to the FERC's regulations concerning open access transportation since AWG accepted a blanket transportation certificate in connection with its merger with Associated.

In May 1999, the Staff of the APSC initiated a proceeding in which it sought an annual reduction of approximately $2.3 million in the rates AWG charges its customers in northwest Arkansas. Staff's position was based on various adjustments to the utility's rate base, operating expenses, capital structure and rate of return. A large portion of the proposed reduction was based on a downward adjustment to the utility's current return on equity authorized by the APSC in 1996. During the third quarter of 1999, the Company reached agreement with the Staff and the APSC to resolve this issue and to close several other open dockets. In the settlement agreement, the Company agreed to reduce its rates collected from customers on a prospective basis in the amount of $1.4 million annually, effective December 1, 1999. The agreement also includes the resolution of a proceeding initiated in December 1998 by the Staff of the APSC where the Staff had recommended the disallowance of approximately $3.1 million of gas supply costs. As a part of the settlement, this docket was closed with no negative adjustment to the Company.

In February 2001, the APSC approved a 90-day temporary tariff to collect additional gas costs not yet billed to customers through the normal purchased gas adjustment clause in the utility's approved tariffs. The Company had under-recovered purchased gas costs of $12.9 million in its current assets at December 31, 2000. The amount of under-recovered purchased gas costs had increased to over $30.0 million during January 2001 as a result of rapidly increasing gas costs. The temporary tariff allows the Company to bill customers an additional $3.00 per Mcf of usage and is expected to generate $14.0 to $15.0 million of additional cash flow over the next few months allowing the Company faster recovery of gas costs already incurred.

MARKETING AND TRANSPORTATION

Gas Marketing

The marketing group was formed in mid-1996 to better enable the Company to capture downstream opportunities which arise through marketing and transportation activity. Through utilization of Southwestern's existing asset base, the group's focus is to create and capture value beyond the wellhead. The merger of the NOARK Pipeline with the Ozark Gas Transmission System discussed below afforded greater supply and market opportunities.

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The Company's marketing operations include the marketing of Southwestern's own gas production and third-party natural gas. Operating income for this segment was $2.5 million in 2000, compared to $2.1 million in 1999 and $1.8 million in 1998. The segment marketed 59.6 Bcf of natural gas in 2000, compared to 63.1 Bcf in 1999 and 49.6 Bcf in 1998. Of the total volumes marketed, purchases from the Company's exploration and production subsidiaries accounted for 33% in 2000, 31% in 1999 and 24% in 1998.

NOARK Partnership

At December 31, 2000, the Company held a 25% general partnership interest in the NOARK Pipeline System, Limited Partnership (NOARK). NOARK Pipeline was a 258-mile long intrastate natural gas transmission system that originated in western Arkansas and terminated in northeast Arkansas, crossing three major interstate pipelines and interconnecting with the Company's distribution systems. NOARK Pipeline was completed and placed in service in 1992 and has been operating below capacity and generating losses since it was placed in service. The Company's share of the pretax loss from operations related to its NOARK investment was $1.8 million in 2000, $2.0 million in 1999 and $3.1 million in 1998.

In January 1998, the Company entered into an agreement with Enogex Inc. (Enogex), a subsidiary of OGE Energy Corp., to expand NOARK Pipeline and provide access to Oklahoma gas supplies through an integration of NOARK Pipeline with the Ozark Gas Transmission System (Ozark). Ozark was a 437-mile interstate pipeline system that began in eastern Oklahoma and terminated in eastern Arkansas. On July 1, 1998, the Federal Energy Regulatory Commission (FERC) authorized the operation and integration of Ozark and NOARK Pipeline as a single, integrated pipeline. The FERC order also authorized the purchase of

Ozark by a subsidiary of Enogex and the construction of integration facilities. Enogex acquired Ozark and contributed the pipeline system to the NOARK partnership and also acquired the NOARK partnership interests not held by Southwestern. Enogex funded the acquisition of Ozark and the expansion and integration with NOARK Pipeline which resulted in the Company's interest in the partnership decreasing to 25% with Enogex owning a 75% interest. There are also provisions in the agreement with Enogex which allow for future revenue allocations to the Company above its 25% partnership interest if certain minimum throughput and revenue assumptions are not met.

The merged pipeline system now has greater access to major gas producing fields in Oklahoma. With access to greater regional production, Southwestern expects the pipeline's additional throughput to create new marketing and transportation opportunities and reduce the losses experienced on the project in the past. The merged pipeline also provides the Company's utility systems with additional access to gas supply.

The new integrated system, known as Ozark Pipeline, became operational November 1, 1998, and includes 749 miles of pipeline with a total throughput capacity of 330 MMcfd. Deliveries are currently being made by the pipeline to portions of AWG's distribution system, to Associated, and to the interstate pipelines with which it interconnects. The average daily throughput for the pipeline was 188.2 MMcfd in 2000, compared to 167.5 MMcfd in 1999. Before the integration with Ozark, NOARK Pipeline had an average daily throughput of 27.3 MMcfd in 1998. At December 31, 2000, AWG had transportation contracts with Ozark Pipeline for 66.9 MMcfd of firm capacity. These contracts expire in 2002 and 2003 and are renewable annually thereafter until terminated with 180 days' notice.

Competition

The Company's gas marketing activities are in competition with numerous other companies offering the same services, many of which possess larger financial and other resources than those of Southwestern. Some of these competitors are affiliates of companies with extensive pipeline systems that are used for transportation from producers to end-users. Other factors affecting competition are cost and availability of alternative fuels, level of consumer demand, and cost of and

proximity of pipelines and other transportation facilities. The Company believes that its ability to effectively compete within the marketing segment in the future depends upon establishing and maintaining strong relationships with producers and end-users.

NOARK Pipeline previously competed with two interstate pipelines, one of which was the Ozark system, to obtain gas supplies for transportation to other markets. Because of the available transportation capacity in the Arkansas portion of the Arkoma Basin, competition had been strong and had resulted in NOARK Pipeline transporting gas for third parties on an interruptible basis at rates well below the maximum tariffs presently allowed. The integration with Ozark provides increased supplies to transport to both local markets and markets served by the three major interstate pipelines that Ozark Pipeline connects with in eastern Arkansas. As discussed below under "Regulation," FERC's Order No. 636 has generally increased competition in the transportation segment as end-users are now acquiring their own supplies and independently arranging for the transportation of those supplies. The Company believes that Ozark Pipeline will provide the additional supplies necessary to compete more effectively for the transportation of natural gas to end-users and markets served by the interstate pipelines.

Regulation

Since the mid-1980's, the FERC has issued a series of orders, culminating in Order No. 636 in April 1992, that have altered the marketing and transportation of natural gas. Order No. 636 required interstate natural gas pipelines to "unbundle," or segregate, the sales, transportation, storage and other components of their existing sales services, and to separately state the rates for each of the unbundled services. Order No. 636 and subsequent FERC orders issued in individual pipeline proceedings have been the subject of appeals, the results of which have generally been supportive of the FERC's open access policy. Generally, Order No. 636 has eliminated or substantially reduced the interstate pipelines' role as wholesalers of natural gas and has substantially increased competition in natural gas markets.

Prior to the integration with Ozark, the operations of NOARK Pipeline were regulated by the APSC. The APSC had established a maximum transportation rate of approximately $.285 per dekatherm. The integration of NOARK Pipeline with Ozark resulted in an interstate pipeline system subject to FERC regulations and FERC approved tariffs. The APSC no longer has jurisdiction over NOARK Pipeline's transportation rates and services. The FERC initially set the maximum transportation rate of Ozark Pipeline at $.2455 per dekatherm. As the result of a rate case filed in 2000, Ozark Pipeline's maximum transportation rate increased to $.2867 per dekatherm, effective November 1, 2000. Also as a result of the rate case, Ozark Pipeline plans to begin offering no-notice service to its customers in September 2001.

OTHER ITEMS

Environmental Matters

The Company's operations are subject to extensive federal, state and local laws and regulations, including the Comprehensive Environmental Response, Compensation and Liability Act, the Clean Water Act, the Clean Air Act and similar state statutes. These laws and regulations require permits for drilling wells and the maintenance of bonding requirements in order to drill or operate wells and also regulate the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, the prevention and cleanup of pollutants and other matters. Southwestern maintains insurance against costs of clean-up operations, but is not fully insured against all such risks.

Compliance with environmental laws and regulations has had no material effect on Southwestern's capital expenditures, earnings, or competitive position. Although future environmental obligations are not expected to have a material impact on the results of operations or financial condition of the Company, there can be no assurance that

future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause the Company to incur material environmental liabilities or costs.

Real Estate Development

A. W. Realty Company (AWR) owns an interest in approximately 150 acres of real estate, most of which is undeveloped. AWR's real estate development activities are concentrated on a 130-acre tract of land located in northwest Arkansas, which is the seventh fastest growing metropolitan area in the United States. The Company has owned an interest in this land for many years. The property is zoned for commercial, office, and multi-family residential development. AWR continues to review with a joint venture partner various options for developing this property that would minimize the Company's initial capital expenditures, but still enable it to retain an interest in any appreciation in value. This activity, however, does not represent a significant portion of the Company's business.

Employees

At December 31, 2000, the Company had 536 employees, 31 of whom are represented under a collective bargaining agreement. The Company believes that its relations with its employees are good.

ITEM 2. PROPERTIES

For additional information about the Company's gas and oil operations, refer to Notes 5 and 6 to the financial statements in Item 8 ("Financial Statement and Supplementary Data"). For information concerning capital expenditures, refer to page 32 ("Capital Expenditures" section of Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations"). Also refer to Item 6 ("Selected Financial Data") for information concerning gas and oil produced.

The following table provides information concerning miles of pipe of the Company's gas distribution systems. For a further description of Arkansas Western's properties, see the discussion under Item 1 ("Business").

	AWG	Associated	Total
Gathering	386	-	386
Transmission	812	172	984
Distribution	3,172	520	3,692
	4,370	692	5,062

The following information is provided to supplement that presented in Item 8. For a further description of Southwestern's oil and gas properties, see the discussion under Item 1.

Leasehold Acreage

	Undeveloped		Developed	
	Gross	Net	Gross	Net
Arkoma	150,372	93,710	237,261	155,557
Mid-Continent	72,964	23,049	91,491	34,650
Texas/New Mexico	262,734	99,720	173,785	36,405
Louisiana	61,597	24,825	40,430	7,011
	547,667	241,304	542,967	233,623

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Producing Wells

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Arkoma	808	401.4	-	-	808	401.4

Mid-Continent	163	111.2	401	79.6	564	190.8
Texas/New Mexico	170	53.0	231	125.2	401	178.2
Louisiana	14	4.7	18	12.6	32	17.3
	1,155	570.3	650	217.4	1,805	787.7

Wells Drilled During the Year

	Exploratory					
	Productive Wells		Dry Holes		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2000	13.0	4.0	12.0	4.8	25.0	8.8
1999	4.0	1.5	4.0	1.6	8.0	3.1
1998	3.0	.5	10.0	3.9	13.0	4.4

	Development					
	Productive Wells		Dry Holes		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2000	65.0	21.9	14.0	6.3	79.0	28.2
1999	47.0	18.3	15.0	6.1	62.0	24.4
1998	72.0	29.4	10.0	6.4	82.0	35.8

Wells in Progress as of December 31, 2000

	Gross	Net
Exploratory	-	-
Development	1.0	0.4
Total	1.0	0.4

During 2000, Southwestern was required to file Form 23, "Annual Survey of Domestic Oil and Gas Reserves" with the Department of Energy. The basis for reporting reserves on Form 23 is not comparable to the reserve data included in Note 6 to the financial statements in the 2000 Annual Report to Shareholders. The primary differences are that Form 23 reports gross reserves, including the royalty owners' share, and includes reserves for only those properties where the Company is the operator.

ITEM 3. LEGAL PROCEEDINGS

In its Form 8-K filed July 2, 1996, the Company disclosed that a lawsuit relating to overriding royalty interests in certain Arkansas oil and gas properties had been filed against it and two of its wholly-owned subsidiaries. This matter went to a non-jury trial as to liability on January 10, 2000. The court in this matter issued Findings of Fact and Conclusions of Law that found no fraud was committed. The court also found that any override royalty interests that might ultimately be found to be due under the plaintiffs' claim for additional override royalties accrued after

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March 1, 1990. All claims prior to March 1, 1990 have been barred by the statute of limitations. The ultimate measure of damages will be determined during the damages phase of the non-jury proceeding that is scheduled for April 30, 2001. While the Company anticipates that it will owe some additional override royalties to plaintiffs, it does not believe that its liability will be material to its financial condition, but in any one period it could be significant to its results of operations.

The United States Minerals Management Service (MMS), a federal agency responsible for the administration of federal oil and gas leases, is investigating the Company and its subsidiaries in respect of claims similar to those in the Hales class action royalty litigation previously reported. The Company was found to be ultimately liable and satisfied the Hales judgment in July 2000. MMS was included in the class action litigation against its objections, but did not pursue further action to remove itself from the class.

On August 25, 2000, a class action suit was filed against the Company and its subsidiaries in Sebastian County, Arkansas, on behalf of all mineral owners who own or owned a royalty and/or overriding royalty interest in oil and gas leases or other agreements in certain sections of Franklin County, Arkansas. The Company was granted authority in 1968 by the Arkansas Oil and Gas Commission to operate a gas storage facility in one section of Franklin County. Based upon subsequently developed geological data, the Company sought authority to expand this area and was granted authority by the Arkansas Oil and Gas Commission to operate gas storage in additional sections. Plaintiffs are challenging the storage agreements that the Company obtained from the mineral interest owners in 1968, 1999 and 2000 to operate the gas storage facility known as "Stockton." Plaintiffs allege various wrongful, intentional and fraudulent acts relating to the operation of the storage pool beginning in 1968 and continuing to the present and allege that the above-referenced agreements from the mineral owners were obtained through misrepresentation and fraud. The Company has owned and operated the Stockton storage unit through its Arkansas Western Gas Company subsidiary until 1994, at which time it was transferred to its subsidiary, SEECO, Inc. Plaintiffs claim ownership rights in the gas that the Company has stored in the storage pool in an amount in excess of $5 million in actual damages, interest, attorney's fees and punitive damages. The Company and its outside counsel believe that this action is without merit and does not meet the requirements for a class action. The Company believes that plaintiffs claim to the storage gas, which the Company has injected into the storage facility, has no merit and is not supported by the Arkansas gas storage statute under which the Company operates this facility. While the amount of this claim could be significant, management believes, based upon its investigation, that this claim is without merit and that the Company's ultimate liability, if any, will not be material to its consolidated financial position, but in any one period it could be significant to its results of operations.

The Company is subject to laws and regulations relating to the protection of the environment. The Company's policy is to accrue environmental and cleanup related costs of a non-capital nature when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on the financial position or reported results of operations of the Company.

The Company is subject to other litigation and claims that have arisen in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of such litigation and claims will not have a material effect on the results of operations or the financial position of the Company.

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

No matters were submitted during the fourth quarter of the fiscal year ended December 31, 2000, to a vote of security holders, through the solicitation of proxies or otherwise.

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Executive Officers of the Registrant

Name	Officer Position	Age	Years Served as Officer
Harold M. Korell	President and Chief Executive Officer and Director	56	4
Greg D. Kerley	Executive Vice President and Chief Financial Officer	45	11
Richard F. Lane	Senior Vice President, Southwestern Energy Production Company and SEECO, Inc.	43	3
George A. Taaffe	Senior Vice President, General Counsel and Secretary	54	2
Charles V. Stevens	Senior Vice President, Arkansas Western Gas Company	51	12

Mr. Korell was appointed to his present position in October 1998 and assumed the position of Chief Executive Officer on January 1, 1999. He joined the Company in 1997 as Executive Vice President and Chief Operating Officer. From 1992 to 1997, he was employed by American Exploration Company where he was most recently Senior Vice President - Operations. From 1990 to 1992, he was Executive Vice President of McCormick Resources and from 1973 to 1989, he held various positions with Tenneco Oil Company, including Vice President, Production.

Mr. Kerley was appointed to his present position in December 1999. Previously, he served as Senior Vice President and Chief Financial Officer from 1998 to 1999, Senior Vice President - Treasurer and Secretary from 1997 to 1998, Vice President - Treasurer and Secretary from 1992 to 1997, and Controller from 1990 to 1992. Mr. Kerley also served as the Chief Accounting Officer from 1990 to 1998.

Mr. Lane was appointed to his present position in February 2001. Previously, he served as Vice President - Exploration and he joined the Company in February 1998 as Manager - Exploration. From 1993 to 1998, he was employed by American Exploration Company where he was most recently Offshore Exploration Manager. Previously, he held various managerial and geological positions at FINA, Inc. and Tenneco Oil Company.

Mr. Taaffe joined the Company in his present position in July 1999.

Prior to joining the Company, he served as Vice President and Assistant General Counsel for Consolidated Natural Gas Company from 1988 to 1999 and Assistant General Counsel for Joy Technologies from 1973 to 1988.

Mr. Stevens has served the Company in his present position since December 1997. Previously, he served as Vice President of Arkansas Western Gas Company from 1988 to 1997.

All officers are elected at the Annual Meeting of the Board of Directors for one-year terms or until their successors are duly elected. There are no arrangements between any officer and any other person pursuant to which he was selected as an officer. There is no family relationship between any of the named executive officers or between any of them and the Company's directors.

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Part II

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

The Company's common stock is traded on the New York Stock Exchange under the symbol "SWN." At December 31, 2000, the Company had 2,192 shareholders of record. The following prices represent closing market transactions on the New York Stock Exchange.

	Range of Market Prices				Cash Dividends Paid	
Quarter Ended	2000		1999		2000	1999
March 31	$7.44	$5.44	$8.50	$5.19	$.06	$.06
June 30	$10.38	$6.06	$10.56	$6.06	$.06	$.06
September 30	$10.00	$6.13	$11.00	$7.38	-	$.06
December 31	$10.44	$7.25	$9.31	$5.63	-	$.06

On June 22, 2000, the Arkansas Supreme Court affirmed a $109.3 million judgment against the Company from a class action lawsuit brought by royalty owners. As a result of the judgment, the Company also suspended its quarterly dividend. Dividends totaling $3.0 million were paid during 2000. The Company paid dividends at an annual rate of $.24 per share in 1999 and 1998.

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ITEM 6. SELECTED FINANCIAL DATA

	2000	1999	1998	1997
Financial Review (in thousands)				
Operating revenues				
Exploration and production	$110,920	$75,039	$86,232	$100,129
Gas distribution	151,234	132,420	134,711	154,155
Gas marketing and other	208,196	137,942	97,795	83,511
Intersegment revenues	(106,467)	(65,005)	(52,433)	(61,606)
	363,883	280,396	266,305	276,189
Operating costs and expenses				
Gas purchases - utility	58,669	45,370	39,863	46,806

Gas purchases - marketing	133,221	92,851	73,235	63,054
Operating and general	59,790	57,957	61,915	59,167
Unusual items	111,288	-	-	-
Depreciation, depletion and amortization	45,869	41,603	46,917	48,208
Write-down of oil and gas properties	-	-	66,383	-
Taxes, other than income taxes	8,515	6,557	6,943	7,018
	417,352	244,338	295,256	224,253
Operating income	(53,469)	36,058	(28,951)	51,936
Interest expense, net	(23,230)	(17,351)	(17,186)	(16,414)
Other income (expense)	1,997	(2,331)	(3,956)	(5,017)
Income before income taxes and extraordinary item	(74,702)	16,376	(50,093)	30,505
Income taxes:				
Current	-	537	(6,029)	(732)
Deferred	(28,905)	5,912	(13,467)	12,522
	(28,905)	6,449	(19,496)	11,790
Income (loss) before extraordinary item	(45,797)	9,927	(30,597)	18,715
Extraordinary item	(890)	-	-	-
Net income (loss)	$(46,687)	$9,927	$(30,597)	$18,715
Cash flow from operations, net of working capital changes (in thousands)	$(28,917)(1)	$58,131	$93,708	$79,483
Return on equity	n/a	5.21%	n/a	8.45%
Common Stock Statistics				
Basic earnings (loss) per share before extraordinary item	$(1.82)	$.40	$(1.23)	$.76
Basic and diluted earnings (loss) per share	$(1.86)	$.40	$(1.23)	$.76
Cash dividends declared and paid per share	$.12	$.24	$.24	$.24
Book value per share	$5.61	$7.60	$7.45	$8.92
Market price at year-end	$10.38	$6.56	$7.50	$12.88
Number of shareholders of record at year-end	2,192	2,268	2,333	2,379
Average shares outstanding	25,043,586	24,941,550	24,882,170	24,738,882

[FN]
(1) Cash flow from operations, net of working capital changes, for 2000 would have been $82.4 million excluding the effects of unusual and extraordinary items.

	2000	1999	1998	1997	
Capitalization (in thousands)					
Total debt, including current portion	$396,000	$302,200	$283,436	$299,543	$2
Common shareholders' equity	141,291	190,356	185,856	221,565	2
Total capitalization	$537,291	$492,556	$469,292	$521,108	$4
Total assets	$705,378	$671,446	$647,620	$710,866	$6

Capitalization ratios:					
Debt	73.70%	61.35%	60.27%	57.23%	
Equity	26.30%	38.65%	39.73%	42.77%	
Capital Expenditures (in millions)					
Exploration and production	$69.2	$59.0	$52.4	$73.5	
Gas distribution	6.0	7.1	10.1	12.6	
Other	.5	.9	1.9	2.7	
	$75.7	$67.0	$64.4	$88.8	
Exploration and Production					
Natural gas:					
Production, Bcf	31.6	29.4	32.7	33.4	
Average price per Mcf	$2.88	$2.21	$2.34	$2.57	
Oil:					
Production, MBbls	676	578	703	749	
Average price per barrel	$22.99	$17.11	$13.60	$19.02	
Total gas and oil production, Bcfe	35.7	32.9	36.9	37.9	
Average production (lifting) cost per Mcf equivalent	$.55	$.44	$.43	$.45	
Proved reserves at year-end:					
Natural gas, Bcf	331.8	307.5	303.7	291.4	
Oil, MBbls	8,130	7,859	6,850	7,852	
Total reserves, Bcf equivalent	380.6	354.7	344.8	338.5	
Gas Distribution (1)					
Sales and transportation volumes, Bcf:					
Residential	10.9	10.8	11.1	12.6	
Commercial	7.6	7.6	7.6	8.4	
Industrial	3.5	3.5	4.2	6.6	
End-use transportation	8.3	9.6	8.8	6.6	
	30.3	31.5	31.7	34.2	
Off-system transportation	3.1	4.8	1.1	2.8	
	33.4	36.3	32.8	37.0	
Customers - year-end					
Residential	119,024	158,606	156,384	154,864	1
Commercial	16,282	21,929	22,229	21,431	
Industrial	228	290	303	311	
	135,534	180,825	178,916	176,606	1
Degree days	3,994	3,179	3,472	4,131	
Percent of normal	100%	79%	87%	103%	

[FN]
(1) Gas distribution statistics include the operations of the Company's Missouri properties through the sale date of May 31, 2000.

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

The following information should be read in conjunction with the information contained in the financial statements and the notes thereto included in Item 8. of this report and with the discussion below on "Forward-Looking Information." Certain reclassifications have been made to the prior years' financial statements to conform with the 2000 presentation. These reclassifications had no effect on previously reported net income.

RESULTS OF OPERATIONS

The Company reported a net loss of $46.7 million, or $1.86 per share, for 2000, compared to net income of $9.9 million, or $.40 per share, for 1999 and a net loss of $30.6 million, or $1.23 per share, in 1998. The loss for 2000 includes one-time charges for unusual items, including a $109.3 million judgment in the Hales lawsuit (see Note 1 to the financial statements for additional discussion) and a $2.0 million accrual for on-going litigation, an extraordinary loss on the early retirement of debt, and a $3.2 million gain from the sale of the Company's Missouri utility properties. Exclusive of these one-time charges and the gain on sale, net income for 2000 would have been $20.5 million, or $.82 per share. The loss for 1998 reflects the impact of an after-tax, non-cash ceiling test write-down of the Company's oil and gas properties of $40.5 million, or $1.63 per share. Excluding the non-cash charge, the Company would have recognized net income of $9.9 million, or $.40 per share in 1998.

Results for 2000, exclusive of the one-time charges and the gain on the sale of the utility properties, reflect both increased oil and gas production and higher oil and gas prices realized, offset by higher operating and general expenses and higher depreciation, depletion and amortization expense. Results for 1999 and 1998 were negatively impacted by lower wellhead prices for the Company's oil and gas production and by unseasonably warm weather.

Exploration and Production

The Company's exploration and production segment's revenue, profitability and future rate of growth are substantially dependent upon prevailing prices for natural gas and oil, which are dependent upon numerous factors beyond its control, such as economic, political and regulatory developments and competition from other sources of energy. The energy markets have historically been very volatile, and there can be no assurance that oil and gas prices will not be subject to wide fluctuations in the future.

	2000	1999	1998
Revenues (in thousands)	$110,920	$75,039	$86,232
Operating income (loss) (in thousands)	$(70,584)(1)	$16,451	$(47,273)(2)
Gas production (Bcf)	31.6	29.4	32.7
Oil production (MBbls)	676	578	703
Total production (Bcfe)	35.7	32.9	36.9
Average gas price per Mcf	$2.88	$2.21	$2.34
Average oil price per Bbl	$22.99	$17.11	$13.60
Operating expenses per Mcfe			
Production expenses	$0.40	$0.35	$0.34
Production taxes	$0.15	$0.09	$0.09
General & administrative expenses	$0.32	$0.30	$0.34
Full cost pool amortization	$1.06	$1.00	$1.04

[FN]

(1) Includes a charge of $109.3 million for the Hales judgment and a charge of $2.0 million related to on-going litigation. Excluding these unusual items, operating income for the exploration and production segment would have been $40.7 million for 2000.

(2) Includes a full cost pool ceiling test write-down of $66.4 million. Excluding this non-cash write-down, operating income would have been $19.1 million for 1998.

Revenues and Operating Income

The Company's exploration and production revenues increased 48% in 2000 and decreased 13% in 1999. The increase in 2000 was due to an increase in production and higher average prices received. The decrease in 1999 revenues was due to lower volumes of oil and gas produced and a lower average gas price received.

Operating income of the exploration and production segment was $40.7 million in 2000 excluding the impact of the Hales judgment and the other unusual items, compared to $16.5 million in 1999, and $19.1 million in 1998 excluding the impact of the non-cash write-down of oil and gas properties. The increase in 2000 was due to an 8% increase in equivalent oil and gas production and higher oil and gas prices realized, partially offset by increased operating costs and expenses. The decrease in 1999 was due primarily to an 11% decrease in equivalent oil and gas production volumes.

Production

Gas and oil production totaled 35.7 billion cubic feet equivalent (Bcfe) in 2000, 32.9 Bcfe in 1999 and 36.9 Bcfe in 1998. The increase in 2000 production volumes resulted from new wells added in 2000 and 1999 in the Company's Permian Basin and south Louisiana operating areas, partially offset by the loss of production from certain wells in the Company's Mid-Continent operating area that were sold at auction during 2000. The decrease in 1999 production was due to the combined effects of production declines in the Company's outside operated properties resulting from the industry slowdown that began in 1998, production declines in some of the Company's Gulf Coast properties, and the loss of production from marginal properties that were sold in 1999.

Gas sales to unaffiliated purchasers were 23.8 Bcf in 2000, up from 21.2 Bcf in 1999 and 21.4 Bcf in 1998. Sales to unaffiliated purchasers are primarily made under contracts which reflect current short-term prices and which are subject to seasonal price swings.

Intersegment sales to Arkansas Western Gas Company (AWG), the utility subsidiary which operates the Company's northwest Arkansas utility system, were 5.1 Bcf in both 2000 and 1999 and 7.7 Bcf in 1998. Although weather as measured in degree days was normal in 2000 and colder than 1999, sales to AWG were flat as record cold weather in the months of November and December caused the Company to utilize its storage facilities in addition to gas production to meet contractual commitments to AWG. Affiliated deliveries for 1999 were down as unseasonably warm weather decreased AWG's demand for the Company's gas supply. The Company's gas production provided approximately 36% of AWG's requirements in 2000, 38% in 1999 and 55% in 1998.

Prior to 1999, most of the sales to AWG's system were pursuant to an intersegment long-term contract entered into in 1978 with SEECO, Inc. (SEECO). In October 1998, AWG instituted a competitive bidding process for its gas supply that included seven different packages. These bid requests included replacement of the gas supply and no-notice service previously provided by the long-term gas supply contract between AWG and SEECO. In the initial 1998 bid, SEECO, along with the Company's marketing subsidiary, successfully bid on five of the seven packages with prices based on the NorAm East Index plus a demand charge. Based on normal weather patterns, the volumes of gas projected to be supplied under these contracts would be approximately equal to the historical annual volumes sold under the expired long-term contract. However, under the new contracts, the Company supplied most of AWG's no-notice service and less of its routine base requirements than it had under the previous contract. During periods of warmer weather, as in early 2000 and in 1999 and 1998, lower total gas volumes will be sold to AWG than compared to periods of normal or colder weather. The total premium over the NorAm East Index under these contracts is estimated to be approximately $1.0 million lower (after-tax) than the annual premium earned under the expired long-term contract. The majority of the premium is received through monthly demand charges which are received regardless of volumes actually delivered. Other sales to AWG are made under long-term contracts with flexible pricing provisions.

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Of the five bid packages originally secured by the Company, three were for a 3-year term, one was for a 2-year term and one was for a 1-year term. The Company was unsuccessful in subsequent bidding for the 2-year and 1-year packages and no longer makes affiliated sales under those contracts. There were no demand fees associated with these two bid packages. In total, these two packages provided approximately 2.5 Bcf annually of AWG's gas supply. Gas volumes previously sold at market prices to AWG under these two packages are now sold to unaffiliated parties. The three remaining packages will again be put out to bid by AWG in 2001. The Company will bid to retain these gas supply packages although there is no assurance that it will be successful. If successful, the Company cannot predict the amount of premium that would be associated with the new contracts.

The Company's intersegment sales to Associated Natural Gas Company (Associated), a division of AWG which operates the Company's natural gas distribution system in northeast Arkansas, were 2.7 Bcf in 2000, 3.1 Bcf in 1999, and 3.6 Bcf in 1998. Affiliated deliveries to Associated decreased in 2000 due to the sale of Associated's Missouri utility operations in May 2000. Deliveries to Associated decreased in 1999 due primarily to corresponding changes in heating weather. Effective October 1990, SEECO entered into a ten-year contract with Associated to supply a portion of its system requirements at a price to be redetermined annually. For the contract period beginning October 1, 1997, the contract was revised to redetermine the sales price monthly based on an index posting plus a reservation fee. Effective October 2000, Associated placed its gas supply out for competitive bids. The Company was successful in obtaining a one-year bid to supply approximately 1.0 Bcf of gas, or approximately 40% of Associated's annual requirement assuming normal weather patterns.

The Company expects future increases in its gas production to come primarily from sales to unaffiliated purchasers. The Company is unable to predict changes in the market demand and price for natural gas, including changes which may be induced by the effects of weather on demand of both affiliated and unaffiliated customers for the Company's production. Additionally, the Company holds a large amount of undeveloped leasehold acreage and producing acreage, and has an inventory of drilling leads, prospects and seismic data that will continue to be evaluated and developed in the future. The Company's exploration programs have been directed primarily toward natural gas in recent years.

Commodity Prices

The overall average price realized for the Company's gas production was $2.88 per Mcf in 2000, $2.21 per Mcf in 1999, and $2.34 per Mcf in 1998. The changes in the average price realized primarily reflects changes in average annual spot market prices and the effects of the Company's price hedging activities. The Company's hedging activities lowered the average gas price $1.04 per Mcf in 2000 and $.06 per Mcf in 1999, and added $.19 per Mcf to the average gas price in 1998. Additionally, the Company receives monthly demand charges related to the no-notice service it makes available to the utility segment which increases the Company's average gas price received.

The Company realized an average price of $22.99 per barrel for its oil production for the year ended December 31, 2000, up from $17.11 per barrel for 1999 and $13.60 per barrel for 1998.

The Company periodically enters into hedging activities with respect to a portion of its projected crude oil and natural gas production through a variety of financial arrangements intended to support oil and gas prices at targeted levels and to minimize the impact of price fluctuations (see Note 8 of the financial statements for additional discussion). The Company's policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings. At December 31, 2000, the Company had hedges in place on 34.7 Bcf of future gas production and 697,000 barrels of future oil production. Subsequent to December 31, 2000, the Company closed its position on 298,000 barrels with a floor price of $18.00. The Company currently has hedged approximately 80% of its 2001 anticipated gas production levels and 50% of its projected oil production.

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Disregarding the impact of hedges, the Company expects the average price it receives for its total gas production to be slightly higher than average spot market prices due to the prices it receives under the contracts covering its intersegment sales which provide swing services to the Company's utility systems. Future changes in revenues from sales of the Company's gas production will be dependent upon changes in the market price for gas, access to new markets, maintenance of existing markets, and additions of new gas reserves.

Operating Costs and Expenses

Production expenses per Mcfe for this segment were $.40 in 2000, compared to $.35 in 1999 and $.34 in 1998. Production taxes per Mcfe were $.15 in 2000 compared to $.09 in both 1999 and 1998. The increase in production expenses per Mcfe in 2000 was due primarily to an increase in workover expenses. The increase in 2000 production taxes per Mcfe was due to increased severance and ad valorem taxes that resulted from higher commodity prices. General and administrative expense per Mcfe was $.32 in 2000, compared to $.30 in 1999 and $.34 in 1998. The increase in general and administrative costs in 2000 as compared to 1999 resulted from increases in incentive compensation pay that is dependent upon the operating results for this segment. The decrease in 1999 general and administrative costs as compared to 1998 resulted from severance costs and other costs related to the closing of the Company's Oklahoma City office in 1998.

The Company's full cost pool amortization rate averaged $1.06 per Mcfe for 2000, compared to $1.00 per Mcfe in 1999 and $1.04 per Mcfe in 1998. The average rate increased in 2000 due primarily to a $9.9 million decline in the balance of unevaluated costs excluded from amortization in the full cost pool. The rate decreased in 1999 as compared to 1998 due to the full cost ceiling write-down taken in 1998.

The Company utilizes the full cost method of accounting for costs related to its oil and natural gas properties. Under this method, all such costs (productive and nonproductive) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test, however, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved gas and oil reserves discounted at 10 percent (standardized measure) plus the lower of cost or market value of unproved properties. At December 31, 2000, 1999 and 1998 the Company's unamortized costs of oil and gas properties did not exceed this ceiling amount. Primarily due to high oil and gas prices in effect at year-end, the Company's standardized measure increased to $895.1 million at December 31, 2000, compared to $262.1 million at December 31, 1999 and $222.8 million at December 31, 1998. Market prices for natural gas have declined since December 31, 2000, although they are still considerably higher than prices in effect at year-end 1999 and 1998. As a comparative measure only, the Company's standardized measure at December 31, 2000, assuming a NYMEX index price of $4.50 per Mcf and a WTI index price of $25.00 per barrel, would have been approximately $487.0 million. A decline in oil and gas prices from year-end 2000 levels or other factors, without other mitigating circumstances, could cause a future write-down of capitalized costs and a noncash charge against future earnings.

Inflation impacts the Company by generally increasing its operating costs and the costs of its capital additions. The effects of inflation on the Company's operations in recent years have been minimal due to low inflation rates. However, during 2000 the impact of inflation intensified in certain areas of the Company's exploration and production segment as shortages in drilling rigs, third party services and qualified labor developed due to an overall increase in the activity level of the domestic oil and gas industry. This impact is continuing into 2001 with the significant increases in oil and gas prices experienced during the past several months. Increased competition in south Louisiana has also had the impact of increasing 3-D seismic and land costs in the area.

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Gas Distribution

The operating results of the Company's gas distribution segment are highly seasonal. The extent and duration of heating weather also impacts the profitability of this segment, although the Company has a weather normalization clause that lessens the impact of revenue increases and decreases which might result from weather variations during the winter heating season. The gas distribution segment's profitability is also dependent upon the timing and amount of regulatory rate increases that are filed with and approved by the Arkansas Public Service Commission (APSC). For periods subsequent to allowed rate increases, the Company's profitability is impacted by its ability to manage and control this segment's operating costs and expenses.

On May 31, 2000, the Company completed the sale of its Missouri gas distribution assets for $32.0 million. The sale resulted in a pre-tax gain of approximately $3.2 million and proceeds from the sale were used to pay down debt. As a result of the adverse Hales judgment, the Company's Board of Directors authorized management to pursue the sale of the Company's remaining gas distribution operations. The sale process did not result in an acceptable bid. Although the Company may sell its gas distribution segment in the future, it currently plans to operate these assets as a continuing part of its business.

	2000	1999	1998
	($ in thousands, except for Mcf amounts)		
Revenues	$151,234	$132,420	$134,711
Gas purchases	$93,992	$68,876	$70,972
Operating costs and expenses	$42,587	$46,357	$47,710
Operating income	$14,655	$17,187	$16,029
Deliveries (Bcf)			
Sales and end-use transportation	30.4	31.6	31.7
Off-system transportation	3.1	4.8	1.1
Average number of customers	152,773	177,328	174,693
Average sales rate per Mcf	$6.55	$5.67	$5.57
Heating weather - degree days	3,994	3,179	3,472
Percent of normal	100%	79%	87%

Note: Amounts and statistics for 2000, 1999 and 1998 include the operations of the Company's Missouri properties through the sale date of May 31, 2000.

Revenues and Operating Income

Gas distribution revenues fluctuate due to the pass-through of gas supply cost changes and due to the effects of weather. Because of the corresponding changes in purchased gas costs, the revenue effect of the pass-through of gas cost changes has not materially affected net income.

Gas distribution revenues increased 14% in 2000 and decreased 2% in 1999. The increase in 2000 was due to a higher sales rate and increased sales volumes caused by colder weather, partially offset by the loss of revenues resulting from the sale of the utility's Missouri assets. The decrease in 1999 was due to the effects of warmer weather. Weather in 2000 was normal and 26% colder than the prior year. Weather in 1999 was 21% warmer than normal and 8% warmer than the prior year.

Operating income for Southwestern's utility systems decreased 15% in 2000 and increased 7% in 1999. The decrease in 2000 resulted from the sale of the Missouri assets and a $1.4 million annual rate reduction that was implemented in December 1999. The increase in 1999 was due to the Company's efforts in reducing operating costs and to customer growth.

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Deliveries and Rates

In 2000, AWG sold 16.8 Bcf to its customers at an average rate of $6.45 per Mcf, compared to 14.5 Bcf at $5.47 per Mcf in 1999 and 15.1 Bcf at $5.37 per Mcf in 1998. Additionally, AWG transported 6.3 Bcf in 2000, 6.2 Bcf in 1999, and 6.0 Bcf in 1998 for its end-use customers. Associated sold 5.3 Bcf to its customers in 2000 at an average rate of $6.89 per Mcf, compared to 7.4 Bcf in 1999 at $6.06 per Mcf and 7.8 Bcf at $5.95 per Mcf in 1998. Associated transported 2.0 Bcf for its end-use customers in 2000, compared to 3.4 Bcf in 1999 and 2.8 Bcf in 1998. The decrease in the combined volumes sold and transported for end-use customers in 2000 resulted from the sale of the Missouri properties, offset by increased deliveries due to colder weather, and decreased in 1999 due to warmer weather, partially offset by customer growth. The fluctuations in the average sales rates reflect changes in the average cost of gas purchased for delivery to the Company's customers, which are passed through to customers under automatic adjustment clauses.

Total deliveries to industrial customers of AWG and Associated, including transportation volumes, were 11.8 Bcf in 2000, 13.1 Bcf in 1999 and 13.0 Bcf in 1998. The decline in deliveries in 2000 resulted from the sale of the Missouri assets. AWG also transported 3.1 Bcf of gas through its gathering system in 2000 for off-system deliveries, all to the Ozark Gas Transmission System, compared to 4.8 Bcf in 1999 and 1.1 Bcf in 1998. The level of off-system deliveries each year generally reflects the changes of on-system demands of the Company's gas distribution systems for the Company's gas production. The average off-system transportation rate was approximately $.10 per Mcf, exclusive of fuel, in 2000 and 1999, and $.11 per Mcf in 1998.

Gas distribution revenues in future years will be impacted by the utility's gas purchase costs, the sale of the Company's Missouri assets, customer growth and rate increases allowed by the APSC. In recent years, AWG has experienced customer growth of approximately 2% to 3% annually, while Associated has experienced customer growth of approximately 1% or less annually. Based on current economic conditions in the Company's service territories, the Company expects this trend in customer growth to continue.

In February 2001, the APSC approved a 90-day temporary tariff to collect additional gas costs not yet billed to customers through the utility's normal purchased gas adjustment clause in its approved tariffs. The Company had under-recovered purchased gas costs of $12.9 million in current assets at December 31, 2000. The level of deferred purchases had increased to over $30.0 million during January 2001 as a result of rapidly increasing gas costs. The temporary tariff allows the utility to bill customers an additional $3.00 per Mcf of usage and is expected to generate $14.0 to $15.0 million of additional cash flow during the next few months allowing the Company faster recovery of gas costs already incurred.

Tariffs implemented in Arkansas as a result of rate increases in both 1996 and 1997 contain a weather normalization clause to lessen the impact of revenue increases and decreases which might result from weather variations during the winter heating season. Rate increase requests, which may be filed in the future, will depend on customer growth, increases in operating expenses, and additional investment in property, plant and equipment. See "Regulatory Matters" below for additional discussion related to the Company's gas distribution segment.

Operating Costs and Expenses

The changes in purchased gas costs for the gas distribution segment reflect volumes purchased, prices paid for supplies, the mix of purchases from intercompany versus third party sources and the sale of Missouri assets as discussed above. Other operating costs and expenses of the gas distribution segment for 2000 were lower than 1999 and 1998 due primarily to the sale of the utility's Missouri assets.

Going forward, Southwestern's comparative operating results for its gas distribution segment will be lower reflecting the Missouri asset divestiture. However, the Company does not expect the sale to materially impact consolidated earnings, as the loss in operating income should generally be offset by a corresponding decrease in corporate interest expense.

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Inflation impacts the Company's gas distribution segment by generally increasing its operating costs and the costs of its capital additions. The effects of inflation on the utility's operations in recent years have been minimal due to low inflation rates. Additionally, delays inherent in the rate-making process prevent the Company from obtaining immediate recovery of increased operating costs of its gas distribution segment.

Regulatory Matters

In May 1999, the Staff of the APSC initiated a proceeding in which it sought an annual reduction of approximately $2.3 million in the rates AWG charges it customers in northwest Arkansas. The Staff's position was based on various adjustments to the utility's rate base, operating expenses, capital structure and rate of return. A large portion of the proposed reduction was based on a downward adjustment to the utility's return on equity authorized by the APSC in 1996. During the third quarter of 1999, the Company reached agreement with the Staff and the APSC to resolve this issue and to close several other dockets that had remained open. In the settlement agreement, the Company agreed to reduce its rates collected from customers on a prospective basis in the amount of $1.4 million annually, effective December 1, 1999. The agreement also includes the resolution of a proceeding initiated in December 1998 by the Staff of the APSC and that was previously disclosed by the Company where the Staff had recommended the disallowance of approximately $3.1 million of gas supply costs. As part of the settlement, this docket was closed with no negative adjustment to the Company.

The Company received approvals in December 1997 from the APSC and the Missouri Public Service Commission (MPSC) for rate increases and tariff changes which allow the utility to collect an additional $3.0 million annually. Of the $3.0 million total, approximately $2.0 million is in the form of base rate increases and $1.0 million is related to the increased cost of service of the Company's gathering plant which is recovered through either the purchased gas adjustment clause or through direct charges to transportation customers.

In its order approving the Missouri changes, the MPSC further ordered Associated to modify its purchased gas adjustment tariff to remove any specific language referencing recovery of the cost of service of its gathering facilities. The MPSC order provided that Associated should base gathering charges to its customers on competitive market conditions and that it would be allowed recovery from its sales and transportation customers of all prudently incurred gathering costs without reference to its cost of service. The MPSC reviews these gathering costs annually as part of its review of Associated's gas costs. Associated believes that the MPSC lacks statutory authority to approve charges which are not based on historical cost of service. Associated appealed this issue to the circuit court which ruled in favor of the MPSC. The Company appealed the lower court's decision to the Missouri Court of Appeals which requested that the MPSC reissue its order making clear the basis for its decision. The Company continued to bill its ratepayers gas gathering costs based on its cost of service through the date of the sale of its Missouri assets. Gathering costs have been recovered in this manner from Missouri customers since Associated's 1990 rate case. Prior to the 1997 changes, Associated's gathering costs were recovered from Arkansas customers through its base rates.

A December 1996 rate increase order issued by the APSC also provided that AWG cause to be filed with the APSC an independent study of its procedures for allocating costs between regulated and non-regulated operations, its staffing levels and executive compensation. The independent study was ordered by the APSC to address issues raised by the Office of the Attorney General of the State of Arkansas. The study was conducted in 1999 with a final report issued in December 1999. The report found the Company's costs to be reasonable in all categories and did not recommend any changes to the rates currently in effect.

The Company is subject to continuing reviews of it gas supply costs by the APSC. The MPSC is currently auditing the last year of Associated's gas costs in Missouri. The Company currently has open issues with the MPSC, however, the Company believes that none of these issues will have a material adverse effect on the Company's financial condition or results of operations.

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AWG also purchases gas from unaffiliated producers under take-or-pay contracts. The Company believes that it does not have a significant exposure to liabilities resulting from these contracts and expects to be able to continue to satisfactorily manage its exposure to take-or-pay liabilities.

Marketing and Other
Marketing

	2000	1999	1998
Revenues (in thousands)	$207.7	$137.5	$97.2
Operating income (in thousands)	$2.5	$2.1	$1.8
Gas volumes marketed (Bcf)	59.6	63.1	49.6

Operating income for the marketing segment was $2.5 million on revenues of $207.7 million in 2000, compared to $2.1 million on revenues of $137.5 million in 1999, and $1.8 million on revenues of $97.2 million in 1998. The

Company marketed 59.6 Bcf in 2000, compared to 63.1 Bcf in 1999 and 49.6 Bcf in 1998. The Company enters into hedging activities with respect to its gas marketing activities to provide margin protection (see Note 8 of the financial statements for additional discussion).

NOARK Partnership

The marketing segment also manages the Company's 25% interest in the NOARK Pipeline System, Limited Partnership (NOARK). The NOARK Pipeline was a 258-mile long intrastate gas transmission system that extended across northern Arkansas, crossing three major interstate pipelines and interconnecting with the Company's distribution systems. The NOARK Pipeline had been operating below capacity and generating losses since it was placed in service in September 1992. The Company's share of the pretax loss from operations included in other income related to its NOARK investment was $1.8 million in 2000, $2.0 million in 1999, and $3.1 million in 1998. The improvements in the 2000 and 1999 results primarily reflect the benefits of the integration of the NOARK Pipeline System with the Ozark Gas Transmission System (Ozark). The integration of the two systems was completed in November, 1998.

In January 1998, the Company entered into an agreement with Enogex Inc. (Enogex), a subsidiary of OGE Energy Corp., to expand the NOARK system and provide access to Oklahoma gas supplies through an integration of NOARK with Ozark. Ozark was a 437-mile interstate pipeline system which began in eastern Oklahoma and terminated in eastern Arkansas. Effective August 1, 1998, Enogex acquired Ozark and contributed the pipeline system to the NOARK partnership. Enogex also acquired the NOARK partnership interests not held by Southwestern. Enogex funded the acquisition of Ozark and the expansion and integration with NOARK, which resulted in the Company's interest in the partnership decreasing to 25% with Enogex owning a 75% interest. There are also provisions in the agreement with Enogex which allow for future revenue allocations to the Company above its 25% partnership interest if certain minimum throughput and revenue assumptions are not met. As a result of the changes discussed above, the Company believes that it will be able to continue to reduce the losses it has experienced on the NOARK project and expects its investment in NOARK to be realized over the life of the system (see Note 7 of the financial statements for additional discussion).

Ozark Pipeline, the new integrated system became operational November 1, 1998, and includes 749 miles of pipeline with a total throughput capacity of 330 MMcfd. Deliveries are currently being made by the integrated pipeline to portions of AWG's distribution system, to Associated, and to the interstate pipelines with which it interconnects. Ozark Pipeline had an average daily throughput of 188 million cubic feet of gas per day (MMcfd) in 2000 and 168 MMcfd in 1999. In 1998, NOARK had an average daily throughput of 27.3 MMcfd before the integration with Ozark. As a result of a rate case filed in 2000, Ozark Pipeline's maximum transportation rate increased from $.2455 per dekatherm to $.2867 per dekatherm effective November 1, 2000. At December 31, 2000, the Company's gas distribution subsidiary has transportation contracts with Ozark Pipeline for 66.9 MMcfd of firm capacity. These contracts expire in 2002 and 2003 and are renewable annually thereafter until terminated with 180 days' notice.

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As further explained in Note 11 of the financial statements, the Company has severally guaranteed 60% of NOARK's currently outstanding debt. This debt financed a portion of the original cost to construct the NOARK Pipeline.

Other Income, Costs and Expenses

Interest costs, net of capitalization, were up 34% in 2000 and 1% in 1999, both as compared to prior years. The increase in 2000 was caused primarily by higher average borrowings that resulted from payment of the Hales judgment and to the current lower level of capitalized interest related to the Company's oil and gas properties. Interest capitalized decreased 26% in 2000 and 15% in 1999. The changes in capitalized interest are due primarily to decreases in the level of costs excluded from amortization in the exploration and production segment.

The increase in other income in 2000 resulted from the $3.2 million gain on the sale of the Company's Missouri gas distribution assets and gains from the sale of other miscellaneous assets. The changes in other income in 1999 and 1998 relate primarily to changes in the Company's share of operating losses incurred by NOARK, as discussed above. Additionally, in 1999 and 1998 the Company incurred certain costs related to a judgment bond that the Company was required to post after receiving the initial adverse verdict in the Hales case.

The Hales judgment was the primary cause for the Company's deferred tax benefit of $28.9 million in 2000. In 1998, the write-down of the Company's oil and gas properties resulted in a deferred tax benefit of $25.9 million. Excluding the impacts of these changes in deferred income taxes, the changes in the provisions for current and deferred income taxes recorded each year result primarily from the level of taxable income, the collection of under-recovered purchased gas costs, abandoned property costs, and the deduction of intangible drilling costs in the year incurred for tax purposes, netted against the turnaround of intangible drilling costs deducted for tax purposes in prior years. Intangible drilling costs are capitalized and amortized over future years for financial reporting purposes under the full cost method of accounting.

LIQUIDITY AND CAPITAL RESOURCES

The Company depends on internally generated funds and its revolving line of credit discussed under Financing Requirements as its major sources of liquidity. Due to the Hales judgment and the impact of high year-end gas prices on working capital, net cash used in operating activities was $53.2 million in 2000, compared to cash provided by operating activities of $58.1 million in 1999 and $93.7 million in 1998. The primary components of cash generated from operations are net income, depreciation, depletion and amortization, write-down of oil and gas properties, the provision for deferred income taxes and changes in current assets and current liabilities. Net cash from operating activities provided 89% of the Company's capital requirements for routine capital expenditures, cash dividends, and scheduled debt retirements in 1999 and 125% in 1998.

Capital Expenditures

Capital expenditures totaled $75.7 million in 2000, $67.0 million in 1999, and $64.4 million in 1998. The Company's exploration and production segment expenditures included acquisitions of oil and gas producing properties totaling $6.7 million in 2000 and $9.4 million in 1999. The Company made no producing property acquisitions in 1998.

	2000	1999	1998
		(in thousands)	
Capital Expenditures			
Exploration and production	$69,211	$59,004	$52,376
Gas distribution	5,994	7,124	10,108
Other	512	839	1,875
	$75,717	$66,967	$64,359

Capital investments planned for 2001 total $81.6 million, consisting of $75.0 million for exploration and production, $6.1 million for gas distribution system expenditures and $.5 million for general purposes. The Company expects that its level of capital investments will be adequate to allow the Company to maintain its present markets, explore and develop its existing gas and oil properties as well as generate new drilling prospects, and finance improvements necessary due to normal customer growth in its gas distribution segment.

Financing Requirements

At year-end 2000, Southwestern's total debt was $396.0 million, including $171.0 million under a short-term credit facility. This compares to year-end 1999 total debt of $302.2 million, including $7.5 million classified as short-term debt. In July 2000, the Company replaced its existing revolving credit facilities that had previously provided the Company access to $80.0 million of variable rate capital with a new credit facility that has a capacity of $180.0 million. This new facility was used to fund the Hales judgment of $109.3 million, pay off the existing revolver balance and retire $22.0 million of private placement debt. The new credit facility is also being used to fund normal working capital needs. The interest rate on the new facility is 112.5 basis points over the LIBOR rate and was 7.85% at December 31, 2000. The new credit facility has a term of 364 days and expires in July 2001. The Company intends to renew or replace this facility prior to its expiration.

In August 2000, the Company retired $22.0 million of 9.36% private placement notes. Certain costs of the redemption were expensed and are classified as an extraordinary loss, net of related income tax effects.

In 1997, the Company issued $60.0 million of 7.625% Medium-Term Notes due 2027 and $40.0 million of 7.21% Medium-Term Notes due 2017. These notes were issued under a supplement to the Company's $250.0 million shelf registration statement filed with the Securities and Exchange Commission in February 1997, for the issuance of up to $125.0 million of Medium-Term Notes. The Company has $25.0 million of capacity remaining under the shelf registration statement. The Company also has $125.0 million of 6.7% Notes due in 2005 that were issued under the shelf registration. The Company's public notes are rated BBB by Standard and Poor's and Baa3 by Moody's.

In connection with the Enogex transaction in 1998 discussed above under "NOARK Partnership," the Company and a previous general partner converted certain of their loans to the NOARK partnership, plus accrued interest, into equity, and contributed approximately $10.7 million to the partnership to fund costs incurred in connection with the prepayment of NOARK's 9.74% Senior Secured notes. The Company's share of the contribution was $6.5 million. In June 1998, the NOARK partnership issued $80.0 million of 7.15% Notes due 2018. The notes require semi-annual principal payments of $1.0 million that began in December 1998. The Company and the other general partner of NOARK have severally guaranteed the principal and interest payments on the NOARK debt. The Company's share of the several guarantee is 60%. The Company advanced $3.3 million to NOARK to fund its share of debt service payments in 2000 and advanced $2.3 million in 1999. If NOARK is unable to generate sufficient cash in the future to service its debt and the Company is required to continue contributing cash to fund its debt guarantee, the Company may be required to record the NOARK debt commitment under current accounting rules.

Under its short-term credit agreement the Company may not issue total debt in excess of 80% of its total capital, shareholders' equity may not be less than $120.0 million (excluding any adjustments for SFAS No. 133 after its adoption) and the Company may not declare or pay any dividends on its common stock. The Company must also have a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to fixed charges of at least 2.5 or higher for the previous 12 months. For 2000, this calculation excludes the impact of the Hales judgment. At the end of 2000, the Company's capital structure consisted of 73.7% debt (including short-term debt but excluding the Company's several guarantee of NOARK's obligations) and 26.3% equity, with a ratio of EBITDA to fixed charges of 4.1. Over the long term, the Company will continue to consider the sale of its remaining gas distribution assets to pay down existing debt.

In the short term, funds provided by operating activities are expected to increase significantly due to higher gas and oil prices currently being received for the Company's production. As part of its strategy to reduce its debt level, the Company has hedged approximately 80% of its expected 2001 gas production and 50% of its expected 2001 oil production to insure it receives attractive prices. Under these assumptions and assuming no other unanticipated uses of cash arise during the year, the Company expects to reduce its debt level by $50 million to $70 million during 2001.

Working Capital

The Company maintains access to funds which may be needed to meet seasonal requirements through its credit facility explained above. The Company had net negative working capital of $127.0 million at the end of 2000 due to the short-term revolving credit facility balance of $171.0 million, compared to positive working capital of $13.9 million at the end of 1999. Current assets increased by 61% to $112.9 million in 2000, while current liabilities (without consideration of short-term debt) increased 41%. The increases in current assets and current liabilities at December 31, 2000, was due primarily to increases in accounts receivable, accounts payable and under-recovered purchased gas costs that resulted from extremely high market prices for natural gas at year end.

FORWARD-LOOKING INFORMATION

All statements, other than historical financial information, included in this discussion and analysis of financial condition and results of operations may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Although the Company believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance and actual results or developments may differ materially from those in the forward-looking statements. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include, but are not limited to, the timing and extent of changes in commodity prices for gas and oil, the effects of commodity hedges and the volatility in earnings caused by new hedge accounting standards, the timing and extent of the Company's success in discovering, developing, producing, and estimating reserves, the effects of weather and regulation on the Company's gas distribution segment, the value that the Company's gas distribution segment may bring in exploring sales opportunities for this segment and the timing of any proposed sale, increased competition, legal and economic factors, governmental regulation, changing market conditions, the comparative cost of alternative fuels, conditions in capital markets and changes in interest rates, availability of oil field services, drilling rigs, and other equipment, as well as various other factors beyond the Company's control.

ITEM 7.A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISKS

Market risks relating to the Company's operations result primarily from changes in commodity prices and interest rates, as well as credit risk concentrations. The Company uses natural gas and crude oil swap agreements and options to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and oil. The Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price risks. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with acceptable credit standings.

Credit Risks

The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of customers and their dispersion across geographic areas. No single customer accounts for greater than 7% of accounts receivable. See the discussion of credit risk associated with commodities trading below.

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Interest Rate Risk

The following table provides information on the Company's financial instruments that are sensitive to changes in interest rates. The table presents the Company's debt obligations, principal cash flows and related weighted-average interest rates by expected maturity dates. Variable average interest rates reflect the rates in effect at December 31, 2000 for borrowings under the Company's credit facility. The Company's policy is to manage interest rates through use of a combination of fixed and floating rate debt. Interest rate swaps may be used to adjust interest rate exposures when appropriate. There were no interest rate swaps outstanding at December 31, 2000.

	Expected Maturity Date						
	2001	2002	2003	2004	2005	Thereafter	Total
	($ in millions)						
Fixed Rate	-	-	-	-	$125.0	$100.0	$225.0
Average Interest Rate	-	-	-	-	6.70%	7.46%	7.04%
Variable Rate	$171.0	-	-	-	-	-	$171.0
Average Interest Rate	7.83%	-	-	-	-	-	7.83%

Commodities Risk

The Company uses over-the-counter natural gas and crude oil swap agreements and options to hedge sales of Company production and marketing activity against the inherent price risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX (New York Mercantile Exchange) futures markets. These swaps and options include (1) transactions in which one party will pay a fixed price (or variable price) for a notional quantity in exchange for receiving a variable price (or fixed price) based on a published index (referred to as price swaps), (2) transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps), and (3) the purchase and sale of index-related puts and calls (collars) that provide a "floor" price below which the counterparty pays the Company the amount by which the price of the commodity is below the contracted floor and a "ceiling"price above which the Company pays the counterparty the amount by which the price of the commodity is above the contracted ceiling.

The primary market risk related to these derivative contracts is the volatility in market prices for natural gas and crude oil. However, this market risk is offset by the gain or loss recognized upon the related sale of the natural gas or oil that is hedged. Credit risk relates to the risk of loss as a result of non-performance by the Company's counterparties. The counterparties are primarily major investment and commercial banks which management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure the Company has to each counterparty are periodically reviewed to ensure limited credit risk exposure.

The following table provides information about the Company's financial instruments that are sensitive to changes in commodity prices. The table presents the notional amount in Bcf (billion cubic feet) or MBbls (thousand barrels), the weighted average contract prices, and the total dollar contract amount by expected maturity dates. The "Carrying Amount" for the contract amounts are calculated as the contractual payments for the quantity of gas or oil to be exchanged under futures contracts and do not represent amounts recorded in the Company's financial statements. The "Fair Value" represents values for the same contracts using comparable market prices at December 31, 2000. At December 31, 2000, the "Carrying Amount" of these financial instruments exceeded the "Fair Value" by $60.6 million.

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	Expected Maturity Date				
	2001		2002		2003
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Natural Gas					
Swaps with a fixed-price receipt					
Contract volume (Bcf)	1.9		1.0		.2
Weighted average price per Mcf	$3.42		$2.65		$2.75
Contract amount (in millions)	$6.4	$1.4	$2.6	$.8	$.6
Swaps with a fixed-price payment					
Contract volume (Bcf)	.4		-		-
Weighted average price per Mcf	$4.83		-		-
Contract amount (in millions)	$1.8	$2.8	-	-	-
Price collars					
Contract volume (Bcf)	25.2		6.0		-
Weighted average floor price per Mcf	$3.66		$4.0		-
Contract amount of floor (in millions)	$92.3	$96.0	$24.0	$27.1	-
Weighted average ceiling price per Mcf	$4.52		$4.72		-
Contract amount of ceiling (in millions)	$113.9	$56.3	$28.3	$24.1	-
Oil					
Swaps with a fixed-price receipt					
Contract volume (MBbls)	72		-		-
Weighted average price per Bbl	$17.49		-		-
Contract amount (in millions)	$1.3	$.8	-	-	-
Price floor					
Contract volume (MBbls)	325(1)		-		-
Weighted average price per Bbl	$18.00		-		-
Contract amount (in millions)	$5.9	$6.0	-	-	-
Price collar					
Contract volume (MBbls)	300		-		-
Weighted average floor price per Bbl	$27.40		-		-
Contract amount of floor (in millions)	$8.2	$9.4	-	-	-
Weighted average ceiling price per Bbl	$29.95		-		-
Contract amount of ceiling (in millions)	$9.0	$8.7	-	-	-

[FN]
(1) Subsequent to December 31, 2000, the Company closed its position relating to the $18.00 per barrel floor on a notional amount of 298 MBbls covering eleven months of 2001 production.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Report of Management

Management is responsible for the preparation and integrity of the Company's financial statements. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States consistently applied, and necessarily include some amounts that are based on management's best estimates and judgment.

The Company maintains a system of internal accounting and administrative controls that management believes provide reasonable assurance that assets are safeguarded and that transactions are properly recorded and executed in accordance with management's authorization. The Company's financial statements have been audited by its independent public accountants, Arthur Andersen LLP. In accordance with auditing standards generally accepted in the United States, the independent auditors obtained a sufficient understanding of the Company's internal controls to plan their audit and determine the nature, timing, and extent of other tests to be performed.

The Audit Committee of the Board of Directors, composed solely of outside directors, meets with management and Arthur Andersen LLP to review planned audit scopes and results and to discuss other matters affecting internal accounting controls and financial reporting. The independent auditors have direct access to the Audit Committee and periodically meet with it without management representatives present.

Report of Independent Public Accountants

To the Board of Directors and Shareholders of Southwestern Energy Company:

We have audited the consolidated balance sheets of SOUTHWESTERN ENERGY COMPANY (an Arkansas corporation) AND SUBSIDIARIES as of December 31, 2000 and 1999, and the related consolidated statements of operations, retained earnings, and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. 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 financial statements referred to above present fairly, in all material respects, the financial position of Southwestern Energy Company and Subsidiaries as of December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Tulsa, Oklahoma
February 5, 2001

Statements of Operations
Southwestern Energy Company and Subsidiaries

For the Years Ended December 31,	2000	1999	1998
	(in thousands, except share and per share amounts)		
Operating Revenues			
Gas sales	$200,269	$165,898	$172,790
Gas marketing	137,234	96,570	76,367
Oil sales	15,537	9,891	9,557
Gas transportation and other	10,843	8,037	7,591
	363,883	280,396	266,305
Operating Costs and Expenses			
Gas purchases - utility	58,669	45,370	39,863
Gas purchases - marketing	133,221	92,851	73,235
Operating expenses	34,808	33,783	34,400
General and administrative expenses	24,982	24,174	27,515
Unusual items	111,288	-	-
Depreciation, depletion and amortization	45,869	41,603	46,917
Write-down of oil and gas properties	-	-	66,383
Taxes, other than income taxes	8,515	6,557	6,943
	417,352	244,338	295,256
Operating Income (Loss)	(53,469)	36,058	(28,951)

Interest Expense			
Interest on long-term debt	24,089	19,735	19,600
Other interest charges	1,588	923	1,470
Interest capitalized	(2,447)	(3,307)	(3,884)
	23,230	17,351	17,186
Other Income (Expense)	1,997	(2,331)	(3,956)
Income (Loss) Before Provision (Benefit) for Income Taxes	(74,702)	16,376	(50,093)
Provision (Benefit) for Income Taxes			
Current	-	537	(6,029)
Deferred	(28,905)	5,912	(13,467)
	(28,905)	6,449	(19,496)
Income (Loss) Before Extraordinary Item	(45,797)	9,927	(30,597)
Extraordinary Loss Due to Early Retirement of Debt (Net of $569,000 Tax Benefit)	(890)	-	-
Net Income (Loss)	$(46,687)	$9,927	$(30,597)
Basic and Diluted Earnings Per Share			
Income (Loss) Before Extraordinary Item	$(1.82)	$.40	$(1.23)
Extraordinary Loss Due to Early Retirement of Debt (Net of $569,000 Tax Benefit)	(.04)	-	-
Net Income (Loss)	$(1.86)	$.40	$(1.23)
Weighted Average Common Shares Outstanding	25,043,586	24,941,550	24,882,170
Diluted Weighted Average Common Shares Outstanding	25,043,586	24,947,021	24,882,170

The accompanying notes are an integral part of the financial statements.

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Balance Sheets
Southwestern Energy Company and Subsidiaries

December 31,	2000	1999
	(in thousands)	
ASSETS		
Current Assets		
Cash	$2,386	$1,240
Accounts receivable	77,041	43,339
Inventories, at average cost	17,000	21,520
Under-recovered purchased gas costs	12,942	-
Other	3,486	4,073
Total current assets	112,855	70,172
Investments	15,574	14,180

Property, Plant and Equipment, at cost		
Gas and oil properties, using the full cost method, including $27,692,000 in 2000 and $37,554,000 in 1999 excluded from amortization	872,023	816,199
Gas distribution systems	190,893	222,145
Gas in underground storage	27,867	28,712
Other	27,940	28,826
	1,118,723	1,095,882
Less: Accumulated depreciation, depletion and amortization	554,616	519,927
	564,107	575,955
Other Assets	12,842	11,139
	$705,378	$671,446
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term debt	$171,000	$7,500
Accounts payable	54,304	33,069
Taxes payable	4,346	3,506
Interest payable	2,806	2,483
Customer deposits	4,799	6,021
Other	2,629	3,767
Total current liabilities	239,884	56,346
Long-Term Debt	225,000	294,700
Other Liabilities		
Deferred income taxes	97,431	126,902
Other	1,772	3,142
	99,203	130,044
Commitments and Contingencies		
Shareholders' Equity		
Common stock, $.10 par value; authorized 75,000,000 shares, issued 27,738,084 shares	2,774	2,774
Additional paid-in capital	20,220	20,732
Retained earnings, per accompanying statements	148,353	198,044
	171,347	221,550
Less: Common stock in treasury, at cost, 2,556,908 shares in 2000 and 2,700,391 shares in 1999	28,485	30,083
Unamortized cost of restricted shares issued under stock incentive plan, 241,452 shares in 2000 and 188,781 shares in 1999	1,571	1,111
	141,291	190,356
	$705,378	$671,446

The accompanying notes are an integral part of the financial statements.

Statements of Cash Flows
Southwestern Energy Company and Subsidiaries

For the Years Ended December 31,	2000	1999	1998
		(in thousands)	
Cash Flows From Operating Activities			
Net income (loss)	$(46,687)	$9,927	$(30,597)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	47,227	42,971	48,267
Write-down of oil and gas properties	-	-	66,383
Deferred income taxes	(28,905)	5,912	(13,467)
Equity in loss of partnership	1,767	2,008	3,087
Gain on sale of Missouri utility assets	(3,209)	-	-
Extraordinary loss due to early retirement of debt (net of tax)	890	-	-
Change in assets and liabilities:			
Accounts receivable	(36,693)	(2,684)	5,097
Income taxes receivable	85	1,658	1,066
Under-recovered purchased gas costs	(14,104)	(273)	10,931
Inventories	2,290	1,292	(2,347)
Accounts payable	22,156	(4,711)	7,877
Other current assets and liabilities	1,980	2,031	(2,589)
Net cash provided by (used in) operating activities	(53,203)	58,131	93,708
Cash Flows From Investing Activities			
Capital expenditures	(75,717)	(66,967)	(64,359)
Sale of Missouri utility assets	32,000	-	-
Sale of oil and gas properties	13,651	-	-
Investment in partnership	(3,250)	(2,273)	(10,062)
(Increase) decrease in gas stored underground	845	(4,433)	(531)
Other items	(1,066)	2,380	340
Net cash used in investing activities	(33,537)	(71,293)	(74,612)
Cash Flows From Financing Activities			
Net increase (decrease) in revolving debt and short-term note	115,800	20,300	(11,500)
Retirement of notes and payments on long-term debt	(24,910)	(1,535)	(4,607)
Dividends paid	(3,004)	(5,985)	(5,970)
Net cash provided by (used in) financing activities	87,886	12,780	(22,077)
Increase (decrease) in cash	1,146	(382)	(2,981)
Cash at beginning of year	1,240	1,622	4,603
Cash at end of year	$2,386	$1,240	$1,622

Statements of Retained Earnings
Southwestern Energy Company and Subsidiaries

For the Years Ended December 31,	2000	1999	1998

	(in thousands)		
Retained Earnings, beginning of year	$198,044	$194,102	$230,669
Net income (loss)	(46,687)	9,927	(30,597)
Cash dividends declared ($.12 per share in 2000, $.24 per share in 1999 and 1998)	(3,004)	(5,985)	(5,970)
Retained Earnings, end of year	$148,353	$198,044	$194,102

The accompanying notes are an integral part of the financial statements.

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Notes to Financial Statements
Southwestern Energy Company and Subsidiaries
December 31, 2000, 1999, and 1998

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations and Consolidation

Southwestern Energy Company (Southwestern or the Company) is an integrated energy company primarily focused on natural gas. Through its wholly-owned subsidiaries, the Company is engaged in oil and gas exploration and production, natural gas gathering, transmission and marketing, and natural gas distribution. Southwestern's exploration and production activities are concentrated in Arkansas, New Mexico, Texas, Oklahoma and Louisiana. The gas distribution segment operates in northern Arkansas and under normal weather conditions obtains approximately 35% to 40% of its gas supply from one of the Company's exploration and production subsidiaries. The customers of the gas distribution segment consist of residential, commercial, and industrial users of natural gas. Southwestern's marketing and transportation business is concentrated in its core areas of operations.

On May 31, 2000, the Company completed the sale of its Missouri gas distribution assets for $32.0 million resulting in a pre-tax gain of approximately $3.2 million. Proceeds from the sale of the Missouri assets were used to reduce the Company's outstanding debt. As a result of the adverse Hales judgment in June 2000, the Company's Board of Directors authorized management to pursue the sale of the Company's remaining gas distribution assets. The sale process did not result in an acceptable bid. Although the Company may sell its gas distribution segment in the future, it currently plans to operate these assets as a continuing part of its business.

The consolidated financial statements include the accounts of Southwestern Energy Company and its wholly-owned subsidiaries, Southwestern Energy Production Company, SEECO, Inc., Arkansas Western Gas Company, Southwestern Energy Services Company, Diamond "M" Production Company, Southwestern Energy Pipeline Company, A.W. Realty Company, and Arkansas Western Pipeline Company. All significant intercompany accounts and transactions have been eliminated. The Company accounts for its general partnership interest in the NOARK Pipeline System, Limited Partnership (NOARK) using the equity method of accounting. In accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," the Company recognizes profit on intercompany sales of gas delivered to storage by its utility subsidiary. Certain reclassifications have been made to the prior years' financial statements to conform with the 2000 presentation. These reclassifications had no effect on previously recorded net income.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Unusual Items

In June 2000, the Company reported that the Arkansas Supreme Court ruled to affirm the 1998 decision of the Sebastian County Circuit Court awarding $109.3 million in a class action to royalty owners of SEECO, Inc. (Hales judgment). The Company fully satisfied the judgment and the Circuit Court in Sebastian County issued an order in complete satisfaction of the judgment effective July 18, 2000. Additionally, the Company incurred an unusual charge of $2.0 million related to other ongoing litigation.

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Property, Depreciation, Depletion and Amortization

Gas and Oil Properties - The Company follows the full cost method of accounting for the exploration, development, and acquisition of gas and oil reserves. Under this method, all such costs (productive and nonproductive) including salaries, benefits, and other internal costs directly attributable to these activities are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. The Company excludes all costs of unevaluated properties from immediate amortization. The Company's unamortized costs of oil and gas properties are limited to the sum of the future net revenues attributable to proved oil and gas reserves discounted at 10 percent plus the lower of cost or market value of any unproved properties. If the Company's unamortized costs in oil and gas properties exceed this ceiling amount, a provision for additional depreciation, depletion and amortization is required. At June 30, 1998, the Company recognized a $40.5 million non-cash charge to earnings by recording a write-down of its oil and gas properties of $66.4 million and a related reduction in the provision for deferred income taxes of $25.9 million. At December 31, 2000, 1999, and 1998, the Company's net book value of oil and gas properties did not exceed the ceiling amounts. Market prices, production rates, levels of reserves, and the evaluation of costs excluded from amortization all influence the calculation of the full cost ceiling.

Gas Distribution Systems - Costs applicable to construction activities, including overhead items, are capitalized. Depreciation and amortization of the gas distribution system is provided using the straight-line method with average annual rates for plant functions ranging from 1.7% to 5.9%. Gas in underground storage is stated at average cost.

Other property, plant and equipment is depreciated using the straight-line method over estimated useful lives ranging from 5 to 35 years.

The Company charges to maintenance or operations the cost of labor, materials, and other expenses incurred in maintaining the operating efficiency of its properties. Betterments are added to property accounts at cost. Retirements are credited to property, plant and equipment at cost and charged to accumulated depreciation, depletion and amortization with no gain or loss recognized, except for abnormal retirements.

Capitalized Interest - Interest is capitalized on the cost of unevaluated gas and oil properties excluded from amortization. In accordance with established utility regulatory practice, an allowance for funds used during construction of major projects is capitalized and amortized over the estimated lives of the related facilities.

Gas Distribution Revenues and Receivables

Customer receivables arise from the sale or transportation of gas by the Company's gas distribution subsidiary. The Company's 136,000 gas distribution customers are located in northern Arkansas and represent a diversified base of residential, commercial, and industrial users. The Company records gas distribution revenues on an accrual basis, as gas volumes are used, to provide a proper matching of revenues with expenses.

The gas distribution subsidiary's rate schedules include purchased gas adjustment clauses whereby the actual cost of purchased gas above or below the level included in the base rates is permitted to be billed or is required to be credited to customers. Each month, the difference between actual costs of purchased gas and gas costs recovered from customers is deferred. The deferred differences are billed or credited, as appropriate, to customers in subsequent months. Rate schedules include a weather normalization clause to lessen the impact of revenue increases and decreases which might result from weather variations during the winter heating season. The pass-through of gas costs to customers is not affected by this normalization clause.

Gas Production Imbalances

The exploration and production subsidiaries record gas sales using the entitlement method. The entitlement method requires revenue recognition of the Company's revenue interest share of gas production from properties in which gas sales are disproportionately allocated to owners because of marketing or other contractual arrangements. The Company's net imbalance position at December 31, 2000 and 1999 was not significant.

Income Taxes

Deferred income taxes are provided to recognize the income tax effect of reporting certain transactions in different years for income tax and financial reporting purposes.

Risk Management

The Company uses derivative financial instruments to manage defined commodity price risks and does not use them for trading purposes. The Company uses commodity swap agreements and options to hedge sales of natural gas and crude oil. Gains and losses resulting from hedging activities have been recognized when the related physical transactions were recognized. Gains or losses from commodity swap agreements and options that did not qualify for accounting treatment as hedges have been recognized currently as other income or expense. See Note 8 for a discussion of the Company's commodity hedging activity and the impact of the adoption of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities."

Earnings Per Share and Shareholders' Equity

Basic earnings per common share is computed by dividing net income by the weighted average number of common shares outstanding during each year. The diluted earnings per share calculation adds to the weighted average number of common shares outstanding the incremental shares that would have been outstanding assuming the exercise of dilutive stock options. The Company had options for 2,602,800 shares with an average exercise price of $9.79 outstanding at December 31, 2000 and options for 1,634,901 shares with a weighted average exercise price of $12.15 outstanding at December 31, 1998. Due to the Company's net loss for 2000 and 1998, these incremental shares would have an anti-dilutive effect and were, therefore, not considered. The Company had options for 1,275,899 shares of common stock with a weighted average exercise price of $12.97 per share at December 31, 1999, that were not included in the calculation of diluted shares because they would have had an anti-dilutive effect. The remaining 785,300 options at December 31, 1999 with a weighted average exercise price of $6.46 were included in the calculation of diluted shares.

During 2000 and 1999, the Company issued 154,438 and 105,436 treasury shares, respectively, under a compensatory plan and for stock awards and returned to treasury 10,955 and 2,300 shares, respectively, canceled from earlier issues under the compensatory plan. The net effect of these transactions was a $1.6 million decrease in 2000 and a $1.2 million decrease in 1999 in treasury stock.

Dividend on Common Stock

As a result of the adverse Hales judgment in June 2000, the Company has indefinitely suspended payment of quarterly dividends on its common stock.

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(2) DEBT

Debt balances as of December 31, 2000 and 1999 consisted of the following:

	2000	1999
	(in thousands)	
Senior Notes		
9.36% Series	$ -	$ 22,000
6.70% Series due 2005	125,000	125,000
7.625% Series due 2027, putable at the holders' option in 2009	60,000	60,000
7.21% Series due 2017	40,000	40,000
	225,000	247,000
Other		
Variable rate unsecured revolving credit arrangements	-	47,700
Total long-term debt	$225,000	$294,700
Short-Term Debt		
Variable rate (7.85% at December 31, 2000) unsecured revolving credit arrangements	$171,000	$ -
Short-term note payable	-	7,500
Total short-term debt	$171,000	$ 7,500

In July 2000, the Company replaced its existing revolving credit facilities with a new credit facility that has a capacity of $180.0 million. This new facility was used to fund the Hales judgment of $109.3 million, pay off the existing revolver balance, and retire $22.0 million of 9.36% Senior Notes. The new credit facility is also being used to fund normal working capital needs. The new credit facility has a term of 364 days, with interest generally based at 112.5 basis points over the LIBOR rate. The Company intends to renew or replace this facility prior to its expiration.

In August 2000, the Company retired $22.0 million of 9.36% Senior Notes. Certain costs of the redemption were expensed and are classified as an extraordinary loss, net of related income tax effects, in the accompanying financial statements.

The terms of the debt instruments and agreements contain covenants which impose certain restrictions on the Company, including limiting of additional indebtedness and prohibiting the payment of cash dividends. The Company was in compliance with its debt agreements at December 31, 2000.

There are no aggregate maturities of long-term debt for each of the years ending December 31, 2001 through 2004. For the year ended December 31, 2005, the aggregate maturity is $125.0 million. Total interest payments were $23.6 million in 2000 and $19.6 million in 1999 and 1998.

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(3) INCOME TAXES

The provision (benefit) for income taxes included the following components:

	2000	1999	1998
	(in thousands)		
Federal:			
Current	$ -	$ -	$ (6,673)
Deferred	(23,723)	5,236	(10,098)
State:			
Current	-	537	644
Deferred	(5,063)	795	(3,250)
Investment tax credit amortization	(119)	(119)	(119)
Provision (benefit) for income taxes	$(28,905)	$6,449	$(19,496)

The provision (benefit) for income taxes was an effective rate of 38.7% in 2000, 39.4% in 1999, and 38.9% in 1998. The following reconciles the provision (benefit) for income taxes included in the consolidated statements of operations with the provision (benefit) which would result from application of the statutory federal tax rate to pretax financial income:

	2000	1999	1998
	(in thousands)		
Expected provision (benefit) at federal statutory rate of 35%	$(26,145)	$5,732	$(17,532)
Increase (decrease) resulting from:			
State income taxes, net of federal income tax effect	(3,291)	866	(1,694)
Other	531	(149)	(270)
Provision (benefit) for income taxes	$(28,905)	$6,449	$(19,496)

The components of the Company's net deferred tax liability as of December 31, 2000 and 1999 were as follows:

2000	1999
(in thousands)	

Deferred tax liabilities:		
Differences between book and tax basis of property	$129,702	$123,516
Stored gas	8,883	8,267
Deferred purchased gas costs	11,313	2,289
Prepaid pension costs	1,884	2,086
Book over tax basis in partnerships	11,755	10,133
Other	1,072	415
	164,609	146,706
Deferred tax assets:		
Accrued compensation	884	705
Alternative minimum tax credit carryforward	3,046	3,127
Net operating loss carryforward	63,449	16,808
Other	1,671	1,155
	69,050	21,795
Net deferred tax liability	$ 95,559	$124,911

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Total income tax payments of $.5 million, $.6 million, and $3.3 million were made in 2000, 1999, and 1998, respectively.

(4) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company applies SFAS No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits." Substantially all employees are covered by the Company's defined benefit pension and postretirement benefit plans. The following provides a reconciliation of the changes in the plans' benefit obligations, fair value of assets, and funded status as of December 31, 2000 and 1999:

	Pension Benefits		Other Postretirement Benefits	
	2000	1999	2000	1999
	(in thousands)			
Change in Benefit Obligations:				
Benefit obligation at January 1	$61,515	$59,194	$3,759	$3,832
Service cost	1,682	1,881	85	99
Interest cost	4,509	4,130	268	261
Amendments	-	5,560	-	-
Actuarial loss (gain)	1,438	(5,359)	(226)	(255)
Benefits paid	(7,256)	(3,891)	(138)	(178)
Amount transferred	(5,317)	-	-	-
Effect of settlement	-	-	(1,737)	-
Benefit obligation at December 31	$56,571	$61,515	$2,011	$3,759
Change in Plan Assets:				
Fair value of plan assets at January 1	$70,478	$71,518	$615	$345
Actual return on plan assets	8,716	2,838	4	20
Employer contributions	-	-	308	428
Benefit payments	(7,243)	(3,878)	(138)	(178)
Amount transferred	(5,668)	-	-	-
Effect of settlement	-	-	(216)	-

Fair value of plan assets at December 31	$66,283	$70,478	$573	$615
Funded Status:				
Funded status at December 31	$9,712	$8,963	$(1,438)	$(3,144)
Unrecognized net actuarial (gain) loss	(9,832)	(9,237)	299	926
Unrecognized prior service cost	4,965	5,417	-	-
Unrecognized transition obligation	(37)	(220)	1,032	1,265
Prepaid (accrued) benefit cost	$4,808	$4,923	$(107)	$(953)

The Company's supplemental retirement plan has an accumulated benefit obligation in excess of plan assets. The plan's accumulated benefit obligation was $286,000 and $233,000 at December 31, 2000 and 1999, respectively. There are no plan assets in the supplemental retirement plan due to the nature of the plan.

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Net periodic pension and other postretirement benefit costs include the following components for 2000, 1999, and 1998:

	Pension Benefits			Other Postretirement Benefits		
	2000	1999	1998	2000	1999	1998
	(in thousands)					
Service cost	$1,682	$1,881	$2,060	$ 85	$ 99	$ 87
Interest cost	4,509	4,130	3,644	268	261	242
Expected return on plan assets	(6,190)	(6,259)	(5,863)	(39)	(28)	-
Amortization of transition obligation	(183)	(183)	(183)	103	103	103
Recognized net actuarial (gain) loss	(142)	(142)	(150)	63	111	55
Amortization of prior service costs	451	451	46	-	-	-
	$127	$(122)	$(446)	$480	$546	$487

Prior to 1998, the Company's pension plans provided for benefits based on years of benefit service and the employee's "average compensation" as defined. During 1998, the Company amended its plans to become "cash balance" plans on a prospective basis. A cash balance plan provides benefits based upon a fixed percentage of an employee's annual compensation. The Company's funding policy is to contribute amounts which are actuarially determined to provide the plans with sufficient assets to meet future benefit payment requirements and which are tax deductible.

The postretirement benefit plans provide contributory health care and life insurance benefits. Employees become eligible for these benefits if they meet age and service requirements. Generally, the benefits paid are a stated percentage of medical expenses reduced by deductibles and other coverages. During 1998, the Company established trusts to partially fund its postretirement benefit obligations.

The weighted average assumptions used in the measurement of the Company's benefit obligations for 2000 and 1999 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2000	1999	2000	1999
Discount rate	7.25%	7.50%	7.25%	7.50%
Expected return on plan assets	9.00%	9.00%	5.00%	5.00%
Rate of compensation increase	4.50%	4.50%	n/a	n/a

For measurement purposes a 9% annual rate of increase in the per capita cost of covered medical benefits and an 8% annual rate of increase in the per capita cost of dental benefits was assumed for 2001. These rates were assumed to gradually decrease to 6% for medical benefits and 5% for dental benefits for 2011 and remain at that level thereafter.

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

	1% Increase	1% Decrease
	(in thousands)	
Effect on the total service and interest cost components	$ 29	$ (25)
Effect on postretirement benefit obligation	$220	$(190)

(5) NATURAL GAS AND OIL PRODUCING ACTIVITIES

All of the Company's gas and oil properties are located in the United States. The table below sets forth the results of operations from gas and oil producing activities:

	2000	1999	1998
	(in thousands)		
Sales	$110,920	$75,039	$86,232
Production (lifting) costs	(19,804)	(14,039)	(15,807)
Depreciation, depletion and amortization	(39,048)	(34,230)	(39,444)
Write-down of oil and gas properties	-	-	(66,383)
	52,068	26,770	(35,402)
Income tax benefit (expense)	(20,023)	(10,528)	13,913
Results of operations	$32,045	$16,242	$(21,489)

The results of operations shown above exclude unusual items in 2000 and overhead and interest costs in all years. Income tax expense is calculated by applying the statutory tax rates to the revenues less costs, including depreciation, depletion and amortization, and after giving effect to permanent differences and tax credits.

The table below sets forth capitalized costs incurred in gas and oil property acquisition, exploration, and development activities during 2000, 1999, and 1998:

	2000	1999	1998
	(in thousands)		
Property acquisition costs	$13,369	$19,845	$12,729
Exploration costs	27,853	19,519	14,273
Development costs	27,519	19,059	24,709
Capitalized costs incurred	$68,741	$58,423	$51,711
Amortization per Mcf equivalent	$1.06	$1.00	$1.04

Capitalized interest is included as part of the cost of oil and gas properties. The Company capitalized $2.4 million, $3.3 million, and $3.9 million during 2000, 1999, and 1998, respectively, based on the Company's weighted average cost of borrowings used to finance the expenditures.

In addition to capitalized interest, the Company also capitalized internal costs of $7.3 million, $7.4 million, and $7.7 million during 2000, 1999, and 1998, respectively. These internal costs were directly related to acquisition, exploration and development activities and are included as part of the cost of oil and gas properties.

The following table shows the capitalized costs of gas and oil properties and the related accumulated depreciation, depletion and amortization at December 31, 2000 and 1999:

	2000	1999
	(in thousands)	
Proved properties	$841,875	$774,473
Unproved properties	30,148	41,726
Total capitalized costs	872,023	816,199
Less: Accumulated depreciation, depletion and amortization	457,551	419,517
Net capitalized costs	$414,472	$396,682

The table below sets forth the composition of net unevaluated costs excluded from amortization as of December 31, 2000. Of the total, approximately $12.8 million is invested in Louisiana. The majority of Louisiana costs are related to seismic projects that will be evaluated over several years as the seismic data is interpreted and the acreage is explored. The remaining costs excluded from amortization are related to properties which are not individually significant and on which the evaluation process has not been completed. The

Company is, therefore, unable to estimate when these costs will be included in the amortization computation.

	2000	1999	1998	Prior	Total
	(in thousands)				
Property acquisition costs	$4,047	$2,157	$1,785	$2,451	$10,440
Exploration costs	2,484	5,295	2,438	3,127	13,344
Capitalized interest	521	1,005	735	1,647	3,908
	$7,052	$8,457	$4,958	$7,225	$27,692

(6) NATURAL GAS AND OIL RESERVES (UNAUDITED)

The following table summarizes the changes in the Company's proved natural gas and oil reserves for 2000, 1999, and 1998:

	2000		1999		1
	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)
Proved reserves, beginning of year	307,523	7,859	303,667	6,850	291,378
Revisions of previous estimates	5,357	(22)	(7,464)	1,155	1,064
Extensions, discoveries, and other additions	53,389	1,347	34,730	225	44,814
Production	(31,602)	(676)	(29,444)	(578)	(32,668)
Acquisition of reserves in place	8,100	82	9,762	576	-
Disposition of reserves in place	(11,013)	(460)	(3,728)	(369)	(921)
Proved reserves, end of year	331,754	8,130	307,523	7,859	303,667
Proved, developed reserves:					
Beginning of year	250,290	7,154	258,092	6,370	252,393
End of year	270,830	7,100	250,290	7,154	258,092

The "Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves" (standardized measure) is a disclosure required by SFAS No. 69, "Disclosures About Oil and Gas Producing Activities." The standardized measure does not purport to present the fair market value of a company's proved gas and oil reserves. In addition, there are uncertainties inherent in estimating quantities of proved reserves. Substantially all quantities of gas and oil reserves owned by the Company were estimated or audited by the independent petroleum engineering firm of K & A Energy Consultants, Inc.

Following is the standardized measure relating to proved gas and oil reserves at December 31, 2000, 1999, and 1998:

	2000	1999	1998
	(in thousands)		

Future cash inflows	$3,366,304	$ 989,997	$ 820,522
Future production and development costs	(506,417)	(227,361)	(176,130)
Future income tax expense	(974,273)	(247,408)	(206,097)
Future net cash flows	1,885,614	515,228	438,295
10% annual discount for estimated timing of cash flows	(990,472)	(253,153)	(215,502)
Standardized measure of discounted future net cash flows	$ 895,142	$ 262,075	$ 222,793

Under the standardized measure, future cash inflows were estimated by applying year-end prices, adjusted for known contractual changes, to the estimated future production of year-end proved reserves. Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pretax cash inflows. Future income taxes were computed by applying the year-end statutory rate, after consideration of permanent differences, to the excess of pretax cash inflows over the Company's tax basis in the associated proved gas and oil properties. Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the standardized measure.

Following is an analysis of changes in the standardized measure during 2000, 1999, and 1998:

	2000	1999	1998
	(in thousands)		
Standardized measure, beginning of year	$262,075	$222,793	$259,063
Sales and transfers of gas and oil produced, net of production costs	(91,116)	(61,000)	(70,425)
Net changes in prices and production costs	837,691	48,506	(71,400)
Extensions, discoveries, and other additions, net of future production and development costs	259,212	48,279	61,146
Acquisition of reserves in place	33,032	14,765	-
Revisions of previous quantity estimates	20,178	(612)	(3,024)
Accretion of discount	38,076	32,447	38,445
Net change in income taxes	(317,527)	(17,015)	23,714
Changes in production rates (timing) and other	(146,479)	(26,088)	(14,726)
Standardized measure, end of year	$895,142	$262,075	$222,793

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(7) INVESTMENT IN UNCONSOLIDATED PARTNERSHIP

The Company holds a 25% general partnership interest in NOARK. NOARK Pipeline was formerly a 258-mile long intrastate gas transmission system which extended across northern Arkansas. In January 1998, the Company entered into an agreement with Enogex Inc. (Enogex) that resulted in the expansion of the NOARK Pipeline and provided the pipeline with access to Oklahoma gas supplies through an integration of NOARK with the Ozark Gas Transmission System (Ozark). Enogex is a subsidiary of OGE Energy Corp. Ozark was a 437-mile interstate pipeline system which began in eastern Oklahoma and terminated in eastern Arkansas. Enogex acquired the Ozark system and contributed it to NOARK. Enogex also acquired the NOARK partnership interests not owned by Southwestern. The acquisition of Ozark and its integration with NOARK Pipeline was approved by the Federal Energy Regulatory Commission in late 1998 at which time NOARK Pipeline was converted to an interstate pipeline and operated in combination with Ozark. Enogex funded the acquisition of Ozark and the expansion and integration with

NOARK Pipeline which resulted in the Company's ownership interest in the partnership decreasing to 25% from 48%.

The Company's investment in NOARK totaled $15.5 million at December 31, 2000 and $14.0 million at December 31, 1999, including advances of $3.3 million made during 2000, $2.3 million made during 1999, and $10.1 million made during 1998. Advances in 1998 included the Company's share of costs related to the prepayment of NOARK's Senior Secured Notes. Other advances are made primarily to service NOARK's long-term debt. See Note 11 for further discussion of NOARK's funding requirements and the Company's investment in NOARK.

NOARK's financial position at December 31, 2000 and 1999 is summarized below:

	2000	1999
	(in thousands)	
Current assets	$ 9,532	$ 7,056
Noncurrent assets	179,136	178,195
	$188,668	$185,251
Current liabilities	$ 11,803	$ 10,413
Long-term debt	73,000	75,000
Partners' capital	103,865	99,838
	$188,668	$185,251

The Company's share of NOARK's pretax loss was $1.8 million, $2.0 million, and $3.1 million for 2000, 1999, and 1998, respectively. The Company records its share of NOARK's pretax loss in other income (expense) on the statements of operations.

NOARK's results of operations for 2000, 1999, and 1998 are summarized below:

	2000	1999	1998
		(in thousands)	
Operating revenues	$73,633	$40,358	$17,445
Pretax net loss	$(1,391)	$(3,564)	$(4,114)

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(8) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate the value:

Cash, Customer Deposits, and Short-Term Debt: The carrying amount is a reasonable estimate of fair value.

Long-Term Debt: The fair value of the Company's long-term debt is estimated based on the expected current rates which would be offered to the

Company for debt of the same maturities.

Commodity Hedges: The fair value of all hedging financial instruments is the amount at which they could be settled, based on quoted market prices or estimates obtained from dealers. The carrying amounts and estimated fair values of the Company's financial instruments as of December 31, 2000 and 1999 were as follows:

	2000		1999	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Cash	$2,386	$2,386	$1,240	$1,240
Customer deposits	$4,799	$4,799	$6,021	$6,021
Short-term debt	$171,000	$171,000	$7,500	$7,500
Long-term debt	$225,000	$226,309	$294,700	$289,193
Commodity hedges	$(160)	$(60,596)	$640	$(399)

Derivatives and Price Risk Management

SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 137 and SFAS No. 138, is effective for fiscal years beginning after June 15, 2000 and requires that all derivatives be recognized as assets or liabilities in the balance sheet and that these instruments be measured at fair value. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement.

Upon adoption of SFAS No. 133 on January 1, 2001, the Company recorded a transition obligation of $60.6 million related to cash flow hedges in place that are used to reduce the volatility in commodity prices for the Company's forecasted oil and gas production. Additionally, the Company recorded a net of tax cumulative loss to retained earnings of $1.7 million and a net of tax loss to other comprehensive income (equity section of the balance sheet) of $35.4 million. The amount recorded in other comprehensive income will be relieved over time and taken to the income statement as the physical transactions being hedged occur. Additional volatility in earnings and other comprehensive income may occur in the future as a result of the adoption of SFAS No. 133.

The Company uses natural gas and crude oil swap agreements and options to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and oil. The Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price risks. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

The Company uses over-the-counter natural gas and crude oil swap agreements and options to hedge sales of Company production and marketing activity against the inherent price risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX (New York Mercantile Exchange) futures market. These swaps and options include (1) transactions in which one party will pay a fixed price (or variable price) for a notional

quantity in exchange for receiving a variable price (or fixed price) based on a published index (referred to as price swaps), (2) transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps), and (3) the purchase and sale of index-related puts and calls (collars) that provide a "floor" price below which the counterparty pays the Company the amount by which the price of the commodity is below the contracted floor and "ceiling" price above which the Company pays the counterparty the amount by which the price of the commodity is above the contracted ceiling.

At December 31, 2000, the Company had collars in place on 31.2 Bcf of future gas production. Of this total, 21.9 Bcf had floors and ceilings ranging from $3.50 to $6.00, respectively. The remaining 9.3 Bcf had floors and ceilings ranging from $2.50 to $3.50, respectively. Additionally, the Company had collars on 300,000 barrels of crude oil with floors and ceilings ranging from $27.00 to $30.33, respectively.

At December 31, 2000, the Company had outstanding natural gas price swaps on total notional volumes of 3.1 Bcf for which the Company will receive fixed prices ranging from $2.57 to $4.62 per MMBtu. Under contracts on .4 Bcf the Company will make average fixed price payments of $4.83 per MMBtu and receive variable prices based on the NYMEX futures market. At December 31, 2000, the Company also had outstanding crude oil swaps to receive fixed prices of $17.49 per barrel in 2001 on notional volumes of 72,000 barrels. The Company's price risk management activities reduced revenues $39.3 million in 2000 and $1.1 million in 1999, and increased revenues $7.4 million in 1998.

At December 31, 2000, the Company also had an $18.00 per barrel floor on 325,000 barrels. Subsequent to December 31, 2000, the Company closed its position on this oil floor. The primary market risk related to these derivative contracts is the volatility in market prices for natural gas and crude oil. However, this market risk is offset by the gain or loss recognized upon the related sale of the natural gas or oil that is hedged. Credit risk relates to the risk of loss as a result of non-performance by the Company's counterparties. The counterparties are primarily major investment and commercial banks which management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure the Company has to each counterparty are periodically reviewed to ensure limited credit risk exposure.

(9) STOCK OPTIONS

The Southwestern Energy Company 2000 Stock Incentive Plan (2000 Plan) was adopted in February, 2000 and provides for the compensation of officers, key employees and eligible non-employee directors of the Company and its subsidiaries. The 2000 Plan replaces the Southwestern Energy Company 1993 Stock Incentive Plan (1993 Plan) and the Southwestern Energy Company 1993 Stock Incentive Plan for Outside Directors (1993 Director Plan). The 2000 Plan provides for grants of options, stock appreciation rights, shares of phantom stock, and shares of restricted stock that in the aggregate do not exceed 1,250,000 shares. The types of incentives which may be awarded are comprehensive and are intended to enable the Board of Directors to structure the most appropriate incentives and to address changes in income tax laws which may be enacted over the term of the 2000 Plan.

The 1993 Plan provided for the compensation of officers and key employees of the Company and its subsidiaries through grants of options, shares of restricted stock, and stock bonuses that in the aggregate did not exceed 1,700,000 shares, the grant of stand-alone stock appreciation rights (SARs), shares of phantom stock and cash awards, the shares related to which in the aggregate did not exceed 1,700,000 shares, and the grant of limited and tandem SARs (all terms as defined in the 1993 Plan). The Company has also awarded stock option grants outside the 2000 Plan and the 1993 Plan to certain non-officer employees and to certain officers at the time of their hire.

The 2000 Plan awards each non-employee director who is eligible to participate in the plan an annual Director's Option with respect to 8,000 shares of common stock. Previously, the 1993 Director Plan provided for annual stock option grants of 12,000 shares (with 12,000 limited SARs) to each non-employee director. Options under the 1993 Director Plan were limited to no more than 240,000 shares.

The Company's 1985 Nonqualified Stock Option Plan expired in 1992, except with respect to awards then outstanding. The following tables summarize stock option activity for the years 2000, 1999, and 1998 and provide information for options outstanding at December 31, 2000:

	2000		1999		1998
	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price	Number of Shares
Options outstanding at January 1	2,061,199	$10.49	1,634,901	$12.15	1,619,114
Granted	666,100	$7.58	562,250	$6.18	394,900
Exercised	-	-	1,333	$7.31	22,200
Canceled	124,499	$9.55	134,619	$12.68	356,913
Options outstanding at December 31	2,602,800	$9.79	2,061,199	$10.49	1,634,901

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Options Outstanding at Year End	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Options Exercisable at Year End	Weighted Average Exercise Price
$6.00 - $7.00	573,084	$6.14	8.8	195,272	$6.18
$7.06 - $8.75	866,701	$7.42	9.3	167,004	$7.34
$9.06 - $13.38	623,800	$11.99	6.0	512,737	$12.24
$14.00 - $17.50	539,215	$14.95	4.3	451,369	$15.01
	2,602,800	$9.79		1,326,382	$11.67

All options are issued at fair market value at the date of grant and expire ten years from the date of grant. Options generally vest to employees and directors over a three to four year period from the date of grant. Of the total options outstanding, 325,000 performance accelerated options were granted in 1994 at an option price of $14.63. These options vest over a four-year period beginning in 2000.

The Company has granted 453,165 shares of restricted stock to employees through 2000. Of this total, 410,615 shares vest over a three-year period and the remaining shares vest over a five-year period. The related compensation expense is being amortized over the vesting periods. As of December 31, 2000, 189,512 shares have vested to employees and 22,201 shares have been cancelled and returned to treasury shares.

The Company applies the disclosure-only provisions of SFAS No. 123, "Accounting for Stock-Based Compensation." Accordingly, no compensation cost has been recognized for the stock option plans. Had compensation cost for the Company's stock option plans been determined consistent with the provisions of SFAS No. 123, the Company's net income (loss) and earnings (loss) per share would have been reduced to the pro forma amounts indicated below:

	2000	1999	1998
Net income (loss), in thousands			
As reported	$(46,687)	$9,927	$(30,597)
Pro forma	$(47,444)	$9,241	$(31,201)
Basic earnings (loss) per share			
As reported	$(1.86)	$.40	$(1.23)
Pro forma	$(1.90)	$.37	$(1.25)
Diluted earnings (loss) per share			
As reported	$(1.86)	$.40	$(1.23)
Pro forma	$(1.90)	$.37	$(1.25)

Because the SFAS No. 123 method of accounting has not been applied to options granted prior to January 1, 1995, the resulting pro forma compensation cost may not be representative of that to be expected in future years. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions: no dividend yield; expected volatility of 44.0%; risk-free interest rate of 6.0%; and expected lives of 6 years.

(10) COMMON STOCK PURCHASE RIGHTS

In 1999, the Company's Common Share Purchase Rights Plan was amended and extended for an additional ten years. Per the terms of the amended plan, one common share purchase right is attached to each outstanding share of the Company's common stock. Each right entitles the holder to purchase one share of common stock at an exercise price of $40.00, subject to adjustment. These rights will become exercisable in the event that a person or group acquires or commences a tender or exchange offer for 15% or more of the Company's outstanding shares or the Board determines that a holder of 10% or more of the Company's outstanding shares presents a threat to the best interests of the Company. At no time will these rights have any voting power.

If any person or entity actually acquires 15% of the common stock (10% or more if the Board determines such acquiror is adverse), rightholders (other than the 15% or 10% stockholder) will be entitled to buy, at the right's then current exercise price, the Company's common stock with a market value of twice the exercise price. Similarly, if the Company is acquired in a merger or other business combination, each right will entitle its holder to purchase, at the right's then current exercise price, a number of the surviving company's common shares having a market value at that time of twice the right's exercise price.

The rights may be redeemed by the Board for $.01 per right or exchanged for common shares on a one-for-one basis prior to the time that they become exercisable. In the event, however, that redemption of the rights is considered in connection with a proposed acquisition of the Company, the Board may redeem the rights only on the recommendation of its independent directors (nonmanagement directors who are not affiliated with the proposed acquiror). These rights expire in 2009.

(11) CONTINGENCIES AND COMMITMENTS

The Company and the other general partner of NOARK have severally guaranteed the principal and interest payments on NOARK's 7.15% Notes due 2018. The Company's share of the several guarantee is 60%. At December 31, 2000 and 1999, the principal outstanding for these Notes was $75.0 million and $77.0 million, respectively. The Notes were issued in June 1998 and require semi-annual principal payments of $1.0 million. The proceeds from the issuance of the Notes were used to repay temporary financing provided by the other general partner and outstanding amounts under an unsecured revolving credit agreement. The temporary financing provided by the other general partner was incurred in connection with the prepayment in early 1998 of NOARK's 9.74% Senior Secured notes. Under the several guarantee, the Company is required to fund its share of NOARK's debt service which is not funded by operations of the pipeline. As a result of the integration of NOARK Pipeline with the Ozark Gas Transmission System, as discussed further in Note 7, management of the Company believes that it will realize its investment in NOARK over the life of the system. Therefore, no provision for any loss has been made in the accompanying financial statements. Additionally, the Company's gas distribution subsidiary has transportation contracts for firm capacity of 66.9 MMcfd on NOARK's integrated pipeline system. These contracts expire in 2002 and 2003, and are renewable year-to-year thereafter until terminated by 180 days' notice.

In its Form 8-K filed July 2, 1996, the Company disclosed that a lawsuit relating to overriding royalty interests in certain Arkansas oil and gas properties had been filed against it and two of its wholly-owned subsidiaries. This matter went to a non-jury trial as to liability on January 10, 2000. The court in this matter issued Findings of Fact and Conclusions of Law that found no fraud was committed. The court also found that any override royalty interests that might ultimately be found to be due under the plaintiffs' claim for additional override royalties accrued after March 1, 1990. All claims prior to March 1, 1990 have been barred by the statute of limitations. The ultimate measure of damages will be determined during the damages phase of the non-jury proceeding that is scheduled for April 30, 2001. While the Company anticipates that it will owe some additional override royalties to plaintiffs, it does not believe that its liability will be material to its financial condition, but in any one period it could be significant to its results of operations.

The United States Minerals Management Service (MMS), a federal agency responsible for the administration of federal oil and gas leases, is investigating the Company and its subsidiaries in respect of claims similar to those in the Hales class action royalty litigation previously reported. The Company was found to be ultimately liable in the Hales litigation and satisfied the judgment in July 2000. MMS was included in the class action litigation against its objections, but did not pursue further action to remove itself from the class.

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On August 25, 2000, a class action suit was filed against the Company and its subsidiaries in Sebastian County, Arkansas, on behalf of all mineral owners who own or owned a royalty and/or overriding royalty interest in oil and gas leases or other agreements in certain sections of Franklin County, Arkansas. The Company was granted authority in 1968 by the Arkansas Oil and Gas Commission to operate a gas storage facility in one section of Franklin County. Based upon subsequently developed geological data, the Company sought authority to expand this area and was granted authority by the Arkansas Oil and Gas Commission to operate gas storage in additional sections. Plaintiffs are challenging the storage agreements that the Company obtained from the mineral interest owners in 1968, 1999 and 2000 to operate the gas storage facility known as "Stockton". Plaintiffs allege various wrongful, intentional and fraudulent acts relating to the operation of the storage pool beginning in 1968 and continuing to the present and allege that the above-referenced agreements from the mineral owners were obtained through misrepresentation and fraud. The Company has owned and operated the Stockton storage unit through its Arkansas Western Gas Company subsidiary until 1994, at which time it was transferred to its subsidiary, SEECO, Inc. Plaintiffs claim ownership rights in the gas that the Company has stored in the storage pool in an amount in excess of $5 million in actual damages, interest, attorney's fees and punitive damages. The Company and its outside counsel believe that this action is without merit and does not meet the requirements for a class action. The Company believes that plaintiffs' claim to the storage gas, which the Company has injected into the storage facility, has no merit and is not supported by the Arkansas gas storage statute under which the Company operates this facility. While the amount of this claim could be significant, management believes, based upon its investigation, that this claim is without merit and that the Company's ultimate liability, if any, will not be material to its consolidated financial position, but in any one period it could be significant to its results of operations.

The Company is subject to laws and regulations relating to the protection of the environment. The Company's policy is to accrue environmental and cleanup related costs of a non-capital nature when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on the financial position or reported results of operations of the Company.

The Company is subject to other litigation and claims that have arisen in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of such litigation and claims will not have a material effect on the results of operations or the financial position of the Company.

(12) SEGMENT INFORMATION

The Company applies SFAS No. 131, "Disclosures About Segments of an Enterprise and Related Information."The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues for the exploration and production segment are derived from the production and sale of natural gas and crude oil. Revenues for the gas distribution segment arise from the transportation and sale of natural gas at retail. The marketing segment generates revenue through the marketing of both Company and third party produced gas volumes.

Summarized financial information for the Company's reportable segments is shown in the following table. The "Other" column includes items related to non-reportable segments (real estate and pipeline operations) and corporate items.

	Exploration and Production	Gas Distribution	Marketing	Other	Tot

(in thousands)

2000					
Revenues from external customers	$ 75,597	$151,052	$137,234	$ -	$363
Intersegment revenues	35,323	182	70,514	448	106
Unusual items (1)	111,288	-	-	-	111
Operating income (loss)	(70,584)	14,655	2,460	-	(53
Depreciation, depletion and amortization expense	39,048	6,625	109	87	45
Interest expense (2)	17,472	4,608	16	1,134	23
Provision (benefit) for income taxes (2)	(34,153)	4,869	912	(533)	(28
Assets	460,296	188,811	20,929	35,342(3)	705
Capital expenditures	69,211	5,994	24	488	75
1999					
Revenues from external customers	$ 51,533	$132,293	$ 96,570	$ -	$280
Intersegment revenues	23,506	127	40,956	416	65
Operating income	16,451	17,187	2,142	278	36
Depreciation, depletion and amortization expense	34,230	7,186	92	95	41
Interest expense (2)	11,345	5,027	-	979	17
Provision (benefit) for income taxes (2)	1,806	4,569	859	(785)	6
Assets	435,022	190,731	11,212	34,481(3)	671
Capital expenditures	59,004	7,124	9	830	66
1998					
Revenues from external customers	$ 55,347	$134,579	$ 76,367	$ 12	$266
Intersegment revenues	30,885	132	20,808	608	52
Operating income (loss)	(47,273)	16,029	1,800	493	(28
Depreciation, depletion and amortization expense	39,444	7,296	41	136	46
Write-down of oil and gas properties	66,383	-	-	-	66
Interest expense (2)	10,906	5,299	38	943	17
Provision (benefit) for income taxes (2)	(23,238)	4,028	704	(990)	(19
Assets	408,193	192,396	8,905	38,126(3)	647
Capital expenditures	52,376	10,108	8	1,867	64

[FN]
(1) Includes $109.3 million for the Hales judgment and $2.0 million for other ongoing litigation.
(2) Interest expense and the provision (benefit) for income taxes by segment are an allocation of corporate amounts as debt and income tax expense (benefit) are incurred at the corporate level.
(3) Other assets include the Company's equity investment in the operations of NOARK (see Note 7), corporate assets not allocated to segments, and assets for non-reportable segments.

Intersegment sales by the exploration and production segment and marketing segment to the gas distribution segment are priced in accordance with terms of existing contracts and current market conditions. Parent company assets include furniture and fixtures, prepaid debt costs, and prepaid pension costs. Parent company general and administrative costs, depreciation expense and taxes other than income are allocated to segments. All of the Company's operations are located within the United States.

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(13) QUARTERLY RESULTS (UNAUDITED)

The following is a summary of the quarterly results of operations for the years ended December 31, 2000 and 1999:

Quarter Ended	March 31	June 30	September 30	December 31
	(in thousands, except per share amounts)			
	2000			
Operating revenues	$96,913	$78,483	$75,342	$113,145
Operating income (loss)	$21,056	$(101,849)	$5,884	$21,440
Net income (loss)	$9,186	$(64,199)	$(754)	$9,080
Basic and diluted earnings (loss) per share	$.37	$(2.57)	$(.03)	$.36
	1999			
Operating revenues	$78,220	$56,039	$60,400	$85,737
Operating income	$19,929	$1,541	$1,664	$12,924
Net income (loss)	$9,132	$(1,704)	$(1,935)	$4,434
Basic and diluted earnings (loss) per share	$.37	$(.07)	$(.08)	$.18

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

There have been no changes in or disagreements with accountants on accounting and financial disclosure.

Part III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The definitive Proxy Statement to holders of the Company's Common Stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Shareholders on May 17, 2001 (the 2001 Proxy Statement), is hereby incorporated by reference for the purpose of providing information about the identification of directors. Refer to the sections "Election of Directors" and "Share Ownership of Management and Directors" for information concerning the directors.

Information concerning executive officers is presented in Part I, Item 4 of this Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

The 2001 Proxy Statement is hereby incorporated by reference for the purpose of providing information about executive compensation. Refer to the section "Executive Compensation."

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The 2001 Proxy Statement is hereby incorporated by reference for the purpose of providing information about security ownership of certain beneficial owners and management. Refer to the sections "Security Ownership of Certain Beneficial Owners" and "Share Ownership of Managment and Directors" for information about security ownership of certain beneficial owners and management.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The 2001 Proxy Statement is hereby incorporated by reference for the purpose of providing information about related transactions. Refer to the section "Share Ownership of Management and Directors" for information about transactions with members of the Company's Board of Directors.

Part IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) (1) The consolidated financial statements of the Company and its subsidiaries and the report of independent public accountants are included in Item 8 of this Report.

(2) The consolidated financial statement schedules have been omitted because they are not required under the related instructions, or are not applicable.

(3) The exhibits listed on the accompanying Exhibit Index (pages 63 and 64) are filed as part of, or incorporated by reference into, this Report.

(b) Reports on Form 8-K:

A Current Report on Form 8-K was filed on November 3, 2000, referencing a conference call conducted on October 31, 2000, announcing the results of the Company's third quarter 2000 activity.

A Current Report on Form 8-K was filed on December 8, 2000, referencing a press release issued on December 7, 2000, announcing the Company's hedge position for 2001 through 2003.

A Current Report on Form 8-K was filed on December 20, 2000, referencing a press release issued on December 18, 2000, announcing the Company's 2001 strategy and outlook. Additional exhibits included the transcript of the December 18, 2000 teleconference regarding the December 18th press release and the accompanying slide presentation.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused the report to be signed on its behalf by the undersigned, thereunto duly authorized.

SOUTHWESTERN ENERGY COMPANY

(Registrant)

Dated: March 30, 2001

BY: /s/ Greg D. Kerley

Greg D. Kerley
Executive Vice President
and Chief Financial Officer

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 indicated on March 30, 2001.

/s/ Harold M. Korell ------------------------------------ Harold M. Korell	President, Chief Executive Officer and Director

/s/ Greg D. Kerley Greg D. Kerley	Executive Vice President and Chief Financial Officer
/s/ Stanley T. Wilson Stanley T. Wilson	Controller and Chief Accounting Officer
/s/ Charles E. Scharlau Charles E. Scharlau	Director and Chairman
/s/ Lewis E. Epley, Jr. Lewis E. Epley, Jr.	Director
/s/ John Paul Hammerschmidt John Paul Hammerschmidt	Director
/s/ Robert L. Howard Robert L. Howard	Director
/s/ Kenneth R. Mourton Kenneth R. Mourton	Director

Supplemental Information to be Furnished With Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant of Section 12 of the Act.

Not Applicable

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EXHIBIT INDEX

Exhibit No.	Description
3.	Articles of Incorporation and Bylaws of the Company (amended and restated Articles of Incorporation incorporated by reference to Exhibit 3 to Annual Report on Form 10-K for the year ended December 31,1993); Bylaws of the Company (amended Bylaws of the Company incorporated by reference to Exhibit 3 to Annual Report on Form 10-K for the year ended December 31, 1994).
4.1	Amended and Restated Rights Agreement, dated April 12, 1999 (incorporated by reference to Exhibit 4.1 to Annual Report on Form 10-K for the year ended December 31, 1999).
4.2	Prospectus, Registration Statement, and Indenture on 6.70% Senior Notes due December 1, 2005 and issued December 5, 1995 (incorporated by reference to the Company's Forms S-3 and S-3/A filed on November 1, 1995, and November 17, 1995, respectively, and also to the Company's filings of a Prospectus and Prospectus Supplement on November 22, 1995, and December 4, 1995, respectively).
4.3	Prospectus Supplement and Form of Distribution Agreement on $125,000,000 of Medium-Term Notes dated February 21, 1997 (Prospectus Supplement

incorporated by reference to the Company's filing of a Prospectus Supplement on February 21, 1997, Form of Distribution Agreement incorporated by reference to Exhibit 10 filed with the Company's Form 8-K dated February 21, 1997).

4.4 Short-Term Credit Agreement dated July 17, 2000 between Southwestern Energy Company and Bank One, N.A., as administrative agent, and Bank of America, N.A., as syndication agent (filed herewith).

Material Contracts:

10.1 Gas Purchase Contract between SEECO, Inc. and Associated Natural Gas Company, dated October 1, 1990, and as amended September 30, 1997 (original contract incorporated by reference to Exhibit 10 to Annual Report on Form 10-K for the year ended December 31, 1990; amendment incorporated by reference to Exhibit 10.2 to Annual Report on Form 10-K for the year ended December 31, 1997).

10.2 Compensation Plans:

(a) Summary of Southwestern Energy Company Annual and Long-Term Incentive Compensation Plan, effective January 1, 1985, as amended July 10, 1989 (replaced by Southwestern Energy Company Incentive Compensation Plan, effective January 1, 1993) (original plan incorporated by reference to Exhibit 10 to Annual Report on Form 10-K for the year ended December 31, 1984; first amendment thereto incorporated by reference to Exhibit 10 to Annual Report on Form 10-K for the year ended December 31, 1989).

(b) Southwestern Energy Company Incentive Compensation Plan, effective January 1, 1993, and Amended and Restated as of January 1, 1999 (incorporated by reference to Exhibit 10.2(b) to Annual Report on Form 10-K for the year ended December 31, 1998).

(c) Nonqualified Stock Option Plan, effective February 22, 1985, as amended July 10, 1989 (replaced by Southwestern Energy Company 1993 Stock Incentive Plan, dated April 7, 1993, which was replaced by the Southwestern Energy Company 2000 Stock Incentive Plan dated February 18, 2000) (original plan incorporated by reference to Exhibit 10 to Annual Report on Form 10-K for the year ended December 31, 1985; amended plan incorporated by reference to Exhibit 10 to Annual Report on Form 10-K for the year ended December 31, 1989).

(d) Southwestern Energy Company 1993 Stock Incentive Plan, dated April 7, 1993 and Amended and Restated as of February 18, 1998 (replaced by the Southwestern Energy Company 2000 Stock Incentive Plan dated February 18, 2000) (incorporated by reference to Exhibit 10.2(d) to Annual Report on Form 10-K for the year ended December 31, 1998).

Exhibit No.	Description

(e) Southwestern Energy Company 1993 Stock Incentive Plan for Outside Directors, dated April 7, 1993 (replaced by the Southwestern Energy Company 2000 Stock Incentive Plan dated February 18, 2000) (incorporated by reference to the appendix filed with the Company's definitive Proxy Statement to holders of the Registrant's Common Stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Shareholders on May 26, 1993).

(f) Southwestern Energy Company 2000 Stock Incentive Plan dated February 18, 2000 (incorporated by reference to the appendix filed with the Company's definitive Proxy Statement to holders of the Registrant's Common Stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Shareholders on May 24, 2000).

10.3 Southwestern Energy Company Supplemental Retirement Plan, adopted May 31, 1989, and Amended and Restated as of December 15, 1993, and as further amended February 1, 1996 (amended and restated plan incorporated by reference to Exhibit 10.5 to Annual Report on Form 10-K for the year ended December 31, 1993; amendment dated February 1, 1996, incorporated by reference to Exhibit 10.5 to Annual Report on Form 10-K for the year ended December 31, 1995).

10.4 Southwestern Energy Company Supplemental Retirement Plan Trust, dated December 30, 1993 (incorporated by reference to Exhibit 10.6 to Annual Report on Form 10-K for the year ended December 31, 1993).

10.5 Southwestern Energy Company Nonqualified Retirement Plan, effective October 4, 1995 (incorporated by reference to Exhibit 10.7 to Annual Report of Form 10-K for the year ended December 31, 1995).

10.6 Employment and Consulting Agreement for Charles E. Scharlau, dated May 21, 1998 (incorporated by reference to Exhibit 10.9 to Annual Report on Form 10-K for the year ended December 31, 1998).

10.7 Form of Indemnity Agreement, between the Company and each officer and director of the Company (incorporated by reference to Exhibit 10.20 to Annual Report on Form 10-K for the year ended December 31, 1991).

10.8 Form of Executive Severance Agreement for the Executive Officers of the Company, effective February 17,1999 (incorporated by reference to Exhibit 10.12 to Annual Report on Form 10-K for the year ended December 31, 1998).

10.9 Omnibus Project Agreement of NOARK Pipeline System, Limited Partnership by and among Southwestern Energy Pipeline Company, Southwestern Energy Company, Enogex Arkansas Pipeline Corporation, and Enogex Inc., dated January 12, 1998 (incorporated by reference to Exhibit 10.17 to Annual Report on Form 10-K for the year ended December 31, 1997).

10.10 Amended and Restated Limited Partnership Agreement of NOARK Pipeline System, Limited Partnership dated January 12, 1998 and amended June 18, 1998 (amended and restated agreement incorporated by reference to Exhibit 10.18 to Annual Report on Form 10-K for the year ended December 31, 1997; first amendment thereto incorporated by reference to Exhibit 10.14 to Annual Report on Form 10-K for the year ended December 31, 1998).

10.11 Asset Sale and Purchase Agreement by and among Southwestern Energy Company, Arkansas Western Gas Company and Atmos Energy Corporation, dated October 15, 1999 (incorporated by reference to Exhibit 10.12 to Annual Report on Form 10-K for the year ended December 31, 1999).

21. Subsidiaries of the Registrant (incorporated by reference to Exhibit 21 to Annual Report on Form 10-K for the year ended December 31, 1996).

23. Consent of Arthur Andersen LLP (filed herewith).