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, 2006

Commission file number 1-08246

Southwestern Energy Company

(Exact name of Registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**71-0205415** (I.R.S. Employer Identification No.)
2350 North Sam Houston Parkway East, Suite 125, Houston, Texas (Address of principal executive offices)	**77032** (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 $0.01 (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 $5,111,562,867 based on the New York Stock Exchange – Composite Transactions closing price on June 30, 2006, of $31.16. For purposes of this calculation, the registrant has assumed that its directors and executive officers are affiliates.

As of February 23, 2007, the number of outstanding shares of the registrant's Common Stock, par value $0.01, was 168,981,002.

Document Incorporated by Reference

Portions of the registrant's definitive proxy statement to be filed with respect to the annual meeting of stockholders to be held on or about May 10, 2007 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, 2006

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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 Governance and Retirement Committees of our Board of Directors are available on our website, and are available in print free of charge to any stockholder upon request.

PART I

ITEM 1. BUSINESS

Southwestern Energy Company is an integrated energy company primarily engaged in exploring for and producing natural gas. We conduct the majority of our exploration and production (E&P) operations in four general regions — the Arkoma Basin, East Texas, the Permian Basin and the onshore Gulf Coast. We also focus on creating and capturing additional value through our drilling, gathering, marketing and natural gas distribution businesses.

Our operations are conducted 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 operations principally located in Arkansas, Oklahoma, Texas and New Mexico. We engage in natural gas and oil exploration and production through our wholly-owned subsidiaries, SEECO, Inc., Southwestern Energy Production Company, or SEPCO, and Diamond "M" Production Company. 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. SEPCO conducts development drilling and exploration programs in the Arkoma Basin, Texas and New Mexico. Diamond "M" has interests in properties in the Permian Basin of Texas. DeSoto Drilling, Inc., or DDI, a wholly-owned subsidiary of SEPCO, operates drilling rigs in the Fayetteville Shale play and in East Texas.

2. *Midstream Services* - 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 gas marketing subsidiary, Southwestern Energy Services Company, captures downstream opportunities which arise through marketing and transportation activity. Our gathering subsidiary, DeSoto Gathering Company, L.L.C., engages in gathering activities primarily related to the development of our Fayetteville Shale play.

3. *Natural Gas Distribution* - We are also engaged in the distribution and transmission of natural gas. Our wholly-owned subsidiary, Arkansas Western Gas Company, or Arkansas Western, operates integrated natural gas distribution systems in northern Arkansas serving approximately 151,000 retail customers.

The vast majority of our operating income and cash flow is derived from our E&P business. In 2006, 96% of our operating income and 93% of our earnings before interest, taxes, depreciation, depletion and amortization, or EBITDA, were generated from our E&P business. Our Midstream Services and Natural Gas Distribution segments each generated 2% of our operating income and 1% and 3%, respectively, of our EBITDA in 2006. In 2005, our E&P, Midstream Services and Natural Gas Distribution segments generated 95%, 3% and 2% of our operating income and 94%, 3% and 3% of our EBITDA, respectively. In 2004, our E&P, Midstream Services and Natural Gas Distribution segments generated 90%, 5%, and 5% of our operating income and 91%, 3% and 6% 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. 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 Present Value Index, or 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 Our Existing Asset Base*. We seek to maximize the value of our existing asset base by developing properties that have production and reserve growth potential while also controlling per unit production costs. Our primary focus is our Fayetteville Shale play, where we hold approximately 892,000 net acres. Our large acreage position holds significant production and reserve growth potential. We intend to aggressively develop our acreage position by accelerating our drilling program and by improving individual well results through the use of advanced technologies and detailed technical analysis of our properties. In our other operating areas, we intend to increase our reserves and production by drilling infill locations, expanding known field limits and selectively recompleting existing wells.

- *Grow Through New Exploration and Development Activities*. We actively seek to find and develop new conventional natural gas and oil properties with significant exploration and exploitation potential, as well as new unconventional resource plays, which we call New Ventures. New prospects are evaluated based on repeatability, multi-well potential and land availability as well as other criteria. Our Fayetteville Shale play began as a New Venture project in 2002.

- *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. Our new drilling company, DDI, has already achieved a level of economies of scale with respect to the drilling of our wells in the Fayetteville Shale play by operating a fleet of rigs designed specifically for the play. DDI has also utilized smaller truck-mounted rigs to drill the vertical portion of the wellbore, decreasing both the number of drilling days and total well costs.

- *Rationalize Our Property Portfolio*. 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.

Recent Developments

2007 Planned Capital Investments and Production Guidance. On December 15, 2006, we announced a planned capital investment program for 2007 of $1,341 million, an increase of 42% over our 2006 capital program. Our 2007 capital program includes $1,237 million for our E&P segment, $84 million for our Midstream Services segment, and $20 million for improvements to our utility systems and for other corporate purposes. The increased capital program is expected to be primarily funded by internally-generated cash flow, borrowings under our revolving credit facility (discussed below) and/or funds raised in the public debt and equity markets. We also announced our targeted 2007 oil and gas production of approximately 105.0 to 110.0 Bcfe, an increase of approximately 45% to 50% over our production in 2006.

Amended and Restated Revolving Credit Agreement. On February 9, 2007, we amended and restated our $500 million unsecured revolving credit facility that was due to expire in January 2010, increasing the borrowing capacity to $750 million, lowering the borrowing costs and extending the maturity date to February 2012. The amount available under the credit agreement can be increased by up to $250 million in the future upon the agreement of the company and our existing or additional lenders.

Sale and Leaseback of Drilling Rigs. On December 29, 2006, we entered into a sale and leaseback transaction through which we sold 13 drilling rigs and related equipment owned by us to various financial institutions and then leased such drilling rigs and equipment back, along with two additional drilling rigs and related equipment, pursuant to a Master Lease Agreement of the same date with the same institutions as lessors. We received $127.3 million in cash for the 13 rigs and related equipment and recorded a deferred gain of $7.4 million which will be amortized over the lease term.

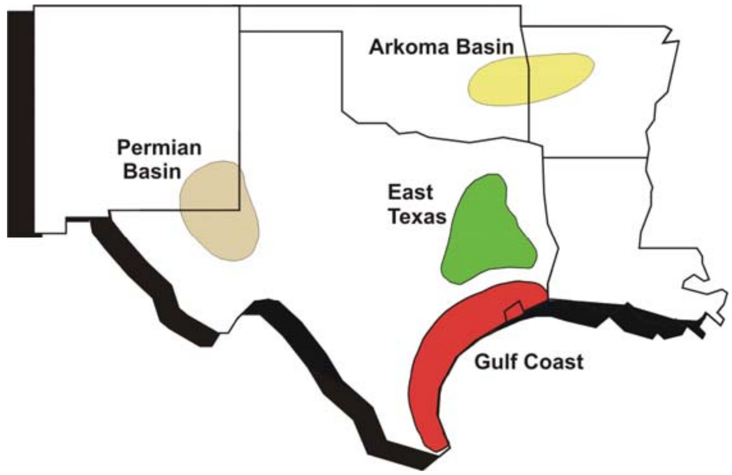
Pipeline Precedent Agreement. On December 15, 2006, our subsidiary, Southwestern Energy Services Company, or SES, signed a precedent agreement pursuant to which SES will contract for firm gas transportation services on two newly-proposed pipeline laterals and related facilities of Texas Gas Transmission, LLC, a subsidiary of Boardwalk Pipeline Partners, L.P. SES will be a “Foundation Shipper” for the project and will use the proposed laterals and related facilities primarily to deliver gas volumes produced from our operations in the Fayetteville Shale play in central Arkansas. Depending on regulatory approvals, the expected in-service date for both laterals is January 1, 2009.

Sale of Interest in NOARK. On May 2, 2006, we sold our 25% interest in NOARK Pipeline System, L.P., or NOARK, a partnership that owns a 723-mile integrated interstate pipeline system known as Ozark Gas Transmission System, to Atlas Pipeline Partners, L.P. for $69.0 million, resulting in a pre-tax gain of $10.9 million.

Sale of South Louisiana Properties. During the fourth quarter of 2006, we completed the sale of our remaining South Louisiana properties to a private company for $12.7 million. These properties had proved reserves of 7.0 Bcfe and produced approximately 1.1 Bcfe for the twelve months ended prior to the sale. As a result of this divestiture, we no longer have producing properties in the South Louisiana area.

Exploration and Production

We operate our E&P business in four general regions — the Arkoma Basin, East Texas, the Permian Basin and the onshore Gulf Coast. Our E&P business is organized into asset management teams based on the geographic location of our exploration and development projects. In addition to our core areas of operations, we actively seek to develop new conventional exploration projects as well as unconventional plays with significant exploration and exploitation potential.



Operating income from our E&P segment was $237.3 million in 2006, up from $234.8 million in 2005 and $164.6 million in 2004. EBITDA from our E&P segment was $386.4 million in 2006, compared to $325.9 million in 2005 and $231.1 million in 2004. The increases in both our operating income and EBITDA in 2006 and 2005 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 1,026 Bcfe at December 31, 2006, up from 827 Bcfe at year-end 2005 and 646 Bcfe at year-end 2004. The overall increase in total reserves in the past three years is primarily due to the discovery and development of the Fayetteville Shale play in Arkansas, the accelerated development of our Overton Field in East Texas and our continued conventional drilling program in the Arkoma Basin. Our year-end 2006 reserves had a pre-tax PV-10 value of $1,309 million, compared to $1,986 million at year-end 2005 and $1,218 million at year-end 2004. The after-tax PV-10 was $1,043 million at year-end 2006, $1,421 million at year-end 2005 and $892 million at year-end 2004. The decrease in the 2006 pre-tax and after-tax PV-10 values of our reserves is primarily due to a lower market price for natural gas at December 31, 2006. At December 31, 2006, the market prices for natural gas and crude oil that were used to calculate our PV-10 value were $5.64 per Mcf and $57.25 per barrel, respectively, compared to $10.08 per Mcf and $61.04 per barrel at December 31, 2005 and $6.18 per Mcf and $43.45 per barrel at December 31, 2004. 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 95% of our year-end proved reserves were natural gas and 65% were classified as proved developed. We operate approximately 77% of our reserves, based on our PV-10 value, and our average proved reserves-to-production ratio, or average reserve life, approximated 14.2 years at year-end 2006. Sales of natural gas production accounted for 91% of total operating revenues for this segment in 2006 and 92% in both 2005 and 2004. Natural gas production has 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.

Our reserve replacement ratio has exceeded 300% for the last three years including 2006, where our results were primarily driven by reserve additions associated with our Fayetteville Shale play. In 2006, we replaced 386% of our production volumes by adding 365.5 Bcfe of proved natural gas and oil reserves at a finding and development cost of $2.75 per Mcfe, including a downward reserve revision of 86.6 Bcfe but excluding $94 million of capital invested in drilling rigs and related equipment which were subsequently sold and then leased back. In 2005 and 2004, our reserve replacement ratios were 399% and 365%, respectively, and our finding and development costs were $1.71 per Mcfe and $1.43 per Mcfe, respectively, including net downward reserve revisions of 31.7 Bcfe in 2005 and 12.7 Bcfe in 2004 but excluding $35 million in capital invested in drilling rigs in 2005. The downward reserve revisions during 2006 were primarily due to a comparative decrease in year-end gas prices, combined with performance revisions in our East Texas and conventional Arkoma Basin properties, which were partially offset by an upward performance revision in our Fayetteville Shale properties. The downward reserve revisions in 2005 and 2004 were primarily due to adjustments to the terminal decline rates for wells at our Overton Field and declines associated with our Gulf Coast properties. 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, and we expect this trend to continue in the future. For the period ending December 31, 2006, our three-year average reserve replacement ratio was 384%, and our three-year average finding and development cost was $2.04 per Mcfe, including reserve revisions and excluding our investments in drilling rigs.

Our reserve replacement ratio during 2006, excluding the effect of reserve revisions, was 505%, compared to 450% in 2005 and 388% in 2004. Our finding and development cost, excluding revisions and our investments in drilling rigs, was $2.10 per Mcfe in 2006, compared to $1.51 per Mcfe in 2005 and $1.34 per Mcfe in 2004. The increases in our finding and development costs during this time period were primarily due to higher costs for drilling and other field services, and we expect this trend to continue in the future. Excluding reserve revisions and our investments in drilling rigs, our three-year average reserve replacement ratio is 454% and our three-year average finding and development cost is $1.72 per Mcfe.

The following table provides information as of December 31, 2006, related to proved reserves, well count, net acreage, PV-10, and 2006 annual information as to production and capital investments, 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)	277	300	383	51	15	-	1,026
Percent of Total	27%	29%	37%	5%	2%	-	100%
Percent Natural Gas	100%	100%	96%	36%	95%	100%	95%
Percent Proved Developed	78%	27%	80%	89%	100%	100%	65%
Production (Bcfe)	20.1	11.8	32.0	5.8	2.6	-	72.3
Capital Investments (millions)(1)	$97	$388(1)	$204	$25	$7	$46(1)	$767
Total Gross Producing Wells	1,009	162	393	411	38	5	2,018
Total Net Producing Wells	493	145	336	160	16	3	1,153
Total Net Acreage	461,761(2)	766,654(3)	94,076(4)	33,193	12,242	99,301	1,467,227
Net Undeveloped Acreage	271,259(2)	715,895(3)	67,488(4)	4,892	5,017	89,592	1,154,143
PV-10:							
Pre-tax (millions)	$470	$158	$537	$114	$29	$1	$1,309
After-tax (millions)	$375	$126	$428	$91	$23	-	$1,043
Percent of Total	36%	12%	41%	9%	2%	-	100%
Percent Operated	82%	99%	75%	45%	57%	100%	77%

(1) Our Fayetteville Shale play capital investments include $29 million in leasehold acquisition costs and exclude $94 million related to the purchase of drilling rigs and related equipment which was sold in December 2006 as part of a sale and leaseback transaction. New Ventures capital investments included $3 million relating to drilling wells in the Arkoma Basin that are now part of our Arkoma Conventional program.

(2) Includes 123,442 net developed acres and 1,930 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.

(3) Assuming we do not drill successful wells to develop the acreage and do not extend the leases in our undeveloped acreage in the Fayetteville Shale play, leasehold expiring over the next three years will be 6,304 net acres in 2007, 19,451 net acres in 2008, and 105,593 net acres in 2009.

(4) Assuming we do not drill successful wells to develop the acreage and do not extend the leases in our undeveloped acreage in the Angelina River Trend in East Texas, leasehold expiring over the next three years will be 404 net acres in 2007, 20,620 net acres in 2008, and 27,300 net acres in 2009.

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 to the south and east of the traditional Fairway area and west 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 unconventional drilling program in the Arkoma Basin. At December 31, 2006, we had approximately 577 Bcf of natural gas reserves in the Arkoma Basin, representing approximately 56% of our total reserves, up from 372 Bcf at year-end 2005 and 247 Bcf at year-end 2004.

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 277 Bcf of our reserves at year-end 2006 were attributable to our conventional Arkoma wells. During 2006, we invested $97 million and participated in 84 wells with 54 producers, four dry holes and 26 wells in progress at year-end, resulting in a 93% drilling success rate while adding 51.6 Bcf of gas reserves at a finding and development cost of $4.04 per Mcf, including a net downward reserve revision of 27.5 Bcf primarily related to lower gas prices and an increase in the terminal decline rates for some of our properties. This compares to finding and development costs of $1.25 per Mcf in 2005 and $1.11 per Mcf in 2004, including net downward reserve revisions of 0.7 Bcf in 2005 and net upward reserve revisions of 4.5 Bcf in 2004. Excluding revisions, finding and development costs would have been $1.89 per Mcf in 2006 and $1.23 per Mcf in both 2005 and 2004. The increase in our finding costs during this time period was primarily due to higher costs for drilling and other oilfield services. Our gas production from our conventional drilling program in the Arkoma Basin was 20.1 Bcf during 2006, or approximately 55.1 MMcf per day, compared to 20.2 Bcf in 2005 and 20.1 Bcf in 2004. Production over this time period has remained fairly constant as our drilling investment is offsetting the natural production decline from existing wells.

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 $1.74 per Mcf, including revisions (or $1.46 per Mcf excluding revisions), and three-year average production, or lifting, costs of $0.60 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 2006 at $0.64 per Mcf (including production taxes), compared to $0.68 per Mcf in 2005 and $0.48 per Mcf in 2004.

Our strategy in the Fairway is to continue to delineate new geologic prospects and extend previously identified trends using our extensive expertise in the area. 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 had previously been less explored. One of these newer areas is our Ranger Anticline prospect area, or Ranger, located at the southern edge of the Arkansas portion of the basin, where we have significantly increased our drilling activity over the last few years.

Our wells at Ranger have primarily targeted the Upper and Lower Borum tight gas sands between 5,000 and 8,000 feet in depth. We drilled our first successful well at Ranger in 1997, and 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 nine miles. In 2006, much of our drilling at Ranger Anticline has focused on the area located between the main producing part of the field and this eastern extension where we have drilled several higher-rate wells. Wells completed in 2006 had average estimated ultimate gross reserves of 1.9 Bcf per well.

From 1997 through year-end 2006, we successfully drilled 104 out of 118 wells, adding 95.7 net Bcf of reserves at a finding and development cost of $1.52 per Mcf, including reserve revisions. During 2006, we successfully completed 27 out of 29 wells (excluding 15 wells in progress at year-end 2006), which added 28.8 Bcf of new reserves. Net production from the field during 2006 was 5.7 Bcf, up from 5.6 Bcf in 2005 and 3.5 Bcf in 2004. Our average working interest in the 104 successful wells drilled through December 31, 2006, is 77% and our average net revenue interest is 63%.

We continue to increase our acreage position at Ranger and, as of December 31, 2006, we held approximately 16,000 gross developed acres and 58,240 gross undeveloped acres and had regulatory approval for well spacing at a minimum distance of 560 feet between wells. Our average working interest in our gross undeveloped acreage position at Ranger is 46%. 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, which is located eleven miles north of Ranger. The USA #1-24 well encountered pay in the Pennsylvania-age Basham and Borum sands, which are also the producing horizons at Ranger. In 2006, we drilled five offsets to the USA #1-24 discovery. Four of these six wells are producing while the remaining wells were waiting on pipeline connection. Depending on the performance of the newly drilled wells, there may be significant drilling potential on our Midway acreage block. At December 31, 2006, we held approximately 28,650 gross acres in our Midway prospect area.

Our conventional Arkoma Basin drilling program continues to be an important 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 2007, we plan to invest approximately $116 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, which we announced in August 2004, is now the 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 550 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. Approximately 300 Bcf of our reserves at year-end 2006 were attributable to our Fayetteville Shale play, up from approximately 101 Bcf at year-end 2005.

At December 31, 2006, we held a total of approximately 892,000 net acres in the play area (716,000 net undeveloped acres, 51,000 net developed acres held by Fayetteville Shale production and approximately 125,000 net acres held by conventional production). Excluding our acreage held by conventional production, our acreage position had an average lease term of 7 years, an average royalty interest of 15% and was obtained at an average cost of $95 per acre. To date, we have established production from the Fayetteville Shale in 28 separate pilot areas located in eight counties in Arkansas over an area which represents approximately 45% of our total acreage position. During 2007, we expect to test a large portion of our remaining acreage position to determine its productivity. During 2006, we also tested gas from both the Moorefield Shale and Chattanooga (Woodford) Shale, which are located beneath the Fayetteville Shale. We believe that approximately 130,000 of our net undeveloped acres also holds potential for the Moorefield Shale. Our Chattanooga Shale test well is located on our acreage that is held by conventional production in the Fairway area of the basin.

During the third quarter of 2006, the Arkansas Oil and Gas Commission approved statewide field rules in the Fayetteville Shale, the Moorefield Shale, and the Chattanooga Shale as "unconventional sources of supply." Under the statewide rules, each drilling unit would consist of a governmental section of approximately 640 acres and operators would be permitted to drill up to 16 wells per drilling unit for each unconventional source of supply. At December 31, 2006, based on the assumptions contained in the field rule applications for these fields, we estimate that the expected drainage from our horizontal wells will be less than 80 acres per well based on existing microseismic data and reservoir simulation modeling. 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 Item 1A of Part I of this Form 10-K.

Since 2004, we have increased our capital investments dramatically as we have accelerated our drilling program in the play area. In 2006, we invested approximately $388 million in our Fayetteville Shale play, which included $316 million to spud 196 wells, $29 million for leasehold acquisition, $14 million for seismic and $29 million in capitalized costs and other expenses. In 2005, we invested approximately $119 million, which included $67 million to spud 67 wells, $41 million for leasehold acquisition, $4 million for seismic and $7 million in capitalized costs. In 2004, we invested approximately $28 million, which included $12 million to spud 21 wells, $14 million for leasehold acquisition, and $2 million for other capitalized costs.

In 2006 and 2005, we also invested $94 million and $35 million, respectively, for the fabrication of 13 new drilling rigs to be used by our subsidiary, DDI, for drilling wells in the play. These rigs were sold in December 2006 as part of a sale and leaseback transaction pursuant to which we also leased two other newly fabricated rigs. We have options to repurchase the rigs under the leases as discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations." At December 31, 2006, DDI had 337 employees, compared to 45 employees at December 31, 2005. We had a total of 19 rigs running in the Fayetteville Shale play at year-end 2006, including 15 rigs capable of drilling horizontal laterals and four smaller rigs which are being utilized to drill the initial vertical section of the horizontal wells. DDI operates 13 of the 19 rigs we currently have working in the play. At year-end 2005, we had three rigs drilling in the Fayetteville Shale play area.

As of December 31, 2006, we had spud a total of 284 wells in the play, 270 of which were operated by us and 14 of which were outside-operated wells. Of the wells spud, 196 were drilled in 2006, 67 were drilled in 2005, and 21 were drilled in 2004, and 226 of the total wells spud were designated as horizontal wells. At year-end 2006, 172 wells had been drilled and completed, including 118 horizontal wells.

Our results to date indicate that optimal development of this large resource will primarily require horizontal wells. Early in the project's life, we hydraulically fractured our wells using nitrogen foam fluid systems. In 2006, we moved away from this completion technique and began using slickwater and crosslinked gel systems to complete our wells. Wells completed using a slickwater or crosslinked gel system have demonstrated improved production performance over the nitrogen foam fractured wells. During 2007, we plan to continue to experiment with new completion techniques, fluid systems and lateral lengths to further optimize the performance of our wells.

The average initial production test rate for the 90 horizontal wells which were fracture stimulated using either slickwater or crosslinked gel fluids and on production as of December 31, 2006, was 1.5 MMcf per day. The well costs for our most recently completed horizontal wells have averaged approximately $2.3 million per well. The horizontal wells drilled through December 31, 2006, have had an average vertical depth of 3,500 feet, an average lateral length of 2,300 feet, and have taken 18 days on average to drill from re-entry to re-entry, after the vertical portion of the wellbore has been drilled.

Gross production from our operated wells in the Fayetteville Shale play increased from approximately 9 MMcf per day at the beginning of 2006 to approximately 100 MMcf per day by year-end, and could reach up to 300 MMcf per day by the end of 2007. Our net production from the Fayetteville Shale play was 11.8 Bcf in 2006, compared to 1.8 Bcf in 2005 and 0.1 Bcf in 2004. Our production in 2007 is estimated to range between 45 and 50 Bcf. Our total proved net gas reserves booked in the play at year-end 2006 were 300 Bcf from a total of 434 locations, of which 162 were proved developed producing, 9 were proved developed non-producing and 263 were proved undeveloped. Of the 434 locations, 381 were horizontal. Our proved developed reserves have ranged from 0.2 Bcf to 2.8 Bcf per well and the average gross proved reserves for each of the proved undeveloped wells included in our year-end reserves was approximately 1.15 Bcf per well, up from 0.95 Bcf per well at the end of 2005. We currently estimate that the average ultimate gross production for these wells will be 1.3 to 1.5 Bcf per horizontal well. Total proved gas reserves booked in the play in 2005 totaled 101 Bcf from a total of 177 locations, of which 54 were proved developed producing, six were proved developed non-producing, and 117 were proved undeveloped. Total proved gas reserves booked in the play in 2004 totaled approximately 8 Bcf from a total of 20 vertical wells.

In 2007, we plan to invest $875 million in our Fayetteville Shale play, which includes drilling between 400 and 450 horizontal wells and shooting 3-D seismic over a large portion of our Fayetteville Shale acreage. We also plan to drill up to seven horizontal wells in the Moorefield Shale and one horizontal well in the Chattanooga Shale. 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. As we continue to gather data about 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 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 million. At December 31, 2006, 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 2006, we drilled and completed a total of 66 wells, of which 44 were 40-acre spaced wells. This compares to 80 wells drilled and completed in 2005 and 83 wells drilled and completed in 2004. 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 MMcfe in March 2001 to approximately 110 MMcfe at year-end 2006 resulting in net production of 29.8 Bcfe, compared to 26.7 Bcfe during 2005 and 21.8 Bcfe in 2004. Wells drilled in the field during 2006 averaged approximately $2.3 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 1.6 Bcfe per well. Our average production costs (including production taxes) were $0.64 per Mcfe in 2006, compared to $0.56 per Mcfe in 2005 and $0.50 per Mcfe in 2004. The increases in our unit production costs were primarily due to higher compression costs.

Our proved reserves in East Texas increased to 383 Bcfe at year-end 2006, or 37% of our total reserves, of which 367 Bcfe were in our Overton Field. Our reserves at Overton were up from 353 Bcfe at year-end 2005 and 297 Bcfe at year-end 2004, primarily due to the acceleration of our infill drilling program which began in early 2003. We invested approximately $155 million at the Overton Field during 2006 which resulted in proved reserve additions of 88.0 Bcfe at a finding and development cost of $3.80 per Mcfe, including a net downward reserve revision of 47.2 Bcfe. The reserve revision related to comparatively lower year-end gas prices and performance revisions in some of our existing wells. This compares to finding and development costs of $1.91 per Mcfe in 2005 and $1.20 per Mcfe in 2004, including net downward reserve revisions of 18.8 Bcfe and 19.2 Bcfe, respectively. Excluding such revisions, our finding and development costs at Overton were $1.76 per Mcfe in 2006, $1.56 per Mcfe in 2005, and $1.04 per Mcfe in 2004. Our finding costs have increased over recent years due to slightly lower reserves per well combined with higher costs for drilling and other oilfield services. We expect that this trend will continue with future development wells in the field. Additionally, as we continue to drill proved undeveloped locations at Overton for which the reserves were added in previous years, our finding and development cost per Mcfe will increase in the future. The average estimated ultimate recovery of gas and oil reserves from new wells completed in 2006 was approximately 1.6 gross Bcfe per well, compared to 1.8 gross Bcfe per well in 2005 and 2.0 gross Bcfe per well in 2004. The consistent decrease in gross reserves 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.

Angelina River Trend - Our Angelina River Trend is a collection of eight new development areas, located primarily in Angelina and Nacogdoches Counties, Texas. At December 31, 2006, we held approximately 68,900 gross undeveloped acres and 6,400 gross developed acres. Our average working interest in this area is 66% and our average net revenue interest is 51%. Through December 31, 2006, we had drilled 28 wells in this trend primarily targeting the Travis Peak formation. In 2006, we invested $40 million in the Angelina River Trend and drilled 16 wells, 11 of which were productive and 5 of which were in progress at year-end. Net production from the area was 1.8 Bcfe in 2006 and 0.9 Bcfe in 2005, with gross initial production rates from wells drilled during 2006 ranging from 1.0 to 5.1 MMcfe per day and estimated proved reserves ranging from 0.2 to 2.1 Bcfe. During 2006, a large portion of our drilling activity consisted of exploratory tests of our acreage position which resulted in the completion of several marginal wells which lowered our average reserves per well. The average estimated ultimate recovery of gas and oil reserves from the wells completed in 2006 was approximately 0.8 gross Bcfe per well with an average drilling and completion cost of $2.7 million per well.

In 2007, we plan to invest approximately $163 million in East Texas, drilling up to 39 wells at our Overton field and we plan on drilling up to 28 wells in our Angelina River Trend, the majority of which are planned offsets to our best existing wells.

Permian Basin. At December 31, 2006, our proved reserves in the Permian Basin were 51 Bcfe, compared to approximately 59 Bcfe at year-end 2005 and 61 Bcfe at year-end 2004. Our production in the basin during 2006 was 5.8 Bcfe, or approximately 15.9 MMcfe per day, compared to 6.9 Bcfe in 2005 and 7.1 Bcfe in 2004. The decrease in reserves and production during both 2006 and 2005 was due to the natural decline in these properties, partially offset by our drilling program. Our production costs (including production taxes) averaged $2.72 per Mcfe in 2006, compared to $1.76 per Mcfe in 2005 and $1.21 per Mcfe in 2004. The increases in our unit production costs during 2006 were primarily due to higher service costs and increased production taxes resulting from higher oil prices, combined with the decline in our production volumes. In 2006, we invested $25 million in the Permian Basin and drilled 12 wells, all of which were successful, resulting in reserve additions of 8.5 Bcfe. These reserve additions were more than offset by a net downward reserve revision of 10.7 Bcfe related to lower commodity prices at year-end and performance revisions. Excluding such revisions, our finding and development costs in the Permian Basin were $2.90 per Mcfe in 2006, $2.70 per Mcfe in 2005 and $2.62 per Mcfe in 2004. The increase in our finding and development costs in both 2006 and 2005 was due to overall higher service costs, and we expect this trend of higher costs to continue. In 2007, we plan to invest approximately $18 million in our Permian Basin program to drill up to 18 exploration and exploitation wells.

Gulf Coast. During 2006, our Gulf Coast operations were located in the onshore areas of Texas and Louisiana. During the fourth quarter of 2006, we completed the sale of our remaining South Louisiana properties to a private company for $12.7 million. These properties had proved reserves of 7.0 Bcfe and produced approximately 1.1 Bcfe annually. With this divestiture, we no longer have producing properties in the South Louisiana area.

Proved reserves in our Gulf Coast properties totaled 15 Bcfe at December 31, 2006, compared to approximately 27 Bcfe at year-end 2005 and 39 Bcfe at year-end 2004. The decline in reserves in 2006 was primarily due to the divestiture of our South Louisiana properties. The decline in reserves in 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 2006 was 2.6 Bcfe, or approximately 7 MMcfe per day, compared to 3.9 Bcfe in 2005 and 4.6 Bcfe in 2004. Production costs (including production taxes) averaged $2.00 per Mcfe during 2006, compared to $1.67 per Mcfe during 2005 and $1.39 per Mcfe during 2004. The increase in our unit production costs over the last three years was primarily due to the decline in production volumes from these properties, as well as general increases in operating costs. During 2006, we invested $7 million in the Gulf Coast area including approximately $4 million associated with an ongoing 3-D seismic program on our Texas Gulf Coast properties. During 2006, we added 0.2 Bcfe of reserves which were more than offset by downward reserve revisions of 2.7 Bcfe. In 2007, we plan to invest up to $7 million in the Texas Gulf Coast area which includes drilling up to three wells in the area of our current seismic program.

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, 2006, we held 89,592 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 116,633 net undeveloped acres held at year-end 2005 and 47,596 net undeveloped acres held at year-end 2004. Of the 89,592 net undeveloped acres held at year-end 2006, approximately 48,956 acres are located in Culberson County, Texas, in the Barnett Shale play in the Permian Basin.

In 2006, we invested approximately $46 million in our New Ventures program and drilled a total of seven exploration wells, of which two were successful, two were dry, and three were in progress at year-end. The two dry holes that we drilled in 2006 were unsuccessful conventional exploration tests in the Rocky Mountains area. Our two successful wells were both located in our Barnett Shale play in the Permian Basin. Additionally in 2006, we began drilling on our recently acquired Riverton coalbed methane project in Caldwell Parish, Louisiana. We have approximately 11,000 net acres in this project area targeting the Tertiary-age lower Wilcox coals at a depth of approximately 2,800 feet.

In 2005, we invested approximately $26 million in our New Ventures program 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 in our Midway prospect area 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 completed this well in the uphole Borum and Basham sands, which are producing horizons in the Ranger Anticline area. In 2005, we 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 $2 million in New Ventures, excluding the Fayetteville Shale play, which included drilling one exploration dry hole in another coalbed methane play.

In 2007, we plan to invest approximately $58 million in various other exploration and New Ventures projects, including drilling up to 10 wells in the Woodford Shale in Oklahoma and up to 30 wells in our new coalbed methane play in northern Louisiana.

Acquisitions and Divestitures

In 2006, we completed the sale of our remaining South Louisiana properties to a private company for $12.7 million. These properties had proved reserves of 7.0 Bcfe and produced approximately 1.1 Bcfe annually. With this divestiture, we no longer have producing properties in the South Louisiana area.

In 2006, we acquired additional working interests in our Overton Field for approximately $9 million. We also acquired interests in a new coalbed methane project located in Caldwell Parish, Louisiana for approximately $9 million. In total, we purchased 2.9 Bcfe of proved reserves for $18 million at an average cost of $6.09 per Mcfe. The cost per Mcfe was higher than for prior acquisitions due to the potential existence of future drilling opportunities not currently classified as proved.

In 2004, we purchased 5.8 Bcfe of proved reserves for $14 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.

Capital Investments

During 2006, we invested a total of $767 million in our primary E&P business activities and $94 million related to the purchase of drilling rigs and related equipment which were sold in December 2006 as part of a sale and leaseback transaction. During 2006, we participated in drilling 382 wells, 230 of which were successful, 9 were dry and 143 were still in progress at year-end. Of the 143 wells in progress at year-end, 104 were located in our Fayetteville Shale play. Our investments focused primarily on our active drilling programs in our Fayetteville Shale play, East Texas, and the conventional Arkoma Basin. These drilling programs accounted for 45%, 24%, and 11% of our E&P capital investments in 2006, respectively, with approximately $388 million invested in our Fayetteville Shale play, $204 million in East Texas and $97 million in our conventional Arkoma Basin program. In addition, we invested approximately $25 million in the Permian Basin, $7 million in the Gulf Coast and $46 million in exploration and New Ventures.

Of the $767 million invested in 2006, approximately $196 million was invested in exploratory drilling, $421 million in development drilling and workovers, $70 million for leasehold acquisition and seismic expenditures, $18 million for producing property acquisitions and $62 million in capitalized interest and expenses and other technology-related expenditures. During 2005, we invested a total of approximately $451 million in our E&P business and participated in 247 wells. Our investments in 2005 included $35 million related to construction payments on the rigs which were sold in December 2006. In 2004, we invested $282 million and participated in 204 wells. The increases in capital investments and wells drilled over the last two years are primarily due to the acceleration of our drilling program in the Fayetteville Shale play.

In 2007, we intend to invest approximately $1,237 million in our E&P program, an increase of approximately 44% over our capital investment level in 2006. We continue to be focused on our strategy of adding value through the drillbit, as approximately 82% of our 2006 E&P capital is allocated to drilling. The Fayetteville Shale play is the primary focus of our E&P business, and we plan to significantly increase our activity and investment in the play to approximately $875 million in 2007. Our capital investments in 2007 will also be focused on our lower-risk conventional drilling programs in East Texas and the Arkoma Basin. We plan to invest approximately $163 million and $116 million in our East Texas and conventional Arkoma Basin programs, respectively, in 2007. The remainder of our E&P capital will be allocated to exploitation projects in the Permian Basin ($18 million), the onshore Texas Gulf Coast ($7 million), and various other exploration and New Venture projects ($58 million).

Of the $1,237 million allocated to our 2007 E&P capital budget, approximately $937 million will be invested in development drilling, $75 million in exploratory drilling, $93 million in seismic and other geological and geophysical expenditures (including approximately $77 million in our Fayetteville Shale play), $46 million in land, and $86 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 Investments” for additional discussion of our planned capital investments in 2007.

Other Revenues

Other revenues and operating income for 2006, 2005 and 2004 also included pre-tax gains of $4.0 million, $3.1 million, and $4.5 million, respectively, related to the sale of gas-in-storage inventory.

Sales and Major Customers

Our daily natural gas equivalent production averaged 198.1 MMcfe in 2006, up 19% from 167.1 MMcfe in 2005 and 148.2 MMcfe in 2004, and we produced a total of 72.3 Bcfe in 2006, up from 61.0 Bcfe in 2005 and 54.1 Bcfe in 2004. Our natural gas production was 68.1 Bcf in 2006, compared to 56.8 Bcf in 2005 and 50.4 Bcf in 2004. The increase in 2006 production resulted primarily from a 10.0 Bcf increase in production related to our Fayetteville Shale play and a 4.0 Bcfe increase in production from East Texas, partially offset by a decrease in production from our Gulf Coast and the Permian Basin properties. The increase in production in 2005 resulted primarily from a 5.8 Bcfe increase in production from East Texas, and a 1.9 Bcf increase in our Arkoma production (including a 1.7 Bcf increase in production from the 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, 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 698,000 barrels of oil in 2006, compared to 705,000 barrels of oil in 2005 and 618,000 barrels of oil in 2004. Our oil production decreased during 2006 due to the sale of our South Louisiana properties in the fourth quarter. Our oil production increased in 2005 due to increased oil production from East Texas and the Permian Basin.

For 2007, we are targeting our total natural gas and crude oil production to be approximately 105.0 Bcfe to 110.0 Bcfe, which equates to a growth rate of approximately 45% to 50% above our 2006 production volumes.

The vast majority of our gas production and all of our oil production is sold to unaffiliated purchasers. Unaffiliated sales of gas and oil production are conducted under contracts that reflect current short-term prices and are subject to seasonal price swings. These combined gas and oil sales to unaffiliated purchasers accounted for 92% of total E&P revenues in 2006, 90% in 2005, and 89% in 2004. In 2006, the largest unaffiliated purchaser accounted for approximately 10% of total E&P revenues.

Our utility subsidiary, Arkansas Western, also purchases a portion 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 7% of total E&P revenues in 2006, 9% in 2005, and 10% in 2004. SEECO's sales to Arkansas Western were 4.7 Bcf in 2006, compared to 5.1 Bcf in 2005 and 5.4 Bcf in 2004. 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 competitive bids. SEECO's gas production provided approximately 36% of the utility's requirements in 2006, 38% in 2005, and 40% in 2004. 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 sales of our gas production to come primarily from sales to unaffiliated purchasers. Future sales to Arkansas Western will be dependent upon our success in obtaining gas supply contracts from them. 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 $6.55 per Mcf for our natural gas production in 2006, compared to $6.51 per Mcf in 2005 and $5.21 per Mcf in 2004, including the effect of hedges. Our hedging activities increased our average gas price $0.18 in 2006 and decreased our average gas price $1.22 per Mcf in 2005 and $0.59 per Mcf in 2004. Our average oil price realized was $58.36 per barrel in 2006, compared to $42.62 in 2005 and $31.47 per barrel in 2004, including the effect of hedges. Our hedging activities lowered our average oil price $4.81 per barrel in 2006, $11.75 per barrel in 2005, and $9.08 per barrel in 2004.

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, 2006, we had hedges in place on 65.0 Bcf, or approximately 60% to 65% of our targeted 2007 gas production, and 35.0 Bcf of our expected 2008 gas production. Subsequent to December 31, 2006 and prior to February 23, 2007, we hedged 12.5 Bcf of 2007, 11.0 Bcf of 2008 and 4.0 Bcf of 2009 gas production under fixed price swaps with average prices of $8.03, $7.65 and $7.29 per Mcf, respectively. Additionally, we hedged 2.0 Bcf of 2007, 11.0 Bcf of 2008 and 4.0 Bcf of 2009 gas production using costless collars. The collars relating to 2007 production have a weighted average floor and ceiling price of $8.00 and $10.00 per Mcf, respectively; the collars relating to 2008 production have a weighted average floor and ceiling price of $8.00 and $10.26 per Mcf, respectively; and the collars relating to 2009 production have a weighted average floor and ceiling price of $7.63 and $10.00 per Mcf, respectively. As of February 19, 2007, we have hedged approximately 75% of our 2007 anticipated gas production level. 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, 2006.

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 NYMEX spot market prices. However, during both 2006 and 2005, widening market differentials caused the difference in our average price received to be approximately $0.90 per Mcf lower than average spot market prices. Assuming a NYMEX commodity price of $7.00 per Mcf of gas for 2007, our differential for the average price received for our gas production is expected to be approximately $0.65 to $0.70 per Mcf below the NYMEX Henry Hub index price, including the impact of our basis hedges. Assuming a NYMEX commodity price of $60.00 per barrel of oil for 2007, we expect the average price received for our oil production during 2007 to be approximately $1.00 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 our 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 and our discovery of the Fayetteville Shale play. 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 the 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 also 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.

Commencing in 1992, the FERC issued a series of 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 a series of 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. The implementation of these orders has not had a material adverse effect on our results of operations to date.

We cannot predict whether and to what extent any market reforms initiated by the FERC or any new energy legislation 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 by the FERC or any other legislative body.

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.

Impact of Federal Regulation of Sales of Natural Gas

Historically, the sale of natural gas in interstate commerce has 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.

The natural gas industry historically has been heavily regulated and from time to time proposals are introduced by Congress and the FERC and judicial decisions are rendered that impact the conduct of business in the natural gas industry. There can be no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

Midstream Services

Our Midstream Services segment generates revenue through the marketing of our own gas production and third-party natural gas and through gathering fees associated with the transportation of natural gas to market. Our operating income from this segment was $4.1 million on revenues of $475.2 million in 2006, compared to $5.7 million on revenues of $459.9 million in 2005 and $3.2 million on revenues of $315.0 million in 2004. The increases in revenues are largely attributable to increased volumes marketed, higher purchased gas costs and increased gathering revenues. The decrease in operating income during 2006 was due to increased operating costs and expenses that resulted from increased staffing and other costs associated with our growing gathering activities, and a decrease in the margin generated by our marketing activities caused in part by increased volatility of locational market differentials in our core operating areas.

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. We marketed 72.7 Bcf of natural gas in 2006, compared to 61.9 Bcf in 2005 and 57.0 Bcf in 2004. Of the total volumes marketed, purchases from our E&P subsidiaries accounted for 72% in 2006, 76% in 2005, and 77% in 2004.

Gas Gathering

In 2004, we formed a new subsidiary, DeSoto Gathering Company, L.L.C., that engages in gathering activities related to the development of our Fayetteville Shale play. In 2006, we invested approximately $48.7 million related to these activities and had gathering revenues of $7.9 million, compared to $15.8 million invested and revenues of $1.0 million in 2005. Gathering revenues and expenses for this segment are expected to grow substantially over the next few years as gathering systems for our Fayetteville Shale play are expanded to support the development of this play.

Competition

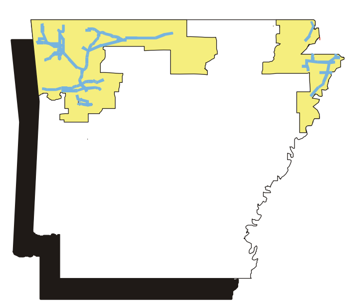
Our gas marketing activities compete with numerous other companies offering the same services, many of which possess larger financial and other resources than we have. Some of these competitors are affiliates of companies with extensive pipeline systems that are used for transportation from producers 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.

Regulation

On March 15, 2006, the Department of Transportation, or the DOT, issued new rules pertaining to certain gathering lines. We do not expect compliance with these new rules to have a material adverse impact on our operations.

Natural Gas Distribution

We distribute natural gas to approximately 151,000 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 67% 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 2003, the Center for Business and Economic Research at the University of Arkansas estimated that the population of the Fayetteville-Springdale-Rogers MSA should continue to grow approximately 3% per year until 2025. 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.



Utility Service Territory

Operating income for our natural gas distribution business was $4.5 million in 2006, compared to $4.9 million in 2005 and $8.5 million in 2004. EBITDA generated by our utility segment was $10.5 million in 2006, compared to $11.7 million in 2005 and $15.2 million in 2004. The decrease in 2006 and 2005 operating income and EBITDA resulted primarily from warmer than normal weather and increased operating costs and expenses, which more than offset a rate increase that became effective October 31, 2005. In September 2006, Arkansas Western filed an application for a general rate increase. Any increased approved is expected to take effect in July 2007. 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 and directly at the wellhead under long-term contracts with flexible pricing provisions. In 2006, SEECO successfully bid on gas supply packages representing approximately 53% of the requirements for Arkansas Western for 2007, compared to approximately 44% for 2005 and 55% for 2004. The contracts awarded to SEECO expire in 2008.

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 3% 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 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 3.1 Bcf, 4.2 Bcf and 4.5 Bcf, respectively, in 2006, 2005, and 2004, which had the effect of increasing its total gas supply costs by $7.7 million, $2.4 million, and $1.1 million, respectively. At December 31, 2006, Arkansas Western had 3.1 Bcf of future gas purchases hedged at an average purchase price of $8.83 per Mcf. We refer you to Item 7A of this Form 10-K, "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 134,000 residential, 17,000 commercial, and 170 industrial customers, while also providing gas transportation services to approximately 113 end-use and off-system customers. Total gas throughput in 2006 was 21.9 Bcf, compared to 23.2 Bcf in 2005 and 25.0 Bcf in 2004. The lower volumes in both 2006 and 2005 primarily resulted from warmer weather and customer conservation brought about by high gas prices in recent years. Weather in 2006 was 17% warmer than normal and 8% warmer than in 2005. Weather in 2005 was 9% warmer than normal and 1% colder than in 2004.

Residential and Commercial. Approximately 89% of the utility's revenues in 2006 were from residential and commercial markets. Residential and commercial customers combined accounted for 56% of total gas throughput for the gas distribution segment in 2006, compared to 57% in 2005 and 2004. Gas volumes sold to residential customers were 7.5 Bcf in 2006, compared to 8.1 Bcf in 2005 and 8.5 Bcf in 2004. Gas sold to commercial customers totaled 4.7 Bcf in 2006, compared to 5.1 Bcf in 2005 and 5.7 Bcf in 2004. The fluctuations in gas volumes sold to both residential and commercial customers were driven primarily by warmer 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 9.6 Bcf in 2006, 10.0 Bcf in 2005, and 9.8 Bcf in 2004. 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 0.1 Bcf in 2006, less than 0.1 Bcf in 2005 and were 1.0 Bcf in 2004, all to the Ozark Gas Transmission System. As of December 31, 2006, a total of 112 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 Arkansas Western must obtain the approval of the APSC in order to increase the rates it charges to its customers. Arkansas Western operates through municipal franchises that are perpetual by virtue of state law but may not be exclusive within a geographic area.

On September 25, 2006, Arkansas Western filed an application with the APSC for a general rate increase of approximately $13.1 million. The filing requests a capital structure using the modified balance sheet approach inclusive of a 50/50 debt-to-equity ratio and a 10.79% return on equity (ROE). The APSC approved an allowed ROE of 9.7% in Arkansas Western's 2005 rate increase. In this rate case, Arkansas Western hopes to resolve the issues associated with recovery of lost revenues resulting from energy efficiency programs and declining consumption per customer. Any increase approved is expected to take effect in July 2007. Arkansas Western's last rate increase of $4.6 million annually was effective October 31, 2005. Rate increase requests, which may be filed in the future, will depend on APSC ratemaking policies, customer growth, increases in operating expenses, and additional investment in property, plant and equipment.

As the regulatory focus of the natural gas industry has shifted from the federal level to the state level, some utilities across the nation have been 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.

On January 12, 2006, the APSC initiated a notice of inquiry regarding a rulemaking for developing and implementing energy efficiency programs. Following a collaborative process, the APSC issued Energy Efficiency Rules on January 11, 2007. These rules require all gas and electric utilities, excluding electric cooperatives, to file energy efficiency plans and programs with the APSC. Quick start or pilot programs are to be implemented by late 2007, and comprehensive programs are to be implemented in 2009. Utilities will recover the costs of energy efficiency programs from their customers. The APSC will address lost revenues associated with these programs in the utilities' rate cases.

In December 2006, the APSC issued new affiliate transactions rules. In January 2007, Arkansas Western and other utilities requested rehearing of these rules. On February 16, 2007, the APSC issued an order granting a rehearing and staying the implementation of the affiliate transaction rules pending further review. A public hearing on this issue is scheduled for March 27, 2007. Arkansas Western anticipates that these rules, if not modified on rehearing, will increase its regulatory costs and overall cost of service.

Gas distribution revenues in future years will be impacted by APSC policies, 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.

Transportation and Other

On May 2, 2006, we sold our 25% interest in NOARK Pipeline System, Limited Partnership (NOARK), a partnership that owns a 723-mile integrated interstate pipeline system known as Ozark Gas Transmission System, to Atlas Pipeline Partners, L.P. for $69.0 million, resulting in a pre-tax gain of $10.9 million. In connection with the sale, we assumed $39.0 million of partnership debt that we had previously guaranteed. Our share of NOARK's results of operations was a pre-tax gain of $0.9 million in 2006 prior to the sale, compared to a pre-tax gain of $1.6 million in 2005 and a pre-tax loss of $0.4 million in 2004. The pre-tax gain in both 2006 and 2005 was primarily due to 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.

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. There were no sales of commercial real estate in 2006. During 2005, we sold approximately 1.6 acres of commercial real estate for a pre-tax gain of $0.4 million. During 2004, we sold 45.5 acres of commercial real estate for a pre-tax gain of $5.8 million. These amounts were reflected in "Gas transportation and other" revenues in our income statement. As of December 31, 2006, 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, 2006, 2005 and 2004:

2006	E&P	Midstream Services	Natural Gas Distribution	Other	Total
Net income	$ 151,157	$ 2,976	$ 2,190	$ 6,313	**$ 162,636**
Depreciation, depletion and amortization	143,500	1,773	6,428	94	**151,795**
Net interest expense	508	-	171	-	**679**
Provision for income taxes	91,276	554	1,698	5,871	**99,399**
EBITDA	$ 386,441	$ 5,303	$ 10,487	$ 12,278	**$ 414,509**
2005					
Net income	$ 144,349	$ 2,962	$ 203	$ 246	**$ 147,760**
Depreciation, depletion and amortization	89,229	303	7,010	99	**96,641**
Net interest expense	8,416	1,054	4,429	1,141	**15,040**
Provision for income taxes	83,921	1,668	11	831	**86,431**
EBITDA	$ 325,915	$ 5,987	$ 11,653	$ 2,317	**$ 345,872**
2004					
Net income	$ 96,307	$ 2,000	$ 2,617	$ 2,652	**$ 103,576**
Depreciation, depletion and amortization	68,065	67	6,696	91	**74,919**
Net interest expense	11,537	-	4,461	994	**16,992**
Provision for income taxes	55,197	1,151	1,471	1,959	**59,778**
EBITDA	$ 231,106	$ 3,218	$ 15,245	$ 5,696	**$ 255,265**

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, 2006, we had 1,278 total employees, including 364 employed by our natural gas utility and 337 employed by our drilling company. None of our employees were covered by a collective bargaining agreement at year-end 2006. 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.

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

"<u>Bbl</u>" 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.

“Fracture stimulation” A process whereby fluids mixed with proppants are injected into a wellbore under pressure in order to fracture, or crack open, reservoir rock, thereby allowing oil and/or natural gas trapped in the reservoir rock to travel through the fractures and into the well for production.

“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.

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

"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.

"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 relatively 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 decline below levels at December 31, 2006, 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 stockholders' 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 2007 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 cash on hand. Our ability to borrow under our credit facility is subject to certain conditions. At December 31, 2006, 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.

Working interest owners of some of our properties may be unwilling or unable to cover their portion of development costs, which could change our exploration and development plans.

Some of our working interest owners may have difficulties obtaining the capital needed to finance their activities, or may believe that estimated drilling and completion costs are excessive. As a result, these working interest owners may be unable or unwilling to pay their share of well costs as they become due. These problems could cause us to change our development plans for these properties.

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 2006, our reserves were revised downward by 86.6 Bcfe, primarily due to lower prevailing oil and gas prices at year-end combined with performance revisions in some of our East Texas and conventional Arkoma Basin properties, which were partially offset by an upward performance revision in our Fayetteville Shale properties. In 2005, our reserves were revised downward by 31.7 Bcfe, primarily due to unexpected declines associated with our Gulf Coast properties and minor changes to decline rates for our wells at the Overton Field. In 2004, reserves were 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. These revisions represented no greater than 8% 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, 2006, approximately 35% 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 7 of Part II of this Form 10-K for additional information regarding the uncertainty of reserve estimates.

Our future level of indebtedness and the terms of our financing arrangements may adversely affect operations and limit our growth.

At December 31, 2006, we had long-term indebtedness of only $137.8 million and we had no borrowings under our revolving credit facility. However, we have significantly increased our planned capital expenditures for 2007 and currently expect to incur significant additional indebtedness in order to fund a portion of these expenditures. See also our risk factor headed “We may have difficulty financing our planned capital expenditures which could adversely affect our growth,” above.

The terms of the indenture relating to our outstanding senior notes, our revolving credit facility and the master lease agreement relating to our drilling rigs, which we collectively refer to as our “financing agreements,” impose 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 one or more of the following:

- 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 off-balance sheet obligations, and the covenants contained in our financing agreements, could have important consequences for our operations, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to required payments, 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 our financing agreements 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 obligations under those agreements, and in the case of the master lease agreement, loss of use of our drilling rigs. We may not have sufficient funds to make such payments. If we are unable to satisfy our obligations with 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, to meet our lease obligations, or that future borrowings, equity financings or proceeds from the sale of assets will be available to pay or refinance such debt or obligations. The terms of our financing agreements 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, 2006, we had drilled and completed 172 wells relating to our Fayetteville Shale play. The majority of these wells were drilled across an area that represents approximately 45% 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 wells 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 131,348 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 depends 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. During the third quarter of 2006, the AOGC approved statewide field rules in the Fayetteville Shale, the Moorefield Shale, and the Chattanooga Shale as “unconventional sources of supply.” Under the statewide rules, each drilling unit will consist of a governmental section of approximately 640 acres and operators will be permitted to drill up to 16 wells per drilling unit for each unconventional source of supply. To the extent that these field rules prevent us from successfully drilling wells in certain areas, 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 and our commitments for transportation on pipelines could make the sale of our gas uneconomic, which could have an adverse effect on our results of operations, financial condition and cash flows.

As of December 31, 2006, we had invested approximately $49 million in our gas gathering operations and we intend to invest approximately $84 million in 2007. Our gas gathering business will largely rely on gas sourced in our Fayetteville Shale play area in Arkansas. In addition, we have signed a precedent agreement committing us to a portion of the transportation fees related to new pipelines being built for our Fayetteville Shale play area by Texas Gas Transmission, LLC, a subsidiary of Boardwalk Pipeline Partners, LP. We have also entered into firm transportation agreements with Ozark Gas Transmission to transport up to 220,000 MMBtu per day of gas volumes from our Fayetteville Shale play over the next three years and up to an additional 50,000 MMBtu per day over the next two years. 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, and we could be forced to pay transportation fees on pipeline capacity that we would not be using. These events 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 23% of our gas and oil properties, based on PV-10 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.

Our ability to sell our natural gas and crude oil production could be materially harmed if we fail to obtain adequate services such as transportation and processing.

Our ability to bring natural gas and crude oil production to market depends on a number of factors including the availability and proximity of pipelines, gathering systems and processing facilities. In some of the areas where we have operations, we deliver natural gas and crude oil through gathering systems and pipelines that we do not own. These facilities may be temporarily unavailable due to market conditions or mechanical reasons, or may not be available to us in the future. Any significant change affecting these facilities or our failure to obtain access to them on acceptable terms could restrict our ability to conduct normal operations.

Shortages of oilfield 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. During the last half of 2006, we had difficulty obtaining additional well completion services due to a shortage of completion crews in our Fayetteville Shale play area, which resulted in a higher inventory of wells that had been drilled but were awaiting completion. 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 made significant investments in our drilling rig operations; however, we are still dependent on third party drilling companies. We also lack experience in operating drilling rigs.

We have made significant investments in our drilling rig operations, including commitments to lease 15 drilling rigs and hiring, as of December 31, 2006, 337 employees for our drilling subsidiary, DeSoto Drilling, Inc. (DDI). The 15 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 2007 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 had no experience prior to 2006 in operating drilling rigs. We cannot assure you that we will be able to continue 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, 2006, we had hedges on approximately 60% to 65% of our targeted 2007 natural gas production. Our price risk management activities increased revenues by $8.7 million in 2006, and reduced revenues by $77.2 million in 2005 and $35.6 million in 2004. 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.

Our certificate of incorporation, bylaws, and stockholder rights plan contain provisions that could make it more difficult for someone to either acquire us or affect a change of control.

Our stockholder rights plan, together with certain provisions of our certificate of incorporation and bylaws, could discourage an effort to acquire us, gain control of the company, or replace members of our executive management team. These provisions could potentially deprive our stockholders of opportunities to sell shares of our common stock at above-market prices.

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 investments, we refer you to “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Capital Investments.” 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, 2006:

	Undeveloped		Developed	
	Gross	Net	Gross	Net
Conventional Arkoma[1]	378,939	271,259	296,929	190,502
Fayetteville Shale Play[2]	1,027,840	715,895	61,440	50,759
East Texas[3]	85,714	67,488	35,793	26,588
Permian Basin	12,333	4,892	92,957	28,301
Gulf Coast	11,574	5,017	18,989	7,225
Exploration and New Ventures	92,198	89,592	14,384	9,709
	1,608,598	1,154,143	520,492	313,084

(1) Includes 123,442 net developed acres and 1,930 net undeveloped acres that are within our Fayetteville Shale focus area that are not included under the Fayetteville Shale Play.

(2) Assuming that we do not drill successful wells to develop the acreage and do not extend the leases in our undeveloped acreage in the Fayetteville Shale play, leasehold expiring over the next three years will be 6,304 net acres in 2007, 19,451 net acres in 2008, and 105,593 net acres in 2009.

(3) Assuming that we do not drill successful wells to develop the acreage and do not extend the leases in our undeveloped acreage in the Angelina River Trend in East Texas, leasehold expiring over the next three years will be 404 net acres in 2007, 20,620 net acres in 2008, and 27,300 net acres in 2009.

Producing wells as of December 31, 2006:

	Gas		Oil		Total		Gross Wells
	Gross	Net	Gross	Net	Gross	Net	Operated
Conventional Arkoma	1,009	493	-	-	1,009	493	444
Fayetteville Shale Play	162	145	-	-	162	145	158
East Texas	391	334	2	2	393	336	294
Unconventional	5	3	-	-	5	3	5
Permian Basin	137	23	274	137	411	160	48
Gulf Coast	33	15	5	1	38	16	7
	1,737	1,013	281	140	2,018	1,153	956

Wells drilled during the year:

Exploratory

	Productive Wells		Dry Holes		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2006	48.0	40.0	4.0	2.3	52.0	42.3
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

Development

	Productive Wells		Dry Holes		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2006	182.0	138.8	5.0	3.4	187.0	142.2
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

Wells in progress as of December 31, 2006:

	Gross	Net
Exploratory	67.0	53.5
Development	76.0	54.0
Total	143.0	107.5

During 2006, we were required to file Form 23, "Annual Survey of Domestic Oil and Gas Reserves," with the Department of Energy. The basis for reporting reserves on Form 23 is not comparable to the reserve data included in Note 6 to the 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 Natural Gas Distribution segment as of December 31, 2006. For a further description of Arkansas Western's properties, we refer you to "Business — Natural Gas Distribution."

	Total
Gathering	393
Transmission	1,033
Distribution	4,266
	5,692

Our Midstream Services segment has 212 miles of pipe in its gathering systems located in Arkansas.

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. In March of 2006, the Texas Supreme Court requested that both parties submit full briefing on the merits of the case. After receiving full briefing from both sides in July 2006, our petition for review with the Texas Supreme Court was denied on December 1, 2006, and the case has been remanded to the trial court for further disposition. Should the other party prevail in the case, 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, we accrued a loss in the fourth quarter of 2006.

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

None.

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	62	10
Greg D. Kerley	Executive Vice President and Chief Financial Officer	51	17
Richard F. Lane	Executive Vice President, and President, Southwestern Energy Production Company and SEECO, Inc.	49	8
Mark K. Boling	Executive Vice President, General Counsel and Secretary	49	5
Gene A. Hammons	President, Southwestern Midstream Services Company	61	2
Alan N. Stewart	President, Arkansas Western Gas Company	62	3

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." On February 23, 2007, the closing price of our stock was $40.37 and we had 2,391 stockholders of record. The following table presents the high and low sales prices for closing market transactions as reported on the New York Stock Exchange, which prices 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	**2006**		**2005**		**2004**	
March 31	$43.42	$29.33	$15.47	$11.22	$6.11	$4.84
June 30	$39.97	$24.80	$23.49	$14.20	$7.17	$5.97
September 30	$37.47	$27.95	$37.18	$24.78	$10.60	$7.42
December 31	$42.59	$27.86	$41.15	$31.30	$13.73	$10.33

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

Issuer Purchases of Equity Securities

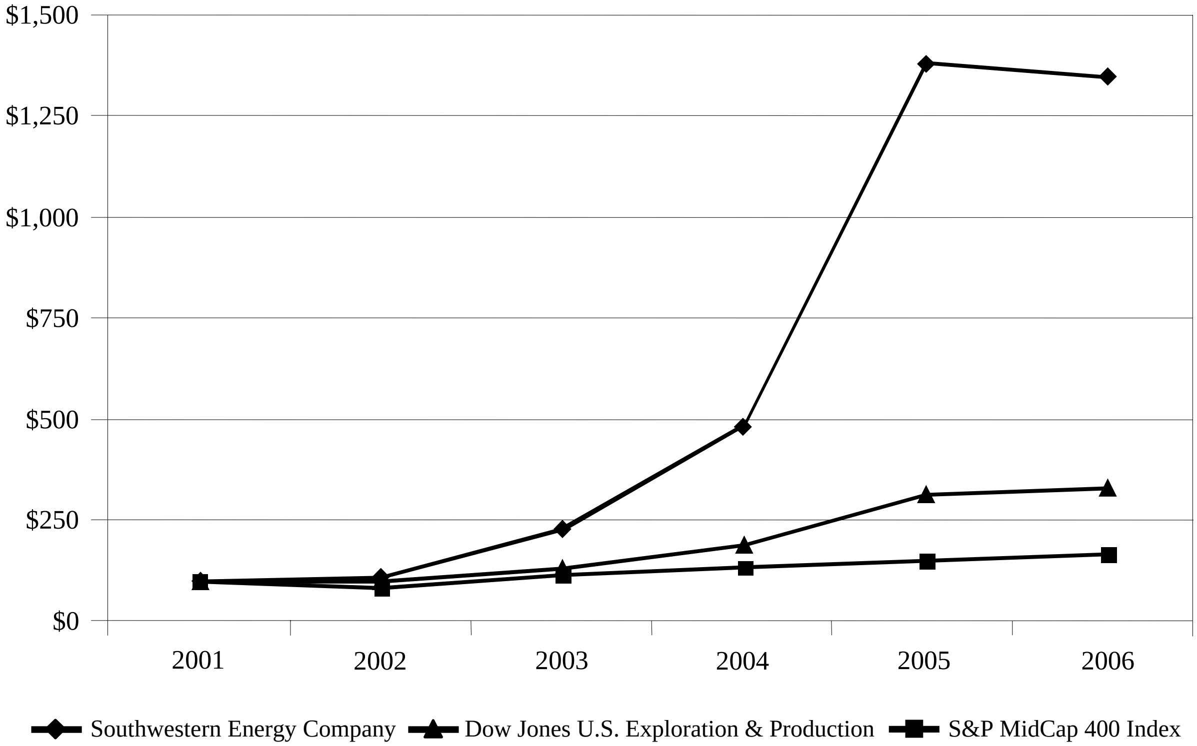
We did not repurchase any shares of our equity securities during the fourth quarter of 2006.

Recent Sales of Unregistered Securities

We did not sell any unregistered equity securities during 2006.

STOCK PERFORMANCE GRAPH

The following graph compares for the last five years, the performance of our common stock to the S&P MidCap 400 Index and the Dow Jones U.S. Exploration & Production Index (previously known as the Dow Jones Oil — Secondary Index). The chart assumes that the value of the investment in our common stock and each index was $100 at December 31, 2001, and that all dividends were reinvested. The stock performance shown on the graph below is not indicative of future price performance.



	12/31/01	12/31/02	12/31/03	12/31/04	12/31/05	12/31/06
Southwestern Energy Company	100	110	230	487	1,382	1,348
Dow Jones U.S. Exploration & Production	100	102	134	190	314	331
S&P MidCap 400 Index	100	85	116	135	152	168

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, 2006. 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."

	2006	2005	2004	2003	2002
	(in thousands except share, per share, stockholder data and percentages)				
Financial Review					
Operating revenues					
Exploration and production	**$ 491,545**	$ 403,234	$ 286,924	$ 176,245	$ 122,207
Midstream services	**475,207**	459,890	314,977	201,976	131,067
Gas distribution and other	**172,655**	179,375	158,698	140,829	116,297
Intersegment revenues	**(376,295)**	(366,170)	(283,462)	(191,649)	(108,069)
	763,112	676,329	477,137	327,401	261,502
Operating costs and expenses					
Gas purchases – midstream services	**128,387**	124,730	60,804	39,428	37,927
Gas purchases – gas distribution	**79,363**	82,689	64,311	52,585	48,388
Operating and general	**132,691**	101,500	78,231	70,479	64,600
Depreciation, depletion and amortization	**151,290**	96,211	73,674	55,948	53,992
Taxes, other than income taxes	**25,109**	25,279	17,830	11,619	10,090
	516,840	430,409	294,850	230,059	214,997
Operating income	**246,272**	245,920	182,287	97,342	46,505
Interest expense, net	**(679)**	(15,040)	(16,992)	(17,311)	(21,466)
Other income (expense)	**17,079**	4,784	(362)	797	(566)
Minority interest in partnership	**(637)**	(1,473)	(1,579)	(2,180)	(1,454)
Income before income taxes and accounting change	**262,035**	234,191	163,354	78,648	23,019
Income taxes					
Current	**—**	—	—	—	—
Deferred	**99,399**	86,431	59,778	28,896	8,708
	99,399	86,431	59,778	28,896	8,708
Income before accounting change	**162,636**	147,760	103,576	49,752	14,311
Cumulative effect of adoption of accounting principle	**—**	—	—	(855)	—
Net income	**$ 162,636**	$ 147,760	$ 103,576	$ 48,897	$ 14,311
Return on equity	**11.3%**	13.3%	23.1%	14.3%	8.1%
Net cash provided by operating activities	**$ 429,937**	$ 304,482	$ 237,897	$ 109,099	$ 77,574
Net cash used in investing activities	**$ (630,006)**	$ (452,918)	$ (285,448)	$ (161,656)	$ (64,469)
Net cash provided by (used in) financing activities	**$ 19,291**	$ 370,906	$ 47,509	$ 52,144	$ (15,056)
Common Stock Statistics [1]					
Earnings per share:					
Basic	**$ 0.97**	$ 0.98	$ 0.72	$ 0.37	$ 0.14
Diluted	**$ 0.95**	$ 0.95	$ 0.70	$ 0.36	$ 0.14
Cash dividends declared and paid per share	**$ —**	$ —	$ —	$ —	$ —
Book value per average diluted share	**$ 8.38**	$ 7.10	$ 3.03	$ 2.49	$ 1.70
Market price at year-end	**$ 35.05**	$ 35.94	$ 12.67	$ 5.98	$ 2.86
Number of stockholders of record at year-end	**2,412**	2,126	2,022	2,026	2,079
Average diluted shares outstanding	**171,287,750**	156,309,039	147,851,088	136,951,736	104,208,952

[1] 2004, 2003, and 2002 restated to reflect two-for-one stock splits effected in June and November 2005.

	2006	2005	2004	2003	2002
Capitalization (in thousands)					
Total debt	**$ 137,800**	$ 100,000	$ 325,000	$ 278,800	$ 342,400
Common stockholders' equity[1]	**1,434,643**	1,110,304	447,677	341,561	177,488
Total capitalization	**$ 1,572,443**	$ 1,210,304	$ 772,677	$ 620,361	$ 519,888
Total assets	**$ 2,379,069**	$ 1,868,524	$ 1,146,144	$ 890,710	$ 740,162
Capitalization ratios:					
Debt	**8.8%**	8.3%	42.1%	44.9%	65.9%
Equity	**91.2%**	91.7%	57.9%	55.1%	34.1%
Capital Investments (in millions) [2]					
Exploration and production					
Exploration and development	**$ 767.4**	$ 416.2	$ 282.0	$ 170.9	$ 85.2
Drilling rigs [3]	**93.6**	35.1	—	—	—
	861.0	451.3	282.0	170.9	85.2
Midstream services	**48.7**	15.8	—	—	—
Gas distribution	**11.2**	10.9	7.3	8.2	6.1
Other	**21.5**	5.1	5.7	1.1	0.8
	$ 942.4	$ 483.1	$ 295.0	$ 180.2	$ 92.1
Exploration and Production					
Natural gas:					
Production, Bcf	**68.1**	56.8	50.4	38.0	36.0
Average price per Mcf, including hedges	**$ 6.55**	$ 6.51	$ 5.21	$ 4.20	$ 3.00
Average price per Mcf, excluding hedges	**$ 6.37**	$ 7.73	$ 5.80	$ 5.15	$ 3.11
Oil:					
Production, MBbls	**698**	705	618	531	682
Average price per barrel, including hedges	**$ 58.36**	$ 42.62	$ 31.47	$ 26.72	$ 21.02
Average price per barrel, excluding hedges	**$ 63.17**	$ 54.37	$ 40.55	$ 29.66	$ 23.94
Total gas and oil production, Bcfe	**72.3**	61.0	54.1	41.2	40.1
Lease operating expenses per Mcfe	**$ .66**	$ .48	$ .38	$ .39	$ .45
General and administrative expenses per Mcfe	**$ .58**	$ .46	$ .36	$ .41	$ .32
Taxes other than income taxes per Mcfe	**$ .30**	$ .37	$ .28	$ .22	$ .19
Proved reserves at year-end:					
Natural gas, Bcf	**978.9**	772.3	594.5	457.0	374.6
Oil, MBbls	**7,898**	9,079	8,508	7,675	6,784
Total reserves, Bcfe	**1,026.3**	826.8	645.5	503.1	415.3
Midstream Services					
Gas volumes marketed	**72.7**	61.9	57.0	42.7	45.5
Natural Gas Distribution					
Sales and transportation volumes, Bcf	**21.8**	23.2	24.0	24.7	25.1
Off-system transportation [4]	**0.1**	—	1.0	0.3	2.2
Total volumes delivered	**21.9**	23.2	25.0	25.0	27.3
Customers at year-end:					
Residential	**133,679**	130,654	127,622	124,776	122,906
Commercial	**17,151**	16,996	16,815	16,623	16,448
Industrial	**173**	170	175	174	189
	151,003	147,820	144,612	141,573	139,543
Degree days	**3,413**	3,744	3,678	3,969	3,950
Percent of normal	**83%**	91%	90%	99%	98%

(1) Stockholders' equity included accumulated other comprehensive income of $31.5 million in 2006 ($41.4 million income related to our cash flow hedges and a $9.9 million loss related to our pension liability and adoption of Statement on Financial Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans"). Stockholders' equity included accumulated other comprehensive losses of $104.9 million in 2005 ($99.8 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).

(2) Capital investments for 2006, 2005, 2004 and 2003 included $88.9 million, $28.1 million, $3.9 million and $12.0 million, respectively, related to the change in accrued expenditures between years.

(3) The drilling rigs and related equipment were sold in December 2006 as part of a sale and leaseback transaction.

(4) 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 Item 1A, "Risk Factors" in Part I 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. Historical per share information provided for years prior to 2005, in "Item 6. Selected Financial Data," financial statements, footnotes and "Management's Discussion and Analysis of Financial Condition and Results of Operations" has 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, and New Mexico. We are also focused on creating and capturing additional value at and beyond the wellhead through our established natural gas distribution and marketing 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 (E&P), Midstream Services and Natural Gas Distribution.

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 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. In recent years, there has been significant price volatility in natural gas and crude oil prices 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, which determines the pricing. 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 2006, our gas and oil production increased 19% to 72.3 Bcfe. Gas and oil production increased 13% to 61.0 Bcfe in 2005. The increase in 2006 production primarily resulted from an increase in production from our Fayetteville Shale play.

We reported net income of $162.6 million in 2006, or $0.95 per share on a fully diluted basis, up 10% from the prior year. Net income in 2005 increased approximately 43% to $147.8 million, or $0.95 per share, compared to 2004. The increase in net income in 2006 was a result of increased production volumes in our E&P segment, a gain on the sale of our NOARK investment and decreased interest expense, partially offset by increased operating costs and expenses. The increase in net income in 2005 was a result of increased production volumes and higher realized natural gas and oil prices in our E&P segment. Our cash flow from operating activities increased 41% to $429.9 million in 2006, primarily due to increased production volumes in our E&P segment. Cash flow from operating activities in 2005 increased 28% to $304.5 million compared to 2004. Operating income for our E&P segment was $237.3 million in 2006, $234.8 million in 2005, and $164.6 million in 2004. Operating income for our E&P segment increased marginally in 2006 as increased production volumes from our Fayetteville Shale play and East Texas were largely offset by increased operating costs and expenses. Operating income for our E&P segment increased in 2005 due to increased production volumes and higher realized prices. Operating income for our Midstream Services segment decreased 28% to $4.1 million in 2006 and increased 80% to $5.7 million in 2005, compared to prior years. Operating income for our Midstream Services segment decreased in 2006 as increased gathering revenues were more than offset by increased operating costs and expenses and a decrease in the margin generated by our marketing activities. Operating income for our Midstream Services segment increased in 2005 primarily due to favorable natural gas price opportunities along with increased volumes marketed. Operating income for our Natural Gas Distribution segment was $4.5 million in 2006, compared to $4.9 million in 2005 and $8.5 million in 2004. The decrease in operating income for our Natural Gas Distribution segment in 2006 resulted primarily from warmer weather and increased operating costs and expenses, partially offset by increased rates implemented in October 2005. The decrease in operating income for our Natural Gas Distribution segment in 2005 resulted primarily from warmer weather and increased operating costs and expenses. Customer conservation in recent years has also impacted operating income for this segment.

On May 2, 2006, we sold our 25% partnership interest in NOARK to Atlas Pipeline Partners, L.P., for $69.0 million. As part of the transaction, we assumed $39.0 million of debt obligations of NOARK Pipeline Finance, L.L.C., which we had previously guaranteed. We recognized a pre-tax gain of $10.9 million ($6.7 million after tax) in the second quarter relating to the transaction.

In our E&P segment, we achieved a reserve replacement ratio of 386% in 2006 at a finding and development cost of $2.75 per Mcfe, including reserve revisions, but excluding $93.6 million of capital invested in acquiring drilling rigs. Our year-end reserves grew 24% to 1,026.3 Bcfe, up from 826.8 Bcfe at the end of 2005. Our results were primarily fueled by our Fayetteville Shale play in Arkansas.

Our capital investments totaled $942.4 million in 2006, an increase of 95% compared to the prior year. Our 2005 capital investments were up 64% to $483.1 million. We invested $861.0 million in our E&P segment in 2006 (including $93.6 million invested in drilling rigs), compared to $451.3 million in 2005 and $282.0 million in 2004. Funds for our 2006 capital investments were provided by cash flow from operations, cash equivalents from our equity offering in 2005, $69.0 million of proceeds from the sale of our investment in NOARK and cash proceeds of $127.3 million from a sale/leaseback transaction to monetize our investment in 13 drilling rigs. As a result, our total debt-to-capitalization ratio increased slightly to 9% at December 31, 2006 from 8% at December 31, 2005.

For 2007, our planned capital investments are $1.3 billion, an increase of 42% over 2006 capital spending. The capital investments for 2007 include $1.2 billion for our E&P segment, $84 million for our Midstream Services segment and $20 million for improvements to our utility system and other corporate purposes. The $1.2 billion of exploration and production investments includes $875 million for the development of our Fayetteville Shale play. We continue to be focused on our strategy of adding value through the drillbit, as approximately 82% of our 2007 E&P capital is allocated to drilling. In addition to the planned investments in the Fayetteville Shale play, our E&P investments in 2007 will be focused on our lower-risk development drilling programs in East Texas and other conventional drilling in the Arkoma Basin. In 2007, we are targeting production to be approximately 105.0 Bcfe to 110.0 Bcfe, compared to 72.3 Bcfe in 2006, an increase of approximately 45% to 50%. We expect our capital investments in 2007 to be funded by cash flow from operations, cash equivalents at December 31, 2006, borrowings under our recently amended revolving credit facility and/or funds raised in the public debt and equity markets.

We expect growth in our reported production volumes and our oil and gas reserve quantities in 2007 given the current commodity price environment and our continued success in our Fayetteville Shale project. We also believe we will have access to sufficient capital to carry out our plans while maintaining an acceptable balance between debt and equity financing.

RESULTS OF OPERATIONS

Exploration and Production

	Year Ended December 31,		
	2006	2005	2004
Revenues (in thousands)	**$491,545**	$403,234	$286,924
Operating income (in thousands)	**$237,307**	$234,759	$164,585
Gas production (Bcf)	**68.1**	56.8	50.4
Oil production (MBbls)	**698**	705	618
Total production (Bcfe)	**72.3**	61.0	54.1
Average gas price per Mcf, including hedges	**$ 6.55**	$ 6.51	$ 5.21
Average gas price per Mcf, excluding hedges	**$ 6.37**	$ 7.73	$ 5.80
Average oil price per Bbl, including hedges	**$ 58.36**	$ 42.62	$ 31.47
Average oil price per Bbl, excluding hedges	**$ 63.17**	$ 54.37	$ 40.55
Average unit costs per Mcfe:			
Lease operating expenses	**$ 0.66**	$ 0.48	$ 0.38
General & administrative expenses	**$ 0.58**	$ 0.46	$ 0.36
Taxes other than income taxes	**$ 0.30**	$ 0.37	$ 0.28
Full cost pool amortization	**$ 1.90**	$ 1.42	$ 1.20

Revenues, Operating Income and Production

Revenues. Revenues for our E&P segment increased 22% in 2006 to $491.5 million due to a 20% increase in gas production volumes. Revenues increased 41% in 2005 to $403.2 million, primarily due to higher prices received for our natural gas and oil production and increased gas production. We expect our production volumes to continue to increase primarily due to the development of our Fayetteville Shale play in Arkansas. Gas and oil prices are difficult to predict and are subject to wide price fluctuations. As of February 23, 2007, we have hedged 79.5 Bcf, 57.0 Bcf and 8.0 Bcf of our 2007, 2008 and 2009 gas production, respectively, to help limit our exposure to price fluctuations. Revenues for 2006, 2005 and 2004 also include pre-tax gains of $4.0 million, $3.1 million and $4.5 million, respectively, related to the sale of gas-in-storage inventory.

Operating Income. Operating income from our E&P segment was $237.3 million in 2006, compared to $234.8 million in 2005, as revenues from increased production volumes were largely offset by increased operating costs and expenses. Operating income was up 43% in 2005 compared to 2004 due to an increase in revenue primarily driven by increased production volumes and higher realized prices.

Production. Gas and oil production was up approximately 19% to 72.3 Bcfe in 2006 and up 13% to 61.0 Bcfe in 2005, compared to prior periods. The increase in 2006 was the result of a 10.0 Bcf increase in production from our Fayetteville Shale play and a 4.0 Bcf increase in our East Texas production, partially offset by declines in production from our Permian and Gulf Coast properties. Our production in the Fayetteville Shale play in 2006 was negatively impacted in the last part of the year by a shortage of pressure pumping equipment and completion crews in the play area. Additional equipment and crews are now available in the play area and are currently keeping pace with our drilling activity. 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 production 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 and by the effect of Hurricane Katrina. Combined, these events reduced our production by an estimated 1.0 Bcfe.

Gas sales to unaffiliated purchasers were up 23% to 63.4 Bcf in 2006 and up 15% to 51.7 Bcf in 2005, compared to the prior years. 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 decreased 7% to 4.7 Bcf in 2006 and decreased 6% to 5.1 Bcf in 2005. We expect future increases in demand for our gas production to come from sales to unaffiliated purchasers. We are unable to predict changes in the market demand and price for natural gas, including weather-related changes affecting demand of both affiliated and unaffiliated customers for our production.

During the fourth quarter of 2006, we completed the sale of our remaining South Louisiana properties to a private company for $12.7 million. These properties had proved reserves of 7.0 Bcfe and produced approximately 1.1 Bcfe annually. With this divestiture, we no longer have producing properties in the South Louisiana area.

We are targeting 2007 gas and oil production of 105.0 to 110.0 Bcfe, an increase of 45% to 50% over our 2006 production. Based on early production histories and modeling and assuming continued positive results, approximately 45.0 to 50.0 Bcf of our 2007 targeted gas production is projected to come from our activities in the Fayetteville Shale play. Although we expect production volumes in 2007 to increase, we cannot guarantee our longer-term success in discovering, developing, and producing reserves, including with respect to our Fayetteville Shale play. 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.

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, including fluctuations in locational market differentials (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, increased slightly to $6.55 per Mcf in 2006 and increased 25% to $6.51 per Mcf in 2005. 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 increased the average gas price $0.18 per Mcf in 2006, compared to reductions of $1.22 per Mcf in 2005 and $0.59 per Mcf in 2004. In recent years, locational differences in market prices for natural gas have been wider than historically experienced. Disregarding the impact of hedges, historically the average price received for our gas production was approximately $0.30 to $0.50 per Mcf lower than average NYMEX spot market prices due to the locational market differentials. However, during both 2006 and 2005, widening market differentials caused the difference in our average price received for our gas production to be approximately $0.90 per Mcf lower than spot market prices. Assuming a NYMEX commodity price for 2007 of $7.00 per Mcf of gas, our differential for the average price received for our gas production is expected to be approximately $0.65 to $0.70 per Mcf below the NYMEX Henry Hub index price, including the impact of our basis hedges. As of December 31, 2006, we have financially protected future gas production volumes of 64.3 Bcf in 2007 and 38.1 Bcf in 2008 from the impact of widening basis differentials through our hedging activities and sales arrangements.

In addition to the basis hedges discussed above, at December 31, 2006, we had NYMEX commodity price hedges in place on 65.0 Bcf of 2007 and 35.0 Bcf of 2008 expected future gas production. Subsequent to December 31, 2006 and prior to February 23, 2007, we hedged 12.5 Bcf of 2007, 11.0 Bcf of 2008 and 4.0 Bcf of 2009 gas production under fixed price swaps with a sales price ranging from $7.29 to $8.62. Additionally, we hedged 2.0 Bcf of 2007, 11.0 Bcf of 2008 and 4.0 Bcf of 2009 gas production under costless collars with floor prices ranging from $7.25 to $8.50 per Mcf and ceiling prices ranging from $9.07 to $10.95 per Mcf. As of February 19, 2007, we have hedged approximately 75% of our 2007 anticipated gas production level.

We realized an average price of $58.36 per barrel, including the effects of hedges, for our oil production for the year ended December 31, 2006, up approximately 37% from the prior year. The 2005 realized average price of $42.62 per barrel, including the effects of hedges, for our oil production was up 35% from 2004. The average price we received for our oil production in 2006, 2005 and 2004 was reduced by $4.81, $11.75 and $9.08 per barrel, respectively, due to the effects of our hedging activities. Assuming a NYMEX commodity price of $60.00 per barrel of oil for 2007, we expect the average price received for our oil production during 2007 to be approximately $1.00 per barrel lower than average spot market prices, as market differentials reduce the average prices received.

Operating Costs and Expenses

Lease operating expenses per Mcfe for the E&P segment were $0.66 in 2006, compared to $0.48 in 2005 and $0.38 in 2004. Lease operating expenses per unit of production increased in 2006 due primarily to increases in gathering and other costs related to our operations in the Fayetteville Shale play. We expect our per unit operating cost for this segment to range between $0.82 and $0.87 per Mcfe in 2007 due to increased production volumes from the Fayetteville Shale play. Additionally, inflationary pressures continue to have an impact in all of our operating areas.

General and administrative expenses per Mcfe for this segment were $0.58 in 2006, up from $0.46 in 2005 and $0.36 in 2004. The increases in general and administrative costs per Mcfe in 2006 and 2005 were due primarily to increased payroll and related costs associated with the expansion of our E&P operations due to the Fayetteville Shale play and to increased incentive compensation costs. We added 494 new employees during 2006, most of which were hired in our E&P segment, and we expect to hire an additional 171 employees in 2007. Approximately 300 of the total new hires during 2006 were employed by our drilling company. We expect our cost per unit for general and administrative expenses to decline in 2007 and to range between $0.41 and $0.46 per Mcfe. The expected decrease in per unit costs is due to increased production volumes from our Fayetteville Shale play and a reduced rate of expansion in our E&P workforce. Future changes in our general and administrative expenses for this segment are primarily dependent upon our salary costs, level of pension expense, stock-based compensation expensing under Statement on Financial Accounting Standards No. 123R “Share-Based Payment” (FAS 123R) and the amount of incentive compensation paid to our employees. For eligible employees, a portion of 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, while another portion is discretionary based upon an employee’s performance. Additional discretionary awards may also be awarded under the incentive compensation plan. See “Critical Accounting Policies” below for further discussion of pension expense, and “Adoption of Accounting Principles” below for further discussion of stock-based compensation expensing under FAS 123R.

Our full cost pool amortization rate averaged $1.90 per Mcfe for 2006, $1.42 per Mcfe for 2005 and $1.20 per Mcfe for 2004. The amortization rate is impacted by reserve additions and the costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, write-downs that result from full cost ceiling tests and the level of unevaluated costs excluded from amortization. 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 amount of future reserves attributed to our Fayetteville Shale play. Unevaluated costs excluded from amortization were

$166.8 million at the end of 2006, compared to $122.3 million at the end of 2005 and $47.2 million at the end of 2004. 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 the exploration, development and acquisition of oil and natural gas 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. These capitalized costs are subject to a ceiling test that 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 the 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. However, commodity price increases subsequent to the end of a reporting period but prior to the release of periodic reports may be utilized to calculate the ceiling value of reserves. At December 31, 2006, 2005 and 2004, our unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At December 31, 2006, our standardized measure was calculated based upon quoted market prices of $5.64 per Mcf for Henry Hub gas and $57.25 per barrel for West Texas Intermediate oil, adjusted for market differentials, and included approximately $135.2 million related to the positive effects of future cash flow hedges of gas production. 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, and at December 31, 2004, our standardized measure was calculated based upon quoted market prices of $6.18 per Mcf for Henry Hub gas and $43.45 per barrel for West Texas Intermediate oil. A decline in natural gas and oil prices from year-end 2006 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.

Taxes other than income taxes per Mcfe were $0.30 in 2006, $0.37 in 2005 and $0.28 in 2004, and vary from year to year primarily due to changes in severance and ad valorem taxes that result from the fluctuations in commodity prices.

The timing and amount of production and reserve additions attributed to our Fayetteville Shale play could have a material impact on our per unit costs; if production or reserves additions are lower than projected, our per unit costs would increase.

Midstream Services

	Year Ended December 31,		
	2006	2005	2004
Revenues (in millions)	**$ 475.2**	$ 459.9	$ 315.0
Gas purchases (in millions)	**$ 458.9**	$ 451.1	$ 310.7
Operating costs and expenses (in millions)	**$ 12.2**	$ 3.1	$ 1.1
Operating income (in millions)	**$ 4.1**	$ 5.7	$ 3.2
Gas volumes marketed (Bcf)	**72.7**	61.9	57.0

Revenues from our Midstream Services segment were up 3% in 2006 and up 46% in 2005, as compared to prior years. The increase in revenues in 2006 resulted from increased marketing and gathering activities. The increase in 2005 revenues was primarily due to an increase in natural gas commodity prices. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in gas purchase expense. Midstream Services had gathering revenues of $7.9 million in 2006, related to its gathering systems in Arkansas, compared to $1.0 million in 2005. Gathering revenues and expenses for this segment are expected to continue to grow in the future as reserves related to our Fayetteville Shale play are developed and production increases. Operating income from our Midstream Services segment decreased 28% in 2006 and increased 80% in 2005. The decrease in 2006 was due to increased operating costs and expenses that resulted from increased staffing and other costs associated with our growing gathering activities, and a decrease in the margin generated by our marketing activities caused in part by increased volatility of locational market differentials in our core operating areas. Operating income from natural gas marketing activities fluctuates depending on the margin we are able to generate between the purchase of the commodity and the ultimate disposition of the commodity. In 2005, we were able to generate higher margins on our marketing efforts. We marketed 72.7 Bcf in 2006, compared to 61.9 Bcf in 2005 and 57.0 Bcf in 2004. The increase in volumes marketed in 2006 and 2005 resulted from marketing our increased production volumes, largely related to our Fayetteville Shale play and our Overton Field in East Texas. Additionally in 2006, volumes marketed for third parties increased due to production growth in areas where we have historically provided marketing services to other working interest owners. Of the total volumes marketed, production from our E&P subsidiaries accounted for 72% in 2006, 76% in 2005 and 77% in 2004. 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 information.

On April 10, 2006, our Midstream Services unit entered into a three-year firm transportation agreement with Ozark Gas Transmission System to transport volumes increasing to 175,000 MMBtu per day in the later stages of the contract. On August 22, 2006, we amended the agreement to increase the maximum volumes transported from 175,000 MMBtu per day to 220,000 MMBtu per day in the later stages of the contract. Additionally, on January 25, 2007, we entered into a separate two-year firm transportation agreement with Ozark Gas Transmission System to transport volumes of 50,000 MMBtu per day. On December 15, 2006, one of our Midstream Services subsidiaries entered into a precedent agreement pursuant to which we will contract for firm gas transportation services on two newly-proposed pipeline laterals and related facilities of Texas Gas Transmission, LLC (Texas Gas), a subsidiary of Boardwalk Pipeline Partners, LP. Depending on regulatory approvals, the expected in-service date for both laterals is January 1, 2009. See "Contractual Obligations and Contingent Liabilities and Commitments" below for further discussion.

Over the next several years, we expect our gathering revenues and operating expenses to increase significantly as our E&P segment grows its production volumes from the development of our Fayetteville Shale play.

Natural Gas Distribution

	Year Ended December 31,		
	2006	2005	2004
	($ in thousands except for per Mcf amounts)		
Revenues	**$172,207**	$178,482	$152,449
Gas purchases	**$112,922**	$120,852	$ 97,274
Operating costs and expenses	**$ 54,811**	$ 52,719	$ 46,659
Operating income	**$ 4,474**	$ 4,911	$ 8,516
Deliveries (Bcf)			
Sales and end-use and off-system transportation	**21.9**	23.2	25.0
Sales customers at year-end	**151,003**	147,820	144,612
Average sales rate per Mcf	**$ 12.30**	$ 11.85	$ 9.39
Heating weather - degree days	**3,413**	3,744	3,678
Percent of normal	**83%**	91%	90%

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. Revenues for 2006 decreased 4% to $172.2 million and revenues for 2005 increased 17% to $178.5 million. The decrease in 2006 gas distribution revenues was primarily due to lower sales volumes as a result of warmer weather. The increase in 2005 gas distribution revenues was primarily due to higher average sales rates as a result of higher gas prices and the effects of a $4.6 million annual rate increase implemented in October 2005.

Operating income for our Natural Gas Distribution segment decreased 9% in 2006 and decreased 42% in 2005. The decrease in 2006 operating income resulted primarily from warmer weather and increased operating costs and expenses partially offset by the effects of the rate increase implemented in October 2005. The decrease in 2005 operating income for this segment resulted primarily from 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. Weather during 2006 in the utility's service territory was 17% warmer than normal and 8% warmer than the prior year. Weather during 2005 in the utility's service territory was 9% warmer than normal and 1% colder than the prior year.

Deliveries and Rates

In 2006, Arkansas Western sold 13.4 Bcf to its customers at an average rate of $12.30 per Mcf, compared to 14.4 Bcf at $11.85 per Mcf in 2005 and 15.5 Bcf at $9.39 per Mcf in 2004. Additionally, Arkansas Western transported 8.4 Bcf in 2006, compared to 8.8 Bcf in 2005 and 8.5 Bcf in 2004 for its end-use customers. The decreases in volumes sold in 2006 and 2005 primarily resulted from warmer than normal weather and customer conservation brought about by high gas prices in recent years. 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.

Arkansas Western has a transportation contract with Ozark Gas Transmission System for approximately 66,900 MMBtu 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.

Operating Costs and Expenses

The changes in purchased gas costs for the Natural 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 2006 to $54.8 million from $52.7 million in 2005. The increase was primarily due to an increase in general and administrative expenses due to increased salaries and incentive compensation costs. Operating costs and expenses for 2005, net of purchased gas costs, increased to $52.7 million from $46.7 million in 2004 due primarily 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. Future changes in our general and administrative expenses for this segment are primarily dependent upon our salary costs, level of pension expense, stock-based compensation expensing under FAS 123R 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 stock-based compensation expensing, respectively.

Inflation impacts our Natural 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 Natural 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.

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 an 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 September 25, 2006, our Natural Gas Distribution segment filed with the APSC an application to modify its general rates and charges. The application seeks to increase annual operating revenues by $13.1 million, a 6.8% annual increase. The APSC has 10 months to render a decision on the application. Any increase approved is expected to take effect in July 2007.

On January 12, 2006, the APSC initiated a notice of inquiry regarding a rulemaking for developing and implementing energy efficiency programs. Following a collaborative process, the APSC issued energy efficiency rules on January 11, 2007. These rules require all gas and electric utilities, excluding electric cooperatives, to file energy efficiency plans and programs with the APSC. Quick start or pilot programs are to be implemented by late 2007, and comprehensive programs are to be implemented in 2009. Utilities will recover the costs of these programs from their customers. The APSC will address lost revenues associated with these programs in the utilities' future rate cases. We have not yet determined the effect of these rules on our future operations and have not included any revenue loss in our pending rate case.

On December 19, 2006, the APSC issued affiliate transactions rules. In January 2007, Arkansas Western and other utilities requested a rehearing of these rules. On February 16, 2007, the APSC issued an order granting a rehearing and staying the implementation of the affiliate transaction rules pending further review. A public hearing on this issue is scheduled for March 27, 2007. Arkansas Western anticipates that these rules, if not modified on rehearing, will increase its regulatory costs and overall cost of service.

Rate increase requests, which may be filed in the future, will depend on APSC policies, customer growth, increases in operating expenses and additional investment in property, plant and equipment.

Transportation

On May 2, 2006, we sold our 25% partnership interest in NOARK Pipeline System, Limited Partnership (NOARK) to Atlas Pipeline Partners, L.P. for $69.0 million and recognized a pre-tax gain of approximately $10.9 million ($6.7 million after-tax) in the second quarter relating to the transaction. We recorded pre-tax income from operations related to our investment in NOARK of $0.9 million in 2006, compared to $1.6 million in 2005 and a pre-tax loss of $0.4 million in 2004. Income from operations and the gain on the sale in the second quarter of 2006 were recorded in other income in our statements of operations. We refer you to Note 7 to the consolidated financial statements for additional discussion.

Other Revenues

In 2006, 2005 and 2004, other revenues included pre-tax gains of $4.0 million, $3.1 million and $4.5 million, respectively, related to the sale of gas-in-storage inventory. Other revenues for 2005 and 2004 also included pre-tax gains of $0.4 million and $5.8 million, respectively, related to sales of undeveloped real estate.

Interest Expense and Interest Income

Interest costs, net of capitalization, were down 95% to $0.7 million in 2006 and down 11% to $15.0 million in 2005, both as compared to prior years. Interest expense decreased in 2006 due to decreased debt levels resulting from our equity offering in September 2005 and increased capitalized interest. Interest expense decreased in 2005 due primarily to increased capitalized interest. 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. Interest capitalized increased to $11.8 million in 2006, up from $6.0 million in 2005 and $2.8 million in 2004. Changes in capitalized interest are primarily due to the level of investment in unevaluated properties and the capitalization of interest during the construction phase of our drilling rigs in our E&P segment. Costs excluded from amortization in the E&P segment increased to $166.8 million at December 31, 2006, compared to $122.3 million at December 31, 2005. Total capital investments for our E&P segment were $861.0 million in 2006, up from $451.3 million in 2005.

During 2006 and 2005, we earned interest income of $6.3 million and $3.4 million, respectively, related to our cash investments. These amounts are recorded in other income. We did not have any interest income in 2004.

Income Taxes

In 2006, the state of Texas enacted legislation to replace its method of taxing businesses from a capital based tax to a tax on modified gross revenue. Although this change in taxation method was not effective until 2007, the provisions of Statement on Financial Accounting Standards No. 109, "Accounting for Income Taxes" (FAS 109), required us to record in 2006 the impact that this change has on our liability for deferred taxes. As a result, we recorded additional income tax expense of $1.8 million, net of federal income tax effect, in the second quarter of 2006. This one-time adjustment increased our effective tax rate to approximately 37.9% for 2006, compared to 36.9% in 2005, and 36.6% in 2004. Other than the change resulting from Texas taxes discussed above, the changes in the provision for deferred income taxes recorded each period result primarily from the level of income before income taxes, adjusted for permanent differences.

Pension Expense

We recorded an expense of $4.0 million in 2006 for our pension and other postretirement benefit plans, compared to $2.3 million in 2005 and $2.2 million in 2004. The amount of pension expense recorded is determined by actuarial calculations and is also impacted by the funded status of our plans. During 2006, $3.4 million was contributed to our pension plans and $0.4 million was contributed to our other postretirement plans. As of December 31, 2006, we have adopted Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans", or FAS 158. See "Adoption of Accounting Principles" below and Note 4 to the consolidated financial statements for further discussion of FAS 158. 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 September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, "Fair Value Measurements", or FAS 157. This Statement defines fair value as used in numerous accounting pronouncements, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosure related to the use of fair value measures in financial statements. The Statement is to be effective for our financial statements issued in 2008; however, earlier application is encouraged. We are currently evaluating the timing of adoption and the impact that adoption might have on our financial position or results of operations.

During the fourth quarter of 2006, we adopted FAS 158 which requires us to recognize the funded status of each defined pension benefit plan, retiree health care and other postretirement benefit plans and post employment benefit plans on the balance sheet. Each over-funded plan is recognized as an asset and each under-funded plan is recognized as a liability. The initial impact of the adoption of the standard as well as subsequent changes in the funded status is recognized as a component of accumulated comprehensive loss in the statement of stockholders equity. Additional minimum pension liabilities and related intangible assets are also derecognized upon adoption of the new standard. FAS 158 requires initial application for fiscal years ending after December 15, 2006. As a result of the application of FAS 158, we have recorded a liability of $13.8 million on our balance sheet in order to recognize the funded status of our pension and other postretirement benefit plans. We have also recorded our unrecognized prior service costs and unrecognized gains and losses from changes in plan assumptions as a component of other comprehensive income (loss). See Note 4 of our financial statements for further information on the impact of this standard on our financial statements.

In July 2006, the FASB issued FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109", or FIN 48, to clarify certain aspects of accounting for uncertain tax positions, including issues related to the recognition and measurement of those tax positions. This interpretation is effective for fiscal years beginning after December 15, 2006. We are in the process of evaluating the impact of the adoption of this interpretation; however, we do not expect any material impacts on our results of operations and financial condition.

In September 2006, the Securities and Exchange Commission, or the SEC, issued Staff Accounting Bulletin No. 108, or SAB 108. Due to diversity in practice among registrants, SAB 108 expresses SEC staff views regarding the process by which misstatements in financial statements are evaluated for purposes of determining whether financial statement restatement is necessary. SAB 108 is effective for fiscal years ending after November 15, 2006. The adoption of SAB 108 had no impact on our financial position or our reported results from operations.

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily 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. In February 2007, we amended our revolving credit facility and may now borrow up to $750 million from time to time. The amount available under our revolving credit facility may be increased to $1 billion at any time upon our agreement with our existing or additional lenders. As of December 31, 2006 and December 31, 2005, we had no indebtedness outstanding under our revolving credit facility. During 2007, we expect to draw on a portion of the funds available under our credit facility to fund our planned capital investments (discussed below under "Capital Investments"), which are expected to exceed the net cash generated by our operations and cash investments that we had at December 31, 2006 that related to the proceeds from our December 2006 sale/leaseback transaction, as discussed below under "Off-Balance Sheet Arrangements."

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 used to pay down outstanding indebtedness under our revolving credit facility, to pay our 6.70% Notes due December 2005 and to fund capital investments.

Net cash provided by operating activities increased 41% to $429.9 million in 2006, compared to a 28% increase in 2005 to $304.5 million. 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 2006 and 2005 due mainly to increased net income, adjusted for increased depreciation, depletion and amortization expense and increased deferred income taxes generated by our E&P segment. Net cash from operating activities provided 46% of our cash requirements for capital investments in 2006, 63% in 2005 and 81% in 2004.

At December 31, 2006, our capital structure consisted of 9% debt and 91% equity. We believe that our operating cash flow, cash investments at December 31, 2006 and borrowings under our credit facility will be adequate to meet our capital and operating requirements for 2007, however, we may also raise funds in the public debt and equity markets to meet a portion of our cash requirements.

Our cash flow from operating activities is highly dependent upon the market prices that we receive for our gas and oil 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 Investments

Our capital investments increased 95% to $942.4 million in 2006 and 64% to $483.1 million in 2005. Capital investments included $88.9 million in 2006, $28.1 million in 2005 and $3.9 million in 2004 related to accrued expenditures. Capital investments for 2006 in our E&P Segment included $767.4 million related to our primary business activities and $93.6 million related to the purchase of drilling rigs and related equipment which were sold in December 2006 as part of a sale and leaseback transaction. Our capital investments in 2005 also included $35.1 million related to construction payments on the rigs that were sold in 2006. Our E&P segment expenditures included $8.6 million for the acquisition of interests in natural gas and oil producing properties in 2006 and $14.2 million in 2004.

	2006	2005	2004
		(in thousands)	
Exploration and production			
Exploration and development	**$ 767,400**	$ 416,161	$ 281,988
Drilling rigs	**93,641**	35,128	—
	861,041	451,289	281,988
Midstream services	**48,660**	15,840	—
Natural gas distribution	**11,232**	10,908	7,298
Other	**21,474**	5,014	5,704
	$ 942,407	$ 483,051	$ 294,990

Our capital investments for 2007 are planned to be $1,341 million, consisting of $1,237 million for exploration and production, $84 million for midstream services, and $20 million for gas distribution system improvements and general purposes. We expect to allocate $875 million of our 2007 E&P capital to our Fayetteville Shale play. Our planned level of capital investments in 2007 will allow us to significantly accelerate our drilling activity in the Fayetteville Shale, continue the development of our Overton Field and Angelina River Trend 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 Natural Gas Distribution segment. As discussed above, our 2007 capital investment program is expected to be funded through cash flow from operations, cash investments at December 31, 2006, and borrowings under our revolving credit facility. We may also raise funds in the public debt and equity markets to fund a portion of our capital investment program. We may adjust the level of 2007 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 $137.8 million at December 31, 2006 and $100.0 million at December 31, 2005. Our revolving credit facility was amended in February 2007 increasing our borrowing capacity to $750 million, with an accordion feature for an additional $250 million, lowering our borrowing cost and extending the maturity date to February 2012. At December 31, 2006 and 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 87.5 basis points over LIBOR. The Credit Facility is guaranteed by our subsidiaries, Southwestern Energy Production Company, SEECO, Inc. and Southwestern Energy Services Company. The Credit Facility requires additional subsidiary guarantors if certain guaranty coverage levels are not satisfied. Our publicly traded notes were downgraded on August 1, 2006 by Standard and Poor's to BB+ with a stable outlook from BBB- with a negative outlook. We have a Corporate Family Rating of Ba2 by Moody's, and our publicly traded notes were rated Ba3 by Moody's under Moody's Loss Given Default Assessment on September 19, 2006. Any future downgrades in our public debt ratings could increase our cost of funds under the credit facility. We do not expect our current ratings to impact our ability to obtain acceptable financing terms if we elect to access the public debt market in the future.

Our revolving credit facility contains covenants which impose certain restrictions on us. Under the credit agreement, we may not issue total debt in excess of 60% of our total capital, must maintain a certain level of stockholders' 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 agreement at December 31, 2006. 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.

At December 31, 2006, our capital structure consisted of 9% debt and 91% equity, with a ratio of EBITDA to interest expense of 610.5. Stockholders' equity in the December 31, 2006 balance sheet includes an accumulated other comprehensive gain of $41.4 million related to our hedging activities that is required to be recorded under the provisions of Statement on Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133), and a loss of $9.9 million related to changes in our pension liability and the adoption FAS 158. The amount recorded for FAS 133 is based on current market values of our hedges at December 31, 2006, 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 and FAS 158 and the non-cash impact of any full cost ceiling write-downs. Our capital structure at December 31, 2006 would remain at 9% debt and 91% equity without consideration of the accumulated other comprehensive gain and loss related to FAS 133 and FAS 158.

As part of our strategy to ensure a certain level of cash flow to fund our operations, we have hedged approximately 75% of our expected 2007 gas 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 their current levels throughout 2007, our capital expenditure plans do not change and we do not issue equity, we will increase our long-term debt in 2007 by approximately $700 to $750 million. If commodity prices significantly decrease, we may decrease and/or reallocate our planned capital investments.

Off-Balance Sheet Arrangements

On December 29, 2006, we sold 13 of our existing drilling rigs and assigned our right to purchase two other drilling rigs to be delivered and related equipment to various financial institutions and leased the rigs from the buyers for an initial term of eight years from January 1, 2007 with aggregate rental payments of $19.6 million annually. We received proceeds of $127.3 million. This transaction was recorded as a sale and operating leaseback with an aggregate deferred gain of $7.4 million on the sale which will be amortized against the lease payments over the lease term. Subject to certain conditions, we have options to purchase the rigs and related equipment from the lessors at the end of the 84th month of the lease term at an agreed upon price or at the end of the lease term for its then fair market value. Additionally, we have the option to renew the lease for a negotiated renewal term at a periodic rental equal to the fair market rental value of the rigs as determined at the time of renewal. In accordance with our accounting procedures, the portion of the lease payments that represent drilling costs for our working interest in wells are capitalized to the full cost pool.

On May 2, 2006, we sold our 25% partnership interest in NOARK to Atlas Pipeline Partners, L.P. for $69.0 million. As part of the transaction, we assumed and recorded $39.0 million of debt obligations of NOARK Pipeline

Finance, L.L.C., which we had previously guaranteed as part of the financing of NOARK. At December 31, 2006, the balance of these debt obligations was $37.8 million. We did not advance funds to NOARK in 2006 or 2005, and we did not derive any liquidity, capital resources, market risk support or credit risk support from our investment in NOARK.

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, 2006 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(1)	$ 137,800	$ 1,200	$ 62,400	$ 2,400	$ 71,800
Interest on senior notes(2)	67,353	10,140	16,986	10,530	29,697
Operating leases(3)	21,475	4,905	8,588	5,234	2,748
Unconditional purchase obligations(4)	—	—	—	—	—
Operating agreements(5)	127,014	61,928	60,766	4,320	—
Rental compression(6)	90,517	18,046	37,359	28,110	7,002
Demand charges(7)	125,225	21,663	41,796	30,085	31,681
Rig Leases(8)	156,671	19,584	39,168	39,168	58,751
Other obligations(9)	22,522	21,790	732	—	—
	$ 748,577	$ 159,256	$ 267,795	$ 119,847	$ 201,679

(1) Debt includes $37.8 million of 7.15% Notes due 2018 and requires semi-annual principal payments of $0.6 million.

(2) 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.

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

(4) Our Natural 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, 2006 totaled 0.7 Bcf, comprised of 0.4 Bcf in less than one year, 0.2 Bcf in one to three years and 0.1 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.

(5) Our E&P segment has commitments for up to $100.8 million in termination fees related to rig operator agreements and up to $3.7 million in termination fees related to rig servicing agreements in the event that the agreements are terminated. Additionally, our E&P segment has secured rig moving services by committing monthly take-or-pay amounts of $938,000, expiring in December 2008.

(6) Our E&P and Midstream Services segments have commitments for approximately $90.5 million of compressor rental fees associated primarily with our Fayetteville Shale play and our Overton operations.

(7) Our Midstream Services segment has commitments for approximately $42.0 million of demand transportation charges related to the Fayetteville Shale play. Our Natural Gas Distribution segment has commitments for approximately $80.8 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 $2.4 million of demand transportation charges.

(8) Our E&P segment has commitments related to the leasing of fifteen drilling rigs through 2014.

(9) Our other significant contractual obligations include approximately $13.1 million related to seismic services, approximately $4.1 million for funding of benefit plans and approximately $1.7 million for various information technology support and data subscription agreements.

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 liabilities for us or increase or accelerate our contingent liabilities. Substantially all of our employees are covered by defined benefit and postretirement benefit plans. Our return on the assets of these plans, 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 2006 and 2005. At December 31, 2006, we recognized a liability of $13.8 million as a result of the underfunded status of our pension and other postretirement benefit plans. We expect to record pension expense of $5.7 million and a postretirement benefit expense of $0.7 million in 2007. See Note 4 to the consolidated financial statements and "Critical Accounting Policies" below for additional information.

On April 10, 2006, our Midstream Services unit entered into a three-year firm transportation agreement with Ozark Gas Transmission System to transport volumes increasing to 175,000 MMBtu per day in the later stages of the contract. On August 22, 2006, we amended the agreement to increase the maximum volumes transported from 175,000 MMBtu per day to 220,000 MMBtu per day in the later stages of the contract. Additionally, on January 25, 2007 our Midstream Services unit entered into a separate two-year firm transportation agreement with Ozark Gas Transmission System to transport volumes of 50,000 MMBtu per day.

On December 15, 2006, one of our Midstream Services subsidiaries entered into a precedent agreement pursuant to which we will contract for firm gas transportation services on two newly-proposed pipeline laterals and related facilities of Texas Gas Transmission, LLC (Texas Gas), a subsidiary of Boardwalk Pipeline Partners, LP. We will be a "Foundation Shipper" for the project and will use the proposed laterals and related facilities primarily to deliver gas volumes produced from Southwestern's operations in its Fayetteville Shale play in central Arkansas. Depending on regulatory approvals, the expected in-service date for both laterals is January 1, 2009. The first lateral line (Fayetteville Lateral) will originate in Conway County, Arkansas, and connect to Texas Gas' mainline system in Coahoma County, Mississippi. The Fayetteville Lateral will be a minimum of 36" in diameter and would have an estimated ultimate capacity of up to 1.1 Bcf per day. The second lateral (Greenville Lateral) will originate at the Texas Gas mainline system near Greenville, Mississippi, and extend eastward to interconnect with various interstate pipelines. The firm transportation agreements entered into by us pursuant to the precedent agreement will have an initial term of ten years and, over time, will enable us to transport up to 500,000 MMBtu per day on the Fayetteville Lateral and up to 400,000 MMBtu per day on the Greenville Lateral. We will also have the option to acquire up to 300,000 MMBtu per day of additional capacity on the Fayetteville Lateral and up to 240,000 MMBtu per day of additional capacity on the Greenville Lateral. Upon execution and delivery of the firm transportation agreements contemplated by the precedent agreement, our Midstream Services segment would have additional demand charges of $503.5 million that would be payable over the ten-year term of the agreements.

On December 29, 2006, we sold 13 of our existing drilling rigs and assigned our right to purchase two other drilling rigs to be delivered and related equipment to various financial institutions and leased the rigs from the buyers for an initial term of eight years from January 1, 2007 with aggregate rental payments of $19.6 million annually. We received proceeds of $127.3 million. This transaction was recorded as a sale and operating leaseback with an aggregate deferred gain of $7.4 million on the sale which will be amortized against the lease payments over the lease term. Subject to certain conditions, we have options to purchase the rigs and related equipment from the lessors at the end of the 84th month of the lease term at an agreed upon price or at the end of the lease term for its then fair market value. Additionally, we have the option to renew the lease for a negotiated renewal term at a periodic rental equal to the fair market rental value of the rigs as determined at the time of renewal. In accordance with our accounting procedures, the portion of the lease payments that represent drilling costs for our working interest in wells is capitalized to the full cost pool.

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 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. In March of 2006, the Texas Supreme Court requested that both parties submit full briefing on the merits of the case. After receiving full briefing from both sides, our petition for review with the Texas Supreme Court was denied on December 1, 2006, and the case has been remanded to the trial court for further disposition. Should the other party prevail in the case, 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, we accrued a loss in the fourth quarter of 2006.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our credit facility described above. We had negative working capital of $55.0 million at the end of 2006 and positive working capital of $158.7 million at the end of 2005. Current assets at December 31, 2006 and 2005 included $42.0 and $222.4 million, respectively, of cash equivalents. The cash equivalents resulted from the proceeds of our drilling rig sale/leaseback in 2006 and from our equity offering in 2005, respectively. Current liabilities increased $76.5 million, due primarily to an increase in accounts payable related to our level of drilling activity, partially offset by a decrease in our current hedging liability at December 31, 2006.

CRITICAL ACCOUNTING POLICIES

Natural Gas and Oil Properties

We utilize the full cost method of accounting for costs related to the exploration, development and acquisition of oil and natural gas 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. These capitalized costs are subject to a ceiling test that 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 the 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. However, commodity price increases subsequent to the end of a reporting period but prior to the release of periodic reports may be utilized to calculate the ceiling value of reserves. At December 31, 2006, 2005 and 2004, our unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At December 31, 2006, our standardized measure was calculated based upon quoted market prices of $5.64 per Mcf for Henry Hub gas and $57.25 per barrel for West Texas Intermediate oil, adjusted for market differentials. The ceiling value calculated at December 31, 2006 includes approximately $135.2 million related to the positive effects of future cash flow hedges of gas production. 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, and at December 31, 2004, our standardized measure was calculated based upon quoted market prices of $6.18 per Mcf for Henry Hub gas and $43.45 per barrel for West Texas Intermediate oil. A decline in natural gas and oil prices from year-end 2006 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.

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. Natural gas pricing has historically been unpredictable and any 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, performance revisions to our proved reserve estimates represented no greater than 5% 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 65% of our total reserve base at December 31, 2006. 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 "Although our estimated natural gas and oil reserve data is independently audited, our estimates may still 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, 2006, 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 95% 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, 2006 were $1,308.7 million and 1,026.3 Bcfe. An assumed decrease of $1.00 per Mcf in the December 31, 2006 gas price used to price our reserves would have resulted in an approximate $190 million decline in our future cash flows discounted at 10%, adjusted for the effects of commodity hedges, and an approximate decrease of 23 Bcfe of our reported reserves. Under this assumption, our unamortized costs would have exceeded 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 and capitalized costs.

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 FAS 149, and are recorded at fair value in our financial statements. We have established the fair value of derivative instruments using data provided by our counterparties in conjunction with assumptions 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 derivative not qualifying for hedge accounting treatment or any ineffective portion of a properly designated hedge is recognized immediately in earnings. For the year ended December 31, 2006, we recorded a loss of $25.8 million related to basis differential swaps that did not qualify for hedge accounting which was partially offset by a $20.2 million gain related to the change in estimated ineffectiveness of our commodity cash flow hedges. We did not enter into any interest rate swaps in 2006, 2005 and 2004. 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, 2006 benefit obligation and the periodic benefit cost to be recorded in 2007, the discount rate assumed is 6.0%. For the 2007 periodic benefit cost, the expected return assumed is 8.0%. This compares to a discount rate of 5.5% and an expected return of 8.25% used in 2006.

Using the assumed rates discussed above, we recorded pension expense of $4.0 million in 2006 and $2.3 million in 2005 related to our pension and other postretirement benefit plans. With the adoption of FAS 158 in December 2006, we recognized a liability of $13.8 million at December 31, 2006, compared to $8.6 million at December 31, 2005 related to our pension and other postretirement benefit plans. During 2006, we also funded $3.8 million to our pension and other postretirement benefit plans. In 2007, we expect to fund $4.1 million to our pension and other postretirement benefit plans and recognize pension expense of $5.7 million and a postretirement benefit expense of $0.7 million. Assuming a 1% change in the 2006 rates (lower discount rate and lower rate of return), we would have recorded pension expense of $4.6 million in 2006.

On September 29, 2006, FAS 158 was issued requiring, among other things, the recognition of the funded status of each defined pension benefit plan, retiree health care and other postretirement benefit plans and postemployment benefit plans on the balance sheet.

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, assuming normal weather patterns, 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 9.6 Bcf at $3.89 per Mcf at December 31, 2006, compared to 8.5 Bcf at $3.78 per Mcf at December 31, 2005.

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 Natural Gas Distribution segment, especially during periods of colder weather. As a result, demand fees paid by the Natural 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 a write down of our gas in storage carrying cost.

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 market conditions and prices for natural gas and oil (including regional basis differentials);
- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- the economic viability of, and our success in drilling, our large acreage position in the Fayetteville Shale play, overall as well as relative to other productive shale gas plays;
- our ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation;
- the costs and availability of oilfield personnel services and drilling supplies, raw materials, and equipment and services, including pressure pumping equipment and crews in the Arkoma basin;
- our ability to fund our planned capital investments;
- our future property acquisition or divestiture activities;
- the effects of weather;
- increased competition;
- the impact of federal, state and local government regulation;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- conditions in capital markets and changes in interest rates, 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 investments, 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, 2006, approximately 35% 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 investments and successful drilling operations. Recovery of proved developed non-producing reserves requires capital investments 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 investments 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 hedging. Concentrations of credit risk with respect to receivables are limited due to the large number of our customers and their dispersion across geographic areas. No single customer accounted for greater than 4% of accounts receivable at December 31, 2006. In addition, please see the discussion of credit risk associated with commodities hedging below.

Interest Rate Risk

The following table provides information on our financial instruments that are sensitive to changes in interest rates. The table presents the principal cash payments for our debt obligations and related weighted-average interest rates by expected maturity dates. At December 31, 2006, we had no borrowings outstanding under our revolving 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
	2007	2008	2009	2010	2011	Thereafter	Total	12/31/06
	($ in millions)							
Fixed Rate	$ 1.2	$ 1.2	$ 61.2	$ 1.2	$ 1.2	$ 71.8	$ 137.8	$ 141.7
Average Interest Rate	7.15%	7.15%	7.62%	7.15%	7.15%	7.18%	7.37%	—

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, 2006, the fair value of these financial instruments was a $58.1 million asset.

Production and Marketing

	Volume	Weighted Average Price to be Swapped ($)	Weighted Average Floor Price ($)	Weighted Average Ceiling Price ($)	Weighted Average Basis Differential ($)	Fair Value at Dec 31, 2006 ($ in millions)
Natural Gas (Bcf):						
Fixed Price Swaps:						
2007	32.5	7.83	-	-	-	27.3
2008	13.0	8.78	-	-	-	8.2
Floating Price Swaps:						
2007	0.2	(7.61)	-	-	-	(0.4)
2008	-	-	-	-	-	-
Costless Collars:						
2007	34.0	-	6.93	12.34	-	26.0
2008	22.0	-	7.92	13.15	-	14.0
Basis Swaps:						
2007	31.9	-	-	-	(0.53)	(4.1)
2008	30.1	-	-	-	(0.48)	(2.6)
Matched-Basis Swaps:						
2007	32.4	-	-	-	(0.47)	(0.9)
2008	8.0	-	-	-	(0.73)	(1.3)
Regulatory Swaps:						
2007	3.1	(8.83)	-	-	-	(8.1)
2008	-	-	-	-	-	-

At December 31, 2006, we had outstanding fixed-price basis differential swaps on 32.4 Bcf of 2007, and 8.0 Bcf of 2008 gas production that qualified for hedge accounting treatment. At December 31, 2006, we also had outstanding fixed-price basis differential swaps on 31.9 Bcf of 2007 and 30.1 Bcf of 2008 gas production that did not qualify for hedge accounting treatment. For the year ended December 31, 2006, we recorded a loss of $25.8 million related to the differential swaps that did not qualify for hedge accounting treatment which was partially offset by a $20.2 million gain related to the change in estimated ineffectiveness of our cash flow hedges.

At December 31, 2005, we 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, we 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, 2005, we had outstanding natural gas price swaps on total notional volumes of 7.9 Bcf at a weighted average price of $6.64 per Mcf of 2006 gas production and 12.0 Bcf at a weighted average price of $6.66 per Mcf of 2007 gas production. Outstanding oil price swaps at December 31, 2005 on 120 MBbls were yielding us an average price of $37.30 per barrel during 2006. At December 31, 2005, we also had outstanding natural gas price swaps on total notional gas purchase volumes of 0.7 Bcf in 2006 for which we paid an average fixed price of $13.03 per Mcf.

At December 31, 2005, we had collars in place on 43.0 Bcf in 2006, 28.0 Bcf in 2007 and 2.0 in 2008 of gas production. The collars relating to 2006 production had a weighted average floor and ceiling price of $5.47 and $10.13 per Mcf, respectively. The collars relating to 2007 production have a weighted average floor and ceiling price of $6.64 and $11.19 per Mcf, respectively. The collars relating to 2008 production have a weighted average floor and ceiling price of $8.00 and $19.40 per Mcf, respectively.

Subsequent to December 31, 2006 and prior to February 23, 2007, we hedged 12.5 Bcf of 2007, 11.0 Bcf of 2008 and 4.0 Bcf of 2009 gas production under fixed price swaps with a sales price ranging from $7.29 to $8.62. Additionally, we hedged 2.0 Bcf of 2007, 11.0 Bcf of 2008 and 4.0 Bcf of 2009 gas production under costless collars with floor prices ranging from $7.25 to $8.50 per Mcf and ceiling prices ranging from $9.07 to $10.95 per Mcf.

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, 2006. 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, 2006, 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, 2006 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 Stockholders of
Southwestern Energy Company:

We have completed integrated audits of Southwestern Energy Company's consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

<u>Consolidated financial statements</u>

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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 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.

<u>Internal control over financial reporting</u>

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing in Item 8, that the Company maintained effective internal control over financial reporting as of December 31, 2006 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, 2006, 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.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Tulsa, Oklahoma
February 28, 2007

STATEMENTS OF OPERATIONS

Southwestern Energy Company and Subsidiaries

	For the years ended December 31,		
	2006	2005	2004
	(in thousands, except share/per share amounts)		
Operating revenues:			
Gas sales	**$ 572,354**	$ 503,111	$ 375,460
Gas marketing	**136,698**	132,690	65,127
Oil sales	**40,742**	30,026	19,461
Gas transportation and other	**13,318**	10,502	17,089
	763,112	676,329	477,137
Operating costs and expenses:			
Gas purchases – midstream services	**128,387**	124,730	60,804
Gas purchases – gas distribution	**79,363**	82,689	64,311
Operating expenses	**66,579**	52,850	42,157
General and administrative expenses	**66,112**	48,650	36,074
Depreciation, depletion and amortization	**151,290**	96,211	73,674
Taxes, other than income taxes	**25,109**	25,279	17,830
	516,840	430,409	294,850
Operating income	**246,272**	245,920	182,287
Interest expense:			
Interest on long-term debt	**11,099**	19,791	18,335
Other interest charges	**1,402**	1,254	1,461
Interest capitalized	**(11,822)**	(6,005)	(2,804)
	679	15,040	16,992
Other income (expense)	**17,079**	4,784	(362)
Income before income taxes and minority interest	**262,672**	235,664	164,933
Minority interest in partnership	**(637)**	(1,473)	(1,579)
Income before income taxes	**262,035**	234,191	163,354
Provision for income taxes:			
Current	**—**	—	—
Deferred	**99,399**	86,431	59,778
	99,399	86,431	59,778
Net income	**$ 162,636**	$ 147,760	$ 103,576
Basic earnings per share [(1)]	**$0.97**	$0.98	$0.72
Diluted earnings per share [(1)]	**$0.95**	$0.95	$0.70
Weighted average common shares outstanding: [(1)]			
Basic	**167,303,141**	150,892,602	142,902,404
Effect of:			
Stock options	**3,476,701**	4,512,564	4,060,404
Restricted stock awards	**507,908**	903,873	888,280
Diluted	**171,287,750**	156,309,039	147,851,088

(1) 2004 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, 2006	December 31, 2005
	(in thousands)	
ASSETS		
Current assets		
Cash and cash equivalents	**$ 42,927**	$ 223,705
Accounts receivable	**131,370**	128,948
Inventories, at average cost	**62,488**	49,513
Deferred income tax benefit	**—**	29,700
Hedging asset - FAS 133	**64,082**	17,467
Other	**22,969**	11,731
Total current assets	**323,836**	461,064
Investments	**—**	17,100
Property, plant and equipment, at cost		
Gas and oil properties, using the full cost method, including $166,826,844 in 2006 and $122,300,659 in 2005 excluded from amortization	**2,651,427**	1,897,613
Gas distribution systems	**226,067**	216,644
Construction-in-progress - drilling rigs	**—**	35,128
Gathering systems	**51,836**	15,742
Gas in underground storage	**32,254**	32,254
Other	**77,702**	45,234
	3,039,286	2,242,615
Less: Accumulated depreciation, depletion and amortization	**1,022,786**	872,218
	2,016,500	1,370,397
Other assets	**38,733**	19,963
	$ 2,379,069	$ 1,868,524
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current portion of long-term debt	**$ 1,200**	$ —
Accounts payable	**266,023**	154,385
Taxes payable	**16,088**	14,519
Advances from partners and customer deposits	**31,941**	7,624
Hedging liability - FAS 133	**23,864**	112,293
Over-recovered purchased gas costs	**10,580**	7,323
Current deferred income taxes	**19,162**	—
Other	**10,002**	6,242
Total current liabilities	**378,860**	302,386
Long-term debt	**136,600**	100,000
Other liabilities		
Deferred income taxes	**370,522**	254,528
Long-term hedging liability	**4,902**	60,442
Pension liability	**11,697**	7,902
Other	**30,811**	21,349
	417,932	344,221
Commitments and contingencies		
Minority interest in partnership	**11,034**	11,613
Stockholders' equity		
Common stock, $0.01 par value in 2006, $0.10 par value in 2005; authorized 540,000,000 shares in 2006 and 220,000,000 shares in 2005, issued 168,953,893 in 2006 and 168,452,336 in 2005	**1,690**	16,845
Additional paid-in capital	**740,609**	711,196
Retained earnings	**660,857**	498,221
Accumulated other comprehensive income (loss)	**31,487**	(104,874)
Common stock in treasury, at cost, 1,217,284 shares in 2005	**—**	(3,390)
Unamortized cost of restricted shares issued under stock incentive plan, 707,142 shares in 2005	**—**	(7,694)
	1,434,643	1,110,304
	$ 2,379,069	$ 1,868,524

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,		
	2006	2005	2004
		(in thousands)	
Cash flows from operating activities			
Net income	**$ 162,636**	$ 147,760	$ 103,576
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**152,519**	97,652	75,377
Deferred income taxes	**99,399**	86,431	59,778
Unrealized (gain) loss on derivatives	**5,579**	(9,666)	2,639
Stock-based compensation expense	**5,164**	1,906	1,973
Equity in (income) loss of NOARK partnership	**(925)**	(1,635)	433
Gain on sale of investment in partnership and other property	**(10,285)**	(445)	(5,802)
Minority interest in partnership	**(579)**	(245)	(268)
Change in assets and liabilities:			
Accounts receivable	**(2,422)**	(42,680)	(27,725)
Inventories	**(12,975)**	(17,265)	(2,741)
Under/over-recovered purchased gas costs	**3,258**	5,911	2,519
Accounts payable	**20,742**	32,837	26,052
Advances from partners and customer deposits	**24,317**	1,513	(653)
Other assets and liabilities	**(16,491)**	2,408	2,739
Net cash provided by operating activities	**429,937**	304,482	237,897
Cash flows from investing activities			
Capital expenditures	**(850,910)**	(453,859)	(291,101)
Investment in NOARK partnership	**—**	—	(2,059)
Proceeds from sale/leaseback of drilling rigs	**127,288**	—	—
Proceeds from sale of investment in partnership and other property	**92,465**	1,519	7,121
Other items	**1,151**	(578)	591
Net cash used in investing activities	**(630,006)**	(452,918)	(285,448)
Cash flows from financing activities			
Issuance of common stock	**—**	579,956	—
Debt retirement	**(1,200)**	(125,000)	—
Payments on revolving long-term debt	**(267,700)**	(563,800)	(395,100)
Borrowings under revolving long-term debt	**267,700**	463,800	441,300
Debt issuance costs	**—**	(1,180)	(1,514)
Excess tax benefit for stock-based compensation	**14,609**	—	—
Change in bank drafts outstanding	**2,009**	11,860	(2,347)
Proceeds from exercise of common stock options	**3,873**	5,270	5,170
Net cash provided by financing activities	**19,291**	370,906	47,509
Increase (decrease) in cash and cash equivalents	**(180,778)**	222,470	(42)
Cash and cash equivalents at beginning of year	**223,705**	1,235	1,277
Cash and cash equivalents at end of year	**$ 42,927**	$ 223,705	$ 1,235

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

STATEMENTS OF CHANGES IN STOCKHOLDERS' 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, 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**
Comprehensive income:								
Net income	—	—	—	162,636	—	—	—	**162,636**
Change in value of derivatives	—	—	—	—	141,230	—	—	**141,230**
Change in value of pension liability	—	—	—	—	2,372	—	—	**2,372**
Total comprehensive income	—	—	—	—	—	—	—	**306,238**
Adoption of FAS 158	—	—	—	—	(7,241)	—	—	**(7,241)**
Adoption of FAS 123(R)	—	—	(7,694)	—	—	—	7,694	**—**
Tax benefit for stock-based compensation	—	—	14,609	—	—	—	—	**14,609**
Stock-based compensation – FAS 123(R)	—	—	6,857	—	—	3	—	**6,860**
Common stock par value adjustment	—	(15,160)	15,160	—	—	—	—	**—**
Exercise of stock options	494	5	927	—	—	2,941	—	**3,873**
Issuance of restricted stock	8	—	(513)	—	—	513	—	**—**
Cancellation of restricted stock	—	—	67	—	—	(67)	—	**—**
Balance at December 31, 2006	168,954	$ 1,690	$ 740,609	$ 660,857	$ 31,487	$ —	$ —	**$ 1,434,643**

[(1)] 2003 and 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 CHANGES IN STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

Southwestern Energy Company and Subsidiaries

RECONCILIATION OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	For the years ended December 31,		
	2006	2005	2004
		(in thousands)	
Balance, beginning of year	**$ (104,874)**	$ (19,816)	$ (12,520)
Current period reclassification to earnings	**(2,326)**	67,481	21,119
Current period ineffectiveness	**(12,726)**	5,969	1,006
Current period change in derivative instruments	**156,282**	(154,494)	(28,922)
Current period change in pension liability	**(4,082)**	(4,014)	(499)
Current period change in other postretirement benefit liability	**(787)**	—	—
Balance, end of year	**$ 31,487**	$(104,874)	$ (19,816)

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Southwestern Energy Company and Subsidiaries
December 31, 2006, 2005 and 2004

(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, New Mexico and Oklahoma. Southwestern's marketing and gas gathering business (Midstream Services) is concentrated in its core areas of operations. The Natural Gas Distribution segment operates in northern Arkansas and its customers 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 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., (iii) Angelina Gathering Company, L.L.C., and (iv) DeSoto Gathering Company, L.L.C. All significant intercompany accounts and transactions have been eliminated. Prior to the sale of its interest, the Company accounted 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.

Effective June 30, 2006, Southwestern Energy Company reincorporated from Arkansas to Delaware. As a result of the reincorporation, the par value of the Company's common stock changed to $0.01 per share. The reincorporation did not result in any change in the Company's business, management, employees, fiscal year, assets or liabilities.

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, 2006, the estimated fair value of the minority ownership position of the partnership does not exceed the minority interest of $11.0 million reflected in the accompanying balance sheet.

Rig Sale/Leaseback

On December 29, 2006, the Company sold 13 of its existing drilling rigs and assigned its right to purchase two other drilling rigs to be delivered and related equipment to various financial institutions and leased the rigs from the buyers for an initial term of eight years from January 1, 2007 with aggregate rental payments of $19.6 million annually. The Company received proceeds of $127.3 million. This transaction was recorded as a sale and operating leaseback with an aggregate deferred gain of $7.4 million on the sale which will be amortized against the lease payments over the lease term. Subject to certain conditions, the Company has options to purchase the rigs and related equipment from the lessors at the end of the 84th month of the lease term at an agreed upon price or at the end of the lease term for its then fair market value. Additionally, the Company has the option to renew the lease for a negotiated renewal term at a periodic rental equal to the fair market rental value of the rigs as determined at the time of renewal. In accordance with the Company's accounting procedures, the portion of the lease payments that represent drilling costs for its working interest in wells is capitalized to the full cost pool.

Property, Depreciation, Depletion and Amortization

Gas and Oil Properties. The Company utilizes the full cost method of accounting for costs related to the exploration, development and acquisition of oil and natural gas 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. These capitalized costs are subject to a ceiling test that 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 the 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. However, commodity price increases subsequent to the end of a reporting period but prior to the release of periodic reports may be utilized to calculate the ceiling value of reserves. At December 31, 2006, 2005 and 2004, the Company’s unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At December 31, 2006, the Company’s standardized measure was calculated based upon quoted market prices of $5.64 per Mcf for Henry Hub gas and $57.25 per barrel for West Texas Intermediate oil, adjusted for market differentials, and included approximately $135.2 million related to the positive effects of future cash flow hedges of gas production. At December 31, 2005, the Company’s 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, and at December 31, 2004, the standardized measure was calculated based upon quoted market prices of $6.18 per Mcf for Henry Hub gas and $43.45 per barrel for West Texas Intermediate oil. A decline in natural gas and oil prices from year-end 2006 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.

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.

Gas Distribution Systems. Costs applicable to construction activities, including overhead items, are capitalized. Depreciation and amortization of the gas distribution system is provided using the straight-line method with average annual rates for plant functions ranging from 1.2% to 4.2%.

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.

Construction-in-Progress – Drilling Rigs. In 2005, the Company entered into agreements to fabricate ten new land drilling rigs which were in process at December 31, 2005. These rigs were included in the December 2006 rig sale/leaseback transaction discussed above.

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 Natural 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, investments in gathering systems until these assets are placed in service and on drilling rigs during their construction phase. 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.

Asset Retirement Obligations. Statement of Financial Accounting Standards No. 143 “Accounting for Asset Retirement Obligations” (FAS 143) 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 following table summarizes the Company's 2006 and 2005 activity related to asset retirement obligations:

	2006	2005
	(in thousands)	
Asset retirement obligation at January 1	**$ 9,229**	$ 8,565
Accretion of discount	**401**	326
Obligations incurred	**1,152**	436
Obligations settled	**(645)**	(1,553)
Revisions of estimates	**408**	1,455
Asset retirement obligation at December 31	**$ 10,545**	$ 9,229
Current liability	**593**	358
Long-term liability	**9,952**	8,871
Total asset retirement obligation at December 31	**$ 10,545**	$ 9,229

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.

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, 2006, the Company had overproduction of 1.2 Bcf valued at $3.5 million and underproduction of 1.5 Bcf valued at $4.4 million. 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.

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, 2006 was $328.6 million with expiration dates in 2020 through 2026.

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 speculative 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) to the extent that they are effective in offsetting the changes in the cash flows of the hedged item. In contrast, gains and losses from the ineffective portion of swap agreements and options as well as those that do not qualify for hedge accounting treatment 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. For the year ended December 31, 2006, 5,351,809 of the Company’s outstanding options with an average exercise price of $3.57 were included in the calculation of diluted shares. Options for 440,431 shares were excluded from the calculation because they would have had an antidilutive effect. All of the Company’s 7,126,465 outstanding options at December 31, 2005 with a weighted average exercise price of $4.34 were included in the calculation of diluted shares. In addition, all of the Company’s 8,884,512 outstanding options at December 31, 2004 with a weighted average exercise price of $3.18 were included in the calculation of diluted shares.

For the year ended December 31, 2006, the number of restricted stock shares included in the calculation of diluted shares was 310,617. Restricted shares of 168,115 were excluded from the calculation because they would have had an antidilutive effect. All of the Company’s 707,142 and 1,281,031 non-vested restricted stock shares for 2005 and 2004, respectively were included in the calculation. The number of options, options prices, and the number of restricted shares for 2004 reflect the two-for-one stock splits effected in each of the second and fourth quarters of 2005.

Accounting for Stock-Based Compensation

In December 2004, the FASB issued Statement on Financial Accounting Standards No. 123R “Share-Based Payment” (FAS 123R). FAS 123R requires that companies recognize compensation expense equal to the fair value of stock options or other share based payments. We adopted this standard during the year ended December 31, 2006 using the modified prospective method. See Note 9 of our consolidated financial statements for a description of the impact of this standard on our financial statements.

Accounting for Defined Benefit Pension and Other Postretirement Plans

In September 2006, Statement of Financial Accounting Standards No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans” (FAS 158) was issued. FAS 158 requires, among other things, the recognition of the funded status of each defined pension benefit plan, retiree health care and other postretirement benefit plans and postemployment benefit plans on the balance sheet. We adopted FAS 158 as of December 31, 2006. See Note 4 for additional information.

(2) DEBT

Debt balances as of December 31, 2006 and 2005 consisted of the following:

	2006	2005
	(in thousands)	
Current portion of long-term debt:		
7.15% Senior Notes due 2018	**$ 1,200**	$ -
Long-term:		
7.625% Senior Notes due 2027, putable at the holders' option in 2009	**60,000**	60,000
7.21% Senior Notes due 2017	**40,000**	40,000
7.15% Senior Notes due 2018	**36,600**	-
Total long-term debt	**136,600**	100,000
Total debt	**$ 137,800**	$ 100,000

In February 2007, the Company amended its unsecured revolving credit facility increasing the borrowing capacity to $750 million, lowering the borrowing cost and extending the maturity date to 2012. The amount available under the revolving credit facility may be increased to $1 billion at any time upon the Company's agreement with its existing or additional lenders. The Company had no indebtedness outstanding under its revolving credit facility at December 31, 2006 and December 31, 2005. The interest rate on the amended credit facility is calculated based upon our debt rating and is currently 87.5 basis points over the current London Interbank Offered Rate (LIBOR). The Credit Facility is guaranteed by the Company's subsidiaries, Southwestern Energy Production Company, SEECO, Inc. and Southwestern Energy Services Company. The Credit Facility requires additional subsidiary guarantors if certain guaranty coverage levels are not satisfied. 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 stockholders' 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, 2006, the Company's capital structure consisted of 9% debt and 91% equity and it was in compliance with the covenants of its debt agreements.

The 7.15% senior notes were assumed in 2006 upon the sale of the Company's general partnership interest in NOARK. The Company had previously guaranteed the notes.

The 7.625% senior notes are putable at the holders' option in 2009. Other than the 7.625% senior notes, aggregate maturities of long-term debt for each of the years ending December 31, 2007 through 2011 are $1.2 million per year for the 7.15% senior notes. Total interest payments were $10.8 million in 2006, $20.3 million in 2005 and $18.3 million in 2004.

(3) INCOME TAXES

The provision for income taxes included the following components:

	2006	2005	2004
		(in thousands)	
Federal:			
Current	**$ —**	$ —	$ —
Deferred	**90,186**	79,845	55,995
State:			
Current	**—**	—	—
Deferred	**9,320**	6,698	3,899
Investment tax credit amortization	**(107)**	(112)	(116)
Provision for income taxes	**$ 99,399**	**$ 86,431**	$ 59,778

The provision for income taxes was an effective rate of 37.9% in 2006, 36.9% in 2005 and 36.6% in 2004. 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:

	2006	2005	2004
		(in thousands)	
Expected provision at federal statutory rate of 35%	**$ 91,712**	$ 81,967	$ 57,174
Increase resulting from:			
State income taxes, net of federal income tax effect	**6,058**	4,354	2,534
Other	**1,629**	110	70
Provision for income taxes	**$ 99,399**	$ 86,431	$ 59,778

The components of the Company's net deferred tax liability as of December 31, 2006 and 2005 were as follows:

	2006	2005
	(in thousands)	
Deferred tax liabilities:		
Differences between book and tax basis of property	**$ 500,386**	$ 330,465
Stored gas	**4,558**	6,343
Book over tax basis in partnerships	**—**	12,883
Cash flow hedges - FAS 133	**24,906**	—
Other	**7,470**	8,963
	537,320	358,654
Deferred tax assets:		
Accrued compensation	**6,795**	2,753
Alternative minimum tax credit carryforward	**3,026**	3,026
Accrued pension costs	**3,702**	2,946
Book over tax basis in partnerships	**1,247**	—
Cash flow hedges - FAS 133	**—**	58,621
Asset retirement obligations - FAS 143	**3,728**	3,390
Net operating loss carryforward	**125,438**	63,369
Other	**4,322**	451
	148,258	134,556
Net deferred tax liability	**$ 389,062**	$ 224,098

The net deferred tax liability at December 31, 2006 consisted of a current deferred income tax liability of $19.2 million and long-term deferred income tax liabilities of $370.5 million including unamortized deferred investment tax credits of $0.6 million. In 2006, the Company paid $6,000 in income taxes. There were no income tax payments in 2005 and 2004. The Company's net operating loss carryforward at December 31, 2006, was $328.6 million with expiration dates in 2020 through 2026. The Company also had an alternative minimum tax credit carryforward of $3.0 million and a statutory depletion carryforward of $7.6 million at December 31, 2006.

(4) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

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 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.

On September 29, 2006, FAS 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" was issued. FAS 158 requires, among other things, the recognition of the funded status of each defined pension benefit plan, retiree health care and other postretirement benefit plans and postemployment benefit plans on the balance sheet. Each overfunded plan is recognized as an asset and each underfunded plan is recognized as a liability. The initial impact of the standard due to unrecognized prior service costs or credits and net actuarial gains or losses as well as subsequent changes in the funded status is recognized as a component of accumulated comprehensive loss in stockholders' equity. Additional minimum pension liabilities (AML) and related intangible assets are also derecognized upon adoption of the new standard. FAS 158 requires initial application for fiscal years ending after December 15, 2006 and was adopted by the Company as of December 31, 2006. The following table summarizes the effect of required changes as of December 31, 2006 prior to the adoption of FAS 158 as well as the impact of the initial adoption of FAS 158 as it relates to our pension plans.

	December 31, 2006 Prior to AML and FAS 158 Adjustments	AML Adjustment	December 31, 2006 Prior to FAS 158	FAS 158 Adjustment	December 31, 2006 Post AML and FAS 158 Adjustment
			(in thousands)		
Other assets	$6,156	$(3,436)	$2,720	$(2,720)	**$ —**
Deferred tax asset	2,946	(1,393)	1,553	3,785	**5,338**
Pension liability	(11,381)	7,201	(4,180)	(7,517)	**(11,697)**
Accumulated other comprehensive income, net of tax	5,017	(2,372)	2,645	6,452	**9,097**

The amounts in accumulated other comprehensive loss that are expected to be recognized as components of net periodic benefit cost (credit) during the next fiscal year are $0.5 million for prior service costs and a $0.4 million net loss.

In addition to the $7.5 million pension liability adjustment recognized at December 31, 2006 for the Company's pension obligation, FAS 158 also required the Company to recognize an additional liability of $1.2 million related to its postretirement benefit obligation at December 31, 2006, resulting in a $0.8 million after-tax adjustment to other comprehensive income (loss). The amount in accumulated other comprehensive income (loss) that is expected to be recognized as a component of net transition obligation/(asset) and net loss/(gain)for 2007 is $0.1 million.

The following provides a reconciliation of the changes in the plans' benefit obligations, fair value of assets, and funded status as of December 31, 2006 and 2005:

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	**2006**	2005
	(in thousands)			
Change in benefit obligations:				
Benefit obligation at January 1	**$ 71,854**	$ 63,800	**$ 4,022**	$ 4,504
Service cost	**3,011**	2,523	**271**	172
Interest cost	**3,881**	3,764	**189**	201
Participant contributions	**—**	—	**116**	116
Actuarial loss/(gain)	**(2,588)**	4,824	**(578)**	(693)
Benefits paid	**(5,683)**	(3,057)	**(326)**	(278)
Plan amendments	**388**	—	**—**	—
Benefit obligation at December 31	**$ 70,863**	$ 71,854	**$ 3,694**	$ 4,022

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	**2006**	2005
	(in thousands)			
Change in plan assets:				
Fair value of plan assets at January 1	**$ 55,932**	$ 54,165	**$ 1,379**	$ 1,114
Actual return on plan assets	**5,504**	3,020	**94**	(19)
Employer contributions	**3,413**	1,804	**354**	446
Participant contributions	**—**	—	**116**	116
Benefit payments	**(5,683)**	(3,057)	**(326)**	(278)
Fair value of plan assets at December 31	**$ 59,166**	$ 55,932	**$ 1,617**	$ 1,379
Funded status:				
Funded status at December 31	**$ (11,697)**	$ (15,922)	**$ (2,078)**	$ (2,643)
Unrecognized net actuarial loss	**—**	16,073	**—**	1,371
Unrecognized prior service cost	**—**	2,726	**—**	—
Unrecognized transition obligation	**—**	—	**—**	602
Net amount recognized	**$ (11,697)**	$ 2,877	**$ (2,078)**	$ (670)

The Company uses a December 31 measurement date for all of its plans. As a result of the application of FAS 158, the Company recorded liabilities of $13.8 million on the balance sheet related to its pension and other postretirement benefit plans. This amount represents the difference between the fair value of the plans' assets and projected benefit obligations for the pension liability, and the difference between the fair value of the plans' assets and accumulated postretirement benefit obligations for the postretirement benefits liability. The Company also recorded an after-tax loss of $7.2 million to other comprehensive income (loss) to reflect unrecognized gains and losses resulting from changes in assumptions and prior service costs.

The change in accumulated other comprehensive loss related to the pension plans was a loss of $6.5 million ($4.1 million after tax) for the year ended December 31, 2006 and a loss of $6.4 million ($4.0 million after tax) for the year ended December 31, 2005. The change in accumulated other comprehensive loss related to the other postretirement benefit plans was a loss of $1.2 million ($0.8 million after tax) for the year ended December 31, 2006. Included in accumulated other comprehensive loss at December 31, 2006 and 2005 was a $15.7 million loss ($9.9 million net of tax) and an $8.0 million loss ($5.1 million net of tax), respectively, related to the Company’s pension and other postretirement benefit plans.

The Company’s pension plans have an accumulated benefit obligation in excess of plan assets as of December 31, 2006 and 2005 as follows:

	2006	2005
	(in thousands)	
Projected benefit obligation	**$70,863**	$71,854
Accumulated benefit obligation	**63,347**	63,834
Fair value of plan assets	**59,166**	55,932

Net periodic pension and other postretirement benefit costs include the following components for 2006, 2005 and 2004:

	Pension Benefits			Other Postretirement Benefits		
	2006	2005	2004	**2006**	2005	2004
	(in thousands)					
Service cost	**$ 3,011**	$ 2,523	$ 2,404	**$ 271**	$ 172	$ 174
Interest cost	**3,881**	3,764	3,692	**189**	201	252
Expected return on plan assets	**(4,578)**	(4,776)	(4,543)	**(69)**	(56)	(42)
Amortization of transition obligation	**—**	—	—	**86**	86	86
Recognized net actuarial loss	**759**	326	233	**34**	41	102
Amortization of prior service cost	**436**	440	444	**—**	—	—
	$ 3,509	$ 2,277	$ 2,230	**$ 511**	$ 444	$ 572

The weighted average assumptions used in the measurement of the Company’s benefit obligations at December 31, 2006 and 2005 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	**2006**	2005
Discount rate	**6.00%**	5.50%	**6.00%**	5.50%
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 2006, 2005 and 2004 are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2006	2005	2004	**2006**	2005	2004
Discount rate	**5.50%**	6.00%	6.25%	**5.50%**	6.00%	6.25%
Expected return on plan assets	**8.25%**	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 2006 and 2005:

	2006	2005
Health care cost trend assumed for next year	**9%**	10%
Rate to which the cost trend is assumed to decline	**5%**	5%
Year that the rate reaches the ultimate trend rate	**2012**	2011

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	$ 58	$ (50)
Effect on postretirement benefit obligation	$ 395	$ (345)

The Company's pension plan weighted-average asset allocations at December 31, 2006 and 2005, by asset category, are as follows:

	2006	2005
Asset category:		
Equity securities	**59%**	65%
Debt securities	**37%**	33%
Cash equivalents	**4%**	2%
Total	**100%**	100%

Assets of the postretirement benefit plans were invested 100% in debt securities for 2006 and 2005.

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, 2006, the defined benefit pension plan had a diversified asset allocation strategy of 55% to 75% and a target of 60% for equity securities and 35% to 45% and a target of 40% for 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 2006, the Company contributed $3.4 million to its pension plans and $0.4 million to its other postretirement benefit plans. The Company expects to contribute $3.7 million to its pension plans and $0.4 million to its other postretirement benefit plans in 2007.

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

	Pension Benefits	Other Benefits
	(in thousands)	
2007	$ 3,385	$ 161
2008	$ 4,027	$ 183
2009	$ 4,121	$ 200
2010	$ 5,255	$ 225
2011	$ 4,399	$ 262
Years 2012-2016	$24,831	$1,751

(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:

	2006	2005	2004
		(in thousands)	
Sales	**$ 491,545**	$ 403,234	$ 286,924
Production (lifting) costs	**(68,479)**	(50,949)	(35,501)
Depreciation, depletion and amortization	**(143,101)**	(88,902)	(66,924)
	279,965	263,383	184,499
Income tax expense	**(105,227)**	(96,651)	(67,031)
Results of operations	**$ 174,738**	$ 166,732	$ 117,468

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 2006, 2005 and 2004:

	2006	2005	2004
		(in thousands)	
Proved property acquisition costs	**$ 18,697**	$ 75	$ 15,384
Unproved property acquisition costs	**55,032**	55,652	21,830
Exploration costs	**231,771**	44,416	24,526
Development costs	**453,956**	313,759	219,455
Capitalized costs incurred	**$ 759,456**	$ 413,902	$ 281,195
Full cost pool amortization per Mcf equivalent	**$ 1.90**	$ 1.42	$ 1.20

Capitalized interest is included as part of the cost of natural gas and oil properties. The Company capitalized $10.3 million, $5.0 million and $2.8 million during 2006, 2005 and 2004, respectively, based on the Company's weighted average cost of borrowings used to finance the expenditures. The increases in capitalized interest since 2004 reflect an increase in the Company's unevaluated costs primarily related to lease acquisition and drilling activities.

In addition to capitalized interest, the Company also capitalized internal costs of $44.1 million, $26.4 million and $14.3 million during 2006, 2005 and 2004, 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 2004 have resulted from the addition of personnel and related costs in Southwestern's exploration and development segment.

The table of capitalized costs incurred above does not include amounts for the acquisition of drilling rigs in 2006 and 2005, which were sold and then leased back in December 2006.

The following table shows the capitalized costs of gas and oil properties and the related accumulated depreciation, depletion and amortization at December 31, 2006 and 2005:

	2006	2005
	(in thousands)	
Proved properties	**$ 2,484,600**	$ 1,775,312
Unproved properties	**166,827**	122,301
Total capitalized costs	**2,651,427**	1,897,613
Less: Accumulated depreciation, depletion and amortization	**883,100**	745,206
Net capitalized costs	**$ 1,768,327**	$ 1,152,407

The table below sets forth the composition of net unevaluated costs excluded from amortization as of December 31, 2006. Of the total, approximately $22.3 million represents costs of wells in progress at December 31, 2006 and approximately $77.2 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. Costs related to wells in progress will be included in the amortization computation in 2007. The timing and amount of the Fayetteville Shale play leasehold costs included in the amortization computation will depend on the success of drilling in pilot areas and the time frame for development of the play. The Company is, therefore, unable to estimate when these costs will be included in the amortization computation.

	2006	2005	2004 (in thousands)	Prior	**Total**
Property acquisition costs	$48,301	$41,416	$14,012	$11,068	**$ 114,797**
Exploration and development costs	32,572	4,683	150	—	**37,405**
Capitalized interest	3,971	5,338	2,369	2,947	**14,625**
	$84,844	$51,437	$16,531	$14,015	**$ 166,827**

(6) NATURAL GAS AND OIL RESERVES (UNAUDITED)

The following table summarizes the changes in the Company's proved natural gas and oil reserves for 2006, 2005 and 2004:

	2006		2005		2004	
	Gas (MMcf)	**Oil (MBbls)**	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)
Proved reserves, beginning of year	**772,339**	**9,079**	594,483	8,508	457,016	7,675
Revisions of previous estimates	**(75,420)**	**(1,870)**	(29,970)	(284)	(13,832)	199
Extensions, discoveries and other additions	**352,734**	**1,645**	264,683	1,669	196,398	1,274
Production	**(68,133)**	**(698)**	(56,758)	(705)	(50,425)	(618)
Acquisition of reserves in place	**2,760**	**22**	28	—	5,634	30
Disposition of reserves in place	**(5,346)**	**(280)**	(127)	(109)	(308)	(52)
Proved reserves, end of year	**978,934**	**7,898**	772,339	9,079	594,483	8,508
Proved developed reserves:						
Beginning of year	**551,456**	**8,309**	491,697	7,767	369,867	6,719
End of year	**623,870**	**6,994**	551,456	8,309	491,697	7,767

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, 2006, 2005 and 2004:

	2006	2005 (in thousands)	2004
Future cash inflows	**$ 5,662,436**	$ 6,699,456	$ 3,857,623
Future production costs	**(1,752,482)**	(1,656,084)	(983,654)
Future development costs	**(737,292)**	(329,528)	(108,911)
Future income tax expense	**(794,388)**	(1,387,765)	(779,386)
Future net cash flows	**2,378,274**	3,326,079	1,985,672
10% annual discount for estimated timing of cash flows	**(1,335,519)**	(1,905,268)	(1,093,364)
Standardized measure of discounted future net cash flows	**$ 1,042,755**	$ 1,420,811	$ 892,308

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 $5.64 per Mcf for gas and $57.25 per barrel for oil in 2006, $10.08 per Mcf for gas and $61.04 per barrel for oil in 2005, and $6.18 per Mcf for gas and $43.45 per barrel for oil in 2004. 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 2006, 2005 and 2004:

	2006	2005	2004
		(in thousands)	
Standardized measure, beginning of year	**$ 1,420,811**	$ 892,308	$ 716,352
Sales and transfers of gas and oil produced, net of production costs	**(423,066)**	(361,815)	(252,241)
Net changes in prices and production costs	**(711,234)**	582,247	28,009
Extensions, discoveries, and other additions, net of future production and development costs	**381,924**	546,523	367,892
Acquisition of reserves in place	**5,106**	58	20,771
Revisions of previous quantity estimates	**(140,257)**	(91,648)	(26,481)
Accretion of discount	**198,641**	121,837	99,432
Net change in income taxes	**299,630**	(239,539)	(48,091)
Changes in estimated future development costs	**(69,450)**	(248,322)	(70,005)
Previously estimated development costs incurred during the year	**116,601**	71,729	42,143
Changes in production rates (timing) and other	**(35,951)**	147,433	14,527
Standardized measure, end of year	**$ 1,042,755**	$ 1,420,811	$ 892,308

(7) INVESTMENT IN UNCONSOLIDATED PARTNERSHIP

On May 2, 2006, the Company sold its 25% partnership interest in NOARK to Atlas Pipeline Partners, L.P. for $69.0 million and recognized a pre-tax gain of approximately $10.9 million ($6.7 million after tax) in the second quarter relating to the transaction. The Company's share of pre-tax income or loss from operations related to our investment in NOARK was income of $0.9 million in 2006 and $1.6 million in 2005, and a loss of $0.4 million in 2004. Income from operations and the gain on the sale in the second quarter of 2006 were recorded in other income in our statements of operations. The Company's investment in NOARK totaled $17.1 million at December 31, 2005.

(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 Hedges: The fair value of all hedging financial instruments is the amount at which they could be settled, based on quoted market prices, best estimates obtained from counterparties and an option pricing model, when necessary, for price option contracts.

The carrying amounts and estimated fair values of the Company's financial instruments as of December 31, 2006 and 2005 were as follows:

	2006		2005	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	(in thousands)			
Cash and cash equivalents	**$ 42,927**	**$ 42,927**	$ 223,705	$ 223,705
Customer deposits	**$ 6,894**	**$ 6,894**	$ 6,352	$ 6,352
Total debt	**$ 137,800**	**$ 141,704**	$ 100,000	$ 105,370
Commodity hedges asset (liability)	**$ 58,102**	**$ 58,102**	$ (153,246)	$ (153,246)

Derivatives and Risk Management

The Company enters into various types of derivative instruments for a portion of its projected gas and oil sales to reduce its exposure to market price volatility for natural gas and oil. 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, 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 or as a component of other comprehensive income.

As of December 31, 2006, derivative instruments utilized by the Company included swaps, basis swaps and costless collars that have been classified as follows:

- For fixed-price swaps, the Company receives a fixed price for the contract and pays a floating market price to the counterparty.
- For floating-price swaps, the Company receives a floating market price from the counterparty and pays a fixed price.
- Costless-collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, the Company receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.
- Basis swaps are arrangements that guarantee a price differential for natural gas from a specified delivery point. For basis protection swaps, the Company receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.
- Regulatory swaps are similar to that of floating price swaps but are used exclusively by the Natural Gas Distribution segment and are subject to accounting requirements set forth by the Arkansas Public Service Commission.

Substantially all of the Company's gas and oil derivative instruments that are not basis related are settled based upon NYMEX prices. Substantially all of the Company's derivative instruments that are basis related are settled based upon "Inside FERC" published prices for the particular locational basis that is traded. The estimated fair value of these derivative instruments are based upon various market factors.

At December 31, 2006, the Company recorded hedging assets of $87.3 million, hedging liabilities of $20.7 million as well as a regulatory asset and corresponding current liability of $8.1 million related to its utility gas purchase hedges. As of December 31, 2006, a net of tax gain to other comprehensive income (loss) of $41.4 million was recorded. 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, 2005, the Company recorded hedging assets of $19.5 million, hedging liabilities of $172.7 million, a regulatory asset and corresponding current liability 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 change in accumulated other comprehensive loss related to derivatives was a gain of $224.2 million ($141.2 million after tax) for the year ended December 31, 2006, a loss of $128.6 million ($81.0 million after tax) for the year ended December 31, 2005 and a loss of $10.7 million ($6.8 million after tax) for the year ended December 31, 2004. Assuming the market prices of futures as of December 31, 2006 remain unchanged, we would expect to transfer a gain of approximately $30.6 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, 2006 are expected to mature by December 31, 2008.

Gains or losses from derivative transactions are reflected as adjustments to oil and gas sales on the consolidated statements of operations. Realized gains from settled contracts included in oil and gas sales were $14.3 million in 2006, compared to realized losses of $85.8 million and $31.8 million in 2005 and 2004, respectively.

Cash Flow Hedges

For cash flow hedges, all derivative instruments are reported as either a hedging asset or hedging liability on the balance sheet and are measured at fair value. The reporting of gains and losses on derivative hedging instruments depends on whether the gains or losses are effective at offsetting changes in the cash flows of the hedged item. The effective portion of the gain or loss on the derivative hedging instrument is recorded in other comprehensive income (OCI) until recognized in earnings during the period that the hedged transaction takes place. The ineffective portion of the gains and losses from hedges is recognized in earnings immediately. The Company recorded a gain on the change in ineffectiveness of $20.2 million in 2006, compared to losses of $9.4 million and $1.5 million in 2005 and 2004, respectively.

For those contracts designated as cash flow hedges, the Company formally documents all relationships between the derivative instruments and the commodity being hedged, as well as its risk management objective and strategy for the particular derivative contracts as required by FAS 133.

Other Derivative Contracts

Although the Company's basis swaps meet the objectives to manage our commodity price exposure, some of these trades do not qualify for hedge accounting under FAS 133. The basis swaps that do qualify for hedge accounting treatment are classified as "matched-basis" swaps. These matched basis swaps have been combined with other derivative trades (i.e., costless collars and swaps) to form a single hedge where both trades are accounted for as a unit. The basis swap trades that have not been designated as hedges are recorded on the balance sheet at their fair values under hedging assets and hedging liabilities. All realized and unrealized gains and losses related to these contracts are recognized immediately in the statement of operations as a component of gas sales. As of December 31, 2006 and 2005, the fair values of the basis swaps that do not meet the requirements of FAS 133 hedges were a $6.7 million liability and a $19.1 million asset, respectively. The unrealized loss included in gas and oil sales for non-qualifying basis swaps was $25.8 million in 2006, compared to an unrealized gain of $19.1 million in 2005 and an unrealized loss of $1.2 million in 2004.

Hedge Position

At December 31, 2006, the Company had outstanding natural gas price swaps on total notional volumes of 32.5 Bcf in 2007 and 13.0 Bcf in 2008 for which the Company will receive fixed prices ranging from $6.20 to $12.06 per MMBtu. At December 31, 2006, the Company also had outstanding natural gas price swaps on total notional volumes of 0.2 Bcf in 2007 for which the Company will pay an average fixed price of $7.61 per Mcf. At December 31, 2006, the Company had outstanding fixed price basis differential swaps on 62.0 Bcf of 2007 and 2008 gas production that did not qualify for hedge treatment.

At December 31, 2006, the Company had collars in place on notional volumes of 34.0 Bcf in 2007, and 22.0 Bcf in 2008. The 34.0 Bcf in 2007 had an average floor and ceiling price of $6.93 and $12.34 per MMBtu, respectively. The 22.0 Bcf in 2008 had an average floor and ceiling price of $7.92 and $13.15 per MMBtu, respectively. The Company's price risk management activities increased revenues by $8.7 million in 2006, and reduced revenues by $77.2 million in 2005 and $35.6 million in 2004.

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 BASED COMPENSATION

The Southwestern Energy Company 2004 Stock Incentive Plan (2004 Plan) was adopted in February 2004 and approved by stockholders 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.

On January 1, 2006, the Company adopted FAS 123R, which requires companies to measure the cost of employee services received in exchange for an award of equity instruments based on the grant date fair value of the award. The Company has elected to use the modified prospective application method such that FAS 123R applies to new awards, the unvested portion of existing awards and to awards modified, repurchased or canceled after the effective date. The Company has equity incentive plans that provide for the issuance of stock options and restricted stock. 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. Generally, stock options granted to employees and directors vest ratably over three to four years from the grant date. The Company issues shares of restricted stock to employees and directors which generally vest over four years. The Company recognizes stock-based compensation expense on a straight-line basis over the requisite service period of the individual grants with the exception of awards granted to participants who have reached retirement age or will reach retirement age during the vesting period. 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 Plan to immediately accelerate vesting upon death, disability or retirement (subject to a minimum of five years of service). This change did not affect awards issued prior to December 8, 2005.

Prior to January 1, 2006, the Company accounted for its long-term equity incentive plans under the intrinsic value method described in APB Opinion No. 25, "Accounting for Stock Issued to Employees" and related interpretations (APB 25). The Company, applying the intrinsic value method, did not record stock-based compensation cost for stock options because the exercise price of the stock options equaled the market price of the underlying stock at the date of grant.

Stock Options

For the year ended December 31, 2006, the Company recognized compensation costs of $3.6 million related to stock options subject to FAS 123R. Of this amount, $0.5 million was directly related to the acquisition, exploration and development activities for the Company's gas and oil properties and was capitalized into the full cost pool. The remaining costs were recorded in general and administrative expenses. Under the provisions of FAS 123R, the Company recorded a deferred tax benefit of $1.1 million related to stock options for the year ended December 31, 2006. Unrecognized compensation costs of $6.4 million related to stock options not yet vested are expected to be recognized over future periods. That cost is expected to be recognized over a weighted-average period of 1.5 years.

The fair value of stock options is estimated on the date of the grant using a Black-Scholes valuation model that uses the weighted average assumptions noted in the following table. Expected volatility is based on historical volatility of the Company's common stock and other factors. The Company uses historical data on exercise of stock options, post vesting forfeitures and other factors to estimate the expected term of the share-based payments granted. The risk free interest rate is based on the U.S. Treasury yield curve in effect at the time of grant.

Assumptions	2006	2005	2004
Risk-free interest rate	4.5%	4.4%	3.5%
Expected dividend yield	—	—	—
Expected volatility	42.7%	40.6%	44.3%
Expected term	5 years	4 years	5-6 years

The Company may utilize treasury shares, if available, or use authorized but unissued shares when a stock option is exercised or when restricted stock is granted.

Prior to the adoption of FAS 123R on January 1, 2006, the Company accounted for its stock-based compensation plans under the recognition and measurement principles of APB 25. The following table illustrates the effect on net income and earnings per share for 2005 and 2004 as if the fair value based method under FAS 123R had been applied to all outstanding vested and unvested awards for those periods.

	For the years ended December 31,	
	2005	2004
	(in thousands, except share/per share amounts)	
Net income, as reported	$ 147,760	$ 103,576
Add back: Stock option based compensation expense included in reported net income, net of related tax effects	1,203	1,251
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)
Pro forma net income	$ 145,968	$ 102,394
Earnings per share:		
Basic-as reported[(1)]	$ 0.98	$ 0.72
Basic-pro forma[(1)]	0.97	0.72
Diluted-as reported[(1)]	0.95	0.70
Diluted-pro forma[(1)]	0.93	0.69

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

The following tables summarize stock option activity for the years 2006, 2005 and 2004 and provide information for options outstanding at December 31, 2006:

	2006		2005		2004 [(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	**7,126,465**	**$ 4.34**	8,884,512	$ 3.18	10,107,640	$ 2.72
Granted	**221,330**	**40.67**	223,780	35.44	500,040	11.99
Exercised	**(1,549,679)**	**2.50**	(1,981,827)	2.66	(1,718,504)	3.02
Canceled	**(5,876)**	**24.41**	—	—	(4,664)	3.14
Options outstanding at December 31	**5,792,240**	**$ 6.19**	7,126,465	$ 4.34	8,884,512	$ 3.18

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

Range of Exercise Prices	Options Outstanding: Options Outstanding at Year End	Options Outstanding: Weighted Average Exercise Price	Options Outstanding: Weighted Average Remaining Contractual Life (Years)	Options Outstanding: Aggregate Intrinsic Value (in thousands)	Options Exercisable: Options Exercisable at Year End	Options Exercisable: Weighted Average Exercise Price	Options Exercisable: Aggregate Intrinsic Value (in thousands)
$1.50 - $1.86	2,075,891	$ 1.73	3.6		2,075,891	$ 1.73	
$1.87 - $2.85	674,828	2.52	4.1		674,828	2.52	
$2.86 - $5.00	1,332,160	2.95	4.6		1,332,160	2.95	
$5.01 - $12.00	854,874	5.53	7.0		800,206	5.46	
$12.01 - $41.00	854,487	25.65	5.7		339,517	17.45	
	5,792,240	$ 6.19	4.7	$ 167,139	5,222,602	$ 3.74	$ 163,523

There were 221,330, 223,780 and 500,040 stock options granted during 2006, 2005 and 2004, respectively. The total intrinsic value of options exercised during 2006, 2005 and 2004 was $49.0 million, $39.3 million and $9.0 million, respectively.

Associated with the exercise of stock options, the Company received a tax benefit of $14.6 million, $12.0 million and $2.7 million in 2006, 2005 and 2004, respectively. The tax benefit is recorded as an increase in additional paid-in capital.

Restricted Stock

For years ended December 31, 2006 and 2005, the Company recognized compensation costs of $3.3 million and $2.6 million, respectively, related to restricted stock grants. Of these amounts, $1.2 million in 2006 and $0.8 million in 2005 were directly related to the acquisition, exploration and development activities for the Company's gas and oil properties and were capitalized into the full cost pool. The remaining costs were recorded in general and administrative expenses. Under the provisions of FAS 123R, the Company recorded a deferred tax liability of $1.6 million related to restricted stock for the year ended December 31, 2006.

The Company granted 192,065 shares of restricted stock in 2006, 132,065 shares of restricted stock in 2005 and 59,690 shares of restricted stock, on a pre-split basis, in 2004. The fair values of the grants were $7.6 million for 2006, $4.3 million for 2005 and $2.8 million for 2004. Of the 4,948,942 shares granted to date under the Company's long-term equity incentive plans, 1,787,100 shares vest over a three-year period, 2,991,642 shares vest over a four-year period and the remaining shares vest over a five-year period. As of December 31, 2006, 4,146,513 shares have vested to employees. In 2006, 24,073 shares of restricted stock were canceled and 46,132 shares were canceled in 2005. In 2004, 3,210 shares of restricted stock, on a pre-split basis, were canceled.

The following tables summarize restricted stock activity for the years 2006, 2005 and 2004 and provide information for restricted stock outstanding at December 31, 2006:

	2006		2005		2004 [1]	
	Number of Shares	**Weighted Average Grant Date Fair Value**	Number of Shares	Weighted Average Grant Date Fair Value	Number of Shares	Weighted Average Grant Date Fair Value
Unvested shares at January 1	**707,142**	**$ 11.14**	1,281,031	$ 4.49	1,686,459	$ 2.48
Granted	**192,065**	**39.81**	132,065	32.39	238,760	11.86
Vested	**(396,402)**	**7.51**	(659,822)	2.89	(631,348)	1.92
Canceled	**(24,073)**	**18.08**	(46,132)	5.48	(12,840)	3.50
Unvested shares at December 31	**478,732**	**$ 25.30**	707,142	$ 11.14	1,281,031	$ 4.49

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

As of December 31, 2006, there was $11.7 million of total unrecognized compensation cost related to unvested shares. That cost is expected to be recognized over a weighted-average period of 1.4 years. The total fair value of shares vested during 2006 was $2,974,000.

(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

Operating Commitments

The Company’s E&P and Midstream Services segments have commitments to third parties for demand transportation charges. At December 31, 2006, future payments under non-cancelable demand charges for the Company’s E&P and Midstream Services segments are approximately $11,794,000 in 2007, $15,929,000 in 2008, $6,991,000 in 2009, $5,495,000 in 2010 and $4,167,000 in 2011.

Additionally, 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, 2006, future payments under these non-cancelable demand contracts are $9,869,000 in 2007, $9,245,000 in 2008, $9,631,000 in 2009, $10,018,000 in 2010, $10,405,000 in 2011 and $31,681,000 thereafter.

On December 15, 2006, the Company entered into a precedent agreement pursuant to which it will contract for firm gas transportation services on two newly-proposed pipeline laterals and related facilities of Texas Gas Transmission, LLC (Texas Gas), a subsidiary of Boardwalk Pipeline Partners, LP. The Company will be a “Foundation Shipper” for the project and will use the proposed laterals and related facilities primarily to deliver gas volumes produced from the Company’s operations in its Fayetteville Shale play in central Arkansas. Depending on regulatory approvals, the expected in-service date for both laterals is January 1, 2009. The first lateral line (Fayetteville Lateral) will originate in Conway County, Arkansas, and connect to Texas Gas’ mainline system in Coahoma County, Mississippi. The Fayetteville Lateral will be a minimum of 36” in diameter and would have an estimated ultimate capacity of up to 1.1 Bcf per day. The second lateral (Greenville Lateral) will originate at the Texas Gas mainline system near Greenville, Mississippi, and extend eastward to interconnect with various interstate pipelines. The firm transportation agreements to be entered into by the Company pursuant to the precedent agreement will have an initial term of ten years and, over time, will enable the Company to transport up to 500,000 MMBtu per day on the Fayetteville Lateral and up to 400,000 MMBtu per day on the Greenville Lateral. The Company will also have the option to acquire up to 300,000 MMBtu per day of additional capacity on the Fayetteville Lateral and up to 240,000 MMBtu per day of additional capacity on the Greenville Lateral. Upon execution and delivery of the firm transportation agreements contemplated by the precedent agreement, the Company’s Midstream Services segment would have additional demand charges of $503.5 million that would be payable over the ten-year term of the agreements.

On December 29, 2006, Southwestern entered into a sale/leaseback transaction pursuant to which the Company sold 13 operating drilling rigs, two rigs yet to be delivered and related equipment and then leased such drilling rigs and equipment from the buyer for an initial term of eight years from January 1, 2007 for rental payments of approximately $19,584,000 annually. Subject to certain conditions, the Company has options to purchase the rigs and related equipment from the lessors at the end of the 84th month of the lease term at an agreed upon price or at the end of the lease term for its then fair market value. Additionally, the Company has the option to renew the lease for a negotiated renewal term at a periodic rental equal to the fair market rental value of the rigs as determined at the time of renewal.

The Company leases compressors related to its Midstream Services and E&P operations under non-cancelable operating leases expiring through 2014. At December 31, 2006, future minimum payments under these non-cancelable leases accounted for as operating leases are approximately $18,046,000 in 2007, $19,646,000 in 2008, $17,713,000 in 2009, $15,492,000 in 2010, $12,618,000 in 2011 and $7,002,000 thereafter. The Company also leases certain office space and equipment under non-cancelable operating leases expiring through 2013. At December 31, 2006, future minimum payments under these non-cancelable leases accounted for as operating leases are approximately $4,905,000 in 2007, $4,545,000 in 2008, $4,043,000 in 2009, $2,690,000 in 2010, $2,544,000 in 2011 and $2,748,000 thereafter.

Environmental Risk

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.

Litigation

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. In March of 2006, the Texas Supreme Court requested that both parties submit full briefing on the merits of the case. After receiving full briefing from both sides, the Company’s petition for review with the Texas Supreme Court was denied on December 1, 2006, and the case has been remanded to the trial court for further disposition. Should the other party prevail in the case, 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, the Company accrued a loss in the fourth quarter of 2006.

(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. The Midstream Services 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. Revenues for the Natural Gas Distribution segment arise from the transportation and sale of natural gas at retail.

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 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 former investment in the Ozark Gas Transmission system and corporate items.

	Exploration And Production	Midstream Services	Natural Gas Distribution	Other	Total
			(in thousands)		
2006					
Revenues from external customers	**$ 452,887**	**$ 138,251**	**$ 171,974**	**$ —**	**$ 763,112**
Intersegment revenues	**38,658**	**336,956**	**233**	**448**	**376,295**
Operating income	**237,307**	**4,111**	**4,474**	**380**	**246,272**
Interest and other income (loss)[1]	**6,271**	**(581)**	**(415)**	**11,804**	**17,079**
Depreciation, depletion and amortization expense	**143,101**	**1,772**	**6,325**	**92**	**151,290**
Interest expense[1]	**508**	**—**	**171**	**—**	**679**
Provision for income taxes[1]	**91,276**	**554**	**1,698**	**5,871**	**99,399**
Assets	**1,965,247**	**112,027**	**206,919**	**94,876[2]**	**2,379,069**
Capital investments[3]	**861,041**	**48,660**	**11,232**	**21,474**	**942,407**
2005					
Revenues from external customers	$ 365,384	$ 132,690	$ 177,810	$ 445	$ 676,329
Intersegment revenues	37,850	327,200	672	448	366,170
Operating income	234,759	5,684	4,911	566	245,920
Interest and other income (loss)[1]	3,401	—	(269)	1,652	4,784
Depreciation, depletion and amortization expense	88,902	303	6,907	99	96,211
Interest expense[1]	8,416	1,054	4,429	1,141	15,040
Provision for income taxes[1]	83,921	1,668	11	831	86,431
Assets	1,315,616	53,894	212,113	286,901[2]	1,868,524
Capital investments[3]	451,289	15,840	10,908	5,014	483,051
2004					
Revenues from external customers	$ 253,920	$ 65,128	$ 152,288	$ 5,801	$ 477,137
Intersegment revenues	33,004	249,849	161	448	283,462
Operating income	164,585	3,151	8,516	6,035	182,287
Depreciation, depletion and amortization expense	66,924	67	6,592	91	73,674
Interest expense[1]	11,537	—	4,461	994	16,992
Provision for income taxes[1]	55,197	1,151	1,471	1,959	59,778
Assets	890,486	29,243	184,213	42,202[2]	1,146,144
Capital investments[3]	281,988	—	7,298	5,704	294,990

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

(2) Other assets include the Company’s investment in cash equivalents for 2006 and 2005, the Company’s equity investment in the operations of NOARK (see Note 7) for 2005 and 2004, corporate assets not allocated to segments and assets for non-reportable segments.

(3) Capital investments for 2006, 2005 and 2004 included $88.9 million, $28.1 million and $3.9 million, respectively, related to the change in accrued expenditures between years.

Included in intersegment revenues of the Midstream Services segment are $284.9 million, $290.9 million and $235.7 million for 2006, 2005 and 2004, respectively, for marketing of the Company’s E&P sales. Intersegment sales by the E&P segment and Midstream Services segment to the Natural Gas Distribution segment are priced in accordance with terms of existing contracts and current market conditions. Parent company assets include furniture and fixtures and prepaid debt 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, 2006 and 2005:

	Mar 31	June 30	Sept 30	Dec 31
	(in thousands, except per share amounts)			
	2006			
Operating revenues	**$ 226,702**	**$ 153,999**	**$ 168,394**	**$ 214,017**
Operating income	**89,804**	**48,294**	**53,118**	**55,056**
Net income	**58,395**	**37,004**	**33,477**	**33,760**
Basic earnings per share	**0.35**	**0.22**	**0.20**	**0.20**
Diluted earnings per share	**0.34**	**0.22**	**0.20**	**0.20**
	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

(14) NEW ACCOUNTING STANDARDS

During the fourth quarter of fiscal 2006, the Company adopted Statement on Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (FAS 158). FAS 158 requires the recognition of the funded status of each defined pension benefit plan, retiree health care and other postretirement benefit plans and postemployment benefit plans on the balance sheet. Each over-funded plan is recognized as an asset and each under-funded plan is recognized as a liability. The initial impact of the adoption of the standard as well as subsequent changes in the funded status is recognized as a component of accumulated comprehensive loss in the statement of stockholders equity. Additional minimum pension liabilities and related intangible assets are also derecognized upon adoption of the new standard. FAS 158 requires initial application for fiscal years ending after December 15, 2006. See Note 4 of our financial statements for a description of the impact of this standard on our financial statements.

In June 2006, the FASB issued FASB Interpretation (FIN) No. 48, Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109. FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS 109, Accounting for Income Taxes. FIN 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. FIN 48 is effective for fiscal years beginning after December 15, 2006. The Company is in the process of evaluating the impact of the adoption of this interpretation on its results of operations and financial condition.

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, 2006. There were no changes in our internal control over financial reporting during the three months ended December 31, 2006 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 59 of this Form 10-K.

ITEM 9B. OTHER INFORMATION

There was no information required to be disclosed in a current report on Form 8-K during the fourth quarter of the fiscal year ended December 31, 2006 that was not reported on such form.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

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 Stockholders to be held on or about May 10, 2007, or the 2007 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 and our audit committee financial expert. We refer you to the sections “Proposal No. 1: Election of Directors” and “Share Ownership of Management, Directors and Nominees” in the 2007 Proxy Statement for information concerning our directors. We refer you to the section “Corporate Governance – Committees of the Board of Directors” for discussion of our audit committee and 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 stockholder who requests it. Requests for copies should be addressed to the Secretary at 2350 N. Sam Houston Parkway East, Suite 125, Houston TX, 77032.

ITEM 11. EXECUTIVE COMPENSATION

The 2007 Proxy Statement is hereby incorporated by reference for the purpose of providing information about executive compensation, compensation committee interlocks and insider participation as well as the Compensation Committee Report. We refer you to the sections “Compensation Discussion & Analysis,” “Executive Compensation,” “Outside Director Compensation,” “Compensation Committee Interlocks and Insider Participation” and “Compensation Committee Report” in the 2007 Proxy Statement.

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

The 2007 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 2007 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 and directors.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The 2007 Proxy Statement is hereby incorporated by reference for the purpose of providing information about certain relationships, related transactions and board independence. Refer to the sections “Transactions with Related Persons,” “Share Ownership of Management, Directors and Nominees,” and “Compensation Discussion and Analysis” for information about transactions with our executive officers, directors or management and to “Corporate Governance – Director Independence” and “ – Committees of the Board of Directors” for information about director independence.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The 2007 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 2007 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, 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: February 28, 2007

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 February 28, 2007.

/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/ 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	Certificate of Incorporation of Southwestern Energy Company. (Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
3.2	Bylaws of Southwestern Energy Company. (Incorporated by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
4.1	Form of Common Stock Certificate. (Incorporated by reference to Exhibit 4.4 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
4.2	Indenture, dated as of December 1, 1995 between Southwestern Energy Company and The First National Bank of Chicago (now J.P. Morgan Chase Bank). (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)
4.3	First Supplemental Indenture between Southwestern Energy Company and J.P. Morgan Trust Company, N.A. as successor to the First National Bank of Chicago dated June 30, 2006. (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
4.4	Indenture dated June 1, 1998 by and among NOARK Pipeline Finance, L.L.C. and The Bank of New York. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed May 4, 2006)
4.5	First Supplemental Indenture dated May 2, 2006 by and among Southwestern Energy Company, NOARK Pipeline Finance, L.L.C., and UMB Bank, N.A. as successor to the Bank of New York (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed May 4, 2006)
4.6	Second Supplemental Indenture between Southwestern Energy Company and UMB Bank, N.A. as successor to the Bank of New York dated June 30, 2006. (Incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
4.7	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)
4.8	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)
4.9	Amendment No. 2 to the Amended and Restated Rights Agreement between Southwestern Energy Company and Computershare Trust Company, N.A. as successor to the First National Bank of Chicago dated June 30, 2006. (Incorporated by reference to Exhibit 4.5 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
4.10	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. (Incorporated by reference to Exhibit 4.6 to the Registrant’s Annual Report filed on Form 10-K (Commission file No. 1-08246) for the year ended December 31, 2005)
4.11*	Second Amended and Restated Credit Agreement dated February 9, 2007 among Southwestern Energy Company, JPMorgan Chase Bank, NA, SunTrust Bank, The Royal Bank of Scotland PLC, Royal Bank of Canada, Bank of America, N.A., and the other lenders named therein, JPMorgan Chase Bank, NA, as administrative agent, SunTrust Bank as syndication agent.
4.12	Policy on Confidential Voting of Southwestern Energy Company. (Incorporated by reference to the Appendix of the Registrant's Definitive Proxy Statement (Commission File No. 1-08246) for the 2006 Annual Meeting of Stockholders)

10.1	Form of Second 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 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
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	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)
10.8	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)
10.9	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 Stockholders)
10.10	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)
10.11	Southwestern Energy Company 2002 Performance Unit Plan, as amended, effective December 8, 2005. (Incorporated by reference to Exhibit 10.1 to Registrant’s Current Report on Form 8-K filed on December 13, 2005)
10.12	Southwestern Energy Company 2004 Stock Incentive Plan. (Incorporated by reference to Appendix A to the Registrant’s Proxy Statement dated March 29, 2004)
10.13	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)
10.14	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)
10.15	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)
10.16	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)
10.17	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)

10.18	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)
10.19	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 May 31, 2006)
10.20	Form of Restricted Stock Agreement for Special Incentives. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on December 14, 2006)
10.21	Project Services Agreement by and between SEECO, Inc., a wholly-owned subsidiary of Southwestern Energy Company, and Schlumberger Technology Corporation dated August 17, 2006. (Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed on October 23, 2006)
10.22*	Master Lease Agreement by and between Southwestern Energy Company and SunTrust Leasing Corporation dated December 29, 2006.
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