UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2005

Commission file number 1-08246

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 North Sam Houston Parkway East, Suite 300, Houston, Texas	**77032**
(Address of principal executive offices)	(Zip Code)

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

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 $0.10 (including associated stock purchase rights)	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒ Accelerated Filer ☐ Non-accelerated filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The aggregate market value of the voting stock held by non-affiliates of the registrant was $3,369,849,326 based on the New York Stock Exchange – Composite Transactions closing price on June 30, 2005, of $23.49 (as adjusted to reflect a subsequent two-for-one stock split). For purposes of this calculation, the registrant has assumed that its directors and executive officers are affiliates.

As of February 27, 2006, the number of outstanding shares of the registrant's Common Stock, par value $0.10, was 167,574,821.

Document Incorporated by Reference

Portions of the registrant's definitive proxy statement to be filed with respect to the annual meeting of shareholders to be held on or about May 25, 2006 are incorporated by reference into Part III of this Form 10-K.

SOUTHWESTERN ENERGY COMPANY
ANNUAL REPORT ON FORM 10-K
For Fiscal Year Ended December 31, 2005

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This Annual Report on Form 10-K includes certain statements that may be deemed to be "forward-looking" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, or the Exchange Act. We refer you to "Risk Factors" in Item 1A of Part I and to "Management's Discussion and Analysis of Financial Condition and Results of Operations — Forward-Looking Information" in Item 7 of Part II of this Form 10-K for a discussion of factors that could cause actual results to differ materially from any such forward-looking statements. The electronic version of this Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those forms filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available free of charge as soon as reasonably practicable after they are filed with the Securities and Exchange Commission, or the SEC, on our website at www.swn.com. Our corporate governance guidelines and the charters of the Audit, Compensation, Nominating and Retirement Committees of our Board of Directors are available on our website, and are available in print free of charge to any shareholder upon request.

PART I

ITEM 1. BUSINESS

Southwestern Energy Company is an independent energy company primarily focused on the exploration for and production of natural gas. We principally operate our natural gas and oil exploration and production, or E&P, business in four well-established productive regions — the Arkoma Basin, East Texas, the Permian Basin and the onshore Gulf Coast. Today, we derive the vast majority of our operating income and cash flow from our E&P business. In addition to our core areas of operations, we actively seek to develop new conventional exploration projects as well as unconventional plays, which we refer to as New Ventures, with significant exploration and exploitation potential. We are also focused on creating and capturing additional value at and beyond the wellhead through our established natural gas distribution, marketing and transportation businesses and our expanding gathering activities. Our marketing and gathering businesses are collectively referred to as our Midstream Services.

We operate principally in the following three segments:

1. *Exploration and Production* - Our primary business is natural gas and oil exploration, development and production within the United States, with our operations principally located in Arkansas, Oklahoma, Texas, New Mexico and Louisiana. We engage in natural gas and oil exploration and production through our wholly-owned subsidiaries, SEECO, Inc., Southwestern Energy Production Company (which we refer to as SEPCO) and Diamond "M" Production Company, as well as through Overton Partners, L.L.C. and DeSoto Drilling, Inc., which are both wholly-owned subsidiaries of SEPCO. SEECO operates exclusively in Arkansas, holds a large base of both developed and undeveloped gas reserves and conducts both the ongoing conventional drilling program in the Arkansas part of the Arkoma Basin and the drilling program for the Fayetteville Shale play, which was announced in 2004. SEPCO conducts development drilling and exploration programs in the Arkoma Basin, the Permian Basin of Texas and New Mexico, and in Louisiana and East Texas. Diamond "M" has interests in properties in the Permian Basin of Texas. DeSoto Drilling, Inc., or DDI, is a newly formed company through which our drilling operations in the Fayetteville Shale play will be conducted.

2. *Natural Gas Distribution* - We are also engaged in the distribution and transmission of natural gas. Our wholly-owned subsidiary, Arkansas Western Gas Company, which we refer to as Arkansas Western, operates integrated natural gas distribution systems in northern Arkansas serving approximately 148,000 retail customers. Arkansas Western is the largest single purchaser of SEECO's gas production.

3. *Midstream Services* - Our gas marketing subsidiary, Southwestern Energy Services Company, was formed in 1996 to better enable us to capture downstream opportunities which arise through marketing and transportation activity. In 2004, we formed a new subsidiary, DeSoto Gathering Company, L.L.C., to engage in gathering activities related to the development of our Fayetteville Shale play. Our Midstream Services segment generates revenue through the marketing of our own gas production and some third-party natural gas and from gathering fees associated with the transportation of natural gas to market. Our gathering revenues have been insignificant to-date but are expected to increase in the future depending upon the level of production from our Fayetteville Shale area.

Our E&P segment has increasingly contributed to our financial results primarily due to the general increase in natural gas and crude oil commodity prices and the growth in our production volumes. In 2005, 95% of our operating income and 94% of our earnings before interest, taxes, depreciation, depletion and amortization, or EBITDA, were generated from our E&P business. Our Natural Gas Distribution and Midstream Services segments generated 2% and 3% of our operating income, respectively, and each generated 3% of our EBITDA in 2005, respectively. In 2004, our E&P segment generated 90% of our operating income and 91% of our EBITDA, while the Natural Gas Distribution and Midstream Services segments each generated 5% of our operating income and generated 6% and 3% of our EBITDA in 2004, respectively. In 2003, our E&P, Natural Gas Distribution and Midstream Services segments generated 87%, 7% and 6% of our operating income, respectively, and 87%, 9% and 4% of our EBITDA, respectively. We refer you to "Business — Other Items — Reconciliation of Non-GAAP Measures" in Item 1 of Part I of this Form 10-K for a table that reconciles EBITDA with our net income as derived from our audited financial information.

Our Business Strategy

We are focused on providing long-term growth in the net asset value of our business, which we achieve in our E&P business through the drillbit. Within the E&P segment, we prepare economic analyses for each of our drilling and acquisition opportunities and rank them based upon the expected present value added for each dollar invested, which we refer to as PVI. The PVI of the future expected cash flows for each project is determined using a 10% discount rate. We target creating at least $1.30 of discounted pre-tax PVI for each dollar we invest in our E&P projects. Our actual PVI results are utilized to help determine the allocation of our future capital investments. The key elements of our E&P business strategy are:

- *Exploit and Develop Existing Asset Base*. We seek to maximize the value of our existing asset base by developing and exploiting properties that have production and reserve growth potential while also controlling per unit production costs. We intend to add proved reserves and increase production through the use of advanced technologies, including detailed technical analysis of our properties, and by drilling infill locations and selectively recompleting existing wells. We also plan to drill step-out wells to expand known field limits.

- *Grow Through New Exploration and Development Activities*. We actively seek to develop natural gas and oil plays as well as New Ventures. New prospects are evaluated based on repeatability, multi-well potential and land availability as well as other criteria. Our Fayetteville Shale play is an outgrowth of our focus on new exploration and development projects.

- *Rationalize Our Property Portfolio and Acquire Selective Properties*. We actively pursue opportunities to reduce production costs of our properties and improve overall return, including selling marginal properties from our E&P portfolio of assets and acquiring producing properties and leasehold acreage in the regions in which we operate. We also seek to acquire operational control of properties with significant unrealized exploration and exploitation potential.

- *Maximize Efficiency Through Economies of Scale*. In our key operating areas, the concentration of our properties allows us to achieve economies of scale in our drilling and production operations that result in lower costs. In addition, we expect DDI to achieve economies of scale with respect to the drilling of our wells in the Fayetteville Shale play.

Recent Developments

2006 Planned Capital Expenditures and Production Guidance. In December 2005, we announced a planned capital investment program for 2006 of $830.1 million, an increase of 72% over our 2005 capital program. Our 2006 capital program includes $770.3 million for our E&P segment (including $78.5 million invested in drilling rigs), $37.5 million for our Midstream Services segment and $11.9 million for improvements to our utility systems and $10.4 million for other corporate purposes. The increased capital program is expected to be funded by internally-generated cash flow, the remaining net proceeds from our September 2005 equity offering (discussed below) and borrowings under our revolving credit facility. We also announced our targeted 2006 oil and gas production of approximately 74.0 to 76.0 Bcfe, an increase of approximately 21% to 25% over our production in 2005.

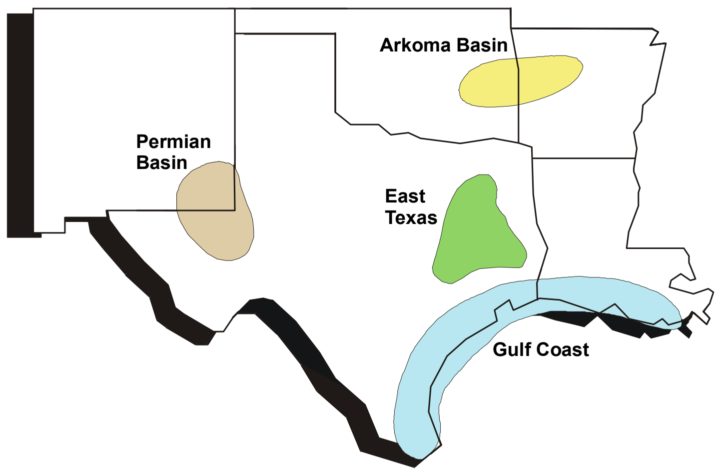
Two-For-One Stock Splits. On November 17, 2005, we distributed additional shares of our common stock to our stockholders in a two-for-one stock split that was declared by our board of directors in October 2005. We also effected a two-for-one stock split with respect to our common stock in June 2005.

Utility Receives Rate Adjustment. Effective October 31, 2005, in response to a request for a $9.7 million annual rate increase, the Arkansas Public Service Commission, or APSC, approved a rate increase for our utility of $4.6 million annually, exclusive of costs to be recovered under Arkansas Western's purchase gas adjustment clause.

Follow-on Equity Offering. In September 2005, we consummated an underwritten offering of 9,775,000 shares of our common stock. The net proceeds of the offering were approximately $580.0 million after deduction of underwriting discounts and offering expenses payable by us. Of the net proceeds, $186.7 million was used to pay down outstanding indebtedness under our revolving credit facility, $125.0 million was used to pay our 6.70% Notes due December 2005 and the remainder was invested in short-term cash equivalents pending use for future working capital and/or capital expenditure needs.

Exploration and Production

In 1943, we commenced a program of exploration for and development of natural gas reserves in Arkansas for supply to our utility customers. In 1971, we initiated an E&P program outside Arkansas, unrelated to the utility's requirements. Since that time, our E&P activities outside Arkansas have expanded substantially. In 1998, we brought in a new executive management team for our E&P business. Our executives have assembled a high-quality team of management and technical professionals with knowledge and experience in the geologic basins in which we have operations, including experienced explorationists with proven track records of finding natural gas and oil. Our E&P business is organized into asset management teams based on the geographic location of our exploration and development projects.



Areas of Operation

We operate our E&P business in four general regions — the Arkoma Basin, East Texas, the Permian Basin and the onshore Gulf Coast. Operating income from our E&P segment was $234.8 million in 2005, up from $164.6 million in 2004 and $84.7 million in 2003. The increases in 2005 and 2004 were due to increased production volumes and higher realized prices, partially offset by increases in operating costs and expenditures. EBITDA from our E&P segment was $325.9 million in 2005, compared to $231.1 million and $131.4 million, respectively, in 2004 and 2003. The increases in 2005 and 2004 were due to increased production volumes and higher realized prices, partially offset by increases in operating costs and expenditures. We refer you to "Business — Other Items — Reconciliation of Non-GAAP Measures" in Item 1 of Part I of this Form 10-K for a reconciliation of EBITDA with our net income.

Our estimated proved natural gas and oil reserves were 826.8 Bcfe as of December 31, 2005, up from 645.5 Bcfe at year-end 2004 and 503.1 Bcfe at year-end 2003. The overall increase in total reserves in the past three years is primarily due to the accelerated development of our Overton Field in East Texas, the discovery and development of the Fayetteville Shale play in Arkansas, our successful conventional drilling program in the Arkoma Basin, and development of a new field in the Permian Basin. Our year-end 2005 reserves had a pre-tax PV-10 value of $1,986.4 million and an after-tax PV-10 value, or standardized measure, of $1,420.8 million, up from $892.3 million at year-end 2004 and $716.4 million at year-end 2003. We refer you to Note 6 in the consolidated financial statements for a discussion of our standardized measure of discounted future cash flows related to our proved natural gas and oil reserves and to the risk factor "Although our estimated natural gas and oil reserve data is independently audited, our estimates may still prove to be inaccurate" in Item 1A of Part I of this Form 10-K and to "Management's Discussion and Analysis of Financial Condition and Results of Operations — Forward-Looking Information" in Item 7 of Part II of this Form 10-K for a discussion of the risks inherent in utilization of standardized measures and estimated reserve data. Approximately 93% of our proved reserves were natural gas and 73% were classified as proved developed. We operate approximately 78% of our reserves, based on our PV-10 value, and our average proved reserves-to-production ratio, or average reserve life, approximated 13.6 years at year-end 2005. Sales of natural gas production accounted for 92% of total operating revenues for this segment in both 2005 and 2004, as compared with 91% in 2003. Natural gas production has increasingly generated a substantial portion of total operating revenues as a result of the natural gas focus of our capital investments in the past three years.

In 2005, we replaced 399% of our production volumes by adding 243.1 Bcfe of proved natural gas and oil reserves at a finding and development cost of $1.71 per Mcfe, including a downward reserve revision of 31.7 Bcfe but excluding $35.1 million of capital invested in drilling rigs. In 2004 and 2003, our reserve replacement ratios were 365%

and 313%, respectively, and our finding and development costs were $1.43 per Mcfe and $1.33 per Mcfe, respectively, including net downward reserve revisions of 12.7 Bcfe in 2004 and 15.5 Bcfe in 2003. The downward reserve revisions during 2005 were primarily due to minor changes to decline rates for wells at our Overton Field and unexpected declines associated with our Gulf Coast properties. The negative reserve revisions during 2004 were primarily due to slightly higher decline rates related to some of the wells in our Overton Field in East Texas, while negative revisions in 2003 were primarily due to poorer-than-expected well performance related to our South Louisiana properties. The increase in our reserve replacement ratio during this time period is primarily due to increased success of our drilling programs in finding new natural gas and crude oil reserves. The increase in our finding and development costs primarily reflects the general increase in material costs and oilfield service costs to drill and complete wells in our key operating areas. Additionally, we invested approximately $40.7 million, $14.0 million and $11.0 million during 2005, 2004 and 2003, respectively, in acquiring leasehold positions in our Fayetteville Shale play. For the period ending December 31, 2005, our three-year average reserve replacement ratio was 364%, and our three-year average finding and development cost was $1.53 per Mcfe, including reserve revisions and excluding our investments in drilling rigs.

Our reserve replacement ratio during 2005, excluding the effect of reserve revisions, was 450%, compared to 388% in 2004 and 351% in 2003. Our finding and development cost, excluding revisions and our investments in drilling rigs, was $1.51 per Mcfe in 2005, compared to $1.34 per Mcfe in 2004 and $1.18 per Mcfe in 2003. The increase in our finding and development costs during this time period were primarily due to higher costs for drilling and other field services. Excluding reserve revisions and our investments in drilling rigs, these three-year averages were 402% and $1.38 per Mcfe, respectively.

The following table provides information as of December 31, 2005 related to proved reserves, well count, and net acreage, and 2005 annual information as to production and capital expenditures, for each of our core operating areas, for our New Ventures and overall:

	Arkoma						
	Conventional	Fayetteville Shale Play	East Texas	Permian	Gulf Coast	New Ventures	Total
Estimated Proved Reserves:							
Total Reserves (Bcfe)	271.0	101.0	368.7	58.6	27.5	-	826.8
Percent of Total	33%	12%	45%	7%	3%	-	100%
Percent Natural Gas	100%	100%	96%	38%	90%	-	93%
Percent Proved Developed	76%	15%	82%	91%	96%	-	73%
Production (Bcfe)	20.2	1.8	28.2	6.9	3.9	-	61.0
Capital Investments (millions)(1)	$64.5	$154.5(1)	$183.6	$15.1	$7.9	$25.7(1)	$451.3
Total Gross Producing Wells	952	54	283	410	57	-	1,756
Total Net Acreage	427,949(2)	739,294	36,086	34,826	17,390	116,633	1,372,178
Net Undeveloped Acreage	240,917(2)	719,680	16,991	7,255	6,351	116,633	1,107,827
PV-10:							
Pre-tax (millions)	$738.9	$156.9	$852.4	$149.5	$88.7	-	$1,986.4
After-tax (millions)	$528.5	$112.3	$609.6	$107.0	$63.4	-	$1,420.8
Percent of Total	37%	8%	43%	8%	4%	-	100%
Percent Operated	81%	100%	81%	38%	59%	-	78%

(1) Our Fayetteville Shale play capital investments include $35.1 million invested in drilling rigs and $40.7 million in leasehold acquisition costs. New Ventures' capital investments include $4.4 million relating to two wells in the Angelina River Trend project that are now part of our East Texas program.

(2) Includes 123,442 net developed acres and 1,431 net undeveloped acres in our Conventional Arkoma Basin operating area that are also within our Fayetteville Shale focus area but not included in the Fayetteville Shale acreage in the table above.

Arkoma Basin. We have traditionally operated in a portion of the Arkoma Basin that is primarily within the boundaries of our utility gathering system in Arkansas, which we refer to as the "Fairway." In recent years, we have expanded our activity in the Arkoma Basin south and east of the traditional Fairway area and into the Oklahoma portion of the basin. Our drilling program in the Arkoma Basin is comprised of both conventional and unconventional activities. We refer to our drilling program targeting stratigraphic Atokan-age objectives in Oklahoma and Arkansas as our "conventional Arkoma" drilling program. Our Fayetteville Shale play represents our entire unconventional drilling program in the Arkoma Basin. At December 31, 2005, we had approximately 372.0 Bcf of natural gas reserves in the Arkoma Basin, representing approximately 45% of our total reserves, up from 247.0 Bcf at year-end 2004 and 211.7 Bcf at year-end 2003.

Conventional Arkoma Program. Our conventional Arkoma drilling program continues to provide a solid foundation for our E&P program and represents a significant source of our production and reserves. Approximately 271.0 Bcf of our reserves at year-end 2005 were attributable to our conventional Arkoma wells. During 2005, we participated in 71 wells with 61 producers, five dry holes and five wells in progress at year-end, resulting in a 92% drilling success rate while adding 51.7 Bcf of gas reserves at a finding and development cost of $1.25 per Mcf, including a net downward reserve revision of 0.7 Bcf. This compares to finding and development costs of $1.11 per Mcf in the basin in 2004 and $0.79 per Mcf in 2003, including net upward reserve revisions of 4.5 Bcf and 13.1 Bcf, respectively. Excluding revisions, finding and development costs would have been $1.23 per Mcf in both 2005 and 2004 and $1.14 per Mcf in 2003. The increase in our finding costs during this time period was primarily due to higher costs for drilling and other oil field services. Our gas production from our conventional drilling program in the Arkoma Basin was 20.2 Bcf during 2005, or approximately 55.5 MMcf per day, compared to 20.1 Bcf in 2004 and 18.9 Bcf in 2003. The increase in production over this time period was primarily due to a greater number of wells drilled in the basin and higher production volumes from our Ranger Anticline area.

Our conventional activities in the Arkoma Basin continue to generate a significant amount of our cash flow. With three-year average finding and development costs of $1.06 per Mcf, including revisions (or $1.21 per Mcf excluding revisions), and three-year average production, or lifting, costs of $0.54 per Mcf (including production taxes), our cash margins from our conventional drilling program in the Arkoma Basin are very attractive. Lifting costs continued to be low during 2005 at $0.68 per Mcf (including production taxes), compared to $0.48 per Mcf in 2004 and $0.46 per Mcf in 2003. While lifting costs from our conventional drilling program have increased primarily due to higher oil field service costs, we continue to be one of the lowest cost producers in the industry.

Our strategy in the Fairway is to delineate new geologic prospects and extend previously identified trends using our extensive database of regional structural and stratigraphic maps. In recent years, we have extended our development program into the Oklahoma portion of the Arkoma Basin, and into other areas of the basin in Arkansas that have been lightly explored to date. Since 2002, we have significantly increased our drilling activity in our Ranger Anticline prospect area, located at the southern edge of the Arkansas portion of the basin.

Our wells at Ranger have primarily targeted the Upper and Lower Borum tight gas sands between 5,000 and 8,000 feet in depth. In 2005, wells completed in the Borum had average estimated ultimate gross reserves of 1.2 Bcf per well. As our understanding of the geology at Ranger has grown, the potentially productive area in the field has expanded. In 2005, we extended the field boundaries to the east approximately 9 miles by drilling four successful wells in shallower Basham, Nichols and Turner tight gas sands. The Borum sands in these wells were not commercially productive. These shallower sands are between 3,500 and 4,500 feet in depth had average estimated ultimate gross reserves of 0.5 Bcf per well.

We drilled our first successful well at Ranger in 1997, and through year-end 2005, we successfully drilled 77 out of 87 wells, adding 82.1 net Bcf of reserves at a finding cost of $1.07 per Mcf, including reserve revisions. During 2005, we successfully completed 34 out of 37 wells (excluding three wells in progress at year-end 2005), which added 19.3 Bcf of new reserves at a finding and development cost of $2.19 per Mcf, including downward reserve revisions of 4.0 Bcf. Excluding reserve revisions, our finding and development cost at Ranger was $1.81 per Mcf. During 2005, our finding and development cost increased due to higher drilling and oil field service costs, combined with lower reserves per well due to completions in the shallower Basham, Nichols and Turner sands. A large portion of our increased costs were related to a greater amount of directional drilling which is more costly and time consuming. While the majority of the wells planned to be drilled at Ranger during 2006 will not require directional drilling, we expect that the general trend of higher costs for drilling and other oil field services will continue with future development wells in the field. Net production from the field during 2005 was 5.6 Bcf, up from 3.5 Bcf produced in 2004 and 1.7 Bcf produced in 2003. Our average working interest in the 77 successful wells drilled through December 31, 2005 is 78% and our average net revenue interest is 64%.

We continue to increase our acreage position at Ranger and, as of December 31, 2005, we held approximately 12,800 gross developed acres and 49,900 gross undeveloped acres and had regulatory approval for well spacing at a minimum distance of 560 feet between wells at Ranger. Our average working interest in our gross undeveloped acreage position at Ranger is 73%. We believe that Ranger holds significant future development potential.

Late in the third quarter of 2005, we drilled the initial exploratory well on our Midway prospect, targeting the Pennsylvanian and Ordovician section. The USA #1-24 well encountered approximately 230 feet of net pay by electric log calculation in the Pennsylvanian age Borum sands, which is the main producing horizon in the Ranger Anticline area. We are testing these sands and will determine the development potential based on the results. We have approximately 20,300 gross undeveloped acres in our Midway prospect area.

Our conventional Arkoma Basin drilling program continues to be a significant focus for our capital program and we intend to allocate funds to our development drilling and workover programs at a level that, at a minimum, maintains our production and reserve base in this area. In 2006, we plan to invest approximately $89.6 million in the conventional Arkoma program and will drill approximately 100 to 110 wells, including 50 to 60 wells at the Ranger Anticline.

Fayetteville Shale Play. Our emerging Fayetteville Shale play is now a primary focus of our E&P business. The Fayetteville Shale is an unconventional gas reservoir located on the Arkansas side of the Arkoma Basin, ranging in thickness from 50 to 325 feet and ranging in depth from 1,500 to 6,500 feet. The shale is a Mississippian-age shale that is the geologic equivalent of the Caney Shale found on the Oklahoma side of the Arkoma Basin and the Barnett Shale found in north Texas. Since we announced the Fayetteville Shale play in August 2004, we have increased our capital investments as we have accelerated our drilling program in the play area. In 2005, as part of our capital investments, we entered into agreements for the fabrication of ten new drilling rigs to be dedicated to drilling wells in the play. The drilling operations will be conducted through our newly formed subsidiary, DeSoto Drilling, Inc., or DDI. At December 31, 2005, DDI had 45 employees and we expect DDI to have a total of approximately 275 employees by year end 2006.

At December 31, 2005, we held a total of approximately 865,000 net acres in the play area (720,000 net undeveloped acres, 20,000 net developed acres held by Fayetteville Shale production and approximately 125,000 net developed acres held by conventional production). As of December 31, 2005, we had spud a total of 88 wells in the play, 86 of which were operated by us and two of which were outside-operated wells. Of the 88 wells spud, 67 were drilled during 2005 and 21 were drilled in 2004. The wells are located in 15 separate pilot areas located in seven counties in Arkansas and, as of December 31, 2005, 54 were producing, 13 were in some stage of completion or waiting on pipeline hook-up and four were shut-in due to marginal performance or temporarily abandoned. The remaining 17 wells were in the drilling phase at year-end, including 13 horizontal wells which had been drilled through the vertical section with a smaller spudder rig and will be re-entered with a larger rig capable of drilling the horizontal section.

Our results to date indicate that optimal development of the resource will primarily require horizontal wells. At December 31, 2005, 37 of the 88 wells spud are designated as horizontal wells, 13 of which were producing, five were completing, four were drilling, two were temporarily abandoned and 13 wells had been drilled through the vertical section. The average initial test rate for 12 of the 13 completed horizontal wells is 2.5 MMcf per day. Our first horizontal well, the Vaughan #4-22-H, is excluded because it is not analogous as wellbore problems limited the fracture stimulation treatment. The well costs for the most recently completed horizontal wells have ranged between $1.4 million and $1.8 million per well, excluding non-recurring costs. The horizontal wells drilled through December 31, 2005, have had an average vertical depth of 3,200 feet and an average lateral length of 2,000 feet, and have taken 15 to 20 days on average to reach total depth.

The wells we have drilled in the Fayetteville Shale play area represent a very small sample of our large acreage position. During 2006, we expect to continue the evaluation of our acreage position in the Fayetteville Shale play by testing an additional 24 to 30 pilot areas. As we continue to gather data about our prospects in the Fayetteville Shale, it is possible that additional information may cause us to alter our drilling schedule or determine that prospects in some portion of our acreage position should not be pursued at all. We refer you to “Risk Factors — Our future reserve and production growth is dependent in part on the success of our Fayetteville Shale drilling program, which has a limited operational history and is subject to change” in Item 1A of Part I of this Form 10-K.

During 2005, we invested approximately $154.5 million in our Fayetteville Shale play, which included $67.4 million to spud 67 wells, $40.7 million for leasehold acquisition, $35.1 million towards the fabrication of ten new drilling rigs to be utilized in the play, $4.3 million for seismic and $7.0 million in capitalized costs. In 2004, we invested approximately $27.9 million, which included $11.6 million in capital for drilling 21 wells, $14.0 million for leasehold acquisition, and $2.3 million for other capitalized costs. In 2003, we invested approximately $11.0 million for leasehold acquisition. Net gas production from the Fayetteville Shale play during 2005 was 1.8 Bcf, compared to 0.1 Bcf produced during 2004. Total proved gas reserves booked in the play as of year-end 2005 totaled 101.0 Bcf from a total of 177 locations, of which 54 were proved developed producing, 6 were proved developed non-producing and 117 were proved undeveloped. Of the 177 locations, 131 were horizontal. The average proved reserves for each of the horizontal wells included in our year-end reserves was approximately 0.95 gross Bcf per well. Netherland, Sewell & Associates, Inc. (“NSA”), our independent petroleum engineering firm, has indicated that their estimate of the average proved reserves for the Fayetteville Shale play wells are lower than our estimates and that, to resolve these differences, additional performance data are required. We estimate average ultimate gross production for these wells of 1.3 to 1.5 Bcf per horizontal well, based on the limited production data through December 31, 2005 and our reservoir simulation shale gas model. Therefore, as our horizontal wells continue to produce over time, our proved reserves estimate of 0.95 gross Bcf on a per well basis could be revised upward in the future. Total proved gas reserves booked in the play in 2004 totaled 7.5 Bcf from a total of 20 vertical wells, 10 of which were classified as proved, undeveloped locations, for an average estimated ultimate recovery per well of 430,000 Mcf (375,000 Mcf net). At the end of 2005, our proved reserves included 5.0 net Bcf associated with 43 vertical wells.

As required, we file applications with the Arkansas Oil and Gas Commission, or the AOGC, for approval of field rules for our pilot area once we have drilled the required number of wells. Through December 31, 2005, the AOGC approved field rules for four fields in the Fayetteville Shale play area located in Conway, Van Buren and Faulkner counties. Subsequent to December 31, 2005 and through February 20, 2006, the AOGC approved field rules for another field, the New Quitman Field, located in Cleburne and Faulkner counties in Arkansas. For each field, the AOGC approved governmental sections of approximately 640 acres as the drilling unit and well spacing requirements within each drilling unit of 560 feet minimum distance between completions in common sources of supply within the Fayetteville Shale formation, up to a maximum of 25 wells per drilling unit. At December 31, 2005, based on the assumptions contained in the field rule applications for these fields, we estimated the expected drainage from horizontal wells to be less than 80 acres per well based on existing microseismic data and reservoir simulation modeling. There can be no assurance that we will be successful in obtaining the same size drilling unit or the same spacing in the field rules for our other pilot areas or for our other Fayetteville Shale acreage as a whole. We refer you to "Risk Factors — We may have difficulty drilling all of the wells that are necessary to hold our Fayetteville Shale acreage before the initial lease terms expire, which could result in the loss of certain leasehold rights."

In 2006, we expect to invest $338.3 million in the Fayetteville Shale play, which would include drilling between 175 to 200 wells. Of those wells, nearly all will be horizontal wells. Our strategy going forward is to increase our production through development drilling while also determining the economic viability of the undrilled portion of our acreage through drilling in new pilot areas. Our drilling program with respect to our Fayetteville Shale play is flexible and will be impacted by a number of factors, including the results of our horizontal drilling efforts, our ability to determine the most effective and economic fracture stimulation, the extent to which we can replicate the results of our most successful Fayetteville Shale wells on our other Fayetteville Shale acreage as well as the natural gas and oil commodity price environment. We refer you to "Risk Factors — Our drilling plans for the Fayetteville Shale play are subject to change" in Item 1A of Part I of this Form 10-K.

East Texas. Our East Texas operations are primarily located in the Overton Field in Smith County, Texas, and our Angelina River Trend located in southern Nacogdoches County, Texas.

Overton Field - Our original interest in the Overton Field (which was approximately 10,800 gross acres) was acquired in April 2000 for $6.1 million. At December 31, 2005, we held approximately 24,400 gross acres with an average working interest in the Overton Field of 96% and average net revenue interest of 77%.

The Overton Field produces from four Taylor series sands in the Cotton Valley formation at approximately 12,000 feet. When we acquired the field in April 2000, it was primarily developed on 640-acre spacing, or one well per square mile. Analogous Cotton Valley fields in the area have been drilled to 80-acre spacing, and in some cases to 40-acre spacing. In 2003, we received regulatory approval from the Texas Railroad Commission to allow downspacing at Overton to optional 80-acre spacing. We also received approval in 2003 to drill four wells at locations that were effectively 40-acre spaced wells. Of the four test wells drilled at 40-acre spacing, three wells indicated pressures near original reservoir pressures and one showed partial depletion. Data from the four 40-acre spaced wells indicated that a significant portion of the field would likely require 40-acre spaced wells to adequately develop the field. During the first quarter of 2004, we received regulatory approval to allow downspacing at Overton to optional 40-acre spacing.

In 2005, we drilled and completed a total of 80 wells, of which 52 were 40-acre spaced wells. This compares to 83 wells drilled and completed in 2004 and 57 wells in 2003. We have experienced a 100% success rate at Overton since we began our development drilling program in 2001. Daily gross production at the Overton Field has increased from approximately 2.0 MMcfe in March 2001 to approximately 109.7 MMcfe at year-end 2005 resulting in net production of 26.7 Bcfe during 2005, compared to 21.8 Bcfe in 2004 and 13.6 Bcfe in 2003. New wells drilled in the field during 2005 averaged approximately $1.8 million to drill and complete, had average initial production rates of approximately 3.0 MMcfe per day and had average estimated ultimate gross reserves of 1.8 Bcfe per well. Our average production costs (including production taxes) were $0.56 per Mcfe in 2005, compared to $0.50 per Mcfe in 2004 and $0.45 per Mcfe in 2003. The increases in our unit production costs were primarily due to higher production taxes resulting from higher realized commodity prices, partially offset by increased production.

Our proved reserves in East Texas increased to 368.7 Bcfe at year-end 2005, or 45% of our total reserves, of which 352.7 Bcfe of reserves were in our Overton Field. Our reserves at Overton were up significantly from 296.6 Bcfe at year-end 2004 and 196.3 Bcfe at year-end 2003, primarily due to the acceleration of our infill drilling program which began in early 2003. We invested approximately $158.0 million at the Overton Field during 2005 which resulted in proved reserve additions of 82.8 Bcfe at a finding and development cost of $1.91 per Mcfe, including a net downward reserve revision of 18.8 Bcfe. This compares to finding and development costs of $1.20 per Mcfe in 2004 and $0.98 per Mcfe in 2003, including net downward reserve revisions of 19.2 Bcfe and 3.7 Bcfe, respectively. Excluding such revisions, our finding and development costs at Overton were $1.56 per Mcfe in 2005, $1.04 per Mcfe in 2004 and $0.95 per Mcfe in 2003. Our finding cost increased in 2005 and 2004 primarily due to slightly lower reserves per well combined with higher costs for drilling and other oil field services. We expect that this trend will continue with future development wells in the field. The average estimated ultimate recovery of gas and oil reserves from new wells completed in 2005 was approximately 1.8 gross Bcfe per well, compared to 2.0 gross Bcfe per well in 2004 and 2.2 gross Bcfe per well in 2003. The consistent decrease in gross reserve per well is primarily due to our drilling of locations with the highest estimated ultimate recovery earlier in our development program and is expected to continue.

In 2006, we plan to invest approximately $161.5 million at Overton and drill approximately 83 wells. Based on reasonable gas price assumptions, the level of industrywide cost increases for services and materials and our investment hurdle rate, it appears that our drilling program at Overton could be extended into 2007.

Angelina River Trend - Our Angelina River Trend is a collection of four new development areas, located primarily in Nacogdoches County, Texas. At December 31, 2005, we held approximately 11,000 gross undeveloped acres and 3,000 gross developed acres. Our average working interest in this area is 72% and our average net revenue interest is 56%. Through December 31, 2005, we had drilled nine wells with 100% success in this trend primarily targeting the Travis Peak formation. Net production from the area was 0.9 Bcfe in 2005. Gross initial production rates from wells drilled during 2005 ranged from 1.7 to 4.4 MMcfe per day. Our proved reserves in the area were 13.5 Bcfe at year-end 2005, compared to 0.5 Bcfe at year-end 2004. The average estimated ultimate recovery of gas and oil reserves from the wells completed in 2005 was approximately 1.6 gross Bcfe per well with an average drill and complete cost of $2.5 million per well. In 2005, we invested $18.7 million in the Angelina River Trend, excluding $4.4 million of capital expenditures for two of the wells that is included in our New Ventures capital expenditures. During 2006, we intend to explore the growth potential of the Angelina River Trend and are planning to invest $34.5 million to drill a total of 16 wells in the area during the year.

Permian Basin. We have had a drilling program since 1997 in the Permian Basin, which is primarily located in west Texas and southeast New Mexico. At December 31, 2005, our proved reserves in the Permian Basin were 58.6 Bcfe, compared to 60.8 Bcfe in 2004 and 55.6 Bcfe in 2003. Our production in the basin during 2005 was 6.9 Bcfe, or approximately 18.9 MMcfe per day, compared to 7.1 Bcfe in 2004 and 4.2 Bcfe in 2003. The decrease in reserves and production during 2005 was primarily due to the natural decline in these properties, partially offset by new reserves added from drilling. The increase in reserves and production in 2004 from 2003 was primarily due to increased volumes from our River Ridge discovery in Eddy County, New Mexico, and subsequent development of that field. Our production costs (including production taxes) averaged $1.76 per Mcfe in 2005, compared to $1.21 per Mcfe in 2004 and $1.15 per Mcfe in 2003. The increases in production costs were primarily due to higher service costs and increased production taxes resulting from higher gas and oil commodity prices. In 2005, we invested $15.1 million in the Permian Basin, drilling 16 wells, of which 15 were successful, resulting in reserve additions of 4.7 Bcfe. Our finding and development cost in the Permian was $3.21 per Mcfe, including a net downward reserve revision of 0.9 Bcfe. This compares to finding and development costs of $2.09 per Mcfe in 2004 and $3.44 per Mcfe in 2003, including a net upward reserve revision of 2.6 Bcfe in 2004 and a net downward revision of 7.1 Bcfe in 2003. Excluding such revisions, our finding and development costs in the Permian Basin were $2.70 per Mcfe in 2005, $2.62 per Mcfe in 2004 and $0.95 per Mcfe in 2003. The increase in our finding and development cost in 2005 was due to overall higher service costs. The increase in finding cost in 2004 was primarily due to the acquisition of additional working interest in our River Ridge discovery.

In July 2004, we acquired additional working interest in our River Ridge field for $14.2 million, which consolidated our position in this property and allowed us to gain additional development opportunities. The acquisition increased our working interest in an existing producing well to 50% from 12.5%, and gave us a 50% working interest in another well in which we previously held no interest. The acquired interest added approximately 5.8 net Bcfe in proved reserves. Our overall finding and development cost in the field from drilling and this acquisition is $2.20 per Mcfe, including downward reserve revisions of 3.1 Bcfe. We hold a 50% working interest in this field.

In 2006, we plan to invest approximately $15.9 million in our Permian Basin program to drill approximately 12 exploration and exploitation wells.

Gulf Coast. Our Gulf Coast operations are located in the onshore areas of Texas and Louisiana. Since our first discovery in December 1999, the efforts of our exploration program have resulted in 10 successful wells out of 23 wildcats drilled in South Louisiana. We have not had a significant discovery in South Louisiana since 2001 and our reserves in the area are naturally declining. Our proved reserves in these areas totaled 27.5 Bcfe at December 31, 2005, compared to 38.6

Bcfe at year-end 2004 and 39.5 Bcfe at year-end 2003. Approximately 9.0 Bcfe of reserves at December 31, 2005, were located in Louisiana. The decline in reserves during 2004 and 2005 was primarily due to the natural decline in these properties, partially offset by new reserve additions from drilling. Net production from this area in 2005 was 3.9 Bcfe, or approximately 10.7 MMcfe per day, compared to 4.6 Bcfe in 2004 and 4.5 Bcfe in 2003. Production costs (including production taxes) averaged $1.67 per Mcfe during 2005, compared to $1.39 per Mcfe in 2004 and $1.23 per Mcfe in 2003. The increase in our unit production costs over this time period was primarily due to the decline in production volumes from these properties, as well as general increases in operating costs. In 2005, we invested $7.9 million in this area, adding 3.7 Bcfe of reserves which were more than offset by downward reserve revisions of 10.2 Bcfe. This compares to net downward reserve revisions of 0.6 Bcfe in 2004 and 17.7 Bcfe in 2003. The downward reserve revisions over the last three years have been primarily due to poorer-than-expected well performance related to our South Louisiana properties. Excluding such revisions, our finding and development costs in the Gulf Coast area were $2.14 per Mcfe in 2005, $3.65 per Mcfe in 2004 and $6.00 per Mcfe in 2003. The relatively high finding costs during this time period was primarily due to the lack of significant success in our South Louisiana exploration program over the last three years.

During 2004 and 2005, we reduced our exploration activities in the Gulf Coast region primarily because our drilling efforts were not meeting our economic criteria. In 2006, we plan to invest $8.6 million in the Gulf Coast area which includes drilling up to three wells which are developmental in nature.

Other Exploration and New Ventures. We have personnel dedicated to the research and identification of active and potential plays, focusing on both conventional exploration plays and unconventional plays (including coalbed methane, shale gas and basin-centered gas) as well as the technological aspects such as horizontal drilling and fracture techniques. New prospects are evaluated based on repeatability, multi-well potential and land availability as well as other criteria.

At December 31, 2005, we held 116,633 net undeveloped acres in areas of the United States outside of our core operating areas in connection with New Ventures that we are pursuing. This compares to 47,596 net undeveloped acres held at year-end 2004 and 345,310 net undeveloped leasehold acres held at year-end 2003. Of the 116,633 net undeveloped acres held at year-end 2005, approximately 49,000 acres are located in Culberson County, Texas, in the emerging Barnett Shale play in the Permian Basin. We anticipate drilling a test well for the Barnett Shale interval in the second quarter of 2006. Of the 345,310 net undeveloped acres held at year-end 2003, approximately 343,351 acres related to our Fayetteville Shale play in Arkansas, which is now part of our Arkoma operations.

In 2005, we invested approximately $25.7 million in our New Ventures and drilled a total of six exploration wells, of which three were successful and one was in progress at year-end. Our three discoveries in 2005 were located in East Texas. Two of the wells are now included in our East Texas operations as part of our Angelina River Trend development project. The third East Texas discovery was at our Pines prospect located in Marion County. Late in the third quarter of 2005, we spudded a deep Arbuckle test northeast of our Ranger Anticline area in the Arkoma Basin. Although the Arbuckle objective did test natural gas, it did not produce at economic rates. We are currently completing this well in the uphole Borum sand, which is the main producing horizon in the Ranger Anticline area. During 2005, we also drilled an exploration well to test the Jackfork objective in Perry County, Arkansas, which was a dry hole and a new coalbed methane test in Sweetwater County, Wyoming that was unsuccessful.

In 2004, we invested approximately $1.5 million in New Ventures, excluding the Fayetteville Shale play, which included drilling one exploration dry hole in another coalbed methane play. In 2003, we invested approximately $11.0 million in leasehold, including our Fayetteville Shale play. However, we did not drill any wells related to the Fayetteville Shale play or other New Ventures projects during 2003.

In 2006, we plan to invest approximately $28.9 million in exploration projects and $14.5 million in New Venture projects, including drilling up to 18 exploration and unconventional wells in the continental United States.

Acquisitions and Divestitures

In 2005, there were no significant acquisitions of natural gas or crude oil producing properties.

In 2004, we purchased 5.8 Bcfe of proved reserves for $14.2 million at an average cost of $2.45 per Mcfe. Almost all of this investment related to the acquisition of additional working interest in our River Ridge discovery in Lea County, New Mexico.

In 2003, we purchased an aggregate of 1.1 Bcfe of proved reserves for $3.0 million, at an average cost of $2.73 per Mcfe. The transactions included working interests in our core Arkoma Basin, Overton Field and Permian Basin producing areas. The average cost per Mcfe was higher than for prior acquisitions due to the potential existence of future drilling opportunities beyond the existing production.

Capital Expenditures

We invested a total of $451.3 million in our E&P program and participated in drilling 247 wells during 2005. Of these drilled wells, 197 were successful, eight were dry and 42 were still in progress at year-end. Our investments have continued to focus primarily on our lower-risk, high-return conventional drilling programs in East Texas and the Arkoma Basin that have driven our production and reserve growth for the past three years. These drilling programs respectively accounted for 41% and 14% of our E&P capital investments in 2005, with approximately $183.6 million invested in East Texas and $64.5 million invested in our conventional Arkoma Basin drilling program. Our Fayetteville Shale resource play emerged as a significant focus of our capital expenditures in 2005 as we accelerated our drilling program in the play. During 2005, we invested approximately $119.4 million in our Fayetteville Shale play, or 26% of our E&P capital investments. In addition, we invested approximately $15.1 million in the Permian Basin, $7.9 million in the Gulf Coast, $25.7 million in Exploration and New Ventures and $35.1 million towards the purchase of drilling rigs and related equipment.

Of the $451.3 million invested in 2005, approximately $35.6 million was invested in exploratory drilling, $287.5 million in development drilling and workovers, $60.5 million for leasehold acquisition and seismic expenditures, $0.1 million for producing property acquisitions, $35.1 million towards the purchase of drilling rigs and related equipment and $32.5 million in capitalized interest and expenses and other technology-related expenditures. During 2004, we invested a total of $282.0 million in our E&P business and participated in 204 wells, and in 2003 we invested $170.9 million and participated in 139 wells. The increases in capital investments and wells drilled during this time was primarily due to the acceleration of our development drilling program at our Overton Field, an increase in conventional drilling activity at our Ranger Anticline area in the Arkoma Basin, and leasehold investments and drilling in our Fayetteville Shale play.

In 2006, we intend to invest approximately $770.3 million in our E&P program, an increase of approximately 71% over our capital investment level in 2005. We continue to be focused on our strategy of adding value through the drillbit, as approximately 80% of our 2006 E&P capital is allocated to drilling, excluding our capital investments in drilling rigs. A primary focus of our E&P business is now the Fayetteville Shale play, and we plan to significantly increase our activity and investment in the play to approximately $338.3 million in 2006. Our investments in 2006 will also be focused on our lower-risk conventional drilling programs in East Texas and the Arkoma Basin. We plan to invest approximately $196.0 million and $89.6 million in our East Texas and conventional Arkoma Basin programs, respectively, in 2006. The remainder of our E&P capital will be allocated to exploration and exploitation in the Permian Basin ($15.9 million), the onshore Gulf Coast ($8.6 million), various other exploration and New Venture projects ($43.4 million) and the balance of the purchase price of drilling rigs and related equipment ($78.5 million).

Of the $770.3 million allocated to the 2006 E&P capital budget, approximately $523.0 million will be invested in development drilling, $25.0 million in exploratory drilling, $70.6 million for land and seismic, $78.5 million for drilling rigs and related equipment, $73.2 million in capitalized interest and expenses and other equipment, facilities and technology-related expenditures. We refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Capital Expenditures" for a discussion of our planned capital expenditures in 2006.

Other Revenues

Other revenues and operating income for 2005, 2004 and 2003 also included pre-tax gains of $3.1 million, $4.5 million and $3.1 million, respectively, related to the sale of gas-in-storage inventory.

Sales and Major Customers

Our daily natural gas equivalent production averaged 167.1 MMcfe in 2005, up 13% from 148.2 MMcfe in 2004 and 112.7 MMcfe in 2003. Our natural gas production was 56.8 Bcf in 2005, compared to 50.4 Bcf in 2004 and 38.0 Bcf in 2003. The increase in 2005 production resulted primarily from a 5.4 Bcfe increase in production from our Overton Field in East Texas and a 1.9 Bcfe increase in our Arkoma production, primarily related to our Fayetteville Shale play. Production during 2005 was reduced by the effects of curtailment of a portion of our Overton Field production due to repairs of a transmission line that is not operated by us and by the effects of Hurricane Katrina. Combined, these events reduced our production by approximately 1.0 Bcfe. The increase in 2004 production resulted primarily from an 8.2 Bcfe increase in production from our Overton Field in East Texas, a 1.3 Bcfe increase in our Arkoma Basin production, and 3.2 Bcfe from our River Ridge discovery in New Mexico.

We also produced 705,000 barrels of oil in 2005, compared to 618,000 barrels of oil in 2004 and 531,000 barrels in 2003. Our oil production increased during 2005 primarily due to increased oil production from East Texas and the Permian Basin. Our oil production increased in 2004 due to increased oil production from our River Ridge discovery in the Permian Basin. For 2006, we are targeting our total natural gas and crude oil production to be approximately 74.0 Bcfe to 76.0 Bcfe, which equates to a growth rate of approximately 21% to 25% above our 2005 production volumes.

Our gas sales to unaffiliated purchasers were 51.7 Bcf in 2005, compared to 45.0 Bcf in 2004 and 32.1 Bcf in 2003. All of our oil production is sold to unaffiliated purchasers. This gas and oil production is sold under contracts that reflect current short-term prices and which are subject to seasonal price swings. These combined gas and oil sales to unaffiliated purchasers accounted for 90% of total E&P revenues in 2005, 89% in 2004 and 86% in 2003. In 2005, the largest unaffiliated purchaser accounted for 6% of total E&P revenues.

Our utility subsidiary, Arkansas Western is the largest single customer for sales of our gas production. These sales are made by SEECO primarily under contracts obtained under a competitive bidding process. We refer you to "Natural Gas Distribution — Gas Purchases and Supply" for further discussion of these contracts. Sales to Arkansas Western accounted for approximately 9% of total E&P revenues in 2005, 10% in 2004 and 12% in 2003. SEECO's sales to Arkansas Western were 5.1 Bcf in 2005, compared to 5.4 Bcf in 2004 and 5.9 Bcf in 2003. Sales to Arkansas Western are primarily driven by the utility's changing supply requirements due to variations in the weather and SEECO's ability to obtain gas supply contracts that are periodically placed out for bids. SEECO's gas production provided approximately 38% of the utility's requirements in 2005, 40% in 2004 and 41% in 2003. We also sell gas directly to industrial and commercial transportation customers located on Arkansas Western's gas distribution systems. SEECO also owns an unregulated natural gas storage facility that has historically been utilized to help meet its peak seasonal sales commitments. The storage facility is connected to Arkansas Western's distribution system.

We expect future increases in our gas production to come primarily from sales to unaffiliated purchasers. Future sales to Arkansas Western's gas distribution systems will be dependent upon our success in obtaining gas supply contracts with the utility systems. We are unable to predict changes in the market demand and price for natural gas, including changes that may be induced by the effects of weather on demand of both affiliated and unaffiliated customers for our production.

We realized an average wellhead price of $6.51 per Mcf for our natural gas production in 2005, compared to $5.21 per Mcf in 2004 and $4.20 per Mcf in 2003, including the effect of hedges. Our hedging activities lowered our average gas price $1.22 per Mcf in 2005, $0.59 per Mcf in 2004, and $0.95 per Mcf in 2003. Our average oil price realized was $42.62 per barrel in 2005, compared to $31.47 per barrel in 2004 and $26.72 per barrel in 2003, including the effect of hedges. Our hedging activities lowered our average oil price $11.75 per barrel in 2005, $9.08 per barrel in 2004 and $2.94 per barrel in 2003.

We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas and crude oil production in order to support certain desired levels of cash flow and to minimize the impact of price fluctuations. Our policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings. At December 31, 2005, we had hedges in place on 50.9 Bcf of 2006 gas production, 40.0 Bcf of 2007 gas production, 2.0 Bcf of 2008 gas production and 120,000 barrels of 2006 oil production. Subsequent to December 31, 2005 and prior to February 20, 2006, we hedged 6.0 Bcf of 2008 gas production under costless collars with floor prices ranging from $7.00 to $9.00 per Mcf and ceiling prices ranging from $12.55 to $15.80 per Mcf. As of December 31, 2005, we had hedges in place on approximately 70% to 75% of our targeted 2006 gas production and approximately 15% to 20% of our targeted crude oil production. We refer you to Item 7A of this Form 10-K, "Quantitative and Qualitative Disclosures About Market Risks," for further information regarding our hedge position at December 31, 2005.

Disregarding the impact of hedges, the average price received for our gas production has historically been approximately $0.30 to $0.50 per Mcf lower than average spot market prices, however, during 2005, widening market differentials caused the difference in our average price received to be approximately $0.90 per Mcf. Assuming a NYMEX commodity price for 2006 of $8.00 per Mcf of gas, our differential for the average price received for our gas production is expected to be approximately $0.60 to $0.70 per Mcf below the NYMEX Henry Hub index price, including the impact of our basis hedges. Disregarding the impact of hedges, based on the current price environment, we expect the average price received for our oil production during 2006 to be approximately $1.50 per barrel lower than average spot market prices, as market differentials reduce the average prices received.

Competition

All phases of the oil and gas industry are highly competitive. We compete in the acquisition of properties, the search for and development of reserves, the production and sale of natural gas and oil and the securing of the labor and equipment required to conduct operations. Our competitors include major oil and gas companies, other independent oil and gas companies and individual producers and operators. Many of these competitors have financial and other resources that substantially exceed those available to us.

Competition in Arkansas has increased in recent years due largely to the development of improved access to interstate pipelines. The competition for new leases in the Fayetteville Shale play has become especially intense. Due to our significant leasehold acreage position in Arkansas and our long-time presence and reputation in this area, we believe we will continue to be successful in acquiring new leases in Arkansas. While improved intrastate and interstate pipeline transportation in Arkansas should increase our access to markets for our gas production, these markets will generally be served by a number of other suppliers. Consequently, we will encounter competition that may affect both the price we receive and contract terms we must offer. Outside Arkansas, we are less established and face competition from a larger number of other producers.

Oil Price Controls and Transportation Rates

Sales of crude oil, condensate and gas liquids are not regulated and are made at negotiated prices. Effective January 1, 1995, the Federal Energy Regulatory Commission, or the FERC, implemented regulations establishing an indexing system for transportation rates for oil that allowed for an increase in the cost of transporting oil to the purchaser. The implementation of these regulations has not had a material adverse effect on our results of operations.

Federal Regulation of Sales and Transportation of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, or the NGA, the Natural Gas Policy Act of 1978, or the NGPA, and regulations promulgated thereunder by the FERC. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, or the Decontrol Act. The Decontrol Act removed all NGA and NGPA price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993 and sales by producers of natural gas can be made at uncontrolled market prices. With respect to transportation, commencing in 1992, the FERC issued Order No. 636 and subsequent orders (collectively, “Order No. 636”), which require interstate pipelines to provide transportation separately, or “unbundled,” from the pipelines’ sales of gas. Order No. 636 also requires pipelines to provide open-access transportation on a basis that is equal for all shippers. Although Order No. 636 does not directly regulate our activities, the FERC has stated that it intends for Order No. 636 to foster increased competition within all phases of the natural gas industry. Starting in 2000, the FERC issued Order No. 637 and subsequent orders (collectively, “Order No. 637”), which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC pricing policy by waiving price ceilings for short-term released capacity for a two-year period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, pipeline penalties, rights of first refusal and information reporting. Most major aspects of Order No. 637 were upheld on judicial review, though certain issues, such as capacity segmentation and rights of first refusal, were remanded to the FERC, which issued a remand order in October of 2002. In January of 2004, the FERC denied rehearing of its October 2002 remand order. Parties appealed such decision to the Court of Appeals for the District of Columbia in late 2004, but no decision has yet been reached. The implementation of these orders has not had a material adverse effect on our results of operations to date.

Starting on November 25, 2003, FERC issued Order No. 2004 and subsequent orders adopting new Standards of Conduct for transmission providers such as interstate natural gas pipelines. Every interstate natural gas pipeline was required to file a compliance plan and to be in compliance with the new standards by September 22, 2004. The primary focus of the new standards was to broaden regulation over certain conduct and interaction between transmission providers and a wider range of affiliates (referred to as “energy affiliates”), including intrastate/Hinshaw natural gas pipelines, processors and gatherers and any company involved in natural gas and electric markets, including gas marketing companies, even if they do not transport natural gas on the affiliated interstate natural gas pipeline. Most local distribution companies are exempt, however, unless they make off-system sales of natural gas to customers not physically connected to their systems. The Standards of Conduct mandate, inter alia, separate staffing of interstate natural gas pipelines and their energy affiliates (with certain exemptions for support staff and senior management at the corporate level), strict limitations on communications from an interstate natural gas pipeline to an energy affiliate, and certain disclosure requirements. The implementation of these orders has not had a material adverse effect on our results of operations to date.

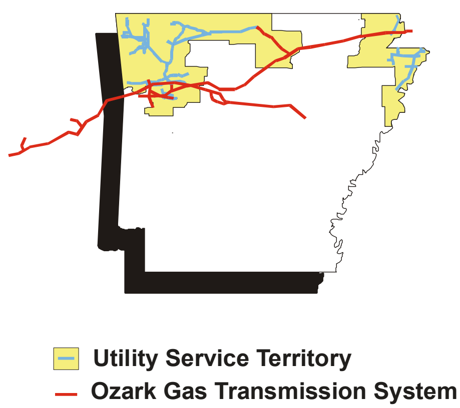
On August 8, 2005, President Bush signed into law the Domenici-Barton Energy Policy Act of 2005, or EP Act. The EP Act is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. With respect to regulation of natural gas transportation, the EP Act amends the NGA and the NGPA by increasing the criminal penalties available for violations of each act. The EP Act also adds a new section to the NGA that provides FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA. Before enactment of the EP Act, FERC was only authorized to impose criminal penalties for violations of the NGA (and criminal or civil penalties for violations of the NGPA).

We cannot predict whether and to what extent FERC's market reforms and the new energy legislation will survive judicial review and, if so, whether the FERC's actions will achieve the goal of increasing competition, lessening preferential treatment and enhancing transparency in markets in which our natural gas is sold. However, we do not believe that we will be disproportionately affected as compared to other natural gas producers and marketers by any action taken.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC and the courts. The natural gas industry historically has been heavily regulated; therefore, there can be no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

Natural Gas Distribution

We distribute natural gas to approximately 148,000 customers in northern Arkansas through our subsidiary, Arkansas Western Gas Company. Our utility is focused on capitalizing on the expanding economy and growth in customers in its Northwest Arkansas service territory. Approximately 66% of Arkansas Western's customers are located in the Fayetteville-Springdale-Rogers MSA, which the U.S. Census Bureau named as the 6th fastest growing MSA in the United States in 2001. In February 2006, the Milken Institute named Northwest Arkansas as the 8th "Best Performing City" in the United States, based upon job creation and local economic growth, attributable in part to the presence of Wal-Mart Stores, Inc., one of the largest public corporations in the world, and other large corporations such as Tyson Foods and J.B. Hunt Transportation.



Operating income for our natural gas distribution business was $4.9 million in 2005, compared to $8.5 million in 2004 and $6.8 million in 2003. EBITDA generated by our utility segment was $11.7 million in 2005, compared to $15.2 million in 2004 and $12.9 million in 2003. The decrease in 2005 operating income and EBITDA resulted primarily from increased operating costs and expenses and warmer than normal weather, which more than offset the rate increase that became effective October 31, 2005. The increase in 2004 operating income and EBITDA resulted primarily from rate increases implemented in late 2003, partially offset by increased operating costs and expenses. We refer you to "Business — Other Items — Reconciliation of Non-GAAP Measures" in Item 1 of Part I of this Form 10-K for a table that reconciles EBITDA with our net income as derived from our audited financial information. In recent years, Arkansas Western has experienced customer growth of approximately 3% annually in its Northwest Arkansas service territory, while it has experienced no customer growth in its service territory in Northeast Arkansas. Based on current economic conditions in our service territories, we expect this trend in customer growth to continue.

Gas Purchases and Supply

Arkansas Western purchases its system gas supply through a competitive bidding process implemented in October 1998, and directly at the wellhead under long-term contracts with flexible pricing provisions. In 2005, SEECO successfully bid on gas supply packages representing approximately 44% of the requirements for Arkansas Western for 2006, compared to approximately 55% for 2005 and 2004. The contracts awarded to SEECO expire through 2007.

Arkansas Western also purchases gas under its gas supply packages from unaffiliated suppliers accessed by interstate pipelines. These purchases are under firm contracts with one-year to two-year terms. The rates charged by most suppliers include demand components to ensure availability of gas supply and a commodity component that is based on monthly indexed market prices. The pipeline transportation rates include demand charges to reserve pipeline capacity and commodity charges based on volumes transported. Less than 4% of the utility's gas purchases are under take-or-pay contracts. Arkansas Western believes that it does not have a significant exposure to take-or-pay liabilities resulting from these contracts and expects to be able to continue to satisfactorily manage these contracts.

Arkansas Western has a regulated natural gas storage facility connected to its distribution system in Northwest Arkansas that it utilizes to help meet its peak seasonal demands. The utility also owns a liquefied natural gas facility and contracts with an interstate pipeline for additional storage capacity to serve its system in the northeastern part of the state. 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.

The utility's rate schedules include a cost of gas rider whereby the actual cost of purchased gas above or below the projected level included in the rates is permitted to be billed or is required to be credited to customers. The difference between actual costs of purchased gas and gas costs recovered from customers is deferred each month and are billed or credited, as appropriate, to customers in subsequent months.

Arkansas Western enters into hedging activities from time to time with respect to its gas purchases to protect against the inherent price risks of adverse price fluctuations. Our gas distribution segment hedged 4.2 Bcf of gas purchases in 2005 which had the effect of increasing its total gas supply costs by $2.4 million. In 2004, our utility hedged 4.5 Bcf of its gas supply which decreased its total gas supply cost by $1.1 million. In 2003, our utility hedged 4.6 Bcf of its gas supply which decreased its total gas supply cost by $6.1 million. At December 31, 2005, Arkansas Western had 1.8 Bcf of future gas purchases hedged at an average purchase price of $12.71 per Mcf. We refer you to "Quantitative and Qualitative Disclosures About Market Risk" and Note 8 to the consolidated financial statements for additional information.

Markets and Customers

Arkansas Western provides natural gas to approximately 131,000 residential, 17,000 commercial, and 170 industrial customers, while also providing gas transportation services to approximately 115 end-use and off-system customers. Total gas throughput in 2005 was 23.2 Bcf, compared to 25.0 Bcf in 2004 and 2003. The lower volumes in 2005 primarily resulted from variations in weather and customer conservation brought about by high gas prices in recent years. Weather in 2005 was 9% warmer than normal and 1% colder than in 2004. Weather in 2004 was 10% warmer than normal and 9% warmer than in 2003.

Residential and Commercial. Approximately 89% of the utility's revenues in 2005 were from residential and commercial markets. Residential and commercial customers combined accounted for 57% of total gas throughput for the gas distribution segment in 2005 and 2004, compared to 60% in 2003. Gas volumes sold to residential customers were 8.1 Bcf in 2005, compared to 8.5 Bcf in 2004 and 9.0 Bcf in 2003. Gas sold to commercial customers totaled 5.1 Bcf in 2005, 5.7 Bcf in 2004 and 6.1 Bcf in 2003. The fluctuations in gas volumes sold to both residential and commercial customers were driven primarily by variations in the weather and customer conservation. 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 as tariffs implemented contain a weather normalization clause to lessen the impact of revenue increases and decreases that might result from weather variations during the winter heating season.

Industrial and End-use Transportation. Deliveries to Arkansas Western's industrial and end-use transportation customers were 10.0 Bcf in 2005, 9.8 Bcf in 2004 and 9.6 Bcf in 2003. No industrial customer accounts for more than 10% of Arkansas Western's total throughput. Arkansas Western offers a transportation service that allows larger business customers to obtain their own gas supplies directly from other suppliers. Off-system transportation volumes were less than 0.1 Bcf in 2005, 1.0 Bcf in 2004 and 0.3 Bcf in 2003, all to the Ozark Gas Transmission System. The level of off-system deliveries each year generally reflects the changes of on-system demands of our gas distribution systems for our gas production. As of December 31, 2005, a total of 115 customers used the end-use transportation service.

Competition

Arkansas Western has historically maintained a price advantage over alternative fuels such as electricity, fuel oil, and propane for most applications, enabling it to achieve excellent market penetration levels. However, Arkansas Western has experienced a general trend in recent years toward lower rates of usage among its customers, largely as a result of conservation efforts, as well as increasing competition from alternative fuels that has eroded its price advantage. Arkansas Western also has the ability to enter into special contracts with larger commercial and industrial customers that contain lower pricing provisions than the approved tariffs. These contracts can be used to meet competition from alternate fuels or threats of bypass and must be approved by the APSC.

Regulation

Arkansas Western's rates and operations are regulated by the APSC and it operates through municipal franchises that are perpetual by virtue of state law. These franchises, however, may not be exclusive within a geographic area. As the regulatory focus of the natural gas industry has shifted from the federal level to the state level, some utilities across the nation are required to unbundle residential sales services from transportation services in an effort to promote greater competition. There is no such legislation in Arkansas and no regulatory directives related to natural gas are presently pending. In recent years, there have been efforts by the Arkansas legislature and the APSC concerning the issues of deregulation of the retail sale of electricity and a large-user access program for electric service choice. Legislation adopted in 2001 for deregulation of the retail sale of electricity was repealed in 2003 and no legislative action has been taken regarding implementing a large-user access program.

In April 2002, the APSC adopted Natural Gas Procurement Plan Rules for utilities. These rules require utilities to take all reasonable and prudent steps necessary to develop a diversified gas supply portfolio. The portfolio should consist of an appropriate combination of different types of gas purchase contracts and/or financial hedging instruments that are designed to yield an optimum balance of reliability, reduced volatility and reasonable price. Utilities are also required to submit on an annual basis their gas supply plan, along with their contracting and/or hedging objectives, to the staff of the APSC for review and determination as to whether it is consistent with these policy principles.

Arkansas Western also purchases gas from unaffiliated producers under take-or-pay contracts. We believe that we do not have significant exposure to liabilities resulting from these contracts and expect to be able to continue to satisfactorily manage our exposure to take-or-pay liabilities.

In October 2005, in response to Arkansas Western's request for a $9.7 million rate increase, the APSC approved a rate increase totaling $4.6 million annually, exclusive of costs to be recovered through Arkansas Western's purchase gas adjustment clause. The rate increase was effective for deliveries made to customers on or after October 31, 2005. The request relating to the October 2005 increase assumed a rate of return of 11.5% and a capital structure of 50% debt and 50% equity. The APSC order provided for an allowed return on equity of 9.7% and as assumed capital structure of 54% debt and 46% equity. In its order approving the rate increase, the APSC stated that it would consider in future generic proceedings, certain regulatory changes including a streamlined rate case process, a revenue decoupling mechanism designed to encourage efficiency and conservation, and a performance based methodology designed to allow a variable return on equity adjustment within a reasonable range.

On January 6, 2006, the APSC approved AWG's Home Weatherization Program, the first customer funded energy efficiency program in Arkansas. Under this three year pilot program, AWG will assist qualifying customers in making certain home weatherization improvements to their homes to make their homes more energy efficient. AWG will recover the cost of this program, including any lost margin revenues, from its customers.

On January 12, 2006, the APSC initiated a Notice of Inquiry regarding a rulemaking for developing and implementing energy efficiency programs. In this proceeding, the APSC will address all aspects of energy efficiency programs, including, the best programs for Arkansas, cost recovery and incentive mechanisms to encourage utilities to participate in energy efficiency programs.

In September 2003, in response to our request for an $11.0 million rate increase, Arkansas Western received regulatory approval from the APSC of a rate increase totaling $4.1 million annually, exclusive of costs to be recovered through Arkansas Western's purchase gas adjustment clause. The order also entitled Arkansas Western to recover certain additional costs totaling $2.3 million through its purchase gas adjustment clause over a two-year period. The rate increase was effective for all customer bills rendered on or after October 1, 2003.

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.

Gas distribution revenues in future years will be impacted by customer growth, customer usage and rate increases allowed by the APSC. We refer you to "Risk Factors — We incur substantial costs to comply with government regulations, especially regulations relating to environmental protection, and could incur even greater costs in the future" in Item 1A of Part I of this Form 10-K for a discussion of the impact of government regulation on our natural gas distribution business.

Midstream Services

Our Midstream Services segment generates revenue through the marketing of our own gas production and some third-party natural gas and through gathering fees associated with the transportation of natural gas to market.

Gas Marketing

Our gas marketing subsidiary, Southwestern Energy Services Company, was formed in 1996 to better enable us to capture downstream opportunities which arise through marketing and transportation activity. Our current marketing operations primarily relate to the marketing of our own gas production and some third-party natural gas that is primarily sold to industrial customers connected to our gas distribution systems. Our operating income from marketing was $5.8 million on revenues of $458.9 million in 2005, compared to $3.2 million on revenues of $315.0 million in 2004, and $2.6 million on revenues of $202.0 million in 2003. We marketed 61.9 Bcf of natural gas in 2005, compared to 57.0 Bcf in 2004 and 42.7 Bcf in 2003. The increase in revenues is largely attributable to increased volumes marketed and higher purchased gas costs. The increase in operating income during 2005 was primarily due to higher marketing margins on natural gas sales caused in large part by the increased volatility of locational market differentials in our core operating areas. In late 2000, we began marketing less third-party natural gas in an effort to reduce our potential credit risk and concentrated more on marketing our affiliated production. Of the total volumes marketed, purchases from our E&P subsidiaries accounted for 76% in 2005, 77% in 2004 and 75% in 2003. Our E&P subsidiaries have accounted for an increasing percentage of our total volumes marketed because of a shift in our focus to marketing our own production in order to reduce our credit risk.

Gas Gathering

In 2004, we formed a new subsidiary, DeSoto Gathering Company, L.L.C., that will be engaging in gathering activities related to the development of our Fayetteville Shale play. During 2005, we invested approximately $15.8 million related to those activities and had gathering revenues of $1.0 million in 2005. Gathering revenues and expenses for this segment are expected to continue to grow in the future as gathering systems for our Fayetteville Shale play are constructed to support the development of this play.

Competition

Our gas marketing activities compete with numerous other companies offering the same services, many of which possess larger financial and other resources than we have. 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 to pipelines and other transportation facilities. We believe that our ability to compete effectively within the marketing segment in the future depends upon establishing and maintaining strong relationships with producers and end-users.

Transportation and Other

We hold a 25% interest in NOARK, a partnership that owns a 723-mile integrated interstate pipeline system with a total throughput capacity of 330.0 MMcf per day, known as Ozark Gas Transmission System, which became operational November 1, 1998. On October 31, 2005, Atlas Pipeline Partners, L.P. purchased the remaining 75% interest in NOARK from Enogex, Inc., a wholly-owned subsidiary of OGE Energy Corp., for $165.3 million.

The average daily throughput for the pipeline was 182.4 MMcf per day in 2005, compared to 155.0 MMcf per day in 2004 and 115.0 MMcf per day in 2003. The increase in throughput over this time is primarily due to increased gas marketing efforts and widening basis differentials. Arkansas Western has a transportation contract with Ozark Gas Transmission System for 66.9 MMcf per day of firm capacity that expires in 2014. Deliveries are made by the pipeline to portions of Arkansas Western's distribution systems and to the interstate pipelines with which it interconnects. Additionally, Midstream Services has transportation contracts with Ozark Gas Transmission System for a total of 20.0 MMcf per day of firm capacity through 2006.

Our share of NOARK's results of operations was a pre-tax gain of $1.6 million in 2005, compared to a pre-tax loss of $0.4 million in 2004, and a pre-tax gain of $1.1 million in 2003. The pre-tax gain in 2005 was primarily due the increase in volumes transported and higher transportation rates collected for those volumes. The pre-tax loss in 2004 was due primarily to a $0.4 negative adjustment from the operator of the pipeline for prior period allocations of income and expenses to the partners. In the first quarter of 2003, NOARK sold a 28-mile portion of its pipeline located in Oklahoma that had limited strategic value to the overall system. Sales proceeds to NOARK were $10.0 million and our share of the proceeds was $2.5 million, resulting in a pre-tax gain to us of $1.3 million recorded in the first quarter of 2003. The improvements experienced recently in operating results of NOARK result primarily from the ability to collect higher transportation rates on interruptible volumes.

The Ozark Gas Transmission System primarily competes with one other interstate pipeline to obtain gas supplies for transportation to other markets. We believe that the Ozark Gas Transmission System will be able to obtain the additional future gas supplies necessary to compete effectively for the transportation of natural gas to end-users and markets served by the interstate pipelines.

The Ozark Gas Transmission System is an interstate pipeline system subject to FERC regulations and FERC-approved tariffs. The FERC has set the maximum transportation rate of Ozark Gas Transmission System at $0.2867 per dekatherm, plus fuel charges.

Historically, our other operations have consisted of the activities of our wholly owned subsidiary, A. W. Realty Company, a company with real estate development activities concentrated on tracts of land located near our offices in Fayetteville, Arkansas. During 2005, we sold approximately 1.6 acres of commercial real estate located in Fayetteville, Arkansas for a pre-tax gain of $0.4 million. During 2004, we sold 45.5 acres of commercial real estate located in Fayetteville, Arkansas for a pre-tax gain of $5.8 million. During 2003, we sold 18.5 acres of commercial real estate for a pre-tax gain of $1.7 million, and we sold certain fixed assets for a pre-tax gain of $1.3 million. These amounts were reflected in "Gas transportation and other" revenues in our income statement. As of December 31, 2005, A. W. Realty Company owned an interest in approximately 15 acres of undeveloped real estate.

Other Items

Reconciliation of Non-GAAP Measures

EBITDA is defined as net income plus interest, income tax expense, depreciation, depletion and amortization. We have included information concerning EBITDA in this Form 10-K because it is used by certain investors as a measure of the ability of a company to service or incur indebtedness and because it is a financial measure commonly used in our industry. EBITDA should not be considered in isolation or as a substitute for net income, net cash provided by operating activities or other income or cash flow data prepared in accordance with generally accepted accounting principles or as a measure of our profitability or liquidity. EBITDA as defined above may not be comparable to similarly titled measures of other companies.

We believe that net income is the financial measure calculated and presented in accordance with generally accepted accounting principles that is most directly comparable to EBITDA as defined. The following table reconciles EBITDA as defined with our net income, as derived from our audited financial information for the years-ended December 31, 2005, 2004 and 2003:

2005	E&P	Natural Gas Distribution	Midstream Services & Other	Total
Net income	$ 144,349	$ 203	$ 3,208	**$ 147,760**
Depreciation, depletion and amortization	89,229	7,010	402	**96,641**
Net interest expense	8,416	4,429	2,195	**15,040**
Provision for income taxes	83,921	11	2,499	**86,431**
EBITDA	$ 325,915	$ 11,653	$ 8,304	**$ 345,872**
2004				
Net income	$ 96,307	$ 2,617	$ 4,652	**$ 103,576**
Depreciation, depletion and amortization	68,065	6,696	158	**74,919**
Net interest expense	11,537	4,461	994	**16,992**
Provision for income taxes	55,197	1,471	3,110	**59,778**
EBITDA(1)	$ 231,106	$ 15,245	$ 8,914	**$ 255,265**
2003				
Net income	$ 43,713	$ 1,423	$ 3,761	**$ 48,897**
Depreciation, depletion and amortization	50,334	6,356	143	**56,833**
Net interest expense	11,911	4,395	1,005	**17,311**
Provision for income taxes (2)	25,486	767	2,119	**28,372**
EBITDA(1)	$ 131,444	$ 12,941	$ 7,028	**$ 151,413**

(1) Revised from prior years' presentation to exclude the amortization of restricted stock issued under our incentive compensation plans.

(2) Provision for income taxes for 2003 includes the tax benefit associated with the cumulative effect of adoption of accounting principle.

Environmental Matters

Our operations are subject to numerous federal, state and local laws and regulations including the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, 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. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. Although future environmental obligations are not expected to have a material impact on the results of our operations or financial condition, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause us to incur material environmental liabilities or costs.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as those in the natural gas and oil industry in general. Although we believe that we are in substantial compliance with applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us, there can be no assurance that this trend will continue in the future.

The Oil Pollution Act, as amended, or the OPA, and regulations thereunder impose a variety of requirements on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States' waters. A "responsible party" includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by OPA. OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

CERCLA, also known as the "Superfund law," imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that transported or disposed or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Resource Conservation and Recovery Act, as amended, or the RCRA, generally does not regulate wastes generated by the exploration and production of natural gas and oil. The RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy." However, legislation has been proposed in Congress from time to time that would reclassify certain natural gas and oil exploration and production wastes as "hazardous wastes," which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as the natural gas and oil industry in general. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

We own or lease, and have in the past owned or leased, onshore properties that for many years have been used for or associated with the exploration and production of natural gas and oil. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, a portion of these properties have been operated by third parties whose treatment and disposal or release of wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, the Clean Water Act, the RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

The Federal Water Pollution Control Act, as amended, or the FWPCA, imposes restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into navigable waters. Permits must be obtained to discharge pollutants to waters and to conduct construction activities in waters and wetlands. The FWPCA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. Many state discharge regulations and the Federal National Pollutant Discharge Elimination System general permits issued by the Environmental Protection Agency, or the EPA, prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the natural gas and oil industry into coastal waters. Although the costs to comply with zero discharge mandates under federal or state law may be significant, the entire industry is expected to experience similar costs and we believe that these costs will not have a material adverse impact on our results of operations or financial position. The EPA has adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans.

Employees

At December 31, 2005, we had 784 total employees, including 358 employed by our natural gas utility, of which 24 are represented under a collective bargaining agreement. We believe that our relationships with our employees are good.

GLOSSARY OF CERTAIN INDUSTRY TERMS

The definitions set forth below shall apply to the indicated terms as used in this Form 10-K. All volumes of natural gas referred to herein are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

"<u>Bcf</u>" One billion cubic feet of gas.

"Bcfe" One billion cubic feet of gas equivalent. Determined using the ratio of one barrel of crude oil to six Mcf of natural gas.

"Bbl" One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

"Btu" British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

"Dekatherm" A thermal unit of energy equal to 1,000,000 British thermal units (Btu's), that is, the equivalent of 1,000 cubic feet of gas having a heating content of 1,000 Btu's per cubic foot.

"Development drilling" The drilling of a well within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

"Downspacing" The process of drilling additional wells within a defined producing area to increase recovery of natural gas and oil from a known reservoir.

"EBITDA" Represents net income attributable to common stock plus interest, income taxes, depreciation, depletion and amortization. We refer you to "Business — Other Items — Reconciliation of Non-GAAP Measures" in Item 1 of Part I of this Form 10-K for a table that reconciles EBITDA with our net income as derived from our audited financial information.

"Exploratory prospects or locations" A location where a well is drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir or to extend a known reservoir.

"Finding and development costs" Costs associated with acquiring and developing proved natural gas and oil reserves which are capitalized pursuant to generally accepted accounting principles, including any capitalized general and administrative expenses.

"Gross acreage or gross wells" The total acres or wells, as the case may be, in which a working interest is owned.

"Infill drilling" Drilling wells in between established producing wells, see also "Downspacing."

"LIBOR" Represents the London Inter-Bank Overnight Rate of interest.

"MBbls" One thousand barrels of crude oil or other liquid hydrocarbons.

"Mcf" One thousand cubic feet of natural gas.

"Mcfe" One thousand cubic feet of natural gas equivalent. Determined using the ratio of one barrel of crude oil to six Mcf of natural gas.

"MMBbls" One million barrels of crude oil or other liquid hydrocarbons.

"MMBtu" One million Btu's.

"MMcf" One million cubic feet of natural gas.

"MMcfe" One million cubic feet of natural gas equivalent. Determined using the ratio of one barrel of crude oil to six Mcf of natural gas.

"Net acres or net wells" The sum of the fractional working interests owned in gross acres or gross wells.

"Net revenue interest" Economic interest remaining after deducting all royalty interests, overriding royalty interests and other burdens from the working interest ownership.

"NYMEX" The New York Mercantile Exchange.

"Operating interest" An interest in natural gas and oil that is burdened with the cost of development and operation of the property.

"Play" A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and gas reserves.

"Producing property" A natural gas and oil property with existing production.

"Proved developed reserves" Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. For additional information, see the SEC's definition in Rule 4-10(a)(3) of Regulation S-X, which is available at the SEC's website, http://www.sec. gov/divisions/corpfin/forms/regsx.htm#gas.

"Proved reserves" The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. For additional information, see the SEC's definition in Rule 4-10(a)(2)(i) through (iii) of Regulation S-X, which is available at the SEC's website, http://www.sec. gov/divisions/corpfin/forms/regsx.htm#gas.

"Proved undeveloped reserves" Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units that offset productive units and that are reasonably certain of production when drilled. For additional information, see the SEC's definition in Rule 4-10(a)(4) of Regulation S-X, which is available at the SEC's website, http://www.sec. gov/divisions/corpfin/forms/regsx.htm#gas.

"PV-10" When used with respect to natural gas and oil reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date of the report or estimate, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%. Also referred to as "present value." After-tax PV-10 is also referred to as "standardized measure" and is net of future income tax expense.

"PVI" A measure that is computed for projects by dividing the dollars invested into the PV-10 resulting from the investment.

"Recomplete" This term refers to the technique of drilling a separate well-bore from all existing casing in order to reach the same reservoir, or redrilling the same well-bore to reach a new reservoir after production from the original reservoir has been abandoned.

"Royalty interest" An interest in a natural gas and oil property entitling the owner to a share of oil or gas production free of production costs.

"Step-out well" A well drilled adjacent to a proven well but located in an unproven area; a well located a "step out" from proven territory in an effort to determine the boundaries of a producing formation.

"Undeveloped acreage" Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

"Well spacing" The regulation of the number and location of wells over an oil or gas reservoir, as a conservation measure. Well spacing is normally accomplished by order of the regulatory conservation commission. The order may be statewide in its application (subject to change for local conditions) or it may be entered for each field after its discovery.

"Working interest" An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and to receive a share of production.

"Workovers" Operations on a producing well to restore or increase production.

"WTI" West Texas Intermediate, the benchmark crude oil in the United States.

ITEM 1A. RISK FACTORS

In addition to the other information included in this Form 10-K, the following risk factors should be considered in evaluating our business and future prospects. The risk factors described below are not necessarily exhaustive and investors are encouraged to perform their own investigation with respect to us and our business. Investors should also read the other information included in this Form 10-K, including our financial statements and the related notes and "Management's Discussion and Analysis of Financial Condition and Results of Operations — Forward-Looking Information."

Natural gas and oil prices are volatile. Volatility in natural gas and oil prices can adversely affect our results and the price of our common stock. This volatility also makes valuation of natural gas and oil producing properties difficult and can disrupt markets.

Natural gas and oil prices have historically been, and are likely to continue to be, volatile. The prices for natural gas and oil are subject to wide fluctuation in response to a number of factors, including:

- relatively minor changes in the supply of and demand for natural gas and oil;
- market uncertainty;
- worldwide economic conditions;
- weather conditions;
- import prices;
- political conditions in major oil producing regions, especially the Middle East;
- actions taken by OPEC;
- competition from other sources of energy; and
- economic, political and regulatory developments.

Price volatility makes it difficult to budget and project the return on exploration and development projects involving our natural gas and oil properties and to estimate with precision the value of producing properties that we may own or propose to acquire. In addition, unusually volatile prices often disrupt the market for natural gas and oil properties, as buyers and sellers have more difficulty agreeing on the purchase price of properties. Our quarterly results of operations may fluctuate significantly as a result of, among other things, variations in natural gas and oil prices and production performance. In recent years, natural gas and oil price volatility has become increasingly severe.

A substantial or extended decline in natural gas and oil prices would have a material adverse affect on us.

Natural gas and oil prices have recently been at or near their highest historical levels. A substantial or extended decline in natural gas and oil prices would have a material adverse effect on our financial position, our results of operations, our access to capital and the quantities of natural gas and oil that may be economically produced by us. A significant decrease in price levels for an extended period would negatively affect us in several ways including:

- our cash flow would be reduced, decreasing funds available for capital expenditures employed to replace reserves or increase production;
- certain reserves would no longer be economic to produce, leading to both lower proved reserves and cash flow; and
- access to other sources of capital, such as equity or long-term debt markets, could be severely limited or unavailable.

Consequently, our revenues and profitability would suffer.

Lower natural gas and oil prices may cause us to record ceiling test write-downs.

We use the full cost method of accounting for our natural gas and oil operations. Accordingly, we capitalize the cost to acquire, explore for and develop natural gas and oil properties. Under the full cost accounting rules of the SEC, the capitalized costs of natural gas and oil properties - net of accumulated depreciation, depletion and amortization, and deferred income taxes - may not exceed a "ceiling limit." This is equal to the present value of estimated future net cash flows from proved natural gas and oil reserves, discounted at 10 percent, plus the lower of cost or fair value of unproved properties included in the costs being amortized, net of related tax effects.

These rules generally require pricing future natural gas and oil production at the unescalated natural gas and oil prices in effect at the end of each fiscal quarter, including the impact of derivatives qualifying as hedges. They also require a write-down if the ceiling limit is exceeded, even if prices declined for only a short period of time. Once a write-down is taken, it cannot be reversed in future periods even if natural gas and oil prices increase.

If natural gas and oil prices fall significantly, a write-down may occur. Write-downs required by these rules do not impact cash flow from operating activities but do reduce net income and shareholders' equity.

We may have difficulty financing our planned capital expenditures which could adversely affect our growth.

We have experienced and expect to continue to experience substantial capital expenditure and working capital needs, particularly as a result of our drilling program. Our planned capital expenditures for 2006 are expected to significantly exceed the net cash generated by our operations. We expect to borrow under our credit facility to fund capital expenditures that are in excess of our net cash flow and the remaining proceeds of our 2005 equity offering. Our ability to borrow under our credit facility is subject to certain conditions. At December 31, 2005, we were in compliance with the borrowing conditions of our credit facility. If we are not in compliance with the terms of our credit facility in the future, we may not be able to borrow under it to fund our capital expenditures. We also cannot be certain that other additional financing will be available to us on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail our drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis. Any such curtailment or sale could have a material adverse effect on our results and future operations.

Although our estimated natural gas and oil reserve data is independently audited, our estimates may still prove to be inaccurate.

Our reserve data represents the estimates of our reservoir engineers made under the supervision of our management. Our reserve estimates are audited each year by Netherland, Sewell & Associates, Inc., an independent petroleum engineering firm. In conducting its audit, the engineers and geologists of Netherland, Sewell & Associates study our major properties in detail and independently develop reserve estimates. The estimates of Netherland, Sewell & Associates, Inc. may differ significantly on an individual property basis from our estimates. When, in the aggregate, such differences are within 10%, Netherland, Sewell & Associates, Inc. is generally satisfied that the estimates of proved reserves are reasonable.

Reserve estimates are prepared for each of our properties annually by the reservoir engineers assigned to the asset management team in the geographic locations in which the property is located. These estimates are reviewed by senior engineers who are not part of the asset management teams and by the president of our E&P subsidiaries. Finally, the estimates of our proved reserves together with the audit report of Netherland, Sewell & Associates, Inc. are reviewed by our Board of Directors. There are numerous uncertainties and risks that are inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and timing of development expenditures as many factors are beyond our control. We incorporate many factors and assumptions into our estimates including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices and quality and locational differentials; and
- future development and operating costs.

Although we believe our assumptions are reasonable based on the information available to us at the time we prepare our estimates, our actual results could vary considerably from estimated quantities of proved natural gas and oil reserves (in the aggregate and for a particular geographic location), production, revenues, taxes and development and operating expenditures. In addition, our estimates of reserves may be subject to downward or upward revision based upon production history, results of future exploration and development, prevailing natural gas and oil prices, operating and development costs and other factors. In 2003, reserves were revised downward by 15.5 Bcfe due to poorer-than-expected well performance related to our South Louisiana properties. In 2004, the reserves were also revised downward by 12.7 Bcfe due primarily to slightly higher decline rates related to some of the wells in our Overton Field in East Texas. In 2005, our reserves were revised downward by 31.7 Bcfe, primarily due to continued unexpected declines associated with our Gulf Coast properties and minor changes to decline rates for our wells at the Overton Field. These revisions represented no greater than 4% of our total reserve estimates in each of these years, which we believe is indicative of the effectiveness of our internal controls. Because we review our reserve projections for every property at the end of every year, any material change in a reserve estimate is included in subsequent reserve reports.

Finally, recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. At December 31, 2005, approximately 27% of our estimated proved reserves were undeveloped. Our reserve data assume that we can and will make these expenditures and conduct these operations successfully, which may not occur. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Forward-Looking Information" in Item 7A of Part II of this Form 10-K for additional information regarding the uncertainty of reserve estimates.

Our future level of indebtedness may adversely affect operations and limit our growth.

At December 31, 2005, we had long-term indebtedness of $100.0 million, excluding our several guarantee of NOARK's debt obligation, none of which was indebtedness under our revolving credit facility. As of February 20, 2006, no bank indebtedness was outstanding under our existing $500 million revolving credit facility. However, as indicated in the risk factor headed "We may have difficulty financing our planned capital expenditures which could adversely affect our growth" above, we also expect to incur significant additional indebtedness in order to fund a portion of capital expenditures in 2006.

The terms of the indenture relating to our outstanding senior notes and our revolving credit facility impose significant restrictions on our ability and, in some cases, the ability of our subsidiaries to take a number of actions that we may otherwise desire to take, including:

- incurring additional debt, including guarantees of indebtedness;
- redeeming stock or redeeming debt;
- making investments;
- creating liens on our assets; and
- selling assets.

Our level of indebtedness, and the covenants contained in the agreements governing our debt, could have important consequences for our operations, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate and other activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- detracting from our ability to successfully withstand a downturn in our business or the economy generally.

Our ability to comply with the covenants and other restrictions in the agreements governing our debt may be affected by events beyond our control, including prevailing economic and financial conditions. If we fail to comply with the covenants and other restrictions, it could lead to an event of default and the acceleration of our repayment of outstanding debt. We may not have sufficient funds to make such repayments. If we are unable to repay our debt out of cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We cannot assure you that we will be able to generate sufficient cash flow to pay the interest on our debt or that future borrowings, equity financings or proceeds from the sale of assets will be available to pay or refinance such debt. The terms of our debt, including our credit facility and our indentures, may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We cannot assure you that any such proposed offering, refinancing or sale of assets can be successfully completed or, if completed, that the terms will be favorable to us.

If we fail to find or acquire additional reserves, our reserves and production will decline materially from their current levels.

The rate of production from natural gas and oil properties generally declines as reserves are depleted. Except to the extent that we acquire additional properties containing proved reserves, conduct successful exploration and development activities, successfully apply new technologies or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline materially as reserves are produced. Future natural gas and oil production is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves.

Our drilling plans for the Fayetteville Shale play are subject to change.

As of December 31, 2005, we have spud 88 wells relating to our Fayetteville Shale play. The wells were drilled in areas that represent a very small sample of our large acreage position. Our drilling plans with respect to our Fayetteville Shale play are flexible and are dependent upon a number of factors, including the extent to which we can replicate the results of our most successful Fayetteville Shale wells on our other Fayetteville Shale acreage as well as the natural gas and oil commodity price environment. The determination as to whether we continue to drill prospects in the Fayetteville Shale may depend on any one or more of the following factors:

- our ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation;
- material changes in natural gas prices;
- changes in the estimates of costs to drill or complete wells;
- the extent of our success in drilling and completing horizontal wells;
- our ability to reduce our exposure to costs and drilling risks;
- the costs and availability of drilling equipment;
- success or failure of wells drilled in similar formations or which would use the same production facilities;
- receipt of additional seismic or other geologic data or reprocessing of existing data;
- the extent to which we are able to effectively operate the drillings rigs we acquire; or
- availability and cost of capital.

We continue to gather data about our prospects in the Fayetteville Shale, and it is possible that additional information may cause us to alter our drilling schedule or determine that prospects in some portion of our acreage position should not be pursued at all.

We may have difficulty drilling all of the wells that are necessary to hold our Fayetteville Shale acreage before the initial lease terms expire, which could result in the loss of certain leasehold rights.

Approximately 25,737 net acres of our Fayetteville Shale acreage will expire in the next three years if we do not drill successful wells to develop the acreage or otherwise take action to extend the leases. As discussed above under "Our drilling plans for the Fayetteville Shale play are subject to change," our ability to drill wells may depend on a number of factors, including certain factors that are beyond our control. The number of wells we will be required to drill to retain our leasehold rights will be determined by field rules established by the Arkansas Oil and Gas Commission or the AOGC. Through February 20, 2006, the AOGC has approved field rules for five of our fields in the Fayetteville Shale play, establishing drilling units of 640 acres and well spacing requirements within each drilling unit of 560 feet minimum distance between completions in common sources of supply within the Fayetteville Shale formation, up to a maximum of 25 wells per drilling unit. There can be no assurance that we will be successful in obtaining the same size drilling unit or the same spacing within each drilling unit in the field rules for our other pilot areas or for our other Fayetteville Shale acreage as a whole. To the extent that the field rules for our other pilot areas or our other Fayetteville Shale acreage are less favorable, we may not be able to drill the wells required to maintain our leasehold rights for certain of our Fayetteville Shale acreage.

If our Fayetteville Shale drilling program fails to produce a significant supply of natural gas, our investments in our gas gathering operations could be lost, which could have an adverse effect on our results of operations, financial condition and cash flows.

As of December 31, 2005, we had invested approximately $15.8 million in our gas gathering operations and we intend to invest approximately $37.5 million in 2006. Our gas gathering business will largely rely on gas sourced in our Fayetteville Shale play area in Arkansas. If our Fayetteville Shale drilling program fails to produce a significant supply of natural gas, our investments in our gas gathering operations could be lost, which could have an adverse effect on our results of operations, financial condition and cash flows.

Our exploration, development and drilling efforts and our operations of our wells may not be profitable or achieve our targeted returns.

We require significant amounts of undeveloped leasehold acreage in order to further our development efforts. Exploration, development, drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We invest in property, including undeveloped leasehold acreage that we believe will result in projects that will add value over time. However, we cannot assure you that all prospects will result in viable projects or that we will not abandon our initial investments. Additionally, there can be no assurance that leasehold acreage acquired by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for natural gas and oil may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting drilling, operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target PVI results are dependent upon the current and future market prices for natural gas and crude oil, costs associated with producing natural gas and crude oil and our ability to add reserves at an acceptable cost. We rely to a significant extent on seismic data and other advanced technologies in identifying leasehold acreage prospects and in conducting our exploration activities. The seismic data and other technologies we use do not allow us to know conclusively prior to acquisition of leasehold acreage or drilling a well whether natural gas or oil is present or may be produced economically. The use of seismic data and other technologies also requires greater pre-drilling expenditures than traditional drilling strategies.

In addition, we may not be successful in implementing our business strategy of controlling and reducing our drilling and production costs in order to improve our overall return. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including unexpected drilling conditions, title problems, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions, environmental and other governmental requirements and the cost of, or shortages or delays in the availability of, drilling rigs, equipment and services.

We incur substantial costs to comply with government regulations, especially regulations relating to environmental protection, and could incur even greater costs in the future.

Our exploration, production, development and gas distribution and marketing operations are regulated extensively at the federal, state and local levels. We have made and will continue to make large expenditures in our efforts to comply with these regulations, including environmental regulation. The natural gas and oil regulatory environment could change in ways that might substantially increase these costs. Hydrocarbon-producing states regulate conservation practices and the protection of correlative rights. These regulations affect our operations and limit the quantity of hydrocarbons we may produce and sell. In addition, at the U.S. federal level, the Federal Energy Regulatory Commission regulates interstate transportation of natural gas under the Natural Gas Act. Other regulated matters include marketing, pricing, transportation and valuation of royalty payments.

As an owner or lessee and operator of natural gas and oil properties, and an owner of gas gathering, transmission and distribution systems, we are subject to various federal, state and local regulations relating to discharge of materials into, and protection of, the environment. These regulations may, among other things, impose liability on us for the cost of pollution clean-up resulting from operations, subject us to liability for pollution damages, and require suspension or cessation of operations in affected areas. Changes in or additions to regulations regarding the protection of the environment could significantly increase our costs of compliance, or otherwise adversely affect our business.

One of the responsibilities of owning and operating natural gas and oil properties is paying for the cost of abandonment. Effective January 1, 2003, companies were required to reflect abandonment costs as a liability on their balance sheets. We may incur significant abandonment costs in the future which could adversely affect our financial results.

Natural gas and oil drilling and producing operations involve various risks.

Our operations are subject to all the risks normally incident to the operation and development of natural gas and oil properties and the drilling of natural gas and oil wells, including encountering well blowouts, cratering and explosions, pipe failure, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, release of contaminants into the environment and other environmental hazards and risks.

We maintain insurance against many potential losses or liabilities arising from our operations in accordance with customary industry practices and in amounts that we believe to be prudent. However, our insurance does not protect us against all operational risks. For example, we do not maintain business interruption insurance. Additionally, pollution and environmental risks generally are not fully insurable. These risks could give rise to significant costs not covered by insurance that could have a material adverse effect upon our financial results.

We cannot control activities on properties we do not operate. Failure to fund capital expenditure requirements may result in reduction or forfeiture of our interests in some of our non-operated projects.

We do not operate some of the properties in which we have an interest and we have limited ability to exercise influence over operations for these properties or their associated costs. Approximately 22% of our gas and oil properties, based on PV10 value, are operated by other companies. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and our targeted production growth rate. The success and timing of drilling, development and exploitation activities on properties operated by others depend on a number of factors that are beyond our control, including the operator's expertise and financial resources, approval of other participants for drilling wells and utilization of technology.

When we are not the majority owner or operator of a particular natural gas or oil project, we may have no control over the timing or amount of capital expenditures associated with such project. If we are not willing or able to fund our capital expenditures relating to such projects when required by the majority owner or operator, our interests in these projects may be reduced or forfeited.

Shortages of oil field equipment, services and qualified personnel could adversely affect our results of operations.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the natural gas and oil industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. There have also been shortages of drilling rigs and other equipment, as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher natural gas and oil prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. We cannot be certain when we will experience shortages or price increases, which could adversely affect our profit margin, cash flow and operating results or restrict our ability to drill wells and conduct ordinary operations.

Our business could be adversely affected by competition with other companies.

The natural gas and oil industry is highly competitive, and our business could be adversely affected by companies that are in a better competitive position. As an independent natural gas and oil company, we frequently compete for reserve acquisitions, exploration leases, licenses, concessions, marketing agreements, equipment and labor against companies with financial and other resources substantially larger than we possess. Many of our competitors may be able to pay more for exploratory prospects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, many of our competitors have been operating in some of our core areas for a much longer time than we have or have established strategic long-term positions in geographic regions in which we may seek new entry.

We have recently made significant investments in our drilling rig operations; however, we are still dependent on third party drilling companies. We also lack experience in owning and operating drilling rigs.

We have recently made significant investments in commencing our drilling rig operations, including commitments to purchase ten drilling rigs and hiring, as of December 31, 2005, 45 new employees for our drilling subsidiary, DeSoto Drilling, Inc, or DDI. We expect DDI to have a total of approximately 275 employees by year end 2006. The ten drilling rigs will not be sufficient to meet the needs of our drilling program and we will still be dependent upon third party rig providers in order to execute our drilling program in 2006 and beyond. There can be no assurance that the commencement of our drilling rig operations will not have an adverse effect on our relationships with our existing third party rig providers or our ability to secure third party rigs from other providers. We may also compete with third party rig providers for qualified personnel, which could adversely affect our relationships with rig providers. If our existing third party rig providers discontinue their relationships with us, we may not be able to secure alternative rigs on a timely basis, or at all. Even if we are able to secure alternative rigs, there can be no assurance that replacement rigs will be of equivalent quality or that pricing and other terms will be favorable to us. If we are unable to secure third party rigs or if the terms are not favorable to us, our financial condition and results of operations could be adversely affected.

In addition, we have no prior experience in owning and operating drilling rigs. We cannot assure you that we will be able to attract and retain qualified field personnel to operate our drilling rigs or to otherwise effectively conduct our drilling operations. If we are unable to retain qualified personnel or to effectively conduct our drilling operations, our financial and operating results may be adversely affected.

We depend upon our management team and our operations require us to attract and retain experienced technical personnel.

The successful implementation of our business strategy and handling of other issues integral to the fulfillment of our business strategy depends, in part, on our experienced management team, as well as certain key geoscientists, geologists, engineers and other professionals employed by us. The loss of key members of our management team or other highly qualified technical professionals could have a material adverse effect on our business, financial condition and operating results.

Our hedging activities may prevent us from benefiting from price increases and may expose us to other risks.

To reduce our exposure to fluctuations in the prices of natural gas and oil, we enter into hedging arrangements with respect to a portion of our expected production. As of December 31, 2005, we had hedges on approximately 70% to 75% of our targeted 2006 natural gas production and approximately 15% to 20% of our targeted 2006 oil production. Our price risk management activities reduced revenues by $77.2 million in 2005, $35.6 million in 2004 and $37.4 million in 2003. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of price increases above the levels of the hedges.

In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

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

In addition, future market price volatility could create significant changes to the hedge positions recorded on our financial statements. We refer you to “Quantitative and Qualitative Disclosures about Market Risk” in Item 7A of Part II of this Form 10-K

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES

For additional information about our natural gas and oil operations, we refer you to Notes 5 and 6 to the financial statements. For information concerning capital expenditures, we refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Capital Expenditures." We also refer you to Item 6, "Selected Financial Data," of Part II of this Form 10-K for information concerning natural gas and oil produced.

The following information is provided to supplement the information that is presented in Item 8 of Part II of this Form 10-K. For a further description of our natural gas and oil properties, we refer you to "Business — Exploration and Production."

Leasehold acreage as of December 31, 2005:

	Undeveloped		Developed	
	Gross	Net	Gross	Net
Conventional Arkoma(1)	351,118	240,917	293,437	187,032
Fayetteville Shale Play(2)	1,067,487	719,680	20,480	19,614
East Texas(3)	22,837	16,991	22,471	19,095
Permian Basin	15,334	7,255	91,839	27,571
Gulf Coast	13,739	6,351	27,394	11,039
Exploration and New Ventures	136,172	116,633	-	-
	1,606,687	1,107,827	455,621	264,351

(1) Includes 123,442 net developed acres and 1,431 net undeveloped acres that are within our Fayetteville Shale focus area that are not included under the Fayetteville Shale Play.

(2) Assuming that the Company does not drill successful wells to develop the acreage or does not attempt to extend the leases in our undeveloped acreage in the Fayetteville Shale play, leasehold expiring over the next three years will be 1,724 net acres in 2006, 4,185 net acres in 2007 and 19,828 net acres in 2008.

(3) Assuming that the Company does not drill successful wells to develop the acreage or does not attempt to extend the leases in our undeveloped acreage in the Angelina River Trend in East Texas, leasehold expiring over the next three years will be 565 net acres in 2006, 2,489 net acres in 2007 and 7,141 net acres in 2008.

Producing wells as of December 31, 2005:

	Gas		Oil		Total		Gross Wells
	Gross	Net	Gross	Net	Gross	Net	Operated
Conventional Arkoma	952	468.4	-	-	952	468.4	419
Fayetteville Shale Play	54	51.7	-	-	54	51.7	54
East Texas	281	264.1	2	2.0	283	266.1	239
Permian Basin	141	24.0	269	129.9	410	153.9	41
Gulf Coast	46	20.9	11	6.2	57	27.1	18
	1,474	829.1	282	138.1	1,756	967.2	771

Wells drilled during the year:

	Exploratory					
	Productive Wells		Dry Holes		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2005	15.0	13.4	2.0	1.8	17.0	15.2
2004	16.0	15.2	5.0	3.7	21.0	18.9
2003	9.0	5.6	1.0	0.6	10.0	6.2

	Development					
	Productive Wells		Dry Holes		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2005	182.0	141.7	6.0	3.3	188.0	145.0
2004	150.0	113.0	9.0	2.8	159.0	115.8
2003	101.0	74.6	15.0	5.2	116.0	79.8

Wells in progress as of December 31, 2005:

	Gross	Net
Exploratory	17.0	13.3
Development	25.0	22.8
Total	42.0	36.1

During 2005, we were required to file Form 23, "Annual Survey of Domestic Natural Gas and Oil 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 consolidated financial statements in Item 8 to this Form 10-K. The primary differences are that Form 23 reports gross reserves, including the royalty owners' share, and includes reserves for only those properties of which we are the operator.

Miles of Pipe:

The following table provides information concerning miles of pipe of our gas distribution systems. For a further description of Arkansas Western's properties, we refer you to "Business — Natural Gas Distribution."

	Total
Gathering	393
Transmission	1,032
Distribution	4,131
	5,556

Title to Properties

We believe that we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to customary royalty and overriding royalty interests, certain contracts relating to the exploration, development, operation and marketing of production from such properties, consents to assignment and preferential purchase rights, liens for current taxes, applicable laws and other burdens, encumbrances and irregularities in title, which we believe do not materially interfere with the use of or affect the value of such properties. Prior to acquiring undeveloped properties, we perform a title investigation that is thorough but less vigorous than that conducted prior to drilling, which is consistent with standard practice in the oil and gas industry. Before we commence drilling operations on properties that we operate, we conduct a thorough title examination and perform curative work with respect to significant defects before proceeding with operations. We have performed a thorough title examination with respect to substantially all of our active properties that we operate.

ITEM 3. LEGAL PROCEEDINGS

We are subject to laws and regulations relating to the protection of the environment. Our 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 our financial position or reported results of operations.

We are subject to litigation and claims that have arisen in the ordinary course of business. Management believes, individually or in aggregate, such litigation and claims will not have a material adverse impact on our financial position or our results of operations but these matters are subject to inherent uncertainties and management's view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position and the results of operations for the period in which the effect becomes reasonably estimable. We accrue for such items when a liability is both probable and the amount can be reasonably estimated.

A lawsuit was filed against us in 2001 alleging a breach of an agreement to indemnify the other party against settlement payments related to our Boure' prospect in Louisiana. The allegations were contested and, in 2002, we were granted a motion for summary judgment by the trial court. The case was appealed to the First Court of Appeals in Houston, Texas, which subsequently transferred the appeal to the Thirteenth Court of Appeals in Corpus Christi. The appeal was briefed and argued during 2003. On April 14, 2005, the Thirteenth Court of Appeals reversed the orders of the trial court and rendered judgment denying our motion for summary judgment and granting the motion for summary judgment of the other party. Our motion for rehearing with the Thirteenth Court of Appeals was denied on May 19, 2005. In August of 2005, we filed a petition for review with the Texas Supreme Court. In October of 2005, the Texas Supreme Court invited additional briefing by the parties, which both parties have done. The matter is currently pending before the Texas Supreme Court. Should the other party prevail on the appeal, we could be required to pay approximately $2.1 million, plus pre-judgment interest and attorney's fees. Based on an assessment of this litigation by us and our legal counsel, no accrual for loss is currently recorded.

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

No matters were submitted to a vote of security holders, through the solicitation of proxies or otherwise, during the fourth quarter of the fiscal year ended December 31, 2005.

Executive Officers of the Registrant

Name	Officer Position	Age	Years Served as Officer
Harold M. Korell	President, Chief Executive Officer and Chairman of the Board	61	9
Greg D. Kerley	Executive Vice President and Chief Financial Officer	50	16
Richard F. Lane	Executive Vice President and President, Southwestern Energy Production Company and SEECO, Inc.	48	7
Mark K. Boling	Executive Vice President, General Counsel and Secretary	48	4
Gene A. Hammons	President, Southwestern Midstream Services Company	60	1
Alan N. Stewart	President, Arkansas Western Gas Company	61	2

Mr. Korell was elected as Chairman of the Board in May 2002 and has served as Chief Executive Officer since January 1999 and President since October 1998. He joined us 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 Executive Vice President of Southwestern Energy Company and promoted to President, SEECO, Inc. and Southwestern Energy Production Company in December 2005. He was appointed to the position of Executive Vice President, SEECO, Inc. and Southwestern Energy Production Company in December 2001. Previously, he served as Senior Vice President from February 2001 and Vice President-Exploration from February 1999. Mr. Lane joined us 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. Boling was appointed to his present position in December 2002. He joined us as Senior Vice President, General Counsel and Secretary in January 2002. Prior to joining the Company, Mr. Boling had a private law practice in Houston specializing in the natural gas and oil industry from 1993 to 2002. Previously, Mr. Boling was a partner with Fulbright and Jaworski L.L.P. where he was employed from 1982 to 1993.

Mr. Hammons was promoted to President of Southwestern Midstream Services Company in December 2005. He joined the company in July 2005 as Vice President of Southwestern Midstream Services Company. Prior to joining us, he provided consulting services to clients in the natural gas industry. Previously, Mr. Hammons was employed by El Paso Natural Gas Company and Burlington Resources and held managerial positions in facility design and installation, gathering management and marketing over the course of his combined 28-year tenure.

Mr. Stewart was promoted to President of Arkansas Western Gas Company in December 2005. He joined the company in March 2004 as Executive Vice President of Arkansas Western Gas Company. Prior to joining the Company, he provided professional consulting services for clients in the energy and LNG industries in California. Previously, Mr. Stewart was employed with San Diego Gas and Electric Company and Southern California Gas Company where he served in a wide range of managerial and leadership positions during a 31-year career.

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 our directors.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on the New York Stock Exchange under the symbol "SWN." At February 24, 2006, we had 2,148 shareholders of record. The following table presents the prices for closing market transactions on the New York Stock Exchange, which have been adjusted as appropriate to reflect the two-for-one stock splits effected in June 2005 and November 2005.

	Range of Market Prices			
Quarter Ended	**2005**		**2004**	
March 31	$15.47	$11.22	$6.11	$4.84
June 30	$23.49	$14.20	$7.17	$5.97
September 30	$37.18	$24.78	$10.60	$7.42
December 31	$41.15	$31.30	$13.73	$10.33

We have indefinitely suspended payment of quarterly cash dividends on our common stock.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth a summary of selected historical financial information for each of the years in the five-year period ended December 31, 2005. This information and the notes thereto are derived from our financial statements. We refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Financial Statements and Supplementary Data."

	2005	2004	2003	2002	2001
	(in thousands except share, per share, shareholder data and percentages)				
Financial Review					
Operating revenues					
Exploration and production	**$ 403,234**	$ 286,924	$ 176,245	$ 122,207	$ 153,937
Gas distribution	**178,482**	152,449	137,356	115,850	147,282
Midstream services and other	**460,783**	321,226	205,449	131,514	190,773
Intersegment revenues	**(366,170)**	(283,462)	(191,649)	(108,069)	(147,065)
	676,329	477,137	327,401	261,502	344,927
Operating costs and expenses					
Gas purchases – gas distribution	**82,689**	64,311	52,585	48,388	68,161
Gas purchases – midstream services	**124,730**	60,804	39,428	37,927	68,010
Operating and general	**101,500**	78,231	70,479	64,600	64,108
Depreciation, depletion and amortization	**96,211**	73,674	55,948	53,992	52,899
Taxes, other than income taxes	**25,279**	17,830	11,619	10,090	9,080
	430,409	294,850	230,059	214,997	262,258
Operating income	**245,920**	182,287	97,342	46,505	82,669
Interest expense, net	**(15,040)**	(16,992)	(17,311)	(21,466)	(23,699)
Other income (expense)	**4,784**	(362)	797	(566)	(799)
Minority interest in partnership	**(1,473)**	(1,579)	(2,180)	(1,454)	(930)
Income before income taxes and accounting change	**234,191**	163,354	78,648	23,019	57,241
Income taxes					
Current	**—**	—	—	—	—
Deferred	**86,431**	59,778	28,896	8,708	21,917
	86,431	59,778	28,896	8,708	21,917
Income before accounting change	**147,760**	103,576	49,752	14,311	35,324
Cumulative effect of adoption of accounting principle	**—**	—	(855)	—	—
Net income	**$ 147,760**	$ 103,576	$ 48,897	$ 14,311	$ 35,324
Return on equity	**13.3%**	23.1%	14.3%	8.1%	19.3%
Net cash provided by operating activities	**$ 304,482**	$ 237,897	$ 109,099	$ 77,574	$ 144,583
Net cash used in investing activities	**$ (452,918)**	$ (285,448)	$ (161,656)	$ (64,469)	$ (110,862)
Net cash provided by (used in) financing activities	**$ 370,906**	$ 47,509	$ 52,144	$ (15,056)	$ (32,466)
Common Stock Statistics [(1)]					
Earnings per share:					
Basic	**$ 0.98**	$ 0.72	$ 0.37	$ 0.14	$ 0.35
Diluted	**$ 0.95**	$ 0.70	$ 0.36	$ 0.14	$ 0.34
Cash dividends declared and paid per share	**$ —**	$ —	$ —	$ —	$ —
Book value per average diluted share	**$ 7.10**	$ 3.03	$ 2.49	$ 1.70	$ 1.79
Market price at year-end	**$ 35.94**	$ 12.67	$ 5.98	$ 2.86	$ 2.60
Number of shareholders of record at year-end	**2,126**	2,022	2,026	2,079	2,124
Average diluted shares outstanding	**156,309,039**	147,851,088	136,951,736	104,208,952	102,404,440

(1) Prior year numbers restated to reflect two-for-one stock splits effected in June and November 2005, except for "Number of shareholders of record at year-end."

	2005	2004	2003	2002	2001
Capitalization (in thousands)					
Total debt	**$ 100,000**	$ 325,000	$ 278,800	$ 342,400	$ 350,000
Common shareholders' equity(1)	**1,110,304**	447,677	341,561	177,488	183,086
Total capitalization	**$ 1,210,304**	$ 772,677	$ 620,361	$ 519,888	$ 533,086
Total assets	**$ 1,868,524**	$ 1,146,144	$ 890,710	$ 740,162	$ 743,123
Capitalization ratios:					
Debt	**8.3%**	42.1%	44.9%	65.9%	65.7%
Equity	**91.7%**	57.9%	55.1%	34.1%	34.3%
Capital Expenditures (in millions) (2)					
Exploration and production	**$ 451.3**	$ 282.0	$ 170.9	$ 85.2	$ 99.0
Gas distribution	**10.9**	7.3	8.2	6.1	5.3
Midstream services	**15.8**	—	—	—	—
Other	**5.1**	5.7	1.1	0.8	1.8
	$ 483.1	$ 295.0	$ 180.2	$ 92.1	$ 106.1
Exploration and Production					
Natural gas:					
Production, Bcf	**56.8**	50.4	38.0	36.0	35.5
Average price per Mcf, including hedges	**$ 6.51**	$ 5.21	$ 4.20	$ 3.00	$ 3.85
Average price per Mcf, excluding hedges	**$ 7.73**	$ 5.80	$ 5.15	$ 3.11	$ 4.16
Oil:					
Production, MBbls	**705**	618	531	682	719
Average price per barrel, including hedges	**$ 42.62**	$ 31.47	$ 26.72	$ 21.02	$ 23.55
Average price per barrel, excluding hedges	**$ 54.37**	$ 40.55	$ 29.66	$ 23.94	$ 23.58
Total gas and oil production, Bcfe	**61.0**	54.1	41.2	40.1	39.8
Lease operating expenses per Mcfe	**$ .48**	$ .38	$ .39	$ .45	$ .45
Taxes other than income taxes per Mcfe	**$ .37**	$ .28	$ .22	$ .19	$ .17
Proved reserves at year-end:					
Natural gas, Bcf	**772.3**	594.5	457.0	374.6	355.8
Oil, MBbls	**9,079**	8,508	7,675	6,784	7,704
Total reserves, Bcfe	**826.8**	645.5	503.1	415.3	402.0
Gas Distribution					
Sales and transportation volumes, Bcf:					
Residential	**8.1**	8.5	9.0	9.0	8.4
Commercial	**5.1**	5.7	6.1	6.2	6.1
Industrial	**1.2**	1.3	1.2	1.5	2.5
End-use transportation	**8.8**	8.5	8.4	8.4	7.0
	23.2	24.0	24.7	25.1	24.0
Off-system transportation (3)	**—**	1.0	0.3	2.2	3.1
	23.2	25.0	25.0	27.3	27.1
Customers at year-end:					
Residential	**130,654**	127,622	124,776	122,906	119,856
Commercial	**16,996**	16,815	16,623	16,448	16,177
Industrial	**170**	175	174	189	209
	147,820	144,612	141,573	139,543	136,242
Degree days	**3,744**	3,678	3,969	3,950	3,654
Percent of normal	**91%**	90%	99%	98%	91%

(1) Shareholders' equity included accumulated other comprehensive losses of $104.9 million in 2005 ($99.8 million related to our cash flow hedges and $5.1 million related to our pension plan), $19.8 million in 2004 ($18.8 million related to our cash flow hedges and $1.0 million related to our pension plan), $12.5 million in 2003 ($12.0 million related to our cash flow hedges and $0.5 million related to our pension plan), and $17.4 million in 2002 ($14.0 million related to our cash flow hedges and $3.4 million related to our pension plan), and accumulated other comprehensive income of $5.8 million in 2001 related to our cash flow hedges.

(2) Capital expenditures for 2005, 2004 and 2003 included $28.1 million, $3.9 million and $12.0 million, respectively, related to the change in accrued expenditures between years.

(3) 2005 off-system transportation volumes were less than 0.1 Bcf.

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

This Form 10-K contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in forward-looking statements for many reasons, including the risks described in "Risk Factors" and elsewhere in this annual report. You should read the following discussion with the "Selected Financial Data" and our financial statements and related notes included elsewhere in this Form 10-K. All historical per share information in the "Selected Financial Data," financial statements, footnotes and "Management's Discussion and Analysis of Financial Condition and Results of Operations" have been adjusted to reflect the two-for-one stock splits effected on June 3, 2005 and November 17, 2005.

OVERVIEW

Southwestern Energy Company is an independent energy company primarily focused on natural gas. Our primary business is the exploration, development and production of natural gas and crude oil within the United States, with operations principally located in Arkansas, Oklahoma, Texas, New Mexico and Louisiana. We are also focused on creating and capturing additional value at and beyond the wellhead through our established natural gas distribution, marketing and transportation businesses and our expanding gathering activities. Our marketing and our gas gathering businesses are collectively referred to as our Midstream Services. We operate principally in three segments: Exploration and Production (or E&P), Natural Gas Distribution and Midstream Services.

Our business strategy is focused on providing long-term growth in the net asset value of our business, which we achieve in our E&P business through the drillbit. In our E&P business, we prepare economic analyses for each of our drilling and acquisition opportunities and rank them based upon the expected present value added for each dollar invested, which we refer to as PVI. The PVI of the future expected cash flows for each project is determined using a 10% discount rate. We target creating at least $1.30 of discounted pre-tax PVI for each dollar we invest in our E&P projects. Our actual PVI results are utilized to help determine the allocation of our future capital investments.

We currently derive the vast majority of our operating income and cash flow from the natural gas production of our E&P business and expect this to continue in the future. We expect that growth in our operating income and revenues will primarily depend on natural gas prices and our ability to increase our natural gas production. There has been significant price volatility in the natural gas and crude oil market in recent years due to a variety of factors we cannot control or predict. These factors, which include weather conditions, political and economic events, and competition from other energy sources, impact supply and demand for natural gas. In addition, the price we realize for our gas production is affected by our hedging activities as well as locational differences in market prices. Our ability to increase our natural gas production is dependent upon our ability to economically find and produce natural gas, our ability to control costs, and our ability to market natural gas on economically attractive terms to our customers.

In 2005, our gas and oil production continued to increase, reaching 61.0 Bcfe, up from 54.1 Bcfe in 2004 and 41.2 Bcfe in 2003. The 13% increase in 2005 production resulted from a 5.4 Bcfe increase in production from our Overton Field in East Texas and a 1.9 Bcfe increase in our Arkoma production.

We reported net income of $147.8 million in 2005, or $0.95 per share on a fully diluted basis, up from $103.6 million, or $0.70 per share in 2004. In 2003, we reported net income of $48.9 million, or $0.36 per share on a fully diluted basis. The increases in net income in 2005 and 2004 were a result of increased production volumes and higher realized natural gas and oil prices in our E&P segment. Operating income for our E&P segment was $234.8 million in 2005, up from $164.6 million in 2004 and $84.7 million in 2003. The increases in operating income for our E&P segment in 2005 and 2004 were also due to increased production volumes and higher realized prices, partially offset by increased operating costs and expenses. Operating income for our gas distribution segment was $4.9 million in 2005, compared to $8.5 million in 2004 and $6.8 million in 2003. The decrease in operating income for our gas distribution segment in 2005 resulted primarily from warmer weather, increased customer conservation and increased operating costs and expenses. The increase in operating income for our gas distribution segment in 2004 resulted primarily from increased rates implemented in October 2003. Our gas distribution segment also implemented increased rates in October 2005 which will generate approximately $4.6 million of annual revenue. Our cash flow from operating activities was $304.5 million in 2005, compared to $237.9 million in 2004 and $109.1 million in 2003.

In our E&P segment, we achieved a reserve replacement ratio of 399% in 2005 at a finding and development cost of $1.71 per Mcfe, including reserve revisions, but excluding $35.1 million of capital invested in acquiring drilling rigs. Our year-end reserves grew 28% to 826.8 Bcfe, up from 645.5 Bcfe at the end of 2004. Our results were primarily fueled by the continued success of our drilling in our Overton Field in East Texas and our emerging Fayetteville Shale play in Arkansas.

Our capital investments totaled $483.1 million in 2005, up from $295.0 million in 2004 and $180.2 million in 2003. We invested $451.3 million in our E&P segment in 2005 (including $35.1 million invested in drilling rigs), compared to $282.0 million in 2004 and $170.9 million in 2003. Funds for our 2005 capital investments were provided by cash flow from operations and our follow-on equity offering in September 2005, which raised approximately $580.0 million, net of related expenses. We also applied a portion of the net proceeds of the equity offering to the repayment of our indebtedness. As a result, our total debt-to-capitalization ratio decreased to 8% at December 31, 2005 from 42% at December 31, 2004.

For 2006, planned capital investments of $830.1 million include $770.3 million for our E&P segment, which is an increase of 71% over our E&P capital investments in 2005. The $770.3 million of exploration and production investments includes $338.3 million for the accelerated development of our Fayetteville Shale play and $78.5 million for the fabrication of drilling rigs. We continue to be focused on our strategy of adding value through the drillbit, as approximately 80% of our 2006 E&P capital, excluding our investment in drilling rigs, is allocated to drilling. In addition to the planned investments in the Fayetteville Shale play, our E&P investments in 2006 will be focused on our lower-risk development drilling programs in East Texas and other conventional drilling in the Arkoma Basin. In 2006, we are targeting production to be approximately 74.0 Bcfe to 76.0 Bcfe, compared to 61.0 Bcfe in 2005, an increase of approximately 21% to 25%. We expect our capital investments in 2006 to be funded by cash flow from operations, the remaining net proceeds from our equity offering and borrowings under our revolving credit facility.

With today's commodity price environment, our current capital program and our inventory of projects for the future, we believe we are well-positioned to continue to build upon the momentum achieved in recent years.

RESULTS OF OPERATIONS

Exploration and Production

	Year Ended December 31,		
	2005	2004	2003
Revenues (in thousands)	**$403,234**	$286,924	$176,245
Operating income (in thousands)	**$234,759**	$164,585	$ 84,737
Gas production (Bcf)	**56.8**	50.4	38.0
Oil production (MBbls)	**705**	618	531
Total production (Bcfe)	**61.0**	54.1	41.2
Average gas price per Mcf, including hedges	**$ 6.51**	$ 5.21	$ 4.20
Average gas price per Mcf, excluding hedges	**$ 7.73**	$ 5.80	$ 5.15
Average oil price per Bbl, including hedges	**$ 42.62**	$ 31.47	$ 26.72
Average oil price per Bbl, excluding hedges	**$ 54.37**	$ 40.55	$ 29.66
Average unit costs per Mcfe			
Lease operating expenses	**$ 0.48**	$ 0.38	$ 0.39
General & administrative expenses	**$ 0.46**	$ 0.36	$ 0.41
Taxes other than income taxes	**$ 0.37**	$ 0.28	$ 0.22
Full cost pool amortization	**$ 1.42**	$ 1.20	$ 1.17

Revenues, Operating Income and Production

Revenues. Our E&P revenues increased 41% in 2005 to $403.2 million compared to $286.9 million in 2004. Higher prices received for our natural gas and oil production accounted for approximately 62% of the increase in 2005 revenues, with increased gas production volumes accounting for the remaining 38%. Revenues increased 63% in 2004 from $176.2 million in 2003. The increase was primarily due to increased gas production and higher prices received for our natural gas and oil production. Revenues for 2005, 2004 and 2003 also include pre-tax gains of $3.1 million, $4.5 million and $3.1 million, respectively, related to the sale of gas in storage inventory.

Operating Income. Operating income from our E&P segment was $234.8 million in 2005, up from $164.6 million in 2004 and $84.7 million in 2003. The increases in 2005 and 2004 were due to the increases in revenues, partially offset by increases in operating costs and expenses.

Production. Gas and oil production totaled 61.0 Bcfe in 2005, 54.1 Bcfe in 2004 and 41.2 Bcfe in 2003. The increase in 2005 production resulted from a 5.4 Bcfe increase in production from our Overton Field in East Texas and a 1.9 Bcfe increase in our Arkoma production, primarily from the Fayetteville Shale. Production during 2005 was reduced by the effect of the curtailment of a portion of our Overton Field production due to repairs of a transmission line that is not operated by us and by the effect of Hurricane Katrina. Combined, these events reduced our production by an estimated 1.0 Bcfe. The increase in 2004 production resulted primarily from an 8.2 Bcfe increase in production from our Overton Field in East Texas, a 1.3 Bcfe increase in our Arkoma Basin production, and 3.2 Bcfe from our River Ridge discovery in New Mexico. Although we expect production volumes in 2006 to increase primarily due to the development of our Fayetteville Shale play, we cannot guarantee our longer-term success in discovering, developing, and producing reserves. Our ability to discover, develop and produce reserves is dependent upon a number of factors, many of which are beyond our control, including the availability of capital, the timing and extent of changes in natural gas and oil prices and competition. There are also many risks inherent to the discovery, development and production of natural gas and oil. We refer you to "Risk Factors" in Item 1A of Part I of this Form 10-K for a discussion of these risks and the impact they could have on our financial condition and results of operations.

Gas sales to unaffiliated purchasers were 51.7 Bcf in 2005, up from 45.0 Bcf in 2004 and 32.1 Bcf in 2003. Sales to unaffiliated purchasers are primarily made under contracts that reflect current short-term prices and are subject to seasonal price swings. Intersegment sales to Arkansas Western were 5.1 Bcf in 2005, 5.4 Bcf in 2004 and 5.9 Bcf in 2003. We expect future increases in demand for our gas production to come primarily from sales to unaffiliated purchasers. Future sales to Arkansas Western's gas distribution systems will be dependent upon our success in obtaining gas supply contracts with the utility systems. We are unable to predict changes in the market demand and price for natural gas, including changes that may be induced by the effects of weather on demand of both affiliated and unaffiliated customers for our production. Additionally, we hold a large amount of undeveloped leasehold acreage and producing acreage, and have an inventory of drilling leads, prospects and seismic data that will continue to be evaluated and developed in the future. Our exploration programs have been and continue to be directed primarily toward natural gas.

Commodity Prices

We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas and crude oil production in order to ensure certain desired levels of cash flow and to minimize the impact of price fluctuations (we refer you to Item 7A of this Form 10-K and Note 8 to the consolidated financial statements for additional discussion). The average price realized for our gas production, including the effects of hedges, was $6.51 per Mcf in 2005, $5.21 per Mcf in 2004 and $4.20 per Mcf in 2003. The changes in the average price realized primarily reflect changes in average annual spot market prices and the effects of our price hedging activities. Our hedging activities lowered the average gas price $1.22 per Mcf in 2005, $0.59 per Mcf in 2004 and $0.95 per Mcf in 2003. Disregarding the impact of hedges, historically the average price received for our gas production has been approximately $0.30 to $0.50 per Mcf lower than average spot market prices due to locational market differentials that reduce the average prices received. In 2005, widening market differentials caused the difference in the average price received to be approximately $0.90 per Mcf. Assuming a NYMEX commodity price for 2006 of $8.00 per Mcf of gas, our differential for the average price received for our gas production is expected to be approximately $0.60 to $0.70 per Mcf below the NYMEX Henry Hub index price, including the impact of our basis hedges. As of December 31, 2005, we have hedged basis differentials on production volumes of 38.3 Bcf in 2006, 39.9 Bcf in 2007 and 2.0 Bcf in 2008 as a means to partially reduce the effect of market differentials on prices we receive.

We realized an average price of $42.62 per barrel, including the effects of hedges, for our oil production for the year ended December 31, 2005, up from $31.47 per barrel for 2004 and $26.72 per barrel for 2003. Our hedging activities lowered the average oil price by $11.75 per barrel in 2005, $9.08 per barrel in 2004 and $2.94 per barrel in 2003. Disregarding the impact of hedges, we expect the average price received for our oil production to be approximately $1.50 lower than posted spot market prices in 2006.

At December 31, 2005, we had commodity price hedges in place on 92.9 Bcf of 2006, 2007 and 2008 gas production and basis hedges on 80.2 Bcf of 2006, 2007 and 2008 gas production. At December 31, 2005, we had hedges in place on 120,000 barrels of 2006 oil production. Subsequent to December 31, 2005 and prior to February 20, 2006, we hedged an additional 6.0 Bcf of 2008 gas production under costless collars with floor prices ranging from $7.00 to $9.00 per Mcf and ceiling prices ranging from $12.55 to $15.80 per Mcf. Additionally, we hedged the basis differential on the 6.0 Bcf of 2008 gas production. As of February 20, 2006, we have hedged approximately 70% to 75% of our 2006 anticipated gas production level and 15% to 20% of our 2006 anticipated oil production level.

Operating Costs and Expenses

Lease operating expenses per Mcfe for the E&P segment were \$0.48 in 2005, up from \$0.38 in 2004 and \$0.39 in 2003. Lease operating expenses per unit of production increased in 2005 due primarily to increases in compression, saltwater disposal and gas processing costs as well as generally higher oil field service costs. We expect our average lease operating expenses per Mcfe for this segment to increase in the future as our Overton and conventional Arkoma producing fields that have lower per unit operating costs, as compared to our other producing areas, continue to mature. Additionally, inflationary pressures continue to have an impact in all of our operating areas. We do not have sufficient operating history for our Fayetteville Shale area to forecast with accuracy the future operating costs that we may incur related to the production from this area.

Taxes other than income taxes per Mcfe were \$0.37 in 2005, compared to \$0.28 in 2004 and \$0.22 in 2003. The increases in 2005 and 2004 taxes other than income taxes per Mcfe were primarily due to increased severance and ad valorem taxes that resulted from increases in commodity prices.

General and administrative expenses per Mcfe for this segment were \$0.46 in 2005, compared to \$0.36 in 2004 and \$0.41 in 2003. The increase in general and administrative costs per Mcfe in 2005 from 2004 was due primarily to increased payroll costs relating to the expansion of our E&P operations due to the Fayetteville Shale play and to increased incentive compensation costs. The number of employees in our E&P segment increased to 280 at December 31, 2005 from 147 at December 31, 2004. We expect our cost per Mcfe for operating and general and administrative expenses to increase in 2006 primarily due to anticipated increases in oil field service costs and a continued increase in our staffing levels to accommodate our future expected growth. Future changes in our general and administrative expenses for this segment are primarily dependent upon our salary costs, level of pension expense, option expensing under FAS 123(R) and the amount of incentive compensation paid to our employees. For eligible employees, incentive compensation is based on the achievement of certain operating and performance results, including targeted cash flow, production, proved reserve additions, present value added for each dollar of capital invested, and lease operating expenses and general and administrative expenses per unit of production. See “Critical Accounting Policies” below for further discussion of pension expense and “Adoption of Accounting Principles” for further discussion of option expensing under FAS 123(R).

Our full cost pool amortization rate averaged \$1.42 per Mcfe for 2005, compared to \$1.20 in 2004 and \$1.17 in 2003. The amortization rate is impacted by reserve additions and the costs incurred for those additions, revisions of previous reserve estimates due to both price and well performance, and the level of unevaluated costs excluded from amortization. Although we expect our amortization rate to continue to increase in the near term as a result of increased costs in finding and developing gas and oil reserves (see discussion on inflation below), we cannot predict our future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as the uncertainty of the future success of our Fayetteville Shale play. Unevaluated costs excluded from amortization were \$115.2 million at the end of 2005, compared to \$47.2 million at the end of 2004 and \$39.0 million at the end of 2003. The increase in unevaluated costs since December 31, 2004 resulted primarily from an increase in our undeveloped leasehold acreage related to our Fayetteville Shale play and increased drilling activity.

We utilize the full cost method of accounting for costs related to our natural gas and oil 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. Any costs in excess of this ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling. Full cost companies must use the prices in effect at the end of each accounting quarter, including the impact of derivatives qualifying as hedges, to calculate the ceiling value of their reserves. At December 31, 2005, 2004 and 2003, our unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At December 31, 2005, our standardized measure was calculated based upon quoted market prices of \$10.08 per Mcf for Henry Hub gas and \$61.04 per barrel for West Texas Intermediate oil, adjusted for market differentials. A significant decline in natural gas and oil prices from year-end 2005 levels or other factors, without other mitigating circumstances, could cause a future write-down of capitalized costs and a non-cash charge against future earnings.

Inflation impacts our E&P operations by generally increasing our operating costs and the costs of our capital additions. The effects of inflation on our operations prior to 2000 were minimal due to low inflation rates. However, since 2001, as commodity prices have increased, the impact of inflation has intensified in our E&P segment as shortages in drilling rigs, third-party services and qualified labor have risen due to increased activity levels in the natural gas and oil industry. This impact will continue to increase to the extent commodity prices remain high or further increase. We have endeavored to mitigate rising costs by obtaining vendor pricing commitments for multiple projects and by offering performance bonuses related to increased economic efficiencies.

Natural Gas Distribution

	Year Ended December 31,		
	2005	2004	2003
	($ in thousands except for per Mcf amounts)		
Revenues	**$178,482**	$152,449	$137,356
Gas purchases	**$120,852**	$ 97,274	$ 84,926
Operating costs and expenses	**$ 52,719**	$ 46,659	$ 45,664
Operating income	**$ 4,911**	$ 8,516	$ 6,766
Deliveries (Bcf)			
Sales and end-use and off-system transportation	**23.2**	25.0	25.0
Sales customers at year-end	**147,820**	144,612	141,573
Average sales rate per Mcf	**$ 11.85**	$ 9.39	$ 7.93
Heating weather - degree days	**3,744**	3,678	3,969
Percent of normal	**91%**	90%	99%

Revenues and Operating Income

Gas distribution revenues fluctuate due to the effects of warm weather on demand for natural gas and the pass-through of gas supply cost changes. Because of the corresponding changes in purchased gas costs, the revenue effect of the pass-through of gas cost changes has not materially affected operating income. Gas distribution revenues increased 17% in 2005 and 11% in 2004. The increase in 2005 gas distribution revenues was primarily due to higher average sales rates as a result of higher gas prices and to the effects of a $4.6 million annual rate increase implemented in October 2005. The increase in 2004 gas distribution revenues was primarily due to higher average sales rates as a result of higher gas prices and to the effects of a $4.1 million annual rate increase implemented in October 2003. Weather during 2005 in the utility's service territory was 9% warmer than normal and 1% colder than the prior year. Weather during 2004 in the utility's service territory was 10% warmer than normal and 9% warmer than the prior year.

Operating income for our gas distribution systems decreased 42% in 2005 and increased 26% in 2004. The decrease in 2005 operating income for this segment resulted primarily from increased operating costs and expenses along with warmer than normal weather. The increase in 2004 operating income for this segment resulted primarily from rate increases implemented in late 2003, partially offset by increased operating costs and expenses. Gas distribution revenues in future years will be impacted by the utility's gas purchase costs, customer growth, usage per customer and rate increases allowed by the Arkansas Public Service Commission, or APSC.

Deliveries and Rates

In 2005, Arkansas Western sold 14.4 Bcf to its customers at an average rate of $11.85 per Mcf, compared to 15.5 Bcf at $9.39 per Mcf in 2004 and 16.3 Bcf at $7.93 per Mcf in 2003. Additionally, Arkansas Western transported 8.8 Bcf in 2005, compared to 8.5 Bcf in 2004 and 8.4 Bcf in 2003 for its end-use customers. The decreases in volumes sold in 2005 and 2004 primarily resulted from variations in weather and customer conservation brought about by high gas prices in recent years. Arkansas Western's tariffs 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. The increase in the gas distribution segment's average sales rate for 2005 reflected changes in the average cost of gas purchased for delivery to our customers, which are passed through to customers under automatic adjustment clauses.

Total deliveries to industrial customers of the gas distribution segment, including transportation volumes, were 10.0 Bcf in 2005, 9.8 Bcf in 2004 and 9.6 Bcf in 2003. Changes in deliveries to industrial customers are impacted by customer conservation caused by high gas prices and by continued industrial growth in the region. Arkansas Western also transported less than 0.1 Bcf of gas through its gathering system in 2005, compared to 1.0 Bcf in 2004 and 0.3 Bcf in 2003 for off-system deliveries, all to the Ozark Gas Transmission System. The level of off-system deliveries each year generally reflects the impact of weather changing the on-system demands of our gas distribution systems for our gas production. The average off-system transportation rate was approximately $0.13 per Mcf, exclusive of fuel, in 2005, 2004 and 2003.

Future volumes delivered to customers will be impacted by customer growth, weather and the effect that gas prices will continue to have on customer conservation.

Operating Costs and Expenses

The changes in purchased gas costs for the gas distribution segment reflect volumes purchased, prices paid for supplies and the mix of purchases from various gas supply contracts (base load, swing and no-notice). Operating costs and expenses, net of purchased gas costs, increased in 2005 to $52.7 million from $46.7 million in 2004. The increase was primarily due to a $2.8 million increase in general and administrative expenses due to increased salaries and incentive compensation costs, and a $1.3 million increase in transmission expense as a result of higher fuel costs. Operating costs and expenses for 2004, net of purchased gas costs, increased to $46.7 million from $45.7 million in 2003 due primarily to a $0.6 million increase in transmission expense as a result of higher fuel costs and a $0.3 million increase in depreciation expense as a result of increases in property, plant and equipment. Future changes in our general and administrative expenses for this segment are primarily dependent upon our salary costs, level of pension expense, option expensing under FAS 123(R) and the amount of incentive compensation paid to our employees. See "Critical Accounting Policies" and "Adoption of Accounting Principles" below for further discussion of pension expense and option expensing, respectively.

In October 1998, Arkansas Western instituted a competitive bidding process for its gas supply. Additionally, Arkansas Western annually submits its gas supply plan to the general staff of the APSC. As a result of the bidding process under the plan filed for the 2005-2006 gas purchase year, SEECO successfully bid on gas supply packages representing approximately 44% of the requirements for Arkansas Western for 2006. The contracts awarded to SEECO expire through 2007. Arkansas Western enters into hedging activities from time to time with respect to its gas purchases to protect against the inherent price risks of adverse price fluctuations. Our gas distribution segment hedged 4.2 Bcf of gas purchases in 2005 which had the effect of increasing its total gas supply costs by $2.4 million. In 2004, our utility hedged 4.5 Bcf of its gas supply which decreased its total gas supply cost by $1.1 million. In 2003, our utility hedged 4.6 Bcf of its gas supply which decreased its total gas supply cost by $6.1 million. At December 31, 2005, Arkansas Western had 1.8 Bcf of future gas purchases hedged at an average purchase price of $12.71 per Mcf. We refer you to "Quantitative and Qualitative Disclosures About Market Risk" and Note 8 to the consolidated financial statements for additional information.

Inflation impacts our gas distribution segment by generally increasing our operating costs and the costs of our 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 us from obtaining immediate recovery of increased operating costs of our gas distribution segment.

Regulatory Matters

Arkansas Western's rates and operations are regulated by the APSC and it operates through municipal franchises that are perpetual by virtue of state law. These franchises, however, may not be exclusive within a geographic area. Although its rates for gas delivered to its retail customers are not regulated by the FERC, its transmission and gathering pipeline systems are subject to the FERC's regulations concerning open access transportation. As the regulatory focus of the natural gas industry has shifted from the federal level to the state level, some utilities across the nation are required to unbundle residential sales services from transportation services in an effort to promote greater competition. There is no such legislation in Arkansas and no regulatory directives related to natural gas are presently pending. In recent years, there have been efforts by the Arkansas legislature and the APSC concerning issues of deregulation of the retail sale of electricity and a large-user access program for electric service choice. Legislation adopted in 2001 for the deregulation of the retail sale of electricity was repealed in 2003 and no legislation has been taken regarding implementing a large-user access program.

In April 2002, the APSC adopted Natural Gas Procurement Plan Rules for utilities. These rules require utilities to take all reasonable and prudent steps necessary to develop a diversified gas supply portfolio. The portfolio should consist of an appropriate combination of different types of gas purchase contracts and/or financial hedging instruments that are designed to yield an optimum balance of reliability, reduced volatility and reasonable price. Utilities are also required to submit on an annual basis their gas supply plan, along with their contracting and/or hedging objectives, to the staff of the APSC for review and determination as to whether it is consistent with these policy principles.

Arkansas Western also purchases gas from unaffiliated producers under take-or-pay contracts. We believe that we do not have significant exposure to liabilities resulting from these contracts and expect to be able to continue to satisfactorily manage our exposure to take-or-pay liabilities.

In October 2005, in response to Arkansas Western's request for a $9.7 million rate increase, the APSC approved a rate increase totaling $4.6 million annually, exclusive of costs to be recovered through Arkansas Western's purchase gas adjustment clause. The rate increase was effective for deliveries made to customers on or after October 31, 2005. The request relating to the October 2005 increase assumed a rate of return of 11.5% and a capital structure of 50% debt and 50% equity. The APSC order provided for an allowed return on equity of 9.7% and as assumed capital structure of 54% debt and 46% equity. In its order approving the rate increase, the APSC stated that it would consider in future generic proceedings, certain regulatory changes including a streamlined ratecase process, a revenue decoupling mechanism designed to encourage efficiency and conservation, and a performance based methodology designed to allow a variable return on equity adjustment within a reasonable range.

In September 2003, in response to our request for an $11.0 million rate increase, Arkansas Western received regulatory approval from the APSC of a rate increase totaling $4.1 million annually, exclusive of costs to be recovered through Arkansas Western's purchase gas adjustment clause. The order also entitled Arkansas Western to recover certain additional costs totaling $2.3 million through its purchase gas adjustment clause over a two-year period. The rate increase was effective for all customer bills rendered on or after October 1, 2003.

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.

Midstream Services

	Year Ended December 31,		
	2005	2004	2003
Revenues (in millions)	**$ 459.9**	$ 315.0	$ 202.0
Gas purchases (in millions)	**$ 451.1**	$ 310.7	$ 198.1
Operating income (in millions)	**$ 5.7**	$ 3.2	$ 2.6
Gas volumes marketed (Bcf)	**61.9**	57.0	42.7

Our operating income from Midstream Services was $5.7 million on revenues of $459.9 million in 2005, compared to $3.2 million on revenues of $315.0 million in 2004 and $2.6 million on revenues of $202.0 million in 2003. The increase in revenues in 2005 resulted from increased volumes marketed and an increase in natural gas commodity prices. The increase in revenues from higher prices was largely offset by a corresponding increase in gas purchase expense. The increase in operating income during 2005 was primarily due to higher marketing margins on natural gas sales caused in large part by the increased volatility of locational market differentials in our core operating areas. We marketed 61.9 Bcf in 2005, compared to 57.0 Bcf in 2004 and 42.7 Bcf in 2003. The increase in volumes marketed in 2005 and 2004 resulted from marketing our increased production volumes, largely related to our Overton Field in East Texas. Of the total volumes marketed, production from our exploration and production subsidiaries accounted for 76% in 2005, 77% in 2004 and 75% in 2003. We enter into hedging activities from time to time with respect to our gas marketing activities to provide margin protection. We refer you to "Quantitative and Qualitative Disclosures About Market Risk" and Note 8 to the financial statements for additional discussion.

Midstream services also had gathering revenues of $1.0 million in 2005 related to gathering systems it owns in Arkansas. Gathering revenues and expenses for this segment are expected to continue to grow in the future as gathering systems supporting our Fayetteville Shale play are constructed.

Transportation

At December 31, 2005, we owned a 25% interest in the Ozark Gas Transmission System. We recorded pre-tax income from operations related to our investment of $1.6 million in 2005, compared to a pre-tax loss of $0.4 million in 2004 and pre-tax income of $1.1 million in 2003. These amounts are recorded in other income (expense) in our income statement. The increase in pre-tax income in 2005 results from an increase in volumes transported and higher transportation rates collected for those volumes. The pre-tax loss in 2004 was primarily due to a $0.4 million negative adjustment from the operator of the pipeline for prior period allocations of income and expenses to the partners. The pre-tax gain in 2003 included a gain of $1.3 million recognized on the sale of a 28-mile portion of Ozark Gas Transmission System's pipeline located in Oklahoma that had limited strategic value to the overall system. We refer you to Note 7 to the consolidated financial statements for additional discussion.

At December 31, 2005 and 2004, we had guaranteed $39.0 million and $40.2 million, respectively, of the partnership debt. This debt financed a portion of the original construction costs. No advances to NOARK were required in 2005 and 2003. We advanced $2.1 million to NOARK in 2004 as an adjustment to prior period cash disbursements. We refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Off-Balance Sheet Arrangements" and Note 11 to the consolidated financial statements for further discussion of our guarantee of NOARK debt.

Our gas distribution subsidiary has a transportation contract with Ozark Gas Transmission System for 66.9 MMcf per day of firm capacity that expires in 2014. Additionally, our Midstream Services segment has transportation contracts with Ozark Gas Transmission System for a total of 20.0 MMcf per day of firm capacity through 2006.

Other Revenues

In 2005, 2004 and 2003, other revenues included gains of $0.4 million, $5.8 million and $3.0 million, respectively, related to sales of undeveloped real estate and certain property and equipment. Other revenues for 2005, 2004 and 2003 also included pre-tax gains of $3.1 million, $4.5 million and $3.1 million, respectively, related to the sale of gas-in-storage inventory.

Interest Expense and Interest Income

Interest costs, net of capitalization, were down 11% in 2005 and down 2% in 2004, both as compared to prior years. In 2005, interest expense was reduced primarily due to lower average borrowings under our revolving debt facility as a result of our equity offering in September 2005. We refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Financing Requirements" and Note 2 to the consolidated financial statements for further discussion of our debt. In 2004, higher interest costs that resulted from increased average borrowings were offset by an increase in capitalized interest in the E&P segment. Interest capitalized increased 114% in 2005 and increased 56% in 2004. Changes in capitalized interest are primarily due to the level of costs excluded from amortization in our E&P segment and the capitalization of interest during the construction phase of our drilling rigs. Costs excluded from amortization in the E&P segment increased to $115.2 million at December 31, 2005, compared to $47.2 million at December 31, 2004. Total capital expenditures for our E&P segment were $451.3 million in 2005, up from $282.0 million in 2004.

During 2005, we earned interest income of $3.4 million related to our cash investments. This amount is recorded in other income.

Income Taxes

Our provision for deferred income taxes was an effective rate of 36.9% in 2005, 36.6% in 2004 and 36.7% in 2003. The changes in the provision for deferred income taxes recorded each year result primarily from the level of taxable income, adjusted for permanent differences.

Pension Expense

We recorded pension expense of $2.3 million in 2005, $2.2 million in 2004 and $3.3 million in 2003. The amount of pension expense recorded by us is determined by actuarial calculations and is also impacted by the funded status of our plans. During 2005, we funded our pension plan with contributions of $1.8 million. At December 31, 2005, our pension plans were underfunded and a liability of $7.9 million was recorded on the balance sheet. As a result of the underfunded status and actuarial data to be completed in early 2006, we expect to record pension expense of $3.3 million in 2006. For further discussion of our pension plans, we refer you to Note 4 to the consolidated financial statements and "Critical Accounting Policies" below.

Adoption of Accounting Principles

In December 2004, the FASB issued Statement on Financial Accounting Standards ("SFAS") No. 123 (Revised 2004), "Share-Based Payment," revising FASB Statement 123, "Accounting for Stock-Based Compensation" and superseding APB opinion No. 25, "Accounting for Stock Issued to Employees." This statement requires a public entity to measure the cost of services provided by employees and directors received in exchange for an award of equity instruments, including stock options, at a grant-date fair value. The fair value cost is then recognized over the period that services are provided. We will adopt FAS 123R in the first quarter of 2006 using the modified prospective method with no restatement of prior periods. In Note 1 of the consolidated financial statements included in this Form 10-K, we disclose the effect on net income and earnings per share for years ended December 31, 2005, 2004 and 2003 if we had applied the fair value recognition provisions of FAS 123 to stock-based employee compensation.

In April 2005, the staff of the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin No. 107 ("SAB 107") to provide additional guidance regarding the application of FAS 123 (Revised 2004). SAB 107 permits registrants to choose an appropriate valuation technique or model to estimate the fair value of share options, assuming consistent application, and provides guidance for the development of assumptions used in the valuation process. Additionally, SAB 107 discusses disclosures to be made under "Management's Discussion and Analysis of Financial Condition and Results of Operations" in registrants' periodic reports upon adoption of this standard.

In November 2005, the FASB issued final Staff Position ("FSP") FAS No. 123R-3, "Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards." The FSP provides an alternative method of calculating excess tax benefits (the APIC pool) from the method defined in FAS 123R for share-based payments. A one-time election to adopt the transition method in this FSP is available to those entities adopting FAS 123R using either the modified retrospective or modified prospective method and is available for up to one year from the initial adoption of FAS 123R or effective date of the FSP. However, until an entity makes its election, it must follow the guidance in FAS 123R. FSP 123R-3 is effective upon initial adoption of FAS 123R and will become effective for us in the first quarter of 2006. We are currently evaluating the potential impact on our financial position and results of operations of calculating the APIC pool with this alternative method.

In the fourth quarter of 2005, we amended the stock option agreements under our incentive plan to allow for the immediate vesting of option awards made on or after December 8, 2005, upon the death, disability or retirement of the plan participant. This change did not affect options issued prior to December 8, 2005 and will not reduce expenses expected to be incurred under FAS 123R. It will result in an earlier recognition of expenses for those participants who have reached retirement age.

In March 2005, the FASB issued FSP No. FIN 46(R)-5, "Implicit Variable Interests under FASB Interpretation No. 46 (revised December 2003), Consolidation of Variable Interest Entities." This FSP clarifies that when applying the variable interest consolidation model, a reporting enterprise should consider whether it holds an implicit variable interest in a variable interest entity ("VIE") or potential VIE. FSP No. FIN 46(R)-5 is effective as of April 1, 2005. Upon the adoption of FSP No. FIN 46(R)-5, we did not identify any potential or implicit VIEs.

In March 2005, the FASB issued Interpretation No. 47 ("FIN 47"), "Accounting for Conditional Asset Retirement Obligations – an interpretation of FASB Statement No. 143." FIN 47 requires an entity to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value can be reasonably estimated. FIN 47 states that a conditional asset retirement obligation is a legal obligation to perform an asset retirement activity in which the timing or method of settlement are conditional upon a future event that may or may not be within control of the entity. FIN 47 is effective no later than the end of the first fiscal year ending after December 15, 2005. The adoption of FIN 47 did not have a material impact on our financial position or results of operations.

In May 2005, the FASB issued SFAS No. 154 "Accounting Changes and Error Corrections" ("FAS 154"). FAS 154 changes the requirements for the accounting for and reporting of a change in accounting principle and requires retrospective applications to prior periods' financial statements of a voluntary change in accounting principle unless it is impracticable. This new accounting standard is effective for fiscal years beginning after December 15, 2005. The adoption of this accounting principle is not expected to have a material impact on our financial position or results of operations.

LIQUIDITY AND CAPITAL RESOURCES

We depend on internally-generated funds, our unsecured revolving credit facility (discussed below under "Financing Requirements") and funds accessed through public debt and equity markets as our primary sources of liquidity. We may borrow up to $500 million under our revolving credit facility from time to time. In September 2005, we consummated an underwritten offering of 9,775,000 shares of our common stock pursuant to an effective shelf registration statement filed with the SEC. The net proceeds of the offering were approximately $580.0 million after deduction of the underwriting discounts and offering expenses. Of the net proceeds, $186.7 million was used to pay down outstanding indebtedness under our revolving credit facility, $125.0 million was used to pay our 6.70% Notes due December 2005 and the remainder was invested in short-term cash equivalents pending our use for capital expenditures. As of February 20, 2006, we had no indebtedness outstanding under our revolving credit facility. During 2006, we expect to draw on a portion of the funds available under our credit facility to fund our planned capital expenditures (discussed below under "Capital Expenditures"), which are expected to exceed the net cash generated by our operations and cash investments.

Net cash provided by operating activities was $304.5 million in 2005, compared to $237.9 million in 2004 and $109.1 million in 2003. The primary components of cash generated from operations are net income, depreciation, depletion and amortization, the provision for deferred income taxes and changes in operating assets and liabilities. Cash from operating activities increased in 2005 and 2004 due mainly to increased net income and the related increases in deferred income taxes generated by our E&P segment. Net cash from operating activities provided 63% of our cash requirements for capital expenditures in 2005, 81% in 2004 and 65% in 2003.

We believe that our operating cash flow, remaining funds from the 2005 equity offering and our credit facility will be adequate to meet our capital and operating requirements for 2006. We may choose to refinance certain portions of our borrowings by issuing long-term debt in the public or private debt markets.

Our cash flow from operating activities is highly dependent upon the market prices that we receive for our gas production. The price received for our production is also influenced by our commodity hedging activities, as more fully discussed in Note 8 to the financial statements included in this Form 10-K and Item 7A, "Quantitative and Qualitative Disclosures about Market Risk." Natural gas and oil prices are subject to wide fluctuations. As a result, we are unable to forecast with certainty our future level of cash flow from operations. We adjust our discretionary uses of cash dependent upon cash flow available.

Capital Expenditures

Capital expenditures totaled $483.1 million in 2005, $295.0 million in 2004 and $180.2 million in 2003. Capital expenditures included $28.1 million in 2005, $3.9 million in 2004, and $12.0 million in 2003 related to the change in the amount of accrued expenditures. Our E&P segment expenditures included no significant acquisition of interests in natural gas and oil producing properties in 2005, compared to $14.2 million in 2004 and $3.0 million in 2003.

	2005	2004	2003
		(in thousands)	
Exploration and production	**$ 451,289**	$ 281,988	$ 170,886
Gas distribution	**10,908**	7,298	8,178
Midstream services	**15,840**	—	10
Other	**5,014**	5,704	1,129
	$ 483,051	$ 294,990	$ 180,203

Our capital investments for 2006 are planned to be $830.1 million, consisting of $770.3 million for exploration and production including $78.5 million for the acquisition of drilling rigs, $37.5 for midstream services, $11.9 million for gas distribution system improvements and $10.4 million for general purposes. We expect to allocate $338.3 million of our 2006 E&P capital to our Fayetteville Shale play. We expect that our planned level of capital investments in 2006 will allow us to accelerate the drilling in the Fayetteville Shale, continue the development of our Overton Field properties in East Texas, continue our conventional drilling in the Arkoma Basin, maintain our present markets, explore and develop other existing gas and oil properties, generate new drilling prospects, and provide for improvements necessary due to normal customer growth in our gas distribution segment. As discussed above, our 2006 capital investment program is expected to be funded through cash flow from operations, the remaining net proceeds from our equity offering, and borrowings under our revolving credit facility. We may adjust the level of 2006 capital investments dependent upon our level of cash flow generated from operations and our ability to borrow under our credit facility.

Financing Requirements

Our total debt outstanding was $100.0 million at December 31, 2005 and $325.0 million at December 31, 2004. In January 2005, we amended and restated our previous $300 million revolving credit facility due to expire in January 2007, increasing the borrowing capacity to $500 million and extending the expiration to January 2010. At December 31, 2005, we had no outstanding debt under our revolving credit facility. The interest rate on the facility is calculated based upon our public debt rating and is currently 125 basis points over LIBOR. Our publicly traded notes were downgraded in January 2005 by Standard and Poor's to BBB- from BBB, and continue to be rated Ba2 by Moody's. Any future downgrades in our public debt ratings could increase the cost of funds under our revolving credit facility.

Our revolving credit facility contains covenants which impose certain restrictions on us. Under the credit agreements, we may not issue total debt in excess of 60% of our total capital, must maintain a certain level of shareholders' equity, and must maintain a ratio of EBITDA to interest expense of 3.5 or above. Additionally, there are certain limitations on the amount of indebtedness that may be incurred by our subsidiaries. We were in compliance with all of the covenants of our credit agreements at December 31, 2005. Although we do not anticipate any violations of our financial covenants, our ability to comply with those covenants is dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and oil. If we are unable to borrow under our credit facility, we would have to decrease our capital expenditure plans.

During the third quarter of 2005, we completed the sale of 9,775,000 shares of our common stock under an effective shelf registration statement. The net proceeds of the offering were approximately $580.0 million after deduction of the underwriting discounts and offering expenses. Of the net proceeds, $186.7 million was used to pay down outstanding indebtedness under our revolving credit facility, $125.0 million was used to pay the 6.70% Notes due December 2005 and the remainder was invested in short-term cash investments. In 1997, we publicly issued $60.0 million of 7.625% Medium-Term Notes due 2027 and $40.0 million of 7.21% Medium-Term Notes due 2017.

In June 1998, the NOARK partnership issued $80.0 million of 7.15% Notes due 2018, which were severally guaranteed by us and Enogex, Inc., the other general partner. The notes required semi-annual principal payments of $1.0 million that began in December 1998. In the fourth quarter of 2005, Enogex sold its interest in NOARK to Atlas Pipeline Partners, L.P. (Atlas) and used a portion of the sales proceeds to prepay its share of NOARK's debt. NOARK's remaining outstanding debt at December 31, 2005 was $39.0 million, all of which is guaranteed by us, and now requires semi-annual payments of $0.6 million. We account for our investment in NOARK under the equity method of accounting and do not consolidate the results of NOARK. We did not advance any funds to NOARK in 2005, compared to $2.1 million of advancements in 2004, and no advances were required in 2003. If NOARK is unable to generate sufficient cash in the future on a sustainable basis to service its debt and we are continually required to contribute cash to fund our debt service guarantee, we could be required to record the NOARK debt commitment under current accounting rules.

At the end of 2005, our capital structure consisted of 8% debt (excluding our guarantee of NOARK's obligations) and 92% equity, with a ratio of EBITDA to interest expense of 22.4. EBITDA is a measure required by our credit facility financial covenants and is defined as net income plus interest expense, income tax expense, and depreciation, depletion and amortization. Shareholders' equity in the December 31, 2005 balance sheet includes an accumulated other comprehensive loss of $99.8 million related to our hedging activities that is required to be recorded under the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133). This amount is based on current market values of our hedges at December 31, 2005, and does not necessarily reflect the value that we will receive or pay when the hedges ultimately are settled, nor does it take into account revenues to be received associated with the physical delivery of sales volumes hedged. Our credit facility's financial covenants with respect to capitalization percentages exclude the effects of non-cash entries that result from FAS 133 as well as the non-cash impact of any full cost ceiling write-downs, and include the guarantee of NOARK's obligations. Our capital structure, including our guarantee of NOARK's obligations of $39.0 million, would be 10% debt and 90% equity at December 31, 2005, without consideration of the accumulated other comprehensive loss related to FAS 133 of $99.8 million. As part of our strategy to ensure a certain level of cash flow to fund our operations, we have hedged approximately 70% to 75% of our expected 2006 gas production and 15% to 20% of our expected 2006 oil production. The amount of long-term debt we incur will be dependent upon commodity prices and our capital expenditure plans. If commodity prices remain at or near 2005 levels throughout 2006 and our capital expenditure plans do not change, we will increase our long-term debt in 2006. If commodity prices significantly decrease, we may decrease and/or reallocate our planned capital expenditures.

We refer you to "Business — Other Items — Reconciliation of Non-GAAP Measures" in Item 1 of Part I of this Form 10-K for a table that reconciles EBITDA with our net income as derived from our audited financial information.

Off-Balance Sheet Arrangements

As discussed above in "Results of Operations — Transportation," we hold a 25% general partnership interest in NOARK, which owns the Ozark Gas Transmission System that is utilized to transport our gas production and the gas production of others. We account for our investment under the equity method of accounting. As a result of the sale by Enogex of its interests in NOARK and their related prepayment of their portion of NOARK's 7.15% Notes due 2018, we are the sole guarantor of the outstanding notes at December 31, 2005. At December 31, 2005 and 2004, the outstanding principal amount of these notes was $39.0 million and $67.0 million, respectively. In 2004, our share of the notes was $40.2 million. The notes require semi-annual principal payments of $0.6 million. Under the guarantee, we are required to fund the notes to the extent that they are not funded by our share of the operations of the pipeline. We did not advance funds to NOARK in 2005. We advanced $2.1 million to NOARK in 2004 as an adjustment to prior period cash disbursements and were not required to advance any funds in 2003. We do not derive any liquidity, capital resources, market risk support or credit risk support from our investment in NOARK.

Our share of the results of operations included in other income (expense) related to our NOARK investment was pre-tax income of $1.6 million in 2005, a pre-tax loss of $0.4 million in 2004 and pre-tax income of $1.1 million in 2003. The increase in pre-tax income in 2005 was primarily due to increased throughput and higher average rates charged to customers. The pre-tax loss in 2004 was primarily due to a $0.4 million negative adjustment from the operator of the pipeline for prior period allocations of income and expenses to the partners. In 2003, our share of pre-tax income included a gain of $1.3 million related to the sale of a 28-mile portion of the pipeline located in Oklahoma. We believe that we will be able to continue to improve the operating results of the NOARK project and expect our investment in NOARK to be realized over the life of the system (see Note 7 of the consolidated financial statements for additional discussion).

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. Significant contractual obligations at December 31, 2005 were as follows:

Contractual Obligations:

	Payments Due by Period				
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	More than 5 Years
	(in thousands)				
Long-term debt	$ 100,000	$ —	$ —	$ 60,000	$ 40,000
Interest on senior notes[1]	49,158	7,459	14,918	7,306	19,475
Operating leases[2]	17,019	2,985	6,022	5,128	2,884
Unconditional purchase obligations[3]	—	—	—	—	—
Operating agreements[4]	22,544	19,564	2,980	—	—
Rental compression[5]	27,125	5,440	12,009	7,883	1,793
Demand charges[6]	95,693	14,571	19,251	20,461	41,410
Drilling rigs[7]	62,294	62,294	—	—	—
Other obligations[8]	10,176	9,770	406	—	—
	$ 384,009	$ 122,083	$ 55,586	$ 100,778	$ 105,562

(1) Interest on the senior notes includes interest through 2009 on the $60 million notes that are due in 2027 and putable at the holder's option in 2009.

(2) We lease certain office space and equipment under non-cancelable operating leases expiring through 2013.

(3) Our Gas Distribution segment has volumetric commitments for the purchase of gas under non-cancelable competitive bid packages and non-cancelable wellhead contracts. Volumetric purchase commitments at December 31, 2005 totaled 1.2 Bcf, comprised of 0.7 Bcf in less than one year, 0.3 Bcf in one to three years and 0.2 Bcf in three to five years. Our volumetric purchase commitments are priced primarily at regional gas indices set at the first of each future month. These costs are recoverable from the utility's end-use customers.

(4) Our E&P segment has commitments for up to $22.5 million in termination fees related to rig operator agreements in the event that the agreements are terminated.

(5) Our E&P and Midstream Services segments have commitments for approximately $27.1 million of compressor rental fees associated primarily with our Overton operations and our Fayetteville Shale play.

(6) Our Gas Distribution segment has commitments for approximately $88.7 million of demand charges on non-cancelable firm gas purchase and firm transportation agreements. These costs are recoverable from the utility's end-use customers. Our E&P segment has commitments for approximately $5.4 million of demand transportation charges, and our Midstream Services segment has commitments for approximately $1.6 million of demand transportation charges.

(7) Our E&P segment has commitments related to the purchase of ten drilling rigs expected to be delivered within 2006 for approximately $62.3 million, including ancillary equipment.

(8) Our other significant contractual obligations include approximately $5.3 million of land leases, approximately $2.4 million for funding of benefit plans, approximately $1.1 million for drilling and well commitments and approximately $0.9 million for various information technology support and data subscription agreements.

In the second quarter of 2005, we entered into an agreement to fabricate five new land drilling rigs for an aggregate purchase price of $37.7 million. In the third quarter of 2005, we entered into an agreement to fabricate an additional five land drilling rigs for an aggregate purchase price of $40.7 million. Including change orders, ancillary equipment and supplies, the total cost of these ten rigs is approximately $97.4 million. Payments made under these agreements were $35.1 million in 2005 with the remainder due in 2006.

We refer you to "Financing Requirements" above for a discussion of the terms of our long-term debt.

Contingent Liabilities and Commitments

We have the following commitments and contingencies that could create, increase or accelerate our liabilities. Substantially all of our employees are covered by defined benefit and postretirement benefit plans. Our return on the assets of these plans was lower than our assumed rate of return which, when combined with other factors including an increase in employees, resulted in an increase in pension expense and our required funding of the plans for 2005 and 2004. At December 31, 2005, we recorded an accrued pension benefit liability of $7.9 million. As a result of the underfunded status and actuarial data to be completed in early 2006, we expect to record pension expense of $3.3 million in 2006. See Note 4 to the consolidated financial statements and "Critical Accounting Policies" below for additional information.

As discussed above in "Off-Balance Sheet Arrangements," we are the sole guarantor of the principal and interest payments on NOARK's 7.15% Notes due 2018. At December 31, 2005, the outstanding principal of these notes was $39.0 million. The notes require semi-annual principal payments of $0.6 million. See Note 11 to the consolidated financial statements for additional information.

We are subject to litigation and claims that arise in the ordinary course of business. Management believes, individually or in aggregate, such litigation and claims will not have a material adverse impact on our financial position or our results of operations but these matters are subject to inherent uncertainties and management's view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position and the results of operations for the period in which the effect becomes reasonably estimable. A lawsuit was filed against us in 2001 alleging a breach of an agreement to indemnify the other party against settlement payments related to the Company's Boure' prospect in Louisiana. The allegations were contested and, in 2002, we were granted a motion for summary judgment by the trial court. The case was appealed to the First Court of Appeals in Houston, Texas, which subsequently transferred the appeal to the Thirteenth Court of Appeals in Corpus Christi. The appeal was briefed and argued during 2003. On April 14, 2005, the Thirteenth Court of Appeals reversed the orders of the trial court and rendered judgment denying our motion for summary judgment and granting the motion for summary judgment of the other party. Our motion for rehearing with the Thirteenth Court of Appeals was denied on May 19, 2005. In August of 2005, we filed a petition for review with the Texas Supreme Court. In October of 2005, the Texas Supreme Court invited additional briefing by the parties, which both parties have done. The matter is currently pending before the Texas Supreme Court. Should the other party prevail on the appeal, we could be required to pay approximately $2.1 million, plus pre-judgment interest and attorney's fees. Based on an assessment of this litigation by us and our legal counsel, no accrual for loss is currently recorded.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our credit facility described above. We had positive working capital of $158.7 million at the end of 2005 and negative working capital of $2.7 million at the end of 2004. Current assets included $222.4 million of remaining proceeds from our 2005 equity offering that is invested in cash investments. Current liabilities increased $168.7 million, due primarily to an increase in our current hedging liability and accounts payable accruals at December 31, 2005.

CRITICAL ACCOUNTING POLICIES

Natural Gas and Oil Properties

We utilize the full cost method of accounting for costs related to our natural gas and oil properties. Under the full cost accounting rules of the SEC, 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. Unevaluated costs are reviewed twice a year for individual impairment. Capitalized costs within the full cost pool are subjected quarterly to a ceiling test, 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 plus the lower of cost or market value of unproved properties. If the net capitalized costs of natural gas and oil properties exceed the ceiling, we will record a ceiling test write-down to the extent of such excess. A ceiling test write-down is a non-cash charge to earnings. If required, it reduces earnings and impacts shareholders' equity in the period of occurrence and results in lower depreciation, depletion and amortization expense in future periods. The write-down may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling.

The risk that we will be required to write-down the carrying value of our natural gas and oil properties increases when natural gas and oil prices are depressed or if there are substantial downward revisions in estimated proved reserves. Under the SEC's full cost accounting rules, our reserves are required to be priced using prices in effect at the end of the reporting period. Application of these rules during periods of relatively low natural gas or oil prices due to seasonality or other reasons, even if temporary, increases the probability of a ceiling test write-down. Based on natural gas and oil prices in effect on December 31, 2005, the unamortized cost of our natural gas and oil properties did not exceed the ceiling of proved natural gas and oil reserves. Natural gas pricing has historically been unpredictable and any significant declines could result in a ceiling test write-down in subsequent quarterly or annual reporting periods.

Natural gas and oil reserves used in the full cost method of accounting cannot be measured exactly. Our estimate of natural gas and oil reserves requires extensive judgments of reservoir engineering data and is generally less precise than other estimates made in connection with financial disclosures. Our reservoir engineers prepare our reserve estimates under the supervision of our management. Reserve estimates are prepared for each of our properties annually by the reservoir engineers assigned to the asset management team in the geographic locations in which the property is located. These estimates are reviewed by senior engineers who are not part of the asset management teams and the president of our E&P subsidiaries. Final authority over the estimates of our proved reserves rests with our Board of Directors. In each of the past three years, revisions to our proved reserve estimates represented no greater than 4% of our total proved reserve estimates, which we believe is indicative of the effectiveness of our internal controls. Proved developed reserves generally have a higher degree of accuracy in this estimation process, when compared to proved undeveloped and proved non-producing reserves, as production history and pressure data over time is available for the majority of our proved developed properties. Proved developed reserves account for 73% of our total reserve base. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. The uncertainties inherent in the reserve estimates are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. We cannot assure you that our internal controls sufficiently address the numerous uncertainties and risks that are inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and timing of development expenditures as many factors are beyond our control. We refer you to “The natural gas and oil reserves data we report are only estimates and may prove to be inaccurate.” in Item 1A, “Risk Factors,” of Part I of this Form 10-K for a more detailed discussion of these uncertainties, risks and other factors.

We engage the services of Netherland, Sewell & Associates, Inc., an independent petroleum engineering firm, to audit our reserves as estimated by our reservoir engineers. Netherland, Sewell & Associates, Inc. reports the results of the reserves audit to our Board of Directors. In conducting its audit, the engineers and geologists of Netherland, Sewell & Associates study our major properties in detail and independently develop reserve estimates. For the year-ended December 31, 2005, Netherland, Sewell & Associates issued its audit opinion as to the reasonableness of our reserve estimates, stating that our estimated proved oil and gas reserves are, in the aggregate, reasonable and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles.

A decline in gas and oil prices used to calculate the discounted future net revenues of our reserves affects both the present value of cash flows and the quantity of reserves reported. Our reserve base is 93% natural gas, therefore changes in oil prices used do not have as significant an impact as gas prices on cash flows and reported reserve quantities. Reported discounted cash flows and reserve quantities at December 31, 2005 were $1,420.8 million and 826.8 Bcfe. An assumed decrease of $1.00 per Mcf in the December 31, 2005 gas price used to price our reserves would have resulted in an approximate $140 million to $150 million decline in our future cash flows discounted at 10% and an approximate decrease of 5 Bcfe of our reported reserves. Under this assumption, our unamortized costs remained below the ceiling of proved natural gas and oil reserves. The decline in reserve quantities, assuming this decrease in gas price, would have the impact of increasing our unit of production amortization of the full cost pool. The unit of production rate for amortization is adjusted quarterly based on changes in reserve estimates.

Hedging

We use natural gas and crude oil swap agreements and options and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and oil and in interest rates. Our policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings to minimize the risk of uncollectability. In recent years, we have hedged 60% to 80% of our annual production. The primary market risks related to our derivative contracts are the volatility in market prices and basis differentials for natural gas and crude oil. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of the oil that is hedged.

Our derivative instruments are accounted for under FAS 133, as amended by FAS 138 and 149, and are recorded at fair value in our financial statements. We have established the fair value of derivative instruments using estimates determined by our counterparties, with such estimates evaluated internally using established index prices and other sources. These valuations are recognized as assets or liabilities in our balance sheet and, to the extent an open position is an effective cash flow hedge on equity production or interest rates, the offset is recorded in other comprehensive income. Results of settled commodity hedging transactions are reflected in natural gas and oil sales or in gas purchases. Results of settled interest rate hedges are reflected in interest expense. Any ineffective hedge, derivative not qualifying for accounting treatment as a hedge, or ineffective portion of a hedge is recognized immediately in earnings. For the year ended December 31, 2005, we recorded a gain of $19.1 million related to differential swaps which was partially offset by a $9.4 million loss related to the change in estimated ineffectiveness of our cash flow hedges. We recorded a loss in revenues of $2.6 million in 2004 and a gain of $0.6 million in 2003 related to the changes in ineffectiveness of our commodity hedges. Future market price volatility could create significant changes to the hedge positions recorded in our financial statements. We refer you to "Quantitative and Qualitative Disclosures about Market Risk" in Item 7A of Part II of this Form 10-K for additional information regarding our hedging activities.

Regulated Utility Operations

Our utility operations are subject to the rate regulation and accounting requirements of the APSC. Allocations of costs and revenues to accounting periods for ratemaking and regulatory purposes may differ from those generally applied by non-regulated operations. Such allocations to meet regulatory accounting requirements are considered generally accepted accounting principles for regulated utilities provided that there is a demonstrated ability to recover any deferred costs in future rates.

During the ratemaking process, the regulatory commission may require a utility to defer recognition of certain costs to be recovered through rates over time as opposed to expensing such costs as incurred. This allows the utility to stabilize rates over time rather than passing such costs on to the customer for immediate recovery. This causes certain expenses to be deferred as a regulatory asset and amortized to expense as they are recovered through rates. The APSC has not required any unbundling of services, although large industrials are free to contract for their own gas supply. There are no pending regulations relating to unbundling of services; however, should such regulation be proposed and adopted, certain of these assets may no longer meet the criteria for deferred recognition and, accordingly, a write-off of regulatory assets and stranded costs may be required.

Pension and Other Postretirement Benefits

We record our prepaid or accrued benefit cost, as well as our periodic benefit cost, for our pension and other postretirement benefit plans using measurement assumptions that we consider reasonable at the time of calculation (see Note 4 to the financial statements for further discussion and disclosures regarding these benefit plans). Two of the assumptions that affect the amounts recorded are the discount rate, which estimates the rate at which benefits could be effectively settled, and the expected return on plan assets, which reflects the average rate of earnings expected on the funds invested. For the December 31, 2005 benefit obligation and the periodic benefit cost to be recorded in 2006, the discount rate assumed is 5.5%. For the 2006 periodic benefit cost, the expected return assumed is 8.25%. This compares to a discount rate of 6.0% and an expected return of 9.0% used in the prior year.

Using the assumed rates discussed above, we recorded pension expense of $2.3 million in 2005 and $2.2 million in 2004 related to our pension and other postretirement benefit plans. We reflected a pension liability of $7.9 million at December 31, 2005 and $1.5 million at December 31, 2004. During 2005, we also funded $1.8 million to our pension plans. In 2006, we expect to fund $3.9 million to our pension and other postretirement benefit plans. Assuming a 1% change in the 2005 rates (lower discount rate and lower rate of return), we would have recorded pension expense of $3.4 million in 2005.

Gas in Underground Storage

We record our gas stored in inventory that is owned by the E&P segment at the lower of weighted average cost or market. Gas expected to be cycled within the next 12 months is recorded in current assets with the remaining stored gas reflected as a long-term asset. The quantity and average cost of gas in storage was 8.5 Bcf at $3.78 per Mcf at December 31, 2005, compared to 9.3 Bcf at $3.49 per Mcf at December 31, 2004.

The gas in inventory for the E&P segment is used primarily to supplement production in meeting the segment's contractual commitments including delivery to customers of our gas distribution business, especially during periods of colder weather. As a result, demand fees paid by the gas distribution segment to the E&P segment, which are passed through to the utility's customers, are a part of the realized price of the gas in storage. In determining the lower of cost or market for storage gas, we utilize the gas futures market in assessing the price we expect to be able to realize for our gas in inventory. A significant decline in the future market price of natural gas could result in us writing down our carrying cost of gas in storage.

See further discussion of our significant accounting policies in Note 1 to the financial statements.

FORWARD-LOOKING INFORMATION

All statements, other than historical fact or present financial information, 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. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Form 10-K identified by words such as "anticipate," "project," "intend," "estimate," "expect," "believe," "predict," "budget," "projection," "goal," "plan," "forecast," "target" or similar expressions.

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- the timing and extent of changes in commodity prices for natural gas and oil;
- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- the extent to which the Fayetteville Shale play can replicate the results of other productive shale gas plays;
- the potential for significant variability in reservoir characteristics of the Fayetteville Shale over such a large acreage position;
- the extent of our success in drilling and completing horizontal wells;
- our ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation;
- our lack of experience owning and operating drilling rigs;
- our ability to fund our planned capital expenditures;
- our future property acquisition or divestiture activities;
- the effects of weather and regulation on our gas distribution segment;
- increased competition;
- the impact of federal, state and local government regulation;
- the financial impact of accounting regulations and critical accounting policies;
- changing market conditions and prices (including regional basis differentials);
- the comparative cost of alternative fuels;
- conditions in capital markets and changes in interest rates;
- the availability of oilfield personnel, services, drilling rigs and other equipment; and
- any other factors listed in the reports we have filed and may file with the SEC.

We caution you that forward-looking statements contained in this Form 10-K are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of natural gas and oil. These risks include, but are not limited to, commodity price volatility, third-party interruption of sales to market, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved natural gas and oil reserves and in projecting future rates of production and timing of development expenditures and the other risks described in Item 1A of Part I of this Form 10-K.

Estimates of our proved natural gas and oil reserves and the estimated future net revenues from such reserves are based upon various assumptions, including assumptions required by the SEC relating to natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating natural gas and oil reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves will most likely vary from those estimated. Such variances may be material. Any significant variance could materially affect the estimated quantities and present value of reserves set forth in this Form 10-K. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control.

At December 31, 2005, approximately 27% of our estimated proved reserves were proved undeveloped and 5% were proved developed non-producing. Proved undeveloped reserves and proved developed non-producing reserves, by their nature, are less certain than proved developed producing reserves. Estimates of reserves in the non-producing categories are nearly always based on volumetric calculations rather than the performance data used to estimate producing reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Recovery of proved developed non-producing reserves requires capital expenditures to recomplete into the zones behind pipe and is subject to the risk of a successful recompletion. Production revenues from proved undeveloped and proved developed non-producing reserves will not be realized, if at all, until sometime in the future. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our natural gas and oil reserves and the costs associated with these reserves in accordance with industry standards, we cannot assure you that the estimated costs are accurate, that development will occur as scheduled or that the actual results will be as estimated.

You should not assume that the present value of future net cash flows referred to in this Form 10-K is the current fair value of our estimated natural gas and oil reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in consumption by gas purchasers or in governmental regulations or taxation could also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of natural gas and oil properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor for our company.

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risks relating to our operations result primarily from the volatility in commodity prices, basis differentials and interest rates, as well as credit risk concentrations. We use natural gas and crude oil swap agreements and options and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and oil and in interest rates. Our Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price and interest rate risks. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

Credit Risk

Our 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 3% of accounts receivable at December 31, 2005. In addition, please see the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

The following table provides information on our financial instruments that are sensitive to changes in interest rates. The table presents our debt obligations, principal cash flows and related weighted-average interest rates by expected maturity dates. At December 31, 2005, we had no borrowings outstanding under our credit facility. Our 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.

	Expected Maturity Date							Fair Value
	2005	2006	2007	2008	2009	Thereafter	Total	12/31/05
	($ in millions)							
Fixed Rate	$ —	$ —	$ —	$ —	$ 60.0	$ 40.0	$ 100.0	$ 105.4
Average Interest Rate	—	—	—	—	7.63%	7.21%	7.46%	—

Commodities Risk

We use over-the-counter natural gas and crude oil swap agreements and options to hedge sales of our production, to hedge activity in our marketing segment and to hedge the purchase of gas in our utility segment against the inherent price risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX 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 (production hedge) or receives (gas purchase hedge) funds equal to the amount by which the price of the commodity is below the contracted floor, and a “ceiling” price above which we pay to (production hedge) or receive from (gas purchase hedge) the counterparty the amount by which the price of the commodity is above the contracted ceiling.

The primary market risks relating to our derivative contracts are the volatility in market prices and basis differentials for natural gas and crude oil. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of the oil that is hedged. Credit risk relates to the risk of loss as a result of non-performance by our 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 we have to each counterparty are periodically reviewed to ensure limited credit risk exposure.

The following table provides information about our financial instruments that are sensitive to changes in commodity prices and that are used to hedge prices for gas and oil production, gas purchases and marketing volumes. The table presents the notional amount in Bcf and MBbls, the weighted average contract prices and the fair value by expected maturity dates. At December 31, 2005, the fair value of these financial instruments was a $153.2 million liability.

	Expected Maturity Date		
	2006	2007	2008
Production and Marketing			
Natural Gas			
Swaps with a fixed-price receipt			
Contract volume (Bcf)	7.9	12.0	—
Weighted average price per Mcf	$ 6.64	$ 6.66	$ —
Fair value (in millions)	$ (32.1)	$ (37.9)	$ —
Price collars			
Contract volume (Bcf)	43.0	28.0	2.0
Weighted average floor price per Mcf	$ 5.47	$ 6.64	$ 8.00
Fair value of floor (in millions)	$ 1.6	$ 8.6	$ 1.5
Weighted average ceiling price per Mcf	$ 10.13	$ 11.91	$ 19.40
Fair value of ceiling (in millions)	$ (73.3)	$ (34.4)	$ (2.0)
Swaps with a fixed-price payment			
Contract volume (Bcf)	0.2	—	—
Weighted average price per Mcf	$ 11.11	$ —	$ —
Fair value (in millions)	$ 0.1	$ —	$ —
Oil			
Swaps with a fixed-price receipt			
Contract volume (MBbls)	120	—	—
Weighted average price per Bbl	$ 37.30	$ —	$ —
Fair value (in millions)	$ (3.1)	$ —	$ —
Natural Gas Purchases			
Swaps with a fixed-price payment			
Contract volume (Bcf)	0.7	—	—
Weighted average price per Mcf	$ 13.03	$ —	$ —
Fair value (in millions)	$ (1.2)	$ —	$ —

At December 31, 2005, the Company had outstanding fixed-price basis differential swaps on 13.0 Bcf of 2006, 29.9 Bcf of 2007 and 2.0 Bcf of 2008 gas production that qualified for hedge accounting treatment. At December 31, 2005, the Company had outstanding fixed-price basis differential swaps on 25.3 Bcf of 2006 and 10.0 Bcf of 2007 gas production that did not qualify for hedge accounting treatment. For the year ended December 31, 2005, we recorded a gain of $19.1 million related to the differential swaps that did not qualify for hedge accounting treatment which was partially offset by a $9.4 million loss related to the change in estimated ineffectiveness of our cash flow hedges.

At December 31, 2004, the Company had outstanding natural gas price swaps on total notional volumes of 12.9 Bcf at a weighted average price of $5.11 per Mcf in 2005 and 5.0 Bcf at a weighted average price of $5.89 per Mcf in 2006. Outstanding oil price swaps at December 31, 2004 on 360 MBbls were yielding us an average price of $33.17 per barrel during 2005. At December 31, 2004, the Company also had outstanding natural gas price swaps on total notional gas purchase volumes of 2.9 Bcf in 2005 for which the Company paid an average fixed price of $6.54 per Mcf.

At December 31, 2004, the Company had collars in place on 33.4 Bcf in 2005 and 22.0 Bcf in 2006 of gas production. The collars relating to 2005 production have a weighted average floor and ceiling price of $4.68 and $8.30 per Mcf, respectively. The collars relating to 2006 production have a weighted average floor and ceiling price of $4.64 and $8.69 per Mcf, respectively.

Subsequent to December 31, 2005 and prior to February 20, 2006, we hedged 6.0 Bcf of 2008 gas production under costless collars with floor prices ranging from $7.00 to $9.00 per Mcf and ceiling prices ranging from $12.55 to $15.80 per Mcf. Additionally, we hedged the basis differential on the 6.0 Bcf of 2008 gas production.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Exchange Act. We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our internal control over financial reporting. Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2005. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Our management used the criteria set forth in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) to perform its assessment. Based on this assessment, our management, including our Chief Executive Officer and our Chief Financial Officer, concluded, that as of December 31, 2005, our internal control over financial reporting was effective based on those criteria.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report below.

Report of Independent Registered Public Accounting Firm

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

We have completed integrated audits of Southwestern Energy Company's 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005 and an audit of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions on Southwestern Energy Company's 2005, 2004 and 2003 consolidated financial statements and on its internal control over financial reporting as of December 31, 2005, based on our audits, are presented below.

Consolidated Financial Statements

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Southwestern Energy Company and its subsidiaries at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. 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 of these statements in accordance with the standards of the Public Company Accounting Oversight Board (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 of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2003, the Company adopted the requirements of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."

Internal Control over Financial Reporting

Also, in our opinion, management's assessment, included in the accompanying "Management's Report on Internal Control Over Financial Reporting," that the Company maintained effective internal control over financial reporting as of December 31, 2005 based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control – Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
March 6, 2006

STATEMENTS OF OPERATIONS

Southwestern Energy Company and Subsidiaries

	For the years ended December 31,		
	2005	2004	2003
	(in thousands, except share/per share amounts)		
Operating revenues:			
Gas sales	**$ 503,111**	$ 375,460	$ 256,467
Gas marketing	**132,690**	65,127	43,313
Oil sales	**30,026**	19,461	14,180
Gas transportation and other	**10,502**	17,089	13,441
	676,329	477,137	327,401
Operating costs and expenses:			
Gas purchases – gas distribution	**82,689**	64,311	52,585
Gas purchases – midstream services	**124,730**	60,804	39,428
Operating expenses	**52,850**	42,157	37,377
General and administrative expenses	**48,650**	36,074	33,102
Depreciation, depletion and amortization	**96,211**	73,674	55,948
Taxes, other than income taxes	**25,279**	17,830	11,619
	430,409	294,850	230,059
Operating Income:	**245,920**	182,287	97,342
Interest Expense:			
Interest on long-term debt	**19,791**	18,335	17,722
Other interest charges	**1,254**	1,461	1,381
Interest capitalized	**(6,005)**	(2,804)	(1,792)
	15,040	16,992	17,311
Other income (expense)	**4,784**	(362)	797
Income before income taxes, minority interest and accounting change	**235,664**	164,933	80,828
Minority interest in partnership	**(1,473)**	(1,579)	(2,180)
Income before income taxes and accounting change	**234,191**	163,354	78,648
Provision for income taxes			
Current	**—**	—	—
Deferred	**86,431**	59,778	28,896
	86,431	59,778	28,896
Income before accounting change	**147,760**	103,576	49,752
Cumulative effect of adoption of accounting principle	**—**	—	(855)
Net Income	**$ 147,760**	$ 103,576	$ 48,897
Basic Earnings per share: [1]			
Income before accounting change	**$0.98**	$0.72	$0.38
Cumulative effect of adoption of accounting principle	**—**	—	(0.01)
Net Income	**$0.98**	$0.72	$0.37
Diluted Earnings per share: [1]			
Income before accounting change	**$0.95**	$0.70	$0.37
Cumulative effect of adoption of accounting principle	**—**	—	(0.01)
Net Income	**$0.95**	$0.70	$0.36
Weighted average common shares outstanding: [1]			
Basic	**150,892,602**	142,902,404	133,584,208
Diluted	**156,309,039**	147,851,088	136,951,736

[1] 2004 and 2003 restated to reflect two-for-one stock splits effected in June and November 2005.

The accompanying notes are an integral part of these consolidated financial statements.

BALANCE SHEETS

Southwestern Energy Company and Subsidiaries

	December 31, 2005	December 31, 2004
	(in thousands)	
ASSETS		
Current assets		
Cash and cash equivalents	**$ 223,705**	$ 1,235
Accounts receivable	**128,948**	86,268
Inventories, at average cost	**49,513**	32,248
Deferred income tax benefit	**29,700**	3,600
Hedging asset - FAS 133	**17,467**	1,205
Other	**11,731**	6,429
Total current assets	**461,064**	130,985
Investments	**17,100**	15,465
Property, plant and equipment, at cost		
Gas and oil properties, using the full cost method, including $115,195,700 in 2005 and $47,239,000 in 2004 excluded from amortization	**1,897,613**	1,483,824
Gas distribution systems	**216,644**	207,447
Construction-in-progress - drilling rigs	**35,128**	—
Gathering systems	**15,742**	—
Gas in underground storage	**32,254**	32,254
Other	**45,234**	37,820
	2,242,615	1,761,345
Less: Accumulated depreciation, depletion and amortization	**872,218**	777,189
	1,370,397	984,156
Other assets	**19,963**	15,538
	$ 1,868,524	$ 1,146,144
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	**$ 154,385**	$ 81,586
Taxes payable	**14,519**	9,333
Interest payable	**1,832**	2,334
Customer deposits	**6,352**	5,903
Hedging liability - FAS 133	**112,293**	29,886
Over-recovered purchased gas costs	**7,323**	1,412
Other	**5,682**	3,246
Total current liabilities	**302,386**	133,700
Long-term debt	**100,000**	325,000
Other liabilities		
Deferred income taxes	**254,528**	203,996
Long-term hedging liability	**60,442**	5,798
Other	**29,251**	18,114
	344,221	227,908
Commitments and contingencies		
Minority interest in partnership	**11,613**	11,859
Shareholders' equity		
Common stock, $0.10 par value; authorized 220,000,000 shares, issued 168,452,336 shares[(1)]	**16,845**	14,890
Additional paid-in capital[(1)]	**711,196**	117,586
Retained earnings	**498,221**	350,461
Accumulated other comprehensive income (loss)	**(104,874)**	(19,816)
Common stock in treasury, at cost, 1,217,284 shares in 2005 and 3,286,304 shares in 2004[(1)]	**(3,390)**	(9,156)
Unamortized cost of restricted shares issued under stock incentive plan, 707,142 shares in 2005 and 1,281,152 shares in 2004[(1)]	**(7,694)**	(6,288)
	1,110,304	447,677
	$ 1,868,524	$ 1,146,144

(1) 2004 restated to reflect the two-for-one stock splits effected on June 3, 2005 and November 17, 2005.

The accompanying notes are an integral part of these consolidated financial statements.

STATEMENTS OF CASH FLOWS

Southwestern Energy Company and Subsidiaries

	For the years ended December 31,		
	2005	2004	2003
		(in thousands)	
Cash flows from operating activities			
Net income	**$ 147,760**	$ 103,576	$ 48,897
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**99,558**	77,350	58,788
Deferred income taxes	**86,431**	59,778	28,896
Unrealized (gain) loss on derivatives	**(9,666)**	2,639	(636)
Equity in (income) loss of NOARK partnership	**(1,635)**	433	(1,053)
Gain on sale of other property, plant and equipment	**(445)**	(5,802)	(2,991)
Minority interest in partnership	**(245)**	(268)	(429)
Cumulative effect of adoption of accounting principle	**—**	—	855
Change in assets and liabilities:			
Accounts receivable	**(42,680)**	(27,725)	(16,427)
Inventories	**(17,265)**	(2,741)	(6,683)
Under/over-recovered purchased gas costs	**5,911**	2,519	(6,804)
Accounts payable	**32,837**	26,052	4,693
Other assets and liabilities	**3,921**	2,086	1,993
Net cash provided by operating activities	**304,482**	237,897	109,099
Cash flows from investing activities			
Capital expenditures	**(453,859)**	(291,101)	(168,172)
Distribution from (investment in) NOARK partnership	**—**	(2,059)	2,500
Proceeds from the sale of property, plant and equipment	**1,519**	7,121	3,649
Other items	**(578)**	591	367
Net cash used in investing activities	**(452,918)**	(285,448)	(161,656)
Cash flows from financing activities			
Issuance of common stock	**579,956**	—	103,085
Payments on revolving long-term debt	**(563,800)**	(395,100)	(273,000)
Borrowings under revolving long-term debt	**463,800**	441,300	209,400
Retirement of 6.70% Notes due December 2005	**(125,000)**	—	—
Debt issuance costs	**(1,180)**	(1,514)	—
Change in bank drafts outstanding	**11,860**	(2,347)	7,988
Proceeds from exercise of common stock options	**5,270**	5,170	4,671
Net cash provided by financing activities	**370,906**	47,509	52,144
Increase (decrease) in cash and cash equivalents	**222,470**	(42)	(413)
Cash and cash equivalents at beginning of year	**1,235**	1,277	1,690
Cash and cash equivalents at end of year	**$ 223,705**	$ 1,235	$ 1,277

The accompanying notes are an integral part of these consolidated financial statements.

STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

Southwestern Energy Company and Subsidiaries

	Common Stock [1] Shares Issued	Common Stock [1] Amount	Additional Paid-In Capital [1]	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Common Stock in Treasury	Unamortized Restricted Stock Awards	Total
				(in thousands)				
Balance at December 31, 2002	110,952	$ 11,095	$ 10,809	$ 197,988	$ (17,358)	$ (19,981)	$ (5,065)	**$ 177,488**
Comprehensive income:								
Net income	—	—	—	48,897	—	—	—	**48,897**
Change in value of derivatives	—	—	—	—	2,027	—	—	**2,027**
Change in value of pension liability	—	—	—	—	2,811	—	—	**2,811**
Total comprehensive income	—	—	—	—	—	—	—	**53,735**
Issuance of common stock	37,950	3,795	99,290	—	—	—	—	**103,085**
Exercise of stock options	—	—	1,202	—	—	4,308	—	**5,510**
Issuance of restricted stock	—	—	1,031	—	—	1,199	(2,230)	**—**
Cancellation of restricted stock	—	—	10	—	—	(119)	109	**—**
Amortization of restricted stock and other	—	—	10	—	—	22	1,711	**1,743**
Balance at December 31, 2003	148,902	$ 14,890	$ 112,352	$ 246,885	$ (12,520)	$ (14,571)	$ (5,475)	**$ 341,561**
Comprehensive income:								
Net income	—	—	—	103,576	—	—	—	**103,576**
Change in value of derivatives	—	—	—	—	(6,797)	—	—	**(6,797)**
Change in value of pension liability	—	—	—	—	(499)	—	—	**(499)**
Total comprehensive income	—	—	—	—	—	—	—	**96,280**
Exercise of stock options	—	—	3,078	—	—	4,786	—	**7,864**
Issuance of restricted stock	—	—	2,166	—	—	665	(2,831)	**—**
Cancellation of restricted stock	—	—	(10)	—	—	(36)	46	**—**
Amortization of restricted stock	—	—	—	—	—	—	1,972	**1,972**
Balance at December 31, 2004	148,902	$ 14,890	$ 117,586	$ 350,461	$ (19,816)	$ (9,156)	$ (6,288)	**$ 447,677**
Comprehensive income:								
Net income	—	—	—	147,760	—	—	—	**147,760**
Change in value of derivatives	—	—	—	—	(81,044)	—	—	**(81,044)**
Change in value of pension liability	—	—	—	—	(4,014)	—	—	**(4,014)**
Total comprehensive income	—	—	—	—	—	—	—	**62,702**
Issuance of common stock	19,550	1,955	578,001	—	—	—	—	**579,956**
Exercise of stock options	—	—	11,821	—	—	5,526	—	**17,347**
Issuance of restricted stock	—	—	3,909	—	—	368	(4,277)	**—**
Cancellation of restricted stock	—	—	(121)	—	—	(128)	249	**—**
Amortization of restricted stock	—	—	—	—	—	—	2,622	**2,622**
Balance at December 31, 2005	168,452	$ 16,845	$ 711,196	$ 498,221	$ (104,874)	$ (3,390)	$ (7,694)	**$ 1,110,304**

[1] All years restated to reflect the two-for-one stock splits effected on June 3, 2005 and November 17, 2005.

The accompanying notes are an integral part of these consolidated financial statements.

STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

Southwestern Energy Company and Subsidiaries

RECONCILIATION OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	For the years ended December 31,		
	2005	2004	2003
		(in thousands)	
Balance, beginning of year	**$ (19,816)**	$ (12,520)	$ (17,358)
Current period reclassification to earnings	**60,708**	21,699	24,667
Current period change in derivative instruments	**(141,752)**	(28,496)	(22,640)
Current period change in pension liability	**(4,014)**	(499)	2,811
Balance, end of year	**$ (104,874)**	$ (19,816)	$ (12,520)

The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Southwestern Energy Company and Subsidiaries
December 31, 2005, 2004 and 2003

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations and Consolidation

Southwestern Energy Company (Southwestern or the Company) is an independent energy company primarily focused on natural gas. Through its wholly-owned subsidiaries, the Company is engaged in natural gas and oil exploration and production, natural gas gathering, transmission and marketing, and natural gas distribution. Southwestern's exploration and production (E&P) activities are concentrated in Arkansas, Texas, Louisiana, New Mexico and Oklahoma. Southwestern's marketing and gas gathering business (Midstream Services segment) is concentrated in its core areas of operations. The gas distribution segment operates in northern Arkansas and, depending upon weather conditions and current supply contracts, can obtain greater than 50% 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.

The consolidated financial statements include the accounts of Southwestern and its wholly-owned subsidiaries, including Southwestern Energy Production Company (SEPCO), SEECO, Inc., Arkansas Western Gas Company, Southwestern Midstream Services Company (SMS), Diamond "M" Production Company, Southwestern Energy Pipeline Company, and A.W. Realty Company. The consolidated financial statements also include the results for (i) Overton Partners, L.P., of which SEPCO is the sole general partner, (ii) DeSoto Drilling Inc., of which SEPCO is the sole shareholder and (iii) DeSoto Gathering Company, L.L.C., of which SMS is the sole member. 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 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.

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.

Issuances of Common Stock

In the third quarter of 2005, the Company consummated an underwritten offering of 9,775,000 shares of its common stock pursuant to an effective shelf registration statement filed with the Securities and Exchange Commission (SEC). The net proceeds of the offering were approximately $580.0 million after deduction of the underwriting discounts and offering expenses payable by the Company. In the first quarter of 2003, the Company consummated an underwritten offering of 9,487,500 shares of its common stock pursuant to a shelf registration statement filed with the SEC in December 2002. The net proceeds of the offering were approximately $103.1 million after deduction of the underwriting discounts and offering expenses payable by the Company.

Minority Interest in Partnership

In 2001, SEPCO formed a limited partnership, Overton Partners, L.P., with an investor to drill and complete 14 development wells in SEPCO's Overton Field located in Smith County, Texas. Because SEPCO is the sole general partner and owns a majority interest in the partnership, the operating and financial results are consolidated with the Company's exploration and production results and the investor's share of the partnership activity is reported as a minority interest item in the financial statements. SEPCO contributed 50% of the capital required to drill the 14 wells. Revenues and expenses are allocated 65% to SEPCO prior to payout of the investor's initial investment and 85% thereafter. Under the terms of the partnership agreement, the partnership has a maximum life of 50 years. At December 31, 2005, the estimated fair value of the minority ownership position of the partnership does not exceed the minority interest of $11.6 million reflected in the accompanying balance sheet.

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 natural gas and oil properties are limited to the sum of the future net revenues attributable to proved natural gas and oil reserves discounted at 10 percent plus the lower of cost or market value of any unproved properties. If the Company's unamortized costs in natural gas and oil properties exceed this ceiling amount, a provision for additional depreciation, depletion and amortization is required. At December 31, 2005, the Company's net book value of natural gas and oil properties did not exceed the ceiling amount. Decreases in market prices from December 31, 2005 levels, as well as changes in production rates, levels of reserves, and the evaluation of costs excluded from amortization, could result in future ceiling test impairments.

The Company's adoption of Statement of Financial Accounting Standards No. 143 "Accounting for Asset Retirement Obligations" (FAS 143), in January 2003 impacted its accounting for gas and oil properties principally by (i) recognizing future asset retirement obligations as a cost of its oil and gas properties and (ii) subjecting to depreciation, depletion and amortization the recorded asset retirement costs as well as estimated future retirement costs associated with future development activities on proved properties, net of salvage value associated with the retirement of the properties.

The adoption of FAS 143, as well as the adoption of Staff Accounting Bulletin No. 106 in September 2004, did not have a material impact upon the Company's calculation of its ceiling test. Additionally, the impact of adoption of FAS 143 did not have a material effect on the Company's financial position or results of operations.

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 2.1% to 6.2%.

Other property, plant and equipment is depreciated using the straight-line method over estimated useful lives ranging from 7 to 24 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.

Gathering Systems. The Company's investment in gathering systems is primarily related to its Fayetteville Shale play in Arkansas. These assets are being depreciated on a straight-line basis over 25 years.

Construction-in-Progress-Drilling-Rigs. The Company entered into contractual commitments in 2005 for the construction of ten drilling rigs. The rigs will be delivered throughout 2006 as each one is completed. These Company-owned rigs will be utilized in the Company's Fayetteville Shale play in Arkansas. Once in service, all rigs will be depreciated on a straight-line basis over 15 years. Costs of operating the drilling rigs, including depreciation, will be charged to the full cost pool as wells in which the Company has an interest are drilled.

Gas in Underground Storage. The Company has two gas storage facilities with the gas in storage stated at average cost, a portion of which is carried as current inventory. The storage facility owned by the gas distribution segment is used for supply to the utility's customers. The cost of the gas withdrawn from this storage facility is passed on to the consumer. The E&P segment primarily uses its storage facility to supplement production in meeting contractual commitments and records revenue on storage withdrawals when such gas is sold. The carrying value of this gas in storage is assessed based on current and future market prices for gas that the Company expects to realize.

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. Interest is also capitalized on investments in gathering systems and drilling rigs until these assets are placed in service.

Asset Retirement Obligations. As discussed above, FAS 143, "Accounting for Asset Retirement Obligations," was adopted by the Company on January 1, 2003. FAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the associated asset retirement costs be capitalized as part of the carrying amount of the long-lived asset. The Company owns natural gas and oil properties which require expenditures to plug and abandon the wells when reserves in the wells are depleted. These expenditures under FAS 143 are recorded in the period the liability is incurred (at the time the wells are drilled or acquired). The effect of this standard on the Company's results of operations and financial condition at adoption was an increase in current and long-term liabilities of $1.2 million and $5.5 million, respectively; a net increase in property, plant and equipment of $5.3 million; a cumulative effect of adoption expense of $0.9 million and a deferred tax asset of $0.5 million. The new standard had no material impact on income before the cumulative effect of adoption in the year ended December 31, 2003. The following table summarizes the Company's 2005 and 2004 activity related to asset retirement obligations:

	2005	2004
	(in thousands)	
Asset retirement obligation at January 1	**$ 8,565**	$ 7,544
Accretion of discount	**326**	314
Obligations incurred	**436**	804
Obligations settled	**(1,553)**	(134)
Revisions of estimates	**1,455**	37
Asset retirement obligation at December 31	**$ 9,229**	$ 8,565
Current liability	**358**	473
Long-term liability	**8,871**	8,092
Total asset retirement obligation at December 31	**$ 9,229**	$ 8,565

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 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 projected level included in the 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.

In the fourth quarter of 2005, the gas distribution subsidiary received regulatory approval from the Arkansas Public Service Commission (APSC) of a rate increase totaling $4.6 million annually, exclusive of costs to be recovered through the utility's purchase gas adjustment clause. The rate increase was effective for deliveries made to customers on or after October 31, 2005.

In the third quarter of 2003, the gas distribution subsidiary received regulatory approval from the APSC of a rate increase totaling $4.1 million annually, exclusive of costs to be recovered through the utility's purchase gas adjustment clause. The order also entitled the gas distribution subsidiary to recover certain additional costs totaling $2.3 million through its purchase gas adjustment clause over a two-year period. The rate increase was effective for all customer bills rendered on or after October 1, 2003.

Gas Production Revenue and Imbalances

The E&P 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. At December 31, 2005, the Company had overproduction of 1.2 Bcf valued at $3.6 million and underproduction of 1.4 Bcf valued at $4.1 million. At December 31, 2004, the Company had overproduction of 1.3 Bcf valued at $3.7 million and underproduction of 1.5 Bcf valued at $4.4 million.

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. The Company's net operating loss carryforward at December 31, 2005 was $169.9 million with expiration dates in 2020 through 2025.

Derivative Financial Instruments

The Company uses derivative financial instruments to manage defined commodity price risks and interest rate risks and does not use them for trading purposes. The Company uses commodity swap agreements and options to hedge sales and purchases of natural gas and sales of crude oil. Gains and losses resulting from hedging activities have been recognized in gas and oil sales in the statements of operations when the related physical transactions of commodities were recognized. Changes in fair value of derivative instruments designated as cash flow hedges are reported in other comprehensive income (loss). Gains or losses from commodity swap agreements and options that do not qualify for accounting treatment as hedges are recognized currently as oil and gas sales. See Note 8 for a discussion of the Company's hedging activities and the effects of FAS 133.

Earnings Per Share

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 and the vesting of unvested restricted shares of common stock. All of the Company's options outstanding at December 31, 2005 and 2004, 7,126,465 options at December 31, 2005, with a weighted average exercise price of $4.34 and 8,884,512 options at December 31, 2004, with a weighted average exercise price of $3.18 were included in the calculation of diluted shares. The Company had options for 888,120 shares of common stock with a weighted average exercise price of $5.48 per share at December 31, 2003, that were not included in the calculation of diluted shares because they would have had an anti-dilutive effect. The remaining 9,219,520 options at December 31, 2003, with a weighted average exercise price of $2.45 were included in the calculation of diluted shares. The number of weighted average restricted stock shares included in the calculation of diluted shares was 903,873, 888,280 and 701,456 for 2005, 2004 and 2003, respectively. The number of options and the options prices, and the number of restricted shares for both 2004 and 2003 reflect the two-for-one stock splits effected in each of the second and fourth quarters of 2005.

Guarantees

The Company follows the disclosure provisions of Financial Accounting Standards Board Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." The nature of the Company's guarantee of debt associated with its investment in NOARK is included in Note 7 and Note 11 to the financial statements. This accounting standard also requires that upon the issuance or modification of guarantees, the guarantor must recognize a liability for the fair value of the obligations it assumes under the guarantee. Liability recognition is required on a prospective basis for guarantees that are made or modified after December 31, 2002.

Accounting for Stock-Based Compensation

The Company has a stock-based employee compensation plan, which is described more fully in Note 9. The Company accounts for this plan under the recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related Interpretations. No stock-based employee compensation cost related to stock options is reflected in net income, as all options granted under the plan had an exercise price equal to the market value of the underlying common stock on the date of grant. The Company does record compensation cost for the amortization of restricted stock issued to employees. The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" (FAS 123), to stock-based employee compensation:

	For the years ended December 31,		
	2005	2004	2003
	(in thousands, except share/per share amounts)		
Net income, as reported	**$ 147,760**	$ 103,576	$ 48,897
Add back: Amortization of restricted stock, net of related tax effects	**1,203**	1,251	1,083
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	**(2,995)**	(2,433)	(2,245)
Pro forma net income	**$ 145,968**	$ 102,394	$ 47,735
Earnings per share:			
Basic-as reported	**$ 0.98**	$ 0.73	$ 0.37
Basic-pro forma	**0.97**	0.72	0.36
Diluted-as reported	**0.95**	0.70	0.36
Diluted-pro forma	**0.93**	0.69	0.35

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 for all years; expected volatility of 40.6% for 2005, 44.3% for 2004 and 47.1% for 2003; risk-free interest rate of 4.4% for 2005, 3.5% for 2004 and 3.7% for 2003; and expected lives of 4 years for the 2005 option grants and 5 to 6 years for 2004 and 2003 option grants. The fair values of the option grants for each of the years 2005, 2004 and 2003 were $2.9 million, $2.6 million and $2.4 million, respectively.

As discussed further in Note 14 below, “New Accounting Standards,” the Company will adopt the provisions of FAS 123 (Revised 2004) in the first quarter of 2006. This standard will require the recognition of the fair value cost of equity awards, including stock options, as an expense over the service period provided by employees and directors.

In the fourth quarter of 2005, the Board of Directors prospectively revised the vesting for restricted stock and stock options granted to participants on or after December 8, 2005 under the 2004 Stock Incentive Plan to immediately accelerate the vesting upon death, disability or retirement (pending a minimum of five years of service). This change did not affect options issued prior to December 8, 2005 and will not reduce expenses expected to be incurred under FAS 123R. It will result in an earlier recognition of expenses for those participants who have reached retirement age.

(2) DEBT

Debt balances as of December 31, 2005 and 2004 consisted of the following:

	2005	2004
	(in thousands)	
Senior notes:		
6.70% Series due 2005	**$ -**	$ 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
	100,000	225,000
Other:		
Variable rate unsecured revolving credit arrangements	**-**	100,000
Total long-term debt	**$ 100,000**	$ 325,000

In January 2005, the Company arranged a new $500 million five-year unsecured revolving credit facility that amended and restated its existing $300 million three-year credit facility that would have expired in January 2007 and replaced a smaller unsecured credit facility that would have matured at the same time. The interest rate on the new credit facility is calculated based upon our debt rating and is currently 125 basis points over the current London Interbank Offered Rate (LIBOR). The revolving credit facility contains covenants which impose certain restrictions on the Company. Under the credit agreement, the Company may not issue total debt in excess of 60% of its total capital, must maintain a certain level of shareholders' equity, and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of 3.5 or above. There are also restrictions on the ability of the Company’s subsidiaries to incur debt. At December 31, 2005, the Company’s capital structure consisted of 8% debt (excluding its several guarantee of NOARK's obligations) and 92% equity, with a ratio of EBITDA to interest expense of 22.4, and the Company was in compliance with its debt agreements.

The 6.70% senior notes in the table above were paid in December 2005 with proceeds from the Company's equity offering in September 2005. The 7.625% senior notes are putable at the holders' option beginning in 2009. Other than the 7.625% senior notes, there are no other aggregate maturities of long-term debt for each of the years ending December 31, 2006 through 2010. Total interest payments were $20.3 million in 2005, $18.3 million in 2004 and $17.3 million in 2003.

(3) INCOME TAXES

The provision for income taxes included the following components:

	2005	2004 (in thousands)	2003
Federal:			
Current	**$ —**	$ —	$ —
Deferred	**79,845**	55,995	26,507
State:			
Current	**—**	—	—
Deferred	**6,698**	3,899	2,506
Investment tax credit amortization	**(112)**	(116)	(117)
Provision for income taxes	**$ 86,431**	$ 59,778	$ 28,896

The provision for income taxes was an effective rate of 36.9% in 2005, 36.6% in 2004 and 36.7% in 2003. The following reconciles the provision for income taxes included in the consolidated statements of operations with the provision which would result from application of the statutory federal tax rate to pre-tax financial income:

	2005	2004 (in thousands)	2003
Expected provision at federal statutory rate of 35%	**$ 81,967**	$ 57,174	$ 27,527
Increase (decrease) resulting from:			
State income taxes, net of federal income tax effect	**4,354**	2,534	1,629
Other	**110**	70	(260)
Provision for income taxes	**$ 86,431**	$ 59,778	$ 28,896

The components of the Company's net deferred tax liability as of December 31, 2005 and 2004 were as follows:

	2005	2004 (in thousands)
Deferred tax liabilities:		
Differences between book and tax basis of property	**$ 330,465**	$ 241,364
Stored gas	**6,343**	6,405
Book over tax basis in partnerships	**12,883**	12,452
Other	**8,963**	9,164
	358,654	269,385
Deferred tax assets:		
Accrued compensation	**2,753**	1,566
Alternative minimum tax credit carryforward	**3,026**	3,026
Accrued pension costs	**2,946**	604
Cash flow hedges - FAS 133	**58,621**	11,024
Asset retirement obligations - FAS 143	**3,390**	3,034
Net operating loss carryforward	**63,369**	46,943
Other	**451**	3,635
	134,556	69,832
Net deferred tax liability	**$ 224,098**	$ 199,553

The net deferred tax liability at December 31, 2005 consisted of a current deferred income tax asset of $29.7 million and long-term deferred income tax liabilities of $254.5 million including unamortized deferred investment tax credits of $0.7 million. There were no income tax payments in 2005, 2004 and 2003. The Company's net operating loss carryforward at December 31, 2005, was $169.9 million with expiration dates in 2020 through 2025. The Company also had an alternative minimum tax credit carryforward of $3.0 million and a statutory depletion carryforward of $7.1 million at December 31, 2005.

(4) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company applies Statement of Financial Accounting Standards No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits" (FAS 132). 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, 2005 and 2004:

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	**2005**	2004
	(in thousands)			
Change in benefit obligations:				
Benefit obligation at January 1	**$ 63,800**	$ 60,665	**$ 4,504**	$ 4,049
Service cost	**2,523**	2,404	**172**	174
Interest cost	**3,764**	3,692	**201**	252
Participant contributions	**—**	—	**116**	88
Actuarial loss/(gain)	**4,824**	1,755	**(693)**	178
Benefits paid	**(3,057)**	(4,716)	**(278)**	(237)
Benefit obligation at December 31	**$ 71,854**	$ 63,800	**$ 4,022**	$ 4,504

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	**2005**	2004
	(in thousands)			
Change in plan assets:				
Fair value of plan assets at January 1	**$ 54,165**	$ 51,956	**$ 1,114**	$ 838
Actual return on plan assets	**3,020**	4,994	**(19)**	(21)
Employer contributions	**1,804**	1,931	**446**	446
Participant contributions	**—**	—	**116**	88
Benefit payments	**(3,057)**	(4,716)	**(278)**	(237)
Fair value of plan assets at December 31	**$ 55,932**	$ 54,165	**$ 1,379**	$ 1,114
Funded status:				
Funded status at December 31	**$ (15,922)**	$ (9,635)	**$ (2,643)**	$ (3,390)
Unrecognized net actuarial loss	**16,073**	9,819	**1,371**	2,030
Unrecognized prior service cost	**2,726**	3,166	**—**	—
Unrecognized transition obligation	**—**	—	**602**	688
Net amount recognized	**$ 2,877**	$ 3,350	**$ (670)**	$ (672)

The Company uses a December 31 measurement date for all of its plans. Amounts recognized in the balance sheets as of December 31, 2005 and 2004 consist of the following:

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	**2005**	2004
	(in thousands)			
Accrued pension cost	**$ (7,902)**	$ (1,518)	**$ (670)**	$ (672)
Intangible asset	**2,773**	3,218	**—**	—
Accumulated other comprehensive loss (pre-tax)	**8,006**	1,650	**—**	—
Net amount recognized	**$ 2,877**	$ 3,350	**$ (670)**	$ (672)

The change in accumulated other comprehensive loss related to the pension plans was a loss of $6.4 million ($4.0 million after tax) for the year ended December 31, 2005 and income of $0.8 million ($0.5 million after tax) for the year ended December 31, 2004. Included in accumulated other comprehensive loss at December 31, 2005 and 2004 was an $8.0 million loss ($5.1 million net of tax) and a $1.6 million loss ($1.0 million net of tax), respectively, related to the Company's pension plans.

The Company's pension plans have an accumulated benefit obligation in excess of plan assets as of December 31, 2005 and 2004 as follows:

	2005	2004
	(in thousands)	
Projected benefit obligation	**$71,854**	$63,800
Accumulated benefit obligation	**63,834**	55,683
Fair value of plan assets	**55,932**	54,165

Net periodic pension and other postretirement benefit costs include the following components for 2005, 2004 and 2003:

	Pension Benefits			Other Postretirement Benefits		
	2005	2004	2003	**2005**	2004	2003
	(in thousands)					
Service cost	**$ 2,523**	$ 2,404	$ 2,171	**$ 172**	$ 174	$ 139
Interest cost	**3,764**	3,692	3,659	**201**	252	238
Expected return on plan assets	**(4,776)**	(4,543)	(3,608)	**(56)**	(42)	(36)
Amortization of transition obligation	**—**	—	—	**86**	86	86
Recognized net actuarial loss	**326**	233	664	**41**	102	87
Amortization of prior service cost	**440**	444	446	**—**	—	—
	$ 2,277	$ 2,230	$ 3,332	**$ 444**	$ 572	$ 514

Prior to January 1, 1998, the Company maintained a traditional defined benefit plan with benefits payable based upon average final compensation and years of service. Effective January 1, 1998, the Company amended its pension plan to become a "cash balance" plan on a prospective basis for its non-bargaining employees. 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. The Company has established trusts to partially fund its postretirement benefit obligations.

The weighted average assumptions used in the measurement of the Company's benefit obligations at December 31, 2005 and 2004 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	**2005**	2004
Discount rate	**5.50%**	6.00%	**5.50%**	6.00%
Rate of compensation increase	**4.00%**	4.00%	**n/a**	n/a

The weighted average assumptions used in the measurement of the Company's net periodic benefit cost for 2005, 2004 and 2003 are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2005	2004	2003	**2005**	2004	2003
Discount rate	**6.00%**	6.25%	6.75%	**6.00%**	6.25%	6.75%
Expected return on plan assets	**9.00%**	9.00%	9.00%	**5.00%**	5.00%	5.00%
Rate of compensation increase	**4.00%**	4.00%	4.00%	**n/a**	n/a	n/a

The expected return on plan assets for the various benefit plans is based upon a review of the historical returns experienced, combined with the future expected returns based upon the asset allocation strategy employed. The plans seek to achieve an adequate return to fund the obligations in a manner consistent with the federal standards of ERISA and with a prudent level of diversification.

For measurement purposes, the following trend rates were assumed for 2005 and 2004:

	2005	2004
Health care cost trend assumed for next year	**10%**	10%
Rate to which the cost trend is assumed to decline	**5%**	5%
Year that the rate reaches the ultimate trend rate	**2011**	2010

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	$ 46	$ (39)
Effect on postretirement benefit obligation	$ 463	$ (399)

The Company's pension plan weighted-average asset allocations at December 31, 2005 and 2004, by asset category, are as follows:

	2005	2004
Asset category:		
Equity securities	**65%**	65%
Debt securities	**33%**	33%
Cash equivalents	**2%**	2%
Total	**100%**	100%

Assets of the postretirement benefit plans were invested 100% in debt securities for 2005 and 2004.

The investment objective of the benefit plans is to ensure, over the long-term life of the plans, an adequate pool of assets to support the benefit obligations to participants, retirees and beneficiaries. As of December 31, 2005, the defined benefit pension plan had a diversified asset allocation strategy of 60%-70% equity securities and 30%-40% debt (fixed income) securities. Within the equity allocation, the plan invests in small cap, international, large cap growth, large cap value and large cap core securities. Plan assets are periodically balanced whenever the allocation to any asset class falls outside of the specified range.

In 2005, the Company contributed $1.8 million to its pension plans and $0.4 million to its other postretirement benefit plans. The Company expects to contribute $3.5 million to its pension plans and $0.4 million to its other postretirement benefit plans in 2006.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

	Pension Benefits	Other Benefits
	(in thousands)	
2006	$ 3,395	$ 192
2007	$ 3,424	$ 184
2008	$ 3,990	$ 207
2009	$ 4,500	$ 227
2010	$ 5,758	$ 249
Years 2011-2015	$27,865	$1,481

(5) NATURAL GAS AND OIL PRODUCING ACTIVITIES (UNAUDITED)

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:

	2005	2004 (in thousands)	2003
Sales	**$ 403,234**	$ 286,924	$ 176,245
Production (lifting) costs	**(41,419)**	(35,501)	(24,993)
Depreciation, depletion and amortization	**(88,902)**	(66,924)	(49,553)
	272,913	184,499	101,699
Income tax expense	**(100,157)**	(67,031)	(37,306)
Results of operations	**$ 172,756**	$ 117,468	$ 64,393

The results of operations shown above exclude general and administrative expenses and interest costs. 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 2005, 2004 and 2003:

	2005	2004 (in thousands)	2003
Proved property acquisition costs	**$ 75**	$ 15,384	$ 3,240
Unproved property acquisition costs	**55,652**	21,830	17,484
Exploration costs	**44,416**	24,526	20,862
Development costs	**313,759**	219,455	129,028
Capitalized costs incurred	**$ 413,902**	$ 281,195	$ 170,614
Full cost pool amortization per Mcf equivalent	**$ 1.42**	$ 1.20	$ 1.17

Capitalized interest is included as part of the cost of natural gas and oil properties. The Company capitalized $5.0 million, $2.8 million and $1.8 million during 2005, 2004 and 2003, respectively, based on the Company's weighted average cost of borrowings used to finance the expenditures. The increases in capitalized interest since 2003 reflect an increase in the Company's unevaluated costs related primarily to Southwestern's Fayetteville Shale properties.

In addition to capitalized interest, the Company also capitalized internal costs of $26.4 million, $14.3 million and $10.6 million during 2005, 2004 and 2003, respectively. These internal costs were directly related to acquisition, exploration and development activities and are included as part of the cost of natural gas and oil properties. The increases in internal costs capitalized since 2003 has resulted from the addition of personnel and related costs for Southwestern's acquisition, exploration and development activities.

The table of capitalized costs incurred above does not include amounts for the acquisition of Company-owned drilling rigs.

The following table shows the capitalized costs of gas and oil properties and the related accumulated depreciation, depletion and amortization at December 31, 2005 and 2004:

	2005 (in thousands)	2004
Proved properties	**$ 1,775,312**	$ 1,436,585
Unproved properties	**122,301**	47,239
Total capitalized costs	**1,897,613**	1,483,824
Less: Accumulated depreciation, depletion and amortization	**745,206**	658,445
Net capitalized costs	**$ 1,152,407**	$ 825,379

The table of net capitalized costs above does not include amounts for the acquisition of drilling rigs.

The table below sets forth the composition of net unevaluated costs excluded from amortization as of December 31, 2005. Of the total, approximately $24.0 million represents costs of wells in progress at December 31, 2005 and approximately $72.2 million is related to undeveloped leasehold costs in the Company's Fayetteville Shale play. 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.

	2005	2004	2003	Prior	**Total**
			(in thousands)		
Property acquisition costs	$56,956	$15,094	$10,821	$1,751	**$ 84,622**
Exploration and development costs	30,224	349	—	—	**30,573**
Capitalized interest	3,047	1,551	1,905	603	**7,106**
	$90,227	$16,994	$12,726	$2,354	**$122,301**

(6) NATURAL GAS AND OIL RESERVES (UNAUDITED)

The following table summarizes the changes in the Company's proved natural gas and oil reserves for 2005, 2004 and 2003:

	2005		2004		2003	
	Gas (MMcf)	**Oil (MBbls)**	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)
Proved reserves, beginning of year	**594,483**	**8,508**	457,016	7,675	374,614	6,784
Revisions of previous estimates	**(29,970)**	**(284)**	(13,832)	199	(16,668)	186
Extensions, discoveries and other additions	**264,683**	**1,669**	196,398	1,274	136,261	1,193
Production	**(56,758)**	**(705)**	(50,425)	(618)	(37,967)	(531)
Acquisition of reserves in place	**28**	—	5,634	30	808	48
Disposition of reserves in place	**(127)**	**(109)**	(308)	(52)	(32)	(5)
Proved reserves, end of year	**772,339**	**9,079**	594,483	8,508	457,016	7,675
Proved developed reserves:						
Beginning of year	**491,697**	**7,767**	369,867	6,719	286,276	5,633
End of year	**551,456**	**8,309**	491,697	7,767	369,867	6,719

The "Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Natural Gas and Oil Reserves" (standardized measure) is a disclosure required by Statement of Financial Accounting Standards No. 69, "Disclosures About Oil and Gas Producing Activities" (FAS 69). 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. The gas and oil reserve quantities owned by the Company were audited by the independent petroleum engineering firm of Netherland, Sewell & Associates, Inc.

Following is the standardized measure relating to proved gas and oil reserves at December 31, 2005, 2004 and 2003:

	2005	2004	2003
		(in thousands)	
Future cash inflows	**$ 6,699,456**	$ 3,857,623	$ 2,914,824
Future production costs	**(1,656,084)**	(983,654)	(644,014)
Future development costs	**(329,528)**	(108,911)	(69,668)
Future income tax expense	**(1,387,765)**	(779,386)	(647,605)
Future net cash flows	**3,326,079**	1,985,672	1,553,537
10% annual discount for estimated timing of cash flows	**(1,905,268)**	(1,093,364)	(837,185)
Standardized measure of discounted future net cash flows	**$ 1,420,811**	$ 892,308	$ 716,352

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. Year-end market prices used for the standardized measures above were $10.08 per Mcf for gas and $61.04 per barrel for oil in 2005, $6.18 per Mcf for gas and $43.45 per barrel for oil in 2004, and $5.97 per Mcf for gas and $32.52 per barrel for oil in 2003. Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future income taxes were computed by applying the year-end statutory rate, after consideration of permanent differences, to the excess of pre-tax 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 2005, 2004 and 2003:

	2005	2004 (in thousands)	2003
Standardized measure, beginning of year	**$ 892,308**	$ 716,352	$ 501,599
Sales and transfers of gas and oil produced, net of production costs	**(361,815)**	(252,241)	(151,793)
Net changes in prices and production costs	**582,247**	28,009	182,019
Extensions, discoveries, and other additions, net of future production and development costs	**546,523**	367,892	338,374
Acquisition of reserves in place	**58**	20,771	1,759
Revisions of previous quantity estimates	**(91,648)**	(26,481)	(34,637)
Accretion of discount	**121,837**	99,432	69,413
Net change in income taxes	**(239,539)**	(48,091)	(85,441)
Changes in estimated future development costs	**(248,322)**	(70,005)	(29,399)
Previously estimated development costs incurred during the year	**71,729**	42,143	29,921
Changes in production rates (timing) and other	**147,433**	14,527	(105,463)
Standardized measure, end of year	**$ 1,420,811**	$ 892,308	$ 716,352

(7) INVESTMENT IN UNCONSOLIDATED PARTNERSHIP

The Company holds a 25% general partnership interest in NOARK. NOARK Pipeline was formerly a 258-mile 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. The combined pipeline systems are now collectively called the Ozark Gas Transmission System. 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 was responsible for 60% of debt principal and interest payments in accordance with its several guarantee of NOARK's debt. In October 2005, Enogex sold its interest in the NOARK partnership to Atlas Pipeline Partners, L.P. As a result of this sale and the related prepayment by Enogex of their portion of the guaranteed debt, the Company is now the sole guarantor of the remaining principal and interest payments for NOARK's 7.15% Notes due 2018.

The Company's investment in NOARK totaled $17.1 million at December 31, 2005, and $15.4 million at December 31, 2004. See Note 11 for further discussion of NOARK's funding requirements and the Company's investment in NOARK.

The Company recorded pre-tax income of $1.6 million in 2005, a pre-tax loss of $0.4 million in 2004, and pre-tax income of $1.1 million for 2003 for its share of NOARK's results of operations. The pre-tax income in 2003 included a gain of $1.3 million recognized on the sale of a 28-mile portion of Ozark Gas Transmission System located in Oklahoma that had limited strategic value to the overall system. The Company records its share of NOARK's results of operations in other income (expense) on the consolidated statements of operations.

(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:

C*ash and Cash Equivalents, and Customer Deposits:* 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 and Interest 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, 2005 and 2004 were as follows:

	2005		2004	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	(in thousands)			
Cash and cash equivalents	**$ 223,705**	**$ 223,705**	$ 1,235	$ 1,235
Customer deposits	**$ 6,352**	**$ 6,352**	$ 5,903	$ 5,903
Long-term debt	**$ 100,000**	**$ 105,370**	$ 325,000	$ 335,440
Commodity and interest hedges asset (liability)	**$ (153,246)**	**$ (153,246)**	$ (34,477)	$ (34,477)

Derivatives and Risk Management

Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133), as amended by FAS 137, FAS 138 and FAS 149, was adopted by the Company on January 1, 2001. FAS 133 requires that all derivatives be recognized in the balance sheet as either an asset or liability measured at its 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.

At December 31, 2005, the Company recorded hedging assets of $19.5 million, hedging liabilities of $172.7 million, a regulatory asset of $1.2 million related to its utility gas purchase hedges, and a net of tax loss to other comprehensive income (loss) of $99.8 million. The amount recorded in other comprehensive income (loss) will be relieved over time and taken to the income statement as the physical transactions being hedged occur. At December 31, 2004, the Company recorded hedging assets of $1.2 million, hedging liabilities of $35.7 million, a regulatory asset of $1.4 million related to its utility gas purchase hedges, and a net of tax loss to other comprehensive income (loss) of $18.8 million. The change in accumulated other comprehensive loss related to derivatives was a loss of $128.6 million ($81.0 million after tax) for the year ended December 31, 2005, a loss of $10.7 million ($6.8 million after tax) for the year ended December 31, 2004, and income of $3.2 million ($2.0 million after tax) for the year ended December 31, 2003. Assuming the market prices of futures as of December 31, 2005 remain unchanged, we would expect to transfer a loss of approximately $62.8 million from accumulated other comprehensive income to earnings during the next 12 months when the transactions actually close. All transactions hedged as of December 31, 2005 are expected to mature by March 31, 2008.

The Company recorded a $9.4 million loss in 2005, a $1.5 million loss in 2004 and a $0.5 million loss in 2003 related to basis differential ineffectiveness associated with the Company's cash flow hedges. Additionally, the Company recorded a $19.1 million gain in 2005 and a $1.1 million loss in 2004 related to mark-to-market adjustments on basis differential swaps which did not qualify for hedge treatment. In early 2003, the Company discontinued an interest hedge when it paid down its revolving credit facility with proceeds from an equity issuance. Additional volatility in earnings and other comprehensive income (loss) may occur in the future as a result of the adoption of FAS 133.

The Company uses natural gas and crude oil swap agreements and options and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and oil and in interest rates. The Company's board of directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price and interest rate 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, to hedge activity in its marketing segment and to hedge the purchase of gas in its utility segment against the inherent price risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX 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 (production hedge) or receives (gas purchase hedge) funds equal to the amount by which the price of the commodity is below the contracted floor, and a "ceiling" price above which the Company pays to (production hedge) or receives from (gas purchase hedge) the counterparty the amount by which the price of the commodity is above the contracted ceiling.

At December 31, 2005, the Company had outstanding natural gas price swaps on total notional volumes of 7.9 Bcf in 2006 and 12.0 Bcf in 2007 for which the Company will receive fixed prices ranging from $6.64 to $6.66 per MMBtu. Outstanding oil price swaps on 120 MBbls were in place that will yield the Company an average price of $37.30 per barrel. At December 31, 2005, the Company also had outstanding natural gas price swaps on total notional volumes of 0.2 Bcf in 2006 for which the Company will pay an average fixed price of $11.11 per Mcf. At December 31, 2005, the Company had outstanding fixed price basis differential swaps on 35.3 Bcf of 2006 and 2007 gas production that did not qualify for hedge treatment.

At December 31, 2005, the Company had collars in place on notional volumes of 43.0 Bcf in 2006, 28.0 Bcf in 2007, and 2.0 Bcf in 2008. The 43.0 Bcf in 2006 had an average floor and ceiling price of $5.47 and $10.13 per MMBtu, respectively. The 28.0 Bcf in 2007 had an average floor and ceiling price of $6.64 and $11.91 per MMBtu, respectively, and the 2.0 Bcf in 2008 had an average floor and ceiling price of $8.00 and $19.40, respectively. The Company's price risk management activities reduced revenues by $77.2 million in 2005, $35.6 million in 2004 and $37.4 million in 2003.

The primary market risks related to the Company's derivative contracts are the volatility in commodity prices, basis differentials and interest rates. However, these market risks are offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of oil that is hedged, and payment of variable rate interest. 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 AND RESTRICTED STOCK GRANTS

The Southwestern Energy Company 2004 Stock Incentive Plan (2004 Plan) was adopted in February 2004 and approved by shareholders in May 2004. The 2004 Plan provides for the compensation of officers, key employees and eligible non-employee directors of the Company and its subsidiaries. The 2004 Plan replaced the Southwestern Energy Company 2000 Stock Incentive Plan (2000 Plan) and the Southwestern Energy Company 2002 Employee Stock Incentive Plan (2002 Plan) but did not affect prior awards under those plans which remained valid and some of which are still outstanding. The awards under the prior plans have been adjusted for the two-for-one stock splits in 2005 as permitted under such plans. The Company also has awards outstanding under 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 2004 Plan provides for grants of options, stock appreciation rights, and shares of restricted stock and restricted stock units to employees, officers and directors that in the aggregate do not exceed 8,400,000 shares (as adjusted for the stock splits). The types of incentives that may be awarded are comprehensive and are intended to enable the Company's 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 2004 Plan.

As initially adopted, the 2000 Plan provided for the grant of options, stock appreciation rights, shares of phantom stock, and shares of restricted stock to employees, officers and directors that in the aggregate did not exceed 1,250,000 shares and an annual award to each non-employee director with respect to 8,000 shares of common stock. The 2002 Plan provided for grants of options, stock appreciation rights, shares of phantom stock and shares of restricted stock that in the aggregate did not exceed 1,200,000 shares to employees who are not officers or directors of the Company under provisions of Section 16 of the Securities Exchange Act of 1934, as amended.

The 1993 Plan, as amended, provided for the compensation of officers and key employees of the Company 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 various stock incentive plans to certain non-officer employees and to certain officers at the time of their hire.

As adopted, the 1993 Director Plan provided for annual stock option grants of 12,000 shares (with 12,000 limited SARs to each non-employee director up to an aggregate of 240,000 shares.

The following tables summarize stock option activity for the years 2005, 2004 and 2003 and provide information for options outstanding at December 31, 2005:

	2005		2004 [1]		2003 [1]	
	Number of Shares	**Weighted Average Exercise Price**	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
Options outstanding at January 1	**8,884,512**	**$ 3.18**	10,107,640	$ 2.72	10,839,272	$ 2.54
Granted	**223,780**	**35.44**	500,040	11.99	888,120	5.48
Exercised	**1,981,827**	**2.66**	1,718,504	3.02	1,606,420	3.10
Canceled	**—**	**—**	4,664	3.14	13,332	1.86
Options outstanding at December 31	**7,126,465**	**$ 4.34**	8,884,512	$ 3.18	10,107,640	$ 2.72

(1) 2004 and 2003 restated to reflect two-for-one stock splits effected in June and November 2005.

	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
$1.50 - $1.86	3,093,060	$ 1.75	4.3	3,093,060	$ 1.75
$1.87 - $2.85	814,200	2.52	5.3	814,200	2.52
$2.86 - $5.00	1,667,672	3.04	4.9	1,627,672	3.04
$5.01 - $12.00	884,876	5.55	7.9	527,503	5.45
$12.01 - $36.00	666,657	20.17	6.3	138,868	12.45
	7,126,465	$ 4.34	5.2	6,201,303	$ 2.75

Associated with the exercise of stock options, the Company received a tax benefit of $12.0 million, $2.7 million and $0.8 million in 2005, 2004 and 2003, respectively. The tax benefit is recorded as an increase in additional paid-in capital.

All options are issued at fair market value at the date of grant and expire seven years from the date of grant for awards under the 2004 Plan and ten years from the date of grant for awards under all other plans. Options generally vest to employees and directors over a three- to four-year period from the date of grant. In the fourth quarter of 2005, the Board of Directors prospectively revised the vesting for restricted stock and stock options granted to participants on or after December 8, 2005 under the 2004 Stock Incentive Plan to immediately accelerate the vesting upon death, disability or retirement (pending a minimum of five years of service).

As disclosed in Note 1, the Company applies the disclosure-only provisions of FAS 123, "Accounting for Stock-Based Compensation." Accordingly, no compensation cost has been recognized for the stock option plans. As discussed further in Note 14 below, "New Accounting Standards," the Company will adopt the provisions of FAS 123 (Revised 2004) in the first quarter of 2006. This standard will require the recognition of the fair value cost of equity awards as an expense over the service period provided by employees and directors.

The Company granted 132,065 shares of restricted stock in 2005 and 59,690 shares and 110,038 shares of restricted stock, on a pre-split basis, in 2004 and 2003, respectively. The fair values of the grants were $4.3 million for 2005, $2.8 million for 2004 and $2.3 million for 2003. Of the 4,756,877 shares granted to date, 1,734,860 shares vest over a three-year period, 2,851,817 shares vest over a four-year period and the remaining shares vest over a five-year period.

The related compensation cost is being amortized over the vesting periods. Compensation cost related to the amortization of restricted stock grants was $2.6 million for 2005, $2.0 million for 2004 and $1.7 million for 2003. As of December 31, 2005, 3,750,111 shares have vested to employees. In 2005, 46,132 shares of restricted stock were cancelled and 3,210 shares and 13,142 shares of restricted stock, on a pre-split basis, were cancelled in 2004 and 2003, respectively.

(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 $10.00, 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 $0.0025 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 (non-management directors who are not affiliated with the proposed acquiror). These rights expire in 2009.

(11) CONTINGENCIES AND COMMITMENTS

At December 31, 2004, the Company and Enogex, the other general partner of NOARK, had severally guaranteed the principal and interest payments on NOARK's 7.15% Notes due 2018 which were issued in June 1998 and required semi-annual principal payments of $1.0 million. The Company's share of the several guarantee was 60%. In October of 2005, Enogex sold its interest in NOARK to Atlas Pipeline Partners L.P. and used a portion of the sales proceeds to prepay its share of the outstanding notes. At December 31, 2005, the Company was the sole guarantor of the notes which had principal outstanding of $39.0 million. The notes require semi-annual payments of $0.6 million. The Company is required to fund the debt service for the notes to the extent they are not funded by the Company's share of the operations of the pipeline. The Company did not make any advances in 2005 and advanced $2.1 million to NOARK in 2004. 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. Our gas distribution subsidiary has a transportation contract with Ozark Gas Transmission System for 66.9 MMcf per day of firm capacity that expires in 2014. Additionally, our Midstream Services segment has transportation contracts with Ozark Gas Transmission System for a total of 20.0 MMcf per day of firm capacity through 2006.

The Company leases certain office space and equipment under non-cancelable operating leases expiring through 2013. Under certain of these leases the Company is required to pay property taxes, insurance, repairs and other costs related to the leased property. At December 31, 2005, future minimum payments under non-cancelable leases accounted for as operating leases are approximately $2,985,000 in 2006, $3,161,000 in 2007, $2,861,000 in 2008, $2,740,000 in 2009, $2,388,000 in 2010 and $2,884,000 thereafter. Total rent expense for all operating leases was $1,589,000, $1,175,000 and $1,196,000 in 2005, 2004 and 2003, respectively.

The Company leases compressors related to its operations for its Midstream Services and E&P segments under non-cancelable operating leases expiring through 2011. At December 31, 2005, future minimum payments under non-cancelable leases accounted for as operating leases are approximately $5,440,000 in 2006, $6,267,000 in 2007, $5,742,000 in 2008, $4,729,000 in 2009, $3,154,000 in 2010 and $1,793,000 thereafter.

The Company's gas distribution segment has entered into various non-cancelable agreements related to demand charges for the transportation and purchase of natural gas with third parties. These costs are recoverable from the utility's end-use customers. At December 31, 2005, future payments under these non-cancelable demand contracts are $9,958,000 in 2006, $8,773,000 in 2007, $9,136,000 in 2008, $9,523,000 in 2009, $9,909,000 in 2010 and $41,410,000 thereafter. Additionally, the E&P and Midstream Services segments have commitments to third parties for demand transportation charges. At December 31, 2005, future payments under these non-cancelable demand contracts are $4,613,000 in 2006, $725,000 in 2007, $617,000 in 2008, $617,000 in 2009, $412,000 in 2010 and $0 thereafter.

In the second quarter of 2005, the Company entered into an agreement to fabricate five new land drilling rigs and the third quarter of 2005, the Company entered into an agreement to fabricate an additional five land drilling rigs. Including change orders, ancillary equipment and supplies, the total cost of these ten rigs is approximately $97.4 million. Payments made under these agreements were $35.1 million in 2005 with the remainder due in 2006.

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 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.

A lawsuit was filed against the Company in 2001 alleging a breach of an agreement to indemnify the other party against settlement payments related to the Company’s Boure' prospect in Louisiana. The allegations were contested and, in 2002, the Company was granted a motion for summary judgment by the trial court. The case was appealed to the First Court of Appeals in Houston, Texas, which subsequently transferred the appeal to the Thirteenth Court of Appeals in Corpus Christi. The appeal was briefed and argued during 2003. On April 14, 2005, the Thirteenth Court of Appeals reversed the orders of the trial court and rendered judgment denying the Company’s motion for summary judgment and granting the motion for summary judgment of the other party. The Company’s motion for rehearing with the Thirteenth Court of Appeals was denied on May 19, 2005. In August of 2005, the Company filed a petition for review with the Texas Supreme Court. In October of 2005, the Texas Supreme Court invited additional briefing by the parties, which both parties have done. The matter is currently pending before the Texas Supreme Court. Should the other party prevail on the appeal, the Company could be required to pay approximately $2.1 million, plus pre-judgment interest and attorney’s fees. Based on an assessment of this litigation by the Company and its legal counsel, no accrual for loss is currently recorded.

(12) SEGMENT INFORMATION

The Company applies Statement of Financial Accounting Standards No. 131, “Disclosures About Segments of an Enterprise and Related Information” (FAS 131). The Company’s reportable business segments have been identified based on the differences in products or services provided. Revenues for the E&P 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 midstream segment generates revenue through the marketing of both Company and third-party produced gas volumes and through gathering fees associated with the transportation of natural gas to market. Gathering revenues have been insignificant to-date but are expected to increase in the future depending upon the level of production from our Fayetteville Shale properties.

Summarized financial information for the Company’s reportable segments is shown in the following table. The accounting policies of the segments are the same as those described in Note 1. Management evaluates the performance of its segments based on operating income, defined as operating revenues less operating costs and expenses. Income before income taxes and the cumulative effect of adoption of accounting principle is the sum of operating income, interest expense, other income (expense) and minority interest in partnership. The “Other” column includes items not related to the Company’s reportable segments including real estate, the Company’s investment in the Ozark Gas Transmission system and corporate items.

	Exploration And Production	Gas Distribution	Midstream Services	Other	Total
			(in thousands)		
2005					
Revenues from external customers	**$ 365,384**	**$ 177,810**	**$ 132,690**	**$ 445**	**$ 676,329**
Intersegment revenues	**37,850**	**672**	**327,200**	**448**	**366,170**
Operating income	**234,759**	**4,911**	**5,684**	**566**	**245,920**
Interest income[(1)]	**3,379**	**—**	**—**	**—**	**3,379**
Depreciation, depletion and amortization expense	**88,902**	**6,907**	**303**	**99**	**96,211**
Interest expense[(1)]	**8,416**	**4,429**	**1,054**	**1,141**	**15,040**
Provision for income taxes[(1)]	**83,921**	**11**	**1,668**	**831**	**86,431**
Assets	**1,315,616**	**212,113**	**53,894**	**286,901[(2)]**	**1,868,524**
Capital expenditures[(3)]	**451,289**	**10,908**	**15,840**	**5,014**	**483,051**
2004					
Revenues from external customers	$ 253,920	$ 152,288	$ 65,128	$ 5,801	$ 477,137
Intersegment revenues	33,004	161	249,849	448	283,462
Operating income	164,585	8,516	3,151	6,035	182,287
Depreciation, depletion and amortization expense	66,924	6,592	67	91	73,674
Interest expense[(1)]	11,537	4,461	—	994	16,992
Provision for income taxes[(1)]	55,197	1,471	1,151	1,959	59,778
Assets	890,486	184,213	29,243	42,202[(2)]	1,146,144
Capital expenditures[(3)]	281,988	7,298	—	5,704	294,990
2003					
Revenues from external customers	$ 143,864	$ 137,200	$ 43,313	$ 3,024	$ 327,401
Intersegment revenues	32,381	156	158,664	448	191,649
Operating income	84,737	6,766	2,612	3,227	97,342
Depreciation, depletion and amortization expense	49,553	6,252	50	93	55,948
Interest expense[(1)]	11,911	4,395	—	1,005	17,311
Provision for income taxes[(1)]	26,010	767	954	1,165	28,896
Assets	666,815	171,027	16,223	36,645[(2)]	890,710
Capital expenditures[(3)]	170,886	8,178	10	1,129	180,203

(1) Interest income, interest expense and the provision (benefit) for income taxes by segment are an allocation of corporate amounts as cash equivalents, debt and income tax expense (benefit) are incurred at the corporate level.

(2) Other assets include the Company's investment in cash equivalents, the Company's equity investment in the operations of the NOARK Pipeline System, Limited Partnership (see Note 7), corporate assets not allocated to segments and assets for non-reportable segments.

(3) Capital expenditures for 2005, 2004 and 2003 included $28.1 million, $3.9 million and $12.0 million, respectively, related to the change in accrued expenditures between years.

Included in intersegment revenues of the Midstream Services segment are $290.9 million, $235.7 million and $154.1 million for 2005, 2004 and 2003, respectively, for marketing of the Company's E&P sales. Intersegment sales by the E&P segment and Midstream Services 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 and intangible pension related 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.

(13) QUARTERLY RESULTS (UNAUDITED)

The following is a summary of the quarterly results of operations for the years ended December 31, 2005 and 2004:

	Mar 31	June 30	Sept 30	Dec 31
	(in thousands, except per share amounts)			
	2005			
Operating revenues	**$ 161,053**	**$ 132,463**	**$ 162,127**	**$ 220,686**
Operating income	**56,226**	**47,181**	**67,201**	**75,312**
Net income	**32,621**	**26,814**	**39,469**	**48,856**
Basic earnings per share	**0.23**	**0.19**	**0.27**	**0.29**
Diluted earnings per share	**0.22**	**0.18**	**0.26**	**0.29**
	2004			
Operating revenues	$ 119,790	$ 96,427	$ 111,395	$ 149,525
Operating income	43,307	38,246	45,437	55,297
Net income	24,472	20,790	25,399	32,915
Basic earnings per share	0.17	0.15	0.18	0.23
Diluted earnings per share	0.17	0.14	0.17	0.22

(14) NEW ACCOUNTING STANDARDS

In December 2004, the FASB issued Statement on Financial Accounting Standards (“SFAS”) No. 123 (Revised 2004), “Share-Based Payment,” revising FASB Statement 123, “Accounting for Stock-Based Compensation” and superseding APB opinion No. 25, “Accounting for Stock Issued to Employees.” This statement requires a public entity to measure the cost of services provided by employees and directors received in exchange for an award of equity instruments, including stock options, at a grant-date fair value. The fair value cost is then recognized over the period that services are provided. The Company will adopt FAS 123R in the first quarter of 2006 using the modified prospective method with no restatement of prior periods. In Note 1, the Company discloses the effect on net income and earnings per share for years ended December 31, 2005, 2004 and 2003 if we had applied the fair value recognition provisions of FAS 123 to stock-based employee compensation.

In April 2005, the staff of the SEC issued Staff Accounting Bulletin No. 107 (SAB 107) to provide additional guidance regarding the application of SFAS 123 (Revised 2004) (“FAS 123R”). SAB 107 permits registrants to choose an appropriate valuation technique or model to estimate the fair value of share options, assuming consistent application, and provides guidance for the development of assumptions used in the valuation process. Additionally, SAB 107 discusses disclosures to be made under “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in registrants’ periodic reports upon adoption of this standard.

In November 2005, the FASB issued final FASB Staff Position (“FSP”) FAS No. 123R-3, “Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards.” The FSP provides an alternative method of calculating excess tax benefits (the APIC pool) from the method defined in FAS 123R for share-based payments. A one-time election to adopt the transition method in this FSP is available to those entities adopting FAS 123R using either the modified retrospective or modified prospective method and is available for up to one year from the initial adoption of FAS 123R or effective date of the FSP. However, until an entity makes its election, it must follow the guidance in FAS 123R. FSP 123R-3 is effective upon initial adoption of FAS 123R and will become effective for the Company in the first quarter of 2006. The Company is currently evaluating the potential impact of calculating the APIC pool using the FSP 123R-3 alternative method. The Company is currently evaluating the potential impact on its financial position and results of operations of calculating the APIC pool with this alternative method.

In the fourth quarter of 2005, the Company amended the stock option agreements under the Company’s incentive plan to allow for the immediate vesting of option awards made on or after December 8, 2005, upon the death, disability or retirement of the plan participant. This change did not affect options issued prior to December 8, 2005 and will not reduce expenses expected to be incurred under FAS 123R. It will result in an earlier recognition of expenses for those participants who have reached retirement age.

In March 2005, the FASB issued FSP No. FIN 46(R)-5, “Implicit Variable Interests under FASB Interpretation No. 46 (revised December 2003), Consolidation of Variable Interest Entities.” This FSP clarifies that when applying the variable interest consolidation model, a reporting enterprise should consider whether it holds an implicit variable interest in a variable interest entity ("VIE") or potential VIE. FSP No. FIN 46(R)-5 is effective as of April 1, 2005. Upon the adoption of FSP No. FIN 46(R)-5, the Company did not identify any potential or implicit VIEs.

In March 2005, the FASB issued Interpretation No. 47 ("FIN 47"), "Accounting for Conditional Asset Retirement Obligations – an interpretation of FASB Statement No. 143." FIN 47 requires an entity to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value can be reasonably estimated. FIN 47 states that a conditional asset retirement obligation is a legal obligation to perform an asset retirement activity in which the timing or method of settlement are conditional upon a future event that may or may not be within control of the entity. FIN 47 is effective no later than the end of the first fiscal year ending after December 15, 2005. The adoption of FIN 47 did not have a material impact on the Company's financial position or results of operations.

In November 2004, the FASB issued SFAS No. 151, "Inventory Costs, an amendment of ARB No. 43, Chapter 4," which clarifies the types of costs that should be expensed rather than capitalized as inventory. The provisions of FAS 151 are effective for years beginning after June 15, 2005. The Company does not expect this statement to have a material impact on it results of operations or its financial condition.

The FASB issued SFAS No. 153, "Exchanges of Productive Assets," in December 2004 that amended APB Opinion No. 29, "Accounting for Nonmonetary Transactions." FAS 153 requires that nonmonetary exchanges of similar productive assets are to be accounted for at fair value. Previously these transactions were accounted for at book value of the assets. This statement is effective for nonmonetary transactions occurring in fiscal periods beginning after June 15, 2005. The adoption of FAS 153 did not have a material impact on the Company's results of operations or its financial condition.

In May 2005, the FASB issued SFAS No. 154 "Accounting Changes and Error Corrections." FAS 154 changes the requirements for the accounting for and reporting of a change in accounting principle and requires retrospective applications to prior periods' financial statements of a voluntary change in accounting principle unless it is impracticable. This new accounting standard is effective for fiscal years beginning after December 15, 2005. The adoption of this accounting principle is not expected to have a material impact on the Company's financial position or results of operations.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act). Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, accumulate and communicate information to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and submission within the time periods specified in the SEC's rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of December 31, 2005. There were no changes in our internal control over financial reporting during the three months ended December 31, 2005 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting is included on page 57 of this Form 10-K.

ITEM 9B. OTHER INFORMATION

There was no information required to be disclosed in a report on Form 8-K during the fourth quarter of the fiscal year ended December 31, 2005 that was not reported on such form.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The definitive Proxy Statement to holders of our common stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Shareholders to be held on or about May 25, 2006, or the 2006 Proxy Statement, is hereby incorporated by reference for the purpose of providing information about the identification of our directors, and for discussion of our audit committee financial expert. We refer you to the sections "Election of Directors" and "Share Ownership of Management, Directors and Nominees" in the 2006 Proxy Statement for information concerning our directors. We refer you to the section "Meetings and Committees of the Board of Directors" for discussion of our audit committee financial expert. Information concerning our executive officers is presented in Part I, Item 4 of this Form 10-K. We refer you to the section "Section 16(a) Beneficial Ownership Reporting Compliance" for information relating to compliance with Section 16(a) of the Exchange Act.

The Company has adopted a code of ethics that applies to the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. The full text of such code of ethics has been posted on the Company's website at www.swn.com, and is available free of charge in print to any shareholder who requests it. Requests for copies should be addressed to the Secretary at 2350 N. Sam Houston Parkway East, Suite 300, Houston TX, 77032.

ITEM 11. EXECUTIVE COMPENSATION

The 2006 Proxy Statement is hereby incorporated by reference for the purpose of providing information about executive compensation. We refer you to the section "Executive Compensation" in the 2006 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The 2006 Proxy Statement is hereby incorporated by reference for the purpose of providing information about securities authorized for issuance under our equity compensation plans and security ownership of certain beneficial owners and our management. For information about our equity compensation plans, refer to "Equity Compensation Plans" in our 2006 Proxy Statement. Refer to the sections "Security Ownership of Certain Beneficial Owners" and "Share Ownership of Management, Directors and Nominees" for information about security ownership of certain beneficial owners and our management.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The 2006 Proxy Statement is hereby incorporated by reference for the purpose of providing information about certain relationships and related transactions. Refer to the sections "Certain Transactions," "Share Ownership of Management, Directors and Nominees," "Agreements Concerning Employment and Change in Control," "Pension Plans" and "Equity Compensation Plans" for information about transactions with our executive officers, directors or management.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The 2006 Proxy Statement is hereby incorporated by reference for the purpose of providing information about fees paid to the principal accountant and the audit committee's pre-approval policies and procedures. We refer you to the section "Relationship with Independent Registered Public Accounting Firm" in the 2006 Proxy Statement and to Exhibit A thereto for information concerning fees paid to our principal accountant and the audit committee's pre-approval policies and procedures and other required information.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) (1) The consolidated financial statements of Southwestern Energy Company and its subsidiaries and the report of independent registered public accounting firm are included in Item 8 of this Form 10-K.

(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 are filed as part of, or incorporated by reference into, this Form 10-K.

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

Dated: March 6, 2006

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 6, 2006.

/s/ Harold M. Korell Harold M. Korell	Director, Chairman, President and Chief Executive Officer
/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/ 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/ Vello A. Kuuskraa Vello A. Kuuskraa	Director
/s/ Kenneth R. Mourton Kenneth R. Mourton	Director
/s/ Charles E. Scharlau Charles E. Scharlau	Director

EXHIBIT INDEX

Exhibit Number	Description
3.1	Amended and Restated By-Laws of Southwestern Energy Company. (Incorporated by reference to Exhibit 3.1 to the Registrant's Annual Report filed on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2002)
3.2	Amended and Restated Articles of Incorporation of Southwestern Energy Company. (Incorporated by reference to the Registrant's Definitive Proxy Statements (Commission File No. 1-08246) for the 2005 Annual Meeting of Shareholders)
4.1	Form of Common Stock Certificate. (Incorporated by reference to Exhibit 4.1 to the Registrant's Form S-3 (File No. 333-101658)
4.2	Amended and Restated Rights Agreement between Southwestern Energy Company and the First Chicago Trust Company of New York dated April 12, 1999. (Incorporated by reference to Exhibit 4.1 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1999)
4.3	Amendment No. 1 to the Amended and Restated Rights Agreement between Southwestern Energy Company and Equiserve Trust Company as successor to the First Chicago Trust Company of New York dated March 15, 2002. (Incorporated by reference to Exhibit 4.1 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2001)
4.4	Indenture, dated as of December 1, 1995 between Southwestern Energy Company and The First National Bank of Chicago (now Bank One Trust Company, N.A.). (Incorporated by reference to Exhibit 4 to Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (File No. 33-63895) filed on November 17, 1995)
4.5	Amended and Restated Credit Agreement dated January 4, 2005 among Southwestern Energy Company, JPMorgan Chase Bank, NA, SunTrust Bank, Royal Bank of Scotland, Royal Bank of Canada, Fleet National Bank, and the other lenders named therein, JPMorgan Chase Bank, NA, as administrative agent, SunTrust Bank as syndication agent. (Incorporated by reference to Exhibit 4.5 to the Registrant’s Annual Report filed on Form 10-K (Commission file No. 1-08246) for the year ended December 31, 2004)
4.6*	Guaranty dated June 1, 1998 by Southwestern Energy Company in favor of The Bank of New York, as trustee (the “Trustee”), under the Indenture dated as of June 1, 1998 between NOARK Pipeline Finance L.L.C. and the Trustee.
10.1	Form of Amended and Restated Indemnity Agreement between Southwestern Energy Company and each Executive Officer and Director of the Registrant. (Incorporated by reference to Exhibit 10.1 of the Registrant's Current Report on Form 8-K filed October 28, 2005)
10.2	Form of Executive Severance Agreement between Southwestern Energy Company and each of the Executive Officers of Southwestern Energy Company, effective February 17, 1999. (Incorporated by reference to Exhibit 10.12 of the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1998)
10.3	Southwestern Energy Company Incentive Compensation Plan. (Incorporated by reference to Exhibit 10.2(b) to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1998)
10.4	Southwestern Energy Company Supplemental Retirement Plan amended as of February 1, 1996. (Incorporated by reference to Exhibit 10.5 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1995)
10.5	Southwestern Energy Company Supplemental Retirement Plan Trust, dated December 30, 1993. (Incorporated by reference to Exhibit 10.6 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1993)
10.6	Southwestern Energy Company Non-Qualified Retirement Plan, effective October 4, 1995. (Incorporated by reference to Exhibit 10.7 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1995)

10.7	Amended and Restated Limited Partnership Agreement of NOARK Pipeline System, Limited Partnership dated January 12, 1998. (Incorporated by reference to Exhibit 10.7 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1997)
10.8	Amendment No. 1 to the Amended and Restated Limited Partnership Agreement of NOARK Pipeline System, Limited Partnership dated June 18, 1998. (Incorporated by reference to Exhibit 10.14 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1998)
10.9	Southwestern Energy Company 1993 Stock Incentive Plan, dated April 7, 1993. (Incorporated by reference to Exhibit 10.4(e) to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1993)
10.10	Southwestern Energy Company 1993 Stock Incentive Plan for Outside Directors, dated April 7, 1993. (Incorporated by reference to Exhibit 10.4(f) to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1993)
10.11	Southwestern Energy Company 2000 Stock Incentive Plan dated February 18, 2000. (Incorporated by reference to the Appendix of the Registrant's Definitive Proxy Statement (Commission File No. 1-08246) for the 2000 Annual Meeting of Shareholders)
10.12	Southwestern Energy Company 2002 Employee Stock Incentive Plan, effective October 23, 2002. (Incorporated by reference to Exhibit 10.1 to the Registrant’s Current Report on Form 8-K (filed December 13, 2005)
10.13	Southwestern Energy Company 2002 Performance Unit Plan, as amended, effective December 8, 2005. (Incorporated by reference to Exhibit 3.1 to Registrant’s Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2002)
10.14	Southwestern Energy Company 2004 Stock Incentive Plan. (Incorporated by reference to Appendix A to the Registrant’s Proxy Statement dated March 29, 2004)
10.15	Form of Incentive Stock Option Agreement for awards prior to December 8, 2005. (Incorporated by reference to Exhibit 10.1 to the Registrant’s Current Report on Form 8-K filed on December 20, 2004)
10.16	Form of Restricted Stock Agreement for awards prior to December 8, 2005. (Incorporated by reference to Exhibit 10.3 to the Registrant’s Current Report on Form 8-K filed on December 20, 2004)
10.17	Form of Non-Qualified Stock Option Agreement for non-employee directors for awards prior to December 8, 2005. (Incorporated by reference to Exhibit 10.2 to the Registrant’s Current Report on Form 8-K filed on December 20, 2004)
10.18	Purchase and Sale Agreement by and between PV Exploration Company (now DeSoto Drilling, Inc.), as Buyer, and M.D. Cowan, as Seller, dated July 1, 2005 (Incorporated by reference to Exhibit 10.1 to the Registrant’s Form 10-Q (Commission File No. 1-08246) for the quarter ended September 30, 2005)
10.19	Purchase and Sale Agreement by and between PV Exploration Company (now DeSoto Drilling, Inc.), as Buyer, and M.D. Cowan, as Seller, dated September 29, 2005 (Incorporated by reference to Exhibit 10.2 to the Registrant’s Form 10-Q (Commission File No. 1-08246) for the quarter ended September 30, 2005)
10.20	Form of Incentive Stock Option for awards granted on or after December 8, 2005 (Incorporated by reference to Exhibit 10.4 to the Registrant’s Current Report on Form 8-K filed on December 13, 2005)
10.21	Form of Restricted Stock Agreement for awards granted on or after December 8, 2005 (Incorporated by reference to Exhibit 10.4 to the Registrant’s Current Report on Form 8-K filed on December 13, 2005)
10.22	Form of Non-Qualified Stock Option Agreement for awards granted on or after December 8, 2005 (Incorporated by reference to Exhibit 10.4 to the Registrant’s Current Report on Form 8-K filed on December 13, 2005)

10.23	Description of Compensation Payable to Non-Management Directors. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on March 2, 2005)
21.1*	List of Subsidiaries.
23.1*	Consent of PricewaterhouseCoopers LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of CEO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of CFO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of CEO and CFO furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

*Filed herewith