BATEMAN GILES H
Form 144
May 14, 2013

UNITED STATES	OMB APPROVAL
SECURITIES AND EXCHANGE COMMISSION	OMB Number: 3235-0101
Washington, D.C. 20549	Expires: February 28, 2014
	Estimated average burden
FORM 144	hours per response 1.00
NOTICE OF PROPOSED SALE OF SECURITIES	SEC USE ONLY
PURSUANT TO RULE 144 UNDER THE SECURITIES ACT OF 1933	DOCUMENT SEQUENCE NO.
	CUSIP NUMBER

ATTENTION: Transmit for filing 3 copies of this form concurrently with either placing an order with a broker to execute sale or executing a sale directly with a market maker.

1 (a) NAME OF ISSUER (Please type or print)		(b) IRS IDENT. NO.	(c) S.E.C. FILE NO		WORK LOCATION
WD 40 CO		951797918	000-06936		
1 (d) ADDRESS OF ISSUER	STREET	CITY	STATE	ZIP CODE	(e) TELEPHONE NO
	1061 Cudahy Place	San Diego	CA	92110	619-275-1400

2 (a) NAME OF PERSON FOR WHOSE ACCOUNT THE SECURITIES ARE TO BE SOLD	(b) RELATIONSHIP TO ISSUER	(c) ADDRESS STREET	CITY	STATE	ZIP CODE
BATEMAN GILES H	Director	1061 Cudahy Place	San Diego	CA	92110

INSTRUCTION: The person filing this notice should contact the issuer to obtain the I.R.S. Identification Number and the S.E.C. File Number.

3 (a)	(b)	SEC USE ONLY	(c)	(d)	(e)	(f)	(g)
Title of the Class of	Name and Address of Each Broker Through	Broker-Dealer	Number of Shares or Other Units	Aggregate Market	Number of Shares or Other Units	Approximate Date of Sale	Name of Each Securities

Securities To Be Sold	Whom the Securities are to be Offered or Each Market Maker who is Acquiring the Securities	File Number	To Be Sold (See instr. 3(c))	Value (See instr. 3(d))	Outstanding (See instr. 3(e))	(See instr. 3(f)) (MO. DAY YR.)	Exchange (See instr. 3(g))
Common Stock	RBC 2 Embarcadero Center, Suite 1200 San Francisco, CA 94111		6,500	364,845 (1)	15,468,334	(2)	NASDAQ

INSTRUCTIONS:

1. (a) Name of issuer
   (b) Issuer's I.R.S. Identification Number
   (c) Issuer's S.E.C. file number, if any
   (d) Issuer's address, including zip code
   (e) Issuer's telephone number, including area code

2. (a) Name of person for whose account the securities are to be sold
   (b) Such person's relationship to the issuer (e.g., officer, director, 10% stockholder, or member of immediate family of any of the foregoing)
   (c) Such person's address, including zip code

3. (a) Title of the class of securities to be sold
   (b) Name and address of each broker through whom the securities are intended to be sold
   (c) Number of shares or other units to be sold (if debt securities, give the aggregate face amount)
   (d) Aggregate market value of the securities to be sold as of a specified date within 10 days prior to filing of this notice
   (e) Number of shares or other units of the class outstanding, or if debt securities the face amount thereof outstanding, as shown by the most recent report or statement published by the issuer
   (f) Approximate date on which the securities are to be sold
   (g) Name of each securities exchange, if any, on which the securities are intended to be sold

TABLE I — SECURITIES TO BE SOLD
Furnish the following information with respect to the acquisition of the securities to be sold and with respect to the payment of all or any part of the purchase price or other consideration therefor:

Title of the Class	Date you Acquired	Nature of Acquisition Transaction	Name of Person from Whom Acquired (If gift, also give date donor acquired)	Amount of Securities Acquired	Date of Payment	Nature of Payment
Common Stock	(2)	Exercise of Stock Options	WD-40 Company	6,500	(2)	Sale Proceeds

INSTRUCTIONS: If the securities were purchased and full payment therefor was not made in cash at the time of purchase, explain in the table or in a note thereto the nature of the consideration given. If the consideration consisted of any note or other obligation, or if payment was made in installments describe the arrangement and state when the note or other obligation was discharged in full or the last installment paid.

TABLE II — SECURITIES SOLD DURING THE PAST 3 MONTHS
Furnish the following information as to all securities of the issuer sold during the past 3 months by the person for whose account the securities are to be sold.

Name and Address of Seller	Title of Securities Sold	Date of Sale	Amount of Securities Sold	Gross Proceeds

EXPLANATION OF RESPONSES:

1. Estimated based on the fair market value at market close on 5/10/2013 of $56.13/share.
2. These control securities, registered on Form S-8, will be acquired upon the proposed exercise of stock options for 6,500 shares and sold on the same day pursuant to a cashless stock option exercise transaction processed by the Issuer’s stock option plan administrator. The proposed transaction will be completed pursuant to a Rule 10b5-1 trading plan adopted by the reporting person on 5/13/13.

REMARKS:

INSTRUCTIONS:
See the definition of “person” in paragraph (a) of Rule 144. Information is to be given not only as to the person for whose account the securities are to be sold but also as to all other persons included in that definition. In addition, information shall be given as to sales by all persons whose sales are required by paragraph (e) of Rule 144 to be aggregated with sales for the account of the person filing this notice.

ATTENTION:
The person for whose account the securities to which this notice relates are to be sold hereby represents by signing this notice that he does not know any material adverse information in regard to the current and prospective operations of the Issuer of the securities to be sold which has not been publicly disclosed. If such person has adopted a written trading plan or given trading instructions to satisfy Rule 10b5-1 under the Exchange Act, by signing the form and indicating the date that the plan was adopted or the instruction given, that person makes such representation as of the plan adoption or instruction date.

May 13, 2013

DATE OF NOTICE

/s/ Maria Mitchell, as attorney-in-fact
for Giles H. Bateman

(SIGNATURE)

May 13, 2013

DATE OF PLAN ADOPTION OR GIVING OF INSTRUCTION, IF RELYING ON RULE 10B5-1

The notice shall be signed by the person for whose account the securities are to be sold. At least one copy of the notice shall be manually signed. Any copies not manually signed shall bear typed or printed signatures.

ATTENTION: Intentional misstatements or omission of facts constitute Federal Criminal Violations (See 18 U.S.C. 1001)

SEC 1147 (02-08)
="8%" align="right" height="21" bgcolor="#FFFFFF">

Income Before Income Taxes and Minority Interest

61,439 42,541 154,274 94,413 **Minority Interest in Partnership** (114) (315) (405) (408)

Income Before Income Taxes

61,325 42,226 153,869 94,005 **Provision for Income Taxes - Deferred** 24,321 15,412 58,470 34,570 **Net Income** $ 37,004 $ 26,814 $ 95,399 $ 59,435 **Earnings Per Share:** Basic $0.22 $0.18 (1) $0.57 $0.41 (1) Diluted $0.22 $0.18 (1) $0.56 $0.40 (1) **Weighted Average Common Shares Outstanding:** Basic 167,044,589 144,949,974 (1) 166,911,812 144,727,942 (1) Diluted 170,888,839 150,404,066 (1) 170,918,407 150,115,522 (1)

(1) 2005 restated to reflect a two-for-one stock split effected in November 17, 2005.

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
BALANCE SHEETS
(Unaudited)

ASSETS

	June 30, 2006	December 31, 2005
	(in thousands)	
Current Assets		
Cash and cash equivalents	$ 175,992	$ 223,705
Accounts receivable	80,990	128,948
Inventories, at average cost	47,248	49,513
Deferred income tax benefit	3,000	29,700
Hedging asset - FAS 133	21,280	17,467
Other	8,360	11,731
Total current assets	336,870	461,064
Investments	-	17,100
Property, Plant and Equipment, at cost		
Gas and oil properties, using the full cost method, including $152,351,146 in 2006 and $115,195,700 in 2005 excluded from amortization	2,194,167	1,897,613
Gas distribution systems	222,445	216,644
Drilling rigs and equipment - in service	43,386	-
Construction-in-progress - drilling rigs and equipment	38,026	35,128
Gathering systems	31,496	15,742
Gas in underground storage	32,254	32,254
Other	55,777	45,234
	2,617,551	2,242,615

Less: Accumulated depreciation, depletion and amortization		933,556	872,218
		1,683,995	1,370,397
Other Assets		23,552	19,963
Total Assets	$	2,044,417	$ 1,868,524

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

5

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
BALANCE SHEETS
(Unaudited)

LIABILITIES AND SHAREHOLDERS' EQUITY

		June 30, 2006		December 31, 2005
		(in thousands)		
Current Liabilities				
Current portion of long-term debt	$	1,200	$	-
Accounts payable		148,873		154,385
Taxes payable		8,507		14,519
Customer deposits		6,367		6,352
Hedging liability - FAS 133		29,780		112,293
Over-recovered purchased gas costs		7,694		7,323
Other		12,219		7,514
Total current liabilities		214,640		302,386
Long-Term Debt		137,200		100,000
Other Liabilities				
Deferred income taxes		329,292		254,528
Long-term hedging liability		20,902		60,442
Other		29,307		29,251
		379,501		344,221
Commitments and Contingencies				
Minority Interest in Partnership		11,604		11,613

Shareholders' 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 168,452,336 shares		1,684		16,845
Additional paid-in capital		727,733		711,196
Retained earnings		593,620		498,221
Accumulated other comprehensive income (loss)		(20,763)		(104,874)
Common stock in treasury, at cost, 287,956 shares at June 30, 2006 and 1,217,284 shares at December 31, 2005		(802)		(3,390)
Unamortized cost of restricted shares issued under stock incentive plan, 707,142 shares at December 31, 2005		-		(7,694)
		1,301,472		1,110,304
Total Liabilities and Shareholders' Equity	$	2,044,417	$	1,868,524

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

6

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
STATEMENTS OF CASH FLOWS
(Unaudited)

		For the six months ended June 30,		
		2006		2005
		(in thousands)		
Cash Flows From Operating Activities				
Net income	$	95,399	$	59,435
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion and amortization		60,657		43,987
Deferred income taxes		58,470		34,570
Unrealized (gain) loss on derivatives		4,919		(531)

Stock-based compensation expense	2,018	1,277
Gain on sale of investment in partnership	(10,863)	-
Equity in income of NOARK partnership	(925)	(273)
Minority interest in partnership	(10)	216
Change in operating assets and liabilities:		
Accounts receivable	47,958	25,373
Inventories	2,265	8,427
Under/over-recovered purchased gas costs	371	6,834
Accounts payable	(24,080)	(13,843)
Taxes payable	(6,012)	(908)
Interest Payable	(1,287)	(154)
Other operating assets and liabilities	171	(19)
Net cash provided by operating activities	229,051	164,391
Cash Flows From Investing Activities		
Capital expenditures	(357,195)	(176,981)
Proceeds from sale of investment in partnership and other property	69,065	1,040
Other items	(43)	(297)
Net cash used in investing activities	(288,173)	(176,238)
Cash Flows From Financing Activities		
Debt retirement	(600)	-
Payments on revolving long-term debt	-	(179,100)
Borrowings under revolving long-term debt	-	182,200
Debt issuance costs	-	(1,180)
Tax benefit for stock-based compensation	6,397	-
Change in bank drafts outstanding	3,222	5,743
Proceeds from exercise of common stock options	2,390	3,694
Net cash provided by financing activities	11,409	11,357
Decrease in cash and cash equivalents	(47,713)	(490)
Cash and cash equivalents at beginning of year	223,705	1,235
Cash and cash equivalents at end of period	$ 175,992	745

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

7

For the three months ended		For the six months ended	
June 30,		June 30,	
2006	2005	2006	2005

REMARKS:

($ in thousands)					($ in thousands)			
Net income			$ 37,004	$	26,814	$ 95,399	$ 59,435
Other comprehensive income, net of income tax:							
Changes in fair value of derivative instruments	23,529	1,426	88,692	(38,713)			
Reclassification of (gain) loss on settled contracts	928	7,921	(115)	8,597			
Ineffective portion of cash flow hedges	(2,760)	(850)	(4,466)	(402)			
Comprehensive income			$ 58,701		$ 35,311	$ 179,510	$ 28,917

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

8

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Southwestern Energy Company and Subsidiaries

June 30, 2006

(1)

BASIS OF PRESENTATION

The financial statements included herein are unaudited; however, such information reflects all adjustments (consisting solely of normal recurring adjustments) which are, in the opinion of management, necessary for a fair presentation of the results for the interim periods. The Company's significant accounting policies, which have been reviewed and approved by the audit committee of the Company s Board of Directors, are summarized in Note 1 of the Notes to Consolidated Financial Statements included in Item 8 of the Company's Annual Report on Form 10-K for the year ended December 31, 2005 (the "2005 Annual Report on Form 10-K").

Historical per share information provided as of June 30, 2005 in the financial statements and footnotes has been adjusted to reflect the two-for-one stock split effected on November 17, 2005.

As discussed below in Note 9, the Company adopted Statement of Financial Accounting Standards No. 123(R) Share-Based Payment (FAS123(R)), effective January 1, 2006. The Company adopted the modified prospective transition method provided under FAS 123(R) and consequently has not restated the presentation of the results for prior periods. Additionally, the Company is currently evaluating alternative methods of calculating the historical pool of windfall tax benefits as permitted by FASB Staff Position No. FAS123(R)-3, Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards. The realization of tax benefits from stock-based compensation in excess of amounts recognized for financial reporting purposes is recognized as a financing activity in the accompanying Consolidated Statements of Cash Flows.

On May 2, 2006, the Company sold its 25% partnership interest in the NOARK Pipeline System, Limited Partnership (NOARK), previously accounted for under the equity method of accounting, to Atlas Pipeline Partners, L.P. for $69.0 million. As part of the transaction, the Company assumed $39.0 million of debt obligations of NOARK Pipeline Finance, L.L.C., which the Company had previously guaranteed. The Company recognized a pre-tax gain of $10.9 million ($6.7 million after tax) in the second quarter relating to the transaction.

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

The state of Texas recently 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 methods is not effective until the year 2007, the provisions of SFAS 109, "Accounting for Income Taxes," requires the Company to record in the period of enactment the impact that this change has on its liability for deferred taxes. As a result, the Company recorded additional income tax expense of $1.8 million, net of

9

federal income tax effect, in the second quarter of 2006. This one-time adjustment increased the effective tax rate to approximately 38% for the first six months of 2006.

Certain reclassifications related to segment disclosures have been made to conform to the current presentation. The effect of the reclassifications was not material to the Company s consolidated financial statements.

(2)

GAS AND OIL PROPERTIES

The Company follows the full cost method of accounting for the exploration, development, and acquisition of gas and oil reserves. Under this method, all such costs (productive and nonproductive) including salaries, benefits, and other internal costs directly attributable to these activities are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. The Company excludes all costs of unevaluated properties from immediate amortization. The Company s unamortized costs of natural gas and oil properties are limited to the sum of the future net revenues attributable to proved natural gas and oil reserves discounted at 10 percent plus the lower of cost or market value of any unproved properties. If the Company s unamortized costs in natural gas and oil properties exceed this ceiling amount, a provision for additional depreciation, depletion and amortization is required. At June 30, 2006, the Company s net book value of natural gas and oil properties did not exceed the ceiling amount. At June 30, 2006, our standardized measure was calculated based upon quoted market prices of $6.09 per Mcf for Henry Hub gas and $70.50 per barrel for West Texas Intermediate oil, adjusted for market differentials. Decreases in market prices from June 30, 2006 levels, as well as changes in production rates, levels of reserves, and the evaluation of costs excluded from amortization, could result in future ceiling test impairments.

(3)

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 period. The diluted earnings per share calculation, using the average market price of our common stock for the period and the treasury stock method per FAS 128, Earnings Per Share (as amended), adds to the weighted average number of common shares outstanding the incremental number of 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 six months ended June 30, 2006, 5,976,163 of the Company s outstanding options with an average exercise price of $3.44 were included in the calculation of diluted shares. Options for 223,780 shares were excluded from the calculation because they would have had an antidilutive effect. Outstanding options for 8,059,664 shares at June 30, 2005, with a weighted average exercise price of $3.18, were included in the calculation of diluted shares. Restricted shares included in the calculation of diluted shares were 569,852 and 830,282 at June 30, 2006 and 2005, respectively. At June 30, 2006, 124,990 shares of restricted stock were excluded from the calculation because they would have had an antidilutive effect. The number of options and the exercise prices, and the number of restricted shares have been adjusted to reflect the two-for-one stock split effected in the fourth quarter of 2005.

(4)

DEBT

Debt balances as of June 30, 2006 and December 31, 2005 consisted of the following:

	June 30, 2006	December 31, 2005
	(in thousands)	
Short-term:		
7.15% Senior Notes due 2018 (current portion)	$ 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	37,200	-
Total long-term debt	137,200	100,000
Total debt	$ 138,400	$ 100,000

The Company has a $500 million unsecured revolving credit facility that expires in January 2010. There were no amounts outstanding under the revolving credit facility at June 30, 2006 and December 31, 2005. The interest rate on the credit facility is calculated based upon the Company's debt rating and is currently 125 basis points over the current London Interbank Offered Rate (LIBOR). The revolving credit facility contains covenants which impose certain restrictions on the Company. Under the credit agreement, the Company may not issue total debt in excess of 60% of its total capital, must maintain a certain level of shareholders' equity, and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of 3.5 or above. There are also restrictions on the ability of the Company's subsidiaries to incur debt. At June 30, 2006, the Company's capital structure consisted of 10% debt and 90% equity, with a ratio of EBITDA to interest expense of 67, and the Company was in compliance with its debt agreements.

On May 2, 2006, in connection with the sale of the Company s interest in NOARK, the Company assumed $39.0 million of debt obligations which the Company had previously guaranteed. These debt obligations require semi-annual principal payments of $0.6 million, plus interest.

(5)

DERIVATIVES AND RISK MANAGEMENT

Management 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. At June 30, 2006, our gas and oil derivative instruments consisted of price swaps, costless collars and basis swaps. 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. The Company s hedging practices are summarized in Item 7A of the 2005 Annual Report on Form 10-K.

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 derivative hedging instruments is recognized in earnings immediately.

Fair Value Hedges

The Company recognized a firm commitment asset of $0.8 million related to future gas sales. This amount relates to floating price swaps that have been designated as fair value hedges. The Company has also recognized a liability of $0.5 million for derivative trades against the firm commitment asset. The net unrealized gain of $0.3 million has been recognized currently in earnings as a component of gas sales.

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 unrealized gains and losses related to these contracts are recognized immediately in the statement of operations as a component of gas sales. As of June 30, 2006, the Company recorded an unrealized gain of $6.8 million related to basis swaps that do not meet the requirements of FAS 133 as hedges.

The Natural Gas Distribution segment periodically enters into derivative contracts designed to mitigate risk related to future gas prices. The Company does not recognize unrealized income/loss for these regulatory hedges as the effects of these hedges are passed through to utility customers. As of June 30, 2006 the Company recognized a liability of $0.4 million related to regulatory hedges.

At June 30, 2006, the Company's net liability related to its hedging activities was $23.4 million. Additionally, at June 30, 2006, the Company had recorded a cumulative loss to other comprehensive income net of tax (equity section of the balance sheet) of $15.7 million. The amount recorded in other comprehensive income will be relieved over time and taken to the income statement as the physical transactions being hedged occur. Assuming the market prices of futures as of June 30, 2006 remain unchanged, the Company would expect to transfer an aggregate loss of approximately $10.2 million from accumulated other comprehensive income to pre-tax earnings as a loss during the next 12 months. The change in accumulated other comprehensive income (loss) related to derivatives was a gain of $34.4 million ($21.7 million after tax) compared to a gain of $13.4 million ($8.5 million after tax) for

---

the three months ended June 30, 2006 and 2005, respectively and gains of $133.5 million ($84.1 million after tax) compared to a loss of $48.4 million ($30.5 million after tax) for the six months ended June 30, 2006 and 2005 respectively. Additional volatility in earnings and other comprehensive income (loss) may occur in the future as a result of the application of FAS 133.

(6)

SEGMENT INFORMATION

The Company's three reportable business segments, Exploration and Production (E&P), Midstream Services and Natural Gas Distribution, 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 in the past, but are expected to increase in the future depending upon the level of production from our Fayetteville Shale area. Revenues for the Natural Gas Distribution segment arise from the transportation and sale of natural gas at retail. Financial statements for periods ended June 30, 2005 included capital expenditures and assets relating to gas gathering in the E&P segment. The June 30, 2005 capital expenditures and assets for the E&P segment reported in this Form 10-Q have been adjusted to exclude the gas gathering amounts, which are now included in the Midstream Services segment.

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 to the financial statements in the 2005 Annual Report on Form 10-K. 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 and minority interest in partnership. Other income in the Company s consolidated statements of operations includes interest income. The "Other" column includes items not related to the Company's reportable segments including real estate, corporate items and for the periods ending prior to June 30, 2006, the Company s investment in the Ozark Gas Transmission system, which was sold to Atlas Pipeline Partners, L.P. during the second quarter of 2006.

	Exploration And Production	Natural Gas Distribution	Midstream Services	Other	Total

(in thousands)

Three months ended June 30, 2006:					
Revenues from external customers	$ 97,243	$ 22,474	$ 34,282	$ -	$ 153,999
Intersegment revenues	9,066	36	69,178	112	78,392
Operating income (loss)	49,501	(2,092)	799	86	48,294
Interest and other income (loss) (1)	2,563	(146)	-	10,864	13,281
Depreciation, depletion and amortization expense	30,186	1,569	172	23	31,950
Interest expense (1)	104	32	-	-	136
Provision (benefit) for income taxes (1)	20,611	(776)	315	4,171	24,321
Assets	1,580,458	177,296	68,828	217,835 (2)	2,044,417 (2)
Capital expenditures (3)	189,309	2,836	11,144	3,842	207,131

Three months ended June 30, 2005:					
Revenues from external customers	$ 77,859	$ 24,400	$ 30,204	$ -	$ 132,463
Intersegment revenues	9,181	33	62,098	112	71,424
Operating income (loss)	48,599	(2,361)	931	12	47,181
Interest and other income (loss) (1)	5	(121)	-	131	15
Depreciation, depletion and amortization expense	21,286	1,688	11	24	23,009
Interest expense (1)	3,331	935	123	266	4,655
Provision (benefit) for income taxes (1)	16,422	(1,264)	300	(46)	15,412
Assets	1,036,504 (4)	156,561	29,725 (4)	46,685 (2)	1,269,475 (2)
Capital expenditures (3)	102,682 (4)	2,701	386 (4)	53	105,822
Six months ended June 30, 2006:					
Revenue from external customers	$ 214,680	$ 100,685	$ 65,336	$ -	$ 380,701
Intersegment revenues	20,793	160	146,798	225	167,976
Operating income	130,280	5,815	1,869	134	138,098

Interest and other income (loss) (1)	4,854	(195)	1	11,797	16,457
Depreciation, depletion and amortization expense	56,433	3,166	406	48	60,053
Interest expense (1)	204	77	-	-	281
Provision for income taxes (1)	51,119	2,107	710	4,534	58,470
Assets	1,580,458	177,296	68,828	217,835 (2)	2,044,417 (2)
Capital expenditures (3)	344,217	6,331	15,912	7,217	373,677
Six months ended June 30, 2005:					
Revenue from external customers	$ 151,707	$ 87,058	$ 54,751	$ -	$ 293,516
Intersegment revenues	17,876	126	116,616	224	134,842
Operating income	96,330	5,086	1,968	23	103,407
Interest and other income (loss) (1)	24	(112)	-	287	199
Depreciation, depletion and amortization expense	39,800	3,387	21	48	43,256
Interest expense (1)	6,441	2,030	197	525	9,193
Provision (benefit) for income taxes (1)	32,904	1,089	656	(79)	34,570
Assets	1,036,504 (4)	156,561	29,725 (4)	46,685 (2)	1,269,475 (2)
Capital expenditures (3)	179,628 (4)	4,783	1,896 (4)	376	186,683

(1)

Interest income, interest expense and the provision (benefit) for income taxes by segment are an allocation of corporate amounts as interest income, debt and income tax expense (benefit) are incurred at the corporate level. Other income (loss) for the three- and six-month periods ended June 30, 2006 includes the $10.9 million pre-tax gain on the sale of the Company s investment in NOARK.

(2)

Other assets include the Company's investment in cash equivalents, corporate assets not allocated to segments, assets for non-reportable segments and, for periods ended June 30, 2005, the Company s equity investment in the operations of the NOARK Pipeline System, Limited Partnership, which was subsequently sold to Atlas Pipeline Partners, L.P. during the second quarter of 2006.

(3)

Capital expenditures include $5.7 million and $15.3 million for the three- and six-month periods ended June 30, 2006, respectively, and $8.9 million and $10.6 million for the three- and six-month periods ended June 30, 2005, respectively, relating to the change in accrued expenditures between periods.

(4)

For the three- and six-month periods ended June 30, 2005, $0.4 million and $1.9 million, respectively, of capital expenditures and $1.9 million of assets relating to gas gathering activities previously included in the Exploration and Production segment are now included in the Midstream Services segment.

Included in intersegment revenues of the Midstream Services segment are $59.1 million and $59.4 million for the second quarters of 2006 and 2005, respectively, and $122.6 million and $108.7 million for the six months ended June 30, 2006 and 2005, 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, prepaid debt costs and prepaid and intangible pension related costs. Parent company general and administrative costs, depreciation expense and taxes other than income are allocated to segments. All of the Company's operations are located within the United States**.**

(7)

INTEREST AND INCOME TAXES PAID

The following table provides interest and income taxes paid during each period presented:

	For the six months ended June 30,	
	2006	2005
	(in thousands)	
Interest payments	$ 5,138	$ 10,287
Income tax payments	$ 6	$ -

(8)

CONTINGENCIES AND COMMITMENTS

Operating Commitments

The Company s Natural Gas Distribution subsidiary has a transportation contract for 66.9 MMcf per day of firm capacity that expires in 2014. Additionally, the Midstream Services segment has transportation contracts for a total of 20.0 MMcf per day of firm capacity through 2006 and has entered into an additional 3-year firm transportation agreement to transport volumes increasing to 175.0 MMcf per day in the later stages of the contract.

The Company leases certain office space and equipment under non-cancelable operating leases expiring through 2013. Under certain of these leases the Company is required to pay property taxes, insurance, repairs and other costs related to the leased property. At June 30, 2006, future minimum payments under non-cancelable leases accounted for as operating leases are approximately $2,060,000 in 2006, $4,002,000 in 2007, $3,672,000 in 2008, $3,401,000 in 2009, $2,690,000 in 2010 and $5,590,000 thereafter.

The Company leases compressors related to its Midstream Services and E&P operations under non-cancelable operating leases expiring through 2012. At June 30, 2006, future minimum payments under non-cancelable leases accounted for as operating leases are approximately $3,017,000 in 2006, $9,516,000 in 2007, $10,954,000 in 2008, $9,785,000 in 2009, $7,815,000 in 2010 and $6,915,000 thereafter.

The Company's Natural 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 June 30, 2006, future

REMARKS:

payments under these non-cancelable demand contracts are $4,452,000 in 2006, $8,865,000 in 2007, $9,251,000 in 2008, $9,638,000 in 2009, $10,024,000 in 2010 and $41,963,000 thereafter. Additionally, our E&P and Midstream Services segments have commitments for demand transportation charges. At June 30, 2006, future payments under these non-cancelable demand contracts are $3,420,000 in 2006, $6,481,000 in 2007, $9,297,000 in 2008, $2,990,000 in 2009, $412,000 in 2010 and $0 thereafter.

In 2005, the Company entered into agreements to fabricate ten new land drilling rigs. In the first six months of 2006, the Company entered into agreements to fabricate two smaller surface rigs, and three land drilling rigs. Including change orders, ancillary equipment and supplies, the total cost of these fifteen rigs is approximately $137.6 million. As of June 30, 2006, payments made under these agreements were $79.4 million.

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 briefs on the merits of the case. The matter is currently pending before the Texas Supreme Court. Should the other party prevail on the appeal, the Company could be required to pay approximately $2.1 million, plus pre-judgment interest and attorney s fees. Based on an assessment of this litigation by the Company and its legal counsel, no accrual for loss is currently recorded.

REMARKS:

(9)

STOCK-BASED COMPENSATION

On January 1, 2006, the Company adopted FAS 123(R), 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 123(R) 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. These plans are discussed more fully in the 2005 Annual Report on Form 10-K. 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 Stock Incentive Plan (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. No new stock options have been granted subsequent to January 1, 2006. 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 the 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 interpretation. 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.

For the three and six months ended June 30, 2006, the Company recognized compensation costs of $670,000 and $1,341,000 related to stock options issued prior to January 1, 2006. Of this amount, $127,000 and $254,000 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. Accordingly, the Company recorded a deferred tax benefit of $352,000 for the six months ended June 30, 2006. A total of $4,165,000 of unrecognized compensation costs related to stock options not yet vested is expected to be recognized over future periods.

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 rate is based on the U.S. Treasury yield curve in effect at the time of grant.

Assumptions	2005
Risk-free interest rate	4.4%
Expected dividend yield	-
Expected volatility	40.6%
Expected term	4 years

The Company currently utilizes treasury shares when a stock option is exercised or when restricted stock is granted. The Company intends to utilize authorized but unissued shares after the remaining treasury shares are issued.

For the three and six months ended June 30, 2006, restricted stock expense recorded in general and administrative expenses, was $475,000 and $932,000, respectively. Additional amounts of $299,000 and $598,000 for the same periods were capitalized into the full cost pool.

The following table illustrates the effect on net income and earnings per share in the comparable quarter and six-month period of the prior year as if the fair value based method under FASB Statement 123(R) had been applied to all outstanding vested and unvested awards in that period.

	For the three months ended June 30, 2005 (in thousands, except per share)	For the six months ended June 30, 2005 (in thousands, except per share)
Net income, as reported	$ 26,814	$ 59,435
Add back: Stock option based compensation expense included in reported net income, net of related tax effects	401	804
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(811)	(1,624)
Pro forma net income	$ 26,404	$ 58,615
Earnings per share:		
Basic - as reported [1]	$0.18	$0.41

Basic - pro forma	$0.18	$0.41
Diluted - as reported (1)	$0.18	$0.40
Diluted - pro forma	$0.18	$0.39

(1) Restated to reflect the two-for-one stock split effected on November 17, 2005.

The following tables summarize stock option activity for the first half of 2006 and provides information for options outstanding at June 30, 2006:

18

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2005	7,126,465	$ 4.34		
Granted	-	-		
Exercised	923,696	2.59		
Forfeited or expired	2,826	12.45		
Outstanding at June 30, 2006	6,199,943	$ 4.59	4.9	$ 164,721
Exercisable at June 30, 2006	5,318,261	$ 2.82	4.6	$ 150,746

There were no options granted during the first six months of 2006 and 2005. The total intrinsic value of options exercised during the first six months of 2006 and 2005 was $23.1 million and $21.1 million, respectively.

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Options Outstanding at June 30, 2006	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Options Exercisable at June 30, 2006	Weighted Average Exercise Price
$1.50 - $1.86	2,587,791	$ 1.74	3.9	2,587,791	$ 1.74
$1.87 - $2.85	704,428	2.52	4.6	704,428	2.52
$2.86 - $5.00	1,381,620	2.98	4.9	1,349,620	2.98
$5.01 - $12.00	879,795	5.55	7.5	547,751	5.48
$12.01 - $36.00	646,309	20.41	5.7	128,671	12.95
	6,199,943	$ 4.59	4.9	5,318,261	$ 2.82

The following table summarizes restricted stock award activity for the first half of 2006 and provides information for unvested restricted stock awards outstanding at June 30, 2006.

	Number of Nonvested Shares	Weighted Average Grant Date Fair Value
Nonvested shares at December 31, 2005	707,142	$ 11.13
Granted	20,225	33.80
Vested	(17,932)	9.61
Forfeited	(14,593)	11.94
Nonvested shares at June 30, 2006	694,842	$ 11.82

As of June 30, 2006, there was $6.7 million of total unrecognized compensation cost related to nonvested shares. That cost is expected to be recognized over a weighted-average period of 1.2 years. The total fair value of shares vested during the first six months of 2006 and 2005 was $172,000 and $88,000, respectively.

Associated with the exercise of stock options, the Company received a tax benefit of $6.4 million for both the first six months of 2006 and 2005. The tax benefit is recorded as an increase in additional paid-in capital.

(10)

PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company applies Statement of Financial Accounting Standards No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits." Substantially all employees are covered by the Company's defined benefit pension and postretirement benefit plans. Net periodic pension and other postretirement benefit costs include the following components for the three- and six-month periods ended June 30, 2006 and 2005:

	Pension Benefits			
	For the three months ended June 30,		For the six months ended June 30,	
	2006	2005	2006	2005
	(in thousands)			
Service cost	$ 753	$ 631	$ 1,505	$ 1,262
Interest cost	970	941	1,940	1,882
Expected return on plan assets	(1,144)	(1,194)	(2,288)	(2,388)
Amortization of prior service cost	109	110	218	220
Amortization of net loss	190	81	380	162
Net periodic benefit cost	$ 878	$ 569	$ 1,755	$ 1,138

	Postretirement Benefits			
	For the three months ended June 30,		For the six months ended June 30,	
	2006	2005	2006	2005
	(in thousands)			

Service cost	$ 67	$ 43	$ 135	$ 86
Interest cost	47	50	94	100
Expected return on plan assets	(17)	(14)	(34)	(28)
Amortization of net loss	9	10	17	20
Amortization of transition obligation	21	22	43	44
Net periodic benefit cost	$ 127	$ 111	$ 255	$ 222

We currently expect to contribute $3.4 million to our pension plans and $0.4 million to our postretirement benefit plans in 2006. As of June 30, 2006, $2.0 million has been contributed to our pension plans and $0.2 million has been contributed to our postretirement benefit plans.

(11)

ASSET RETIREMENT OBLIGATIONS

Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," (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. The estimated liability for these future 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 activity related to asset retirement obligations for the six-month period ended June 30, 2006 and for the year ended December 31, 2005:

	2006	2005
	(in thousands)	
Asset retirement obligation at January 1	$ 9,229	$ 8,565
Accretion of discount	190	326
Obligations incurred	318	436
Obligations settled/removed	(35)	(1,553)
Revisions of estimates	-	1,455
Asset retirement obligation at June 30, 2006 and December 31, 2005	$ 9,702	$ 9,229
Current liability	458	358
Long-term liability	9,244	8,871
Asset retirement obligation at June 30, 2006 and December 31, 2005	$ 9,702	$ 9,229

(12)

NEW ACCOUNTING PRONOUNCEMENTS

In July 2006, the FASB issued FASB Interpretation No. 48 (FIN 48) Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109, 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. The Company is in the process of evaluating the impact of the adoption of this interpretation on the Company s results of operations and financial condition.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following updates information as to Southwestern Energy Company's financial condition provided in our 2005 Annual Report on Form 10-K, and analyzes the changes in the results of operations between the three- and six-month periods ended June 30, 2006 and 2005. For definitions of commonly used gas and oil terms used in this Form 10-Q, please refer to the "Glossary of Certain Industry Terms" provided in our 2005 Annual Report on Form 10-K.

This Form 10-Q 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" and elsewhere in our 2005 Annual Report on Form 10-K and Item 1A, Risk Factors in this Form 10-Q. You should read the following discussion with our financial statements and related notes included in this Form 10-Q. Historical per share information provided as of June 30, 2005 in the 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 split effected on November 17, 2005.

OVERVIEW

Southwestern Energy Company is an independent energy company primarily focused on natural gas. Our primary business is the exploration, development and production of natural gas and crude oil within the United States, with operations principally located in Arkansas, Oklahoma, Texas, New Mexico and Louisiana. We are also focused on creating and capturing additional value at and beyond the wellhead through our established natural gas distribution 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.

We currently derive the vast majority of our operating income and cash flow from the natural gas production of our E&P business and expect this to continue in the future. We expect that growth in our operating income and revenues will primarily depend on natural gas prices and our ability to increase our natural gas production. There has been significant price volatility in the natural gas and crude oil market in recent years due to a variety of factors we cannot control or predict. These factors, which include weather conditions, political and economic events, and competition from other energy sources, impact supply and demand for natural gas. In addition, the price we realize for our gas production is affected by our hedging activities as well as locational differences in market prices. Our ability to increase our natural gas production is dependent upon our ability to economically find and produce natural gas, our ability to control costs, and our ability to market natural gas on economically attractive terms to our customers. For both the three months ended June 30, 2006 and 2005, 100% of our operating income was generated by our E&P and Midstream Services segments, as our Natural Gas Distribution segment generated a seasonal loss for the related periods. For the first six months of 2006, 96% of our operating income was generated by our E&P and Midstream Services segments as compared to 95% for the comparable period in 2005.

Recent Developments

-

Our gross production from the Fayetteville Shale increased to approximately 50 MMcf per day at July 31, 2006, up from approximately 20 MMcf per day at May 1, 2006. The increase was due to the combined effects of the increased pace of our development drilling program as additional drilling rigs were placed in service and due to improved fracture stimulation techniques. We currently have 10 rigs working in the play area and expect to have 19 to 20 rigs running in the play by year-end. We expect production from the Fayetteville Shale to continue to increase as we continue to develop the play.

-

On May 2, 2006, we sold our 25% partnership interest in the NOARK Pipeline System Limited Partnership (NOARK), previously accounted for under the equity method of accounting, 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 previously guaranteed. We recognized a pre-tax gain of approximately $10.9 million ($6.7 million after tax) in the second quarter relating to the transaction.

-

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

Three Months Ended June 30, 2006 Compared with Three Months Ended June 30, 2005

Our revenues for the second quarter of 2006 were approximately 16% higher than the comparable period in 2005 due to increased production volumes and higher market-driven commodity prices received for our gas and oil sales. Net income increased approximately 38% to $37.0 million, or $0.22 per share on a diluted basis, for the three months ended June 30, 2006 and included a $6.7 million after-tax gain resulting from the sale of our 25% interest in NOARK which was partially offset by a one-time adjustment of $1.8 million to record additional deferred income tax expense as a result of recently enacted tax legislation by the state of Texas. Operating income for our E&P segment was up 2% to $49.5 million for the quarter ended June 30, 2006, compared to $48.6 million for the same quarter in 2005. Increased revenues in the second quarter of 2006 were largely offset by an increase in our operating costs and expenses. Operating income for our Midstream Services segment decreased 14% to $0.8 million for the second quarter of 2006 primarily as a result of increased staffing and operating costs associated with gathering activities related to our emerging Fayetteville Shale play. Our Natural Gas Distribution segment s seasonal operating loss decreased 11% to $2.1 million for the three months ended June 30, 2006, as the $4.6 million annual rate increase effective October 31, 2005 was partially offset by warmer weather and increased operating costs.

In the second quarter of 2006, our gas and oil production increased approximately 9% to 16.4 Bcfe due to increased production from our Overton Field in East Texas and our Fayetteville Shale play in Arkansas. Curtailment issues, which were resolved during the quarter, impacted our production from the Overton Field by approximately 0.2 Bcfe.

Our capital investments increased by approximately 96% to $207.1 million for the second quarter of 2006, of which $189.3 million was invested in our E&P segment.

Six Months Ended June 30, 2006 Compared with Six Months Ended June 30, 2005

Net income for the six months ended June 30, 2006 increased approximately 61% to $95.4 million, or $0.56 per share on a diluted basis, on revenues of $380.7 million, compared to the same period in 2005. Included in net income for the first six months of 2006 is a $6.7 million after-tax gain resulting from the sale of our 25% interest in NOARK which was partially offset by a one-time adjustment of $1.8 million to record additional deferred income tax expense as a result of recently enacted tax legislation by the state of Texas. Operating income for our E&P segment was up approximately 35% to $130.3 million for the first six months of 2006 due to increased production volumes and higher prices realized for our production. Operating income for our Midstream Services segment was $1.9 million for the first six months of 2006, down slightly from the prior year. Our cash flow from operating activities

23

REMARKS:

increased 39% to $229.1 million for the six months ended June 30, 2006 primarily due to the improved operating results of our E&P segment. Operating income for our Natural Gas Distribution segment increased approximately 14% to $5.8 million for the first six months ended June 30, 2006, as the $4.6 million annual rate increase effective October 31, 2005 was partially offset by warmer weather and increased operating costs.

In the first six months of 2006, our gas and oil production increased 11% to 32.3 Bcfe due to an increase in production from our Overton Field in East Texas and increased production from our Fayetteville Shale play in Arkansas.

Our capital investments approximately doubled to $373.7 million for the first half of 2006 as compared to the same period last year, of which $344.2 million was invested in our E&P segment.

RESULTS OF OPERATIONS

Exploration and Production

	For the three months ended June 30,		For the six months ended June 30,	
	2006	2005	2006	2005
Revenues (in thousands)	$106,309	$87,040	$235,473	$169,583
Operating income (in thousands)	$49,501	$48,599	$130,280	$96,330
Gas production (MMcf)	15,404	13,940	30,240	26,959
Oil production (MBbls)	170	182	347	343
Total production (MMcfe)	16,426	15,032	32,322	29,019
Average gas price per Mcf, including hedges	$6.23	$5.71	$7.03	$5.17
Average gas price per Mcf, excluding hedges	$6.16	$6.46	$6.87	$6.10
Average oil price per Bbl, including hedges	$61.11	$40.81	$58.91	$39.42
Average oil price per Bbl, excluding hedges	$66.99	$50.08	$63.75	$48.88
Average unit costs per Mcfe				
Lease operating expenses	$0.64	$0.43	$0.58	$0.44
General & administrative expenses	$0.60	$0.39	$0.57	$0.39
Taxes, other than income taxes	$0.39	$0.32	$0.36	$0.32
Full cost pool amortization	$1. 79	$1.38	$1. 69	$1.34

Revenues, Operating Income and Production

Revenues. Revenues for our E&P segment were up 22% for the three months ended June 30, 2006 and up 39% for the six months ended June 30, 2006 primarily due to increased production volumes and higher gas and oil prices realized for our production. Revenues for the first six months of 2006 and 2005 also include pre-tax gains of $1.9 million and $2.1 million, respectively, related to the sale of gas in storage inventory. 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, however, as of July 31, 2006, we have hedged 25.3 Bcf of our remaining 2006 gas production, 55.9 Bcf of 2007 gas production and 22.0 Bcf of 2008 gas production to limit our exposure to price fluctuations.

Operating Income. Operating income for the E&P segment was up 2% for the second quarter of 2006 and up 35% for the first six months of 2006 to $130.3 million from $96.3 million in 2005.

Production. Gas and oil production during the second quarter of 2006 was up approximately 9% to 16.4 Bcfe, and was up approximately 11% to 32.3 Bcfe for the first six months of 2006 as compared to prior periods due to an increase in production from our Overton Field in East Texas and from the Fayetteville Shale play. Gas production was up approximately 11% to 15.4 Bcf for the second quarter of 2006, and up approximately 12% to 30.2 Bcf for the first six months of 2006. Net production from the Fayetteville Shale was 1.8 Bcf in the second quarter of 2006, compared to 0.7 Bcf in the first quarter of 2006 and 0.4 Bcf in the second quarter of 2005. Curtailment issues, which were resolved during the quarter, impacted our production from the Overton Field by approximately 0.2 Bcfe. Additionally, in July we released two third-party rigs that had been drilling at Overton, due to excessive day rates. We expect a newly-contracted third-party rig to be delivered at Overton in August, and expect to bring two company-owned drilling rigs into East Texas by the end of 2006. Due to the release of these two rigs, we now expect to drill a total of 68 wells at Overton in 2006, as compared to our original plan of drilling 83 wells. Early in the year, we experienced delays in rig deliveries in our Fayetteville Shale play. These delays, along with temporary curtailment issues and changes in our current drilling plans in East Texas, have resulted in a slight decrease in our oil and gas production guidance for calendar year 2006 to 73.0 to 75.0 Bcfe, an increase of 20% to 23% over our 2005 production.

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 3 of this Form 10-Q for additional discussion). The average price realized for our gas production, including the effect of hedges, increased approximately 9% to $6.23 per thousand cubic feet (Mcf) for the three months ended June 30, 2006, and 23% to $7.03 for the first six months of 2006 as compared to the same period last year. The change in the average price realized primarily reflects changes in average spot market prices and the effects of our price hedging activities. Our hedging activities increased our average gas price $0.07 per Mcf during the second quarter of 2006, compared to a decrease of $0.75 per Mcf during the same period of 2005. Our hedging activities increased the average gas price realized by $0.16 per Mcf for the first six months of 2006, compared to a decrease of $0.39 per Mcf during the same period of 2005. Locational differences in market prices for natural gas have continued to be wider than historically experienced. We had financially hedged approximately 57% of our production in the second quarter of 2006 from the impact of basis differentials. Through our hedging activities and sales arrangements, for the remainder of 2006 we have financially hedged approximately 50% of our anticipated gas production from the impact of basis differentials. Disregarding the impact of hedges, the average price received for our gas production during the first six months of 2006 was approximately $1.01 lower than average NYMEX spot prices. For the remainder of 2006, we have NYMEX hedges in place for 25.2 Bcf of gas production and for 2007 and 2008 we have 42.6 Bcf and 12.0 Bcf, respectively, of our future gas production hedged. Additionally, we have basis swaps on 19.2 Bcf for the remainder of 2006, and for 2007 and 2008 we

25

---

have basis swaps on 49.2 Bcf and 8.0 Bcf, respectively, in order to reduce the effects of changes in market differentials on prices we receive.

We realized an average price of $58.91 per barrel for our oil production, including the effect of hedges, during the six months ended June 30, 2006, up approximately 49% from the same period of 2005. The average price we received for our oil production in the first six months of 2006 and 2005 was reduced by $4.84 per barrel and $9.46 per barrel, respectively, due to the effects of our hedging activities. For the remainder of 2006, we have hedged 60,000 barrels of our oil production at an average NYMEX price of $37.30 per barrel.

Operating Costs and Expenses

Lease operating expenses per Mcfe for our E&P segment increased 49% to $0.64 for the second quarter of 2006 and 32% to $0.58 for the first six months of 2006 as a result of increases in gathering, compression and workover costs. The majority of the increases relate to the upfront equipment and personnel costs related to building a large scale development program over the company s significant acreage position in the Fayetteville Shale play. Based on our projected production, we expect our per unit operating costs for the remainder of 2006 to range between $0.65 and $0.70 per Mcfe.

General and administrative expenses per Mcfe increased 54% to $0.60 for the second quarter of 2006 and 46% to $0.57 for the first six months of 2006, due primarily to increased compensation and other costs associated with increased staffing levels to meet the demands of our expanding E&P operations primarily related to the Fayetteville Shale play. We added 244 new employees during the first half of 2006, most of which were hired in our E&P segment, and expect to hire an additional 200 to 250 employees by year-end 2006. Approximately 250 to 275 of the total new hires during 2006 are expected to be employed by our drilling company. We expect our per unit G&A expense for the remainder of 2006 to average between $0.50 and $0.55 per Mcfe.

Taxes other than income taxes per Mcfe increased 22% to $0.39 for the second quarter of 2006 and 13% to $0.36 for the six months ended June 30, 2006 due to the effects of higher gas and oil prices, the changing mix of production and tax exemption credits recorded in 2005 related to portions of our Overton Field production.

Our full cost pool amortization rate averaged $1.79 per Mcfe for the second quarter of 2006 and $1.69 for the first six months of 2006, up 30% and 26%, respectively, compared to the same periods in 2005. We currently expect our full cost pool amortization rate to range between $1.80 and $1.90 per Mcfe for the remainder of the year. 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, and the level of unevaluated costs excluded from amortization.

Although we expect our amortization rate to continue to increase as a result of increased costs in finding and developing gas and oil reserves, 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. The timing and amount of reserve additions attributed to our Fayetteville Shale play could have a material impact on our amortization rate; if reserves additions are lower than projected, our amortization rate would increase. Unevaluated costs excluded from amortization were $152.4 million at June 30, 2006, compared to $71.8 million at June 30, 2005.

The increase in unevaluated costs since June 30, 2005 resulted primarily from an increase in our undeveloped leasehold acreage related to our Fayetteville Shale play and our 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. At June 30, 2006 and 2005, our unamortized costs of natural gas and oil properties did not exceed the ceiling amount. At June 30, 2006, our standardized measure was calculated based upon quoted market prices of $6.09 per Mcf for Henry Hub gas and $70.50 per barrel for West Texas Intermediate oil, adjusted for market differentials. A decline in natural gas and oil prices from June 30, 2006 levels as well as changes in production rates, levels of reserves and the evaluation of costs excluded from amortization, without other mitigating circumstances, could cause a future write-down of capitalized costs and a non-cash charge against future earnings.

Midstream Services

	For the three months ended June 30,		For the six months ended June 30,	
	2006	2005	2006	2005
Revenues (in thousands)	$103,460	$92,302	$212,134	$171,367
Gas purchases (in thousands)	$99,853	$91,029	$205,386	$168,745
Operating income (in thousands)	$799	$931	$1,869	$1,968
Gas volumes marketed (Bcf)	16.6	15.0	30.4	29.4

Revenues from our Midstream Services segment were up 12% in the second quarter of 2006 and up 24% for the first six months of 2006, as compared to prior year periods. The increases in revenues were attributable to increases in volumes marketed and, for the six-month period, an increase in natural gas commodity prices. Operating income from our Midstream Services segment decreased 14% in the second quarter of 2006 and 5% for the first six months of 2006, as compared to the same periods of 2005. The decreases in operating income were primarily the result of the increased staffing and operating costs associated with the gathering activities related to the Fayetteville Shale play. We expect this trend to continue until the play becomes more fully developed and additional gathering revenues are generated. Operating income from natural gas marketing also fluctuates depending on the margin we are able to generate between the purchase of the commodity and the ultimate disposition of the commodity. We marketed 11.6 Bcf of affiliated gas in the second quarter of 2006, representing 69% of total volumes marketed, compared to 11.0 Bcf, or 73% of total volumes marketed, for the same period in 2005. In the first six months of 2006, we marketed 21.2 Bcf of affiliated gas, representing 70% of total volumes marketed, compared to 21.7 Bcf, or 74% of total volumes marketed, for the same period in 2005. We enter into hedging activities from time to time with respect to our gas marketing activities to provide margin protection. We refer you to Item 3, "Qualitative and Quantitative Disclosure about Market Risks" in this Form 10-Q for additional information.

Midstream Services had gathering revenues of $1.3 million in the second quarter of 2006 and $1.9 million in the first six months of 2006, related to its gathering systems in Arkansas. Gathering revenues and expenses for this segment are expected to continue to grow in the future as gathering systems supporting our Fayetteville Shale play are constructed.

Natural Gas Distribution

	For the three months ended June 30,		For the six months ended June 30,	
	2006	2005	2006	2005
Revenues (in thousands)	$22,510	$24,433	$100,845	$87,184
Gas purchases (in thousands)	$11,624	$14,237	$68,129	$56,732
Operating costs and expenses (in thousands)	$12,978	$12,557	$26,901	$25,366
Operating income (loss) (in thousands)	($2,092)	($2,361)	$5,815	$5,086
Deliveries (Bcf)				
Sales and end-use transportation	3.6	3.8	11.9	13.0
Sales customers at period-end	146,489	143,855	146,489	143,855
Average sales rate per Mcf	$12.34	$12.57	$12.93	$9.89
Heating weather - degree days	163	315	1,950	2,217
Percent of normal	50%	98%	78%	90%

Revenues and Operating Income

Revenues for the second quarter of 2006 decreased 8% from the comparable period of 2005 due to considerably warmer weather partially offset by the effects of a $4.6 million annual rate increase effective October 31, 2005. Revenues for the six months ended June 30, 2006 increased 16% from the comparable period of 2005 due primarily to higher average sales rates resulting from higher gas prices and the effects of the rate increase.

Operating income for our Natural Gas Distribution segment increased 11% in the second quarter of 2006 and 14% for the first six months of 2006, as compared to the same periods of 2005, due primarily to the effects of the rate increase, which was partially offset by increased operating costs and expenses. Weather during the first six months of 2006 was 22% warmer than normal and 12% warmer than the same period in 2005.

Deliveries and Rates

Deliveries decreased 5% and 8% in the three- and six-month periods ended June 30, 2006, respectively, compared to the same periods of 2005. The decrease in volumes sold was due primarily to warmer weather. The average sales rate per Mcf increased during the first six months due to general increases in natural gas prices.

Our utility segment hedged 1.8 Bcf of derivative gas purchases in the first half of 2006 which had the effect of increasing its total gas supply cost by $6.8 million. In the first six months of 2005, our utility hedged 2.9 Bcf of its gas supply which increased its total gas supply cost by $1.4 million. Additionally, our utility segment currently has hedges in place on 1.0 Bcf of gas purchases at an average purchase price of $10.06 per Mcf for the 2006-2007 winter season. See Item 3 of this Form 10-Q for additional information regarding our commodity price risk hedging activities.

Operating Costs and Expenses

For the first six months of 2006, operating costs and expenses, other than purchased gas costs, for this segment were higher than the comparable period of the prior year due primarily to higher general and administrative expenses and higher transmission expenses. The increase in general and administrative expense primarily resulted from increased compensation costs, and the increase in transmission expense is a direct result of increased natural gas prices.

Transportation

We recorded no pre-tax income from operations related to our investment in the NOARK Pipeline System Limited Partnership (NOARK) for the second quarter of 2006 and $0.9 million in pre-tax income for the first six months of 2006, compared to $0.2 million and $0.3 million for the comparable periods of 2005. On May 2, 2006, we sold our 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. Income from operations for previous periods and the gain on the sale in the second quarter were recorded in other income in our statements of operations.

Other Revenues

Other revenues for the first six months of 2006 and 2005 included pre-tax gains of $1.9 million and $2.1 million, respectively, related to the sale of gas-in-storage inventory.

Interest Expense and Interest Income

Interest costs, net of capitalization, declined to $0.1 million and $0.3 million for the second quarter and the first six months of 2006, respectively, due to decreased debt levels resulting from our equity offering in September 2005 and an increase in the level of capitalized interest. Interest capitalized increased to $5.2 million in the first six months of 2006, as compared to $1.6 million for the same period in 2005. The increase in capitalized interest is 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 $152.4 million at June 30, 2006, compared to $71.8 million at June 30, 2005.

29

During the second quarter and first six months of 2006, we earned interest income of $2.5 million and $4.8 million, respectively, related to our cash equivalents. This amount is recorded in other income.

Income Taxes

The state of Texas recently 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 methods is not effective until the year 2007, the provisions of SFAS 109, "Accounting for Income Taxes," requires us to record in the period of enactment 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 38% for the first six months of 2006. 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 expenses of $1.0 million and $2.0 million in the second quarter and first six months of 2006, respectively, for our pension and other postretirement benefit plans, compared to $0.7 million and $1.4 million for same periods of 2005. The amount of pension expense recorded is determined by actuarial calculations and is also impacted by the funded status of our plans. We currently expect to contribute $3.8 million to our pension and other postretirement plans in 2006. As of June 30, 2006, $2.0 million has been contributed to our pension plans and $0.2 million has been contributed to our other postretirement plans. For further information regarding our pension plans, we refer you to Note 10 of the financial statements in this Form 10-Q.

Stock-Based Compensation

As of January 1, 2006, we adopted Statement of Financial Accounting Standards No.123(R), Share-Based Payment, (FAS 123(R)), which requires companies to recognize in the statement of operations the grant-date fair value of stock awards issued to employees and directors. We adopted FAS 123(R) using the modified prospective transition method. In accordance with the modified prospective transition method, our consolidated financial statements for prior periods have not been restated to reflect the impact of FAS 123(R). As a result of applying FAS 123(R), we recognized an expense of $2.0 million and capitalized $0.9 million to the full cost pool for the first half of 2006. In the first half of 2005, we expensed $0.8 million and capitalized $0.5 million for the amortization of restricted stock grants. We refer you to Note 9 of the financial statements in this Form 10-Q for additional discussion of our equity based compensation plans and our adoption of FAS 123(R).

LIQUIDITY AND CAPITAL RESOURCES

We depend on internally-generated funds, our unsecured revolving credit facility (discussed below under "Financing Requirements") and funds accessed through public debt and equity markets as our primary sources of liquidity. We may borrow up to $500 million under our revolving credit facility from time to time. As of June 30, 2006 and December 31, 2005, we had no indebtedness outstanding under our revolving credit facility. During 2006, we expect to draw on a portion of the funds available

REMARKS:

REMARKS:

under our credit facility to fund our planned capital expenditures (discussed below under "Capital Expenditures"), which are expected to exceed the net cash generated by our operations and cash equivalents.

Net cash provided by operating activities increased 39% to $229.1 million in the first six months of 2006 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. For the first six months of 2006 requirements for capital expenditures were met by cash provided by operating activities, cash equivalents, and $69.0 million of proceeds from the sale of our investment in NOARK.

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

Our cash flow from operating activities is highly dependent upon 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 5 to the financial statements included in this Form 10-Q and Item 3, "Quantitative and Qualitative Disclosures about Market Risks." 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 approximately doubled to $373.7 million (including $15.3 million relating to accrued expenditures) for the first half of 2006 as compared to the same period last year, of which $344.2 million was invested in our E&P segment. Our capital investments for calendar year 2006 are planned to be $830.1 million, including $770.3 million in our E&P segment. We may adjust our planned 2006 capital investments as a result of the level of success experienced in our Fayetteville Shale play.

Our 2006 capital investment program is expected to be funded through cash flow from operations, the remaining net proceeds from our equity offering, the proceeds from the sale of our investment in NOARK and borrowings under our revolving credit facility. We may adjust our level of 2006 capital investments dependent upon our level of cash flow generated from operations and our ability to borrow under our credit facility.

Financing Requirements

Our total debt outstanding was $138.4 million at June 30, 2006 (including $38.4 million of remaining debt assumed from the sale of NOARK) and $100.0 million at December 31, 2005. We have a $500 million revolving credit facility that expires in January 2010. At June 30, 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 125 basis points over LIBOR. 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 and continue to be rated Ba2 by Moody s. This downgrade had no impact on our cost of funds under our revolving credit facility. Any future downgrades in our public debt ratings could increase our cost of funds under the credit facility. We do not expect this downgrade 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 shareholders equity, and must maintain a ratio of EBITDA to interest expense of 3.5 or above. Additionally, there are certain limitations on the amount of indebtedness that may be incurred by our subsidiaries. We were in compliance with all of the covenants of our credit agreement at June 30, 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 June 30, 2006, our capital structure consisted of 10% debt and 90% equity, with a ratio of EBITDA to interest expense of 67. EBITDA is a measure required by our credit facility financial covenants and is defined as net income plus interest expense, income tax expense, and depreciation, depletion and amortization. Shareholders equity in the June 30, 2006 balance sheet includes an accumulated other comprehensive loss of $15.7 million related to our hedging activities that is required to be recorded under the provisions of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (FAS 133). This amount is based on current market values of our hedges at June 30, 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 as well as the non-cash impact of any full cost ceiling write-downs. Our capital structure at June 30, 2006 would remain unchanged at 10% debt and 90% equity without consideration of the accumulated other comprehensive loss related to FAS 133 of $15.7 million.

As part of our strategy to ensure a certain level of cash flow to fund our operations, we have hedged approximately 70% to 75% of our expected 2006 gas production and 15% to 20% of our expected 2006 oil production. The amount of long-term debt we incur will be dependent upon commodity prices and our capital expenditure plans. If commodity prices remain at or near 2005 levels throughout 2006 and our capital expenditure plans do not change, we will increase our long-term debt in 2006. If commodity prices significantly decrease, we may decrease and/or reallocate our planned capital expenditures.

Off-Balance Sheet Arrangements

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. We did not advance funds to NOARK in 2005 or in the first six months of 2006, and we did not derive any liquidity, capital resources, market risk support or credit risk support from our investment in NOARK.

Our share of the results of operations included in other income related to our NOARK investment was pre-tax income of $0.9 million and $0.3 million for the first half of 2006 and 2005, respectively.

32

REMARKS:

The increase in pre-tax income in 2006 was primarily due to increased throughput and higher average rates charged to customers.

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 June 30, 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)				
Debt [1]	$ 138,400	$ 1,200	$ 62,400	$ 2,400	$ 72,400
Interest on senior notes [2]	72,226	9,954	19,359	10,616	32,297
Operating leases [3]	21,415	4,102	7,440	5,626	4,247
Unconditional purchase obligations [4]	-	-	-	-	-
Operating agreements [5]	20,544	20,544	-	-	-
Rental compression [6]	48,002	7,182	21,436	15,781	3,603
Demand charges [7]	106,793	15,138	34,097	20,769	36,789
Drilling rigs [8]	58,212	58,212	-	-	-
Other obligations [9]	15,547	15,084	463	-	-
	$ 481,139	$ 131,416	$ 145,195	$ 55,192	$ 149,336

(1) Debt includes $38.4 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 June 30, 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 $20.5 million in termination fees related to rig operator agreements in the event that the agreements are terminated.

(6) Our E&P and Midstream Services segments have commitments for approximately $48.0 million of compressor rental fees associated primarily with our Overton operations and our Fayetteville Shale play.

(7) Our Natural Gas Distribution segment has commitments for approximately $84.2 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 $3.2 million of demand transportation charges, and our Midstream Services segment has commitments for approximately $19.4 million of demand transportation charges.

(8) Our E&P segment has commitments related to the purchase of the remaining eleven drilling rigs of the original fifteen expected to be delivered in 2006 for approximately $58.2 million, including ancillary equipment.

(9) Our other significant contractual obligations include approximately $7.6 million related to seismic services, approximately $4.5 million in land leases and purchases, approximately $1.4 million for funding of benefit plans, and approximately $1.8 million for various information technology support and data subscription agreements.

In 2005, the Company entered into agreements to fabricate ten new land drilling rigs. In the first six months of 2006, the Company entered into agreements to fabricate two surface rigs, and three land drilling rigs. Including change orders, ancillary equipment and supplies, the total cost of these fifteen rigs is approximately $137.6 million. As of June 30, 2006, payments made under these agreements were $79.4 million. Five of the fifteen drillings rigs have been delivered to date and are in service.

Contingent Liabilities and Commitments

Substantially all of our employees are covered by defined benefit and postretirement benefit plans. As a result of actuarial data, we expect to record expenses of $4.0 million in 2006 for these plans, of which $2.0 million has been recorded in the first six months of 2006. At June 30, 2006, we recorded an accrued pension benefit liability of $7.6 million. For further information regarding our pension and other postretirement benefit plans, we refer you to Note 10 of the financial statements in this Form

10-Q.

We are subject to litigation and claims that arise in the ordinary course of business. Management believes, individually or in aggregate, such litigation and claims will not have a material adverse impact on our financial position or our results of operations but these matters are subject to inherent uncertainties and management's view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position and the results of operations for the period in which the effect becomes reasonably estimable. A lawsuit was filed against us in 2001 alleging a breach of an agreement to indemnify the other party against settlement payments related to the Company s Boure' prospect in Louisiana. The allegations were contested and, in 2002, we were granted a motion for summary judgment by the trial court. The case was appealed to the First Court of Appeals in Houston, Texas, which subsequently transferred the appeal to the Thirteenth Court of Appeals in Corpus Christi. The appeal was briefed and argued during 2003. On April 14, 2005, the Thirteenth Court of Appeals reversed the orders of the trial court and rendered judgment denying our motion for summary judgment and granting the motion for summary judgment of the other party. Our motion for rehearing with the Thirteenth Court of Appeals was denied on May 19, 2005. In August of 2005, we filed a petition for review with the Texas Supreme Court. In October of 2005, the Texas Supreme Court invited additional briefing by the parties. In March of 2006, the Texas Supreme Court requested that both parties submit full briefs on the merits of the case. The matter is currently pending before the Texas Supreme Court. Should the other party prevail on the appeal, we could be required to

REMARKS:

pay approximately $2.1 million, plus pre-judgment interest and attorney's fees. Based on an assessment of this litigation by us and our legal counsel, no accrual for loss is currently recorded.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our credit facility described above. We had positive working capital of $122.2 million at June 30, 2006 and $158.7 million at December 31, 2005. Current assets at June 30, 2006 included $175.2 million of remaining proceeds from our 2005 equity offering that is invested in cash equivalents. Current liabilities decreased $87.7 million, due primarily to a decrease in our current hedging liability at June 30, 2006.

Gas in Underground Storage

We record our gas stored in inventory that is owned by the E&P segment at the lower of weighted average cost or market. Gas expected to be cycled within the next 12 months is recorded in current assets with the remaining stored gas reflected as a long-term asset. The quantity and average cost of gas in storage was 8.3 Bcf at $3.65 at June 30, 2006 and 8.5 Bcf at $3.78 at December 31, 2005.

The gas in inventory for the E&P segment is used primarily to supplement field production in meeting the segment's contractual commitments including delivery to customers of our natural gas distribution business, 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.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of customers and their dispersion across geographic areas. No single customer accounts for greater than 8% of accounts receivable at June 30, 2006. In addition, please see the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

At June 30, 2006, we have $138.4 million of debt with an average fixed interest rate of 7.37%. Our $500 million revolving credit facility has a floating interest rate, and at June 30, 2006, we had no borrowings outstanding under the 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. We do not have any interest rate swaps in effect currently.

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 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. 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 that 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 our gas and oil production, gas purchases and marketing activities. The table presents the notional amount in Bcf (billion cubic feet) and MBbls (thousand barrels), the weighted average contract prices, and the fair value by expected maturity dates. At June 30, 2006, the fair value of these financial instruments was a $24.5 million liability.

36

REMARKS:

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 June 30, 2006 ($ in millions)
Natural Gas (Bcf):						
Fixed Price Swaps:						
2006	3.7	6.36	-	-	-	(2.3)
2007	12.5	6.80	-	-	-	(26.4)
2008	-	-	-	-	-	-
Floating Price Swaps:						
2006	0.5	(7.92)	-	-	-	(0.6)
2007	0.1	(9.54)	-	-	-	0.1
2008	-	-	-	-	-	-
Costless Collars:						
2006	21.0	-	5.36	8.61	-	(7.5)
2007	30.0	-	6.71	12.19	-	(13.7)
2008	12.0	-	7.77	14.81	-	5.4
Basis Swaps:						
2006	13.2	-	-	-	(0.34)	5.4
2007	17.1	-	-	-	(0.57)	1.4
2008	-	-	-	-	-	-
Matched-Basis Swaps:						
2006	6.0	-	-	-	(0.34)	3.5
2007	32.1	-	-	-	(0.46)	12.0
2008	8.0	-	-	-	(0.73)	0.9
Regulatory Swaps:						
2006	0.5	(9.64)	-	-	-	(0.3)
2007	0.5	(10.53)	-	-	-	(0.1)
2008	-	-	-	-	-	-

Oil (MBbls):

Fixed Price Swaps:						
2006	60.0	37.30	-	-	-	(2.3)
2007	-	-	-	-	-	-
2008	-	-	-	-	-	-

Subsequent to June 30, 2006, and through July 31, 2006, we entered into additional hedges on 23.4 Bcf of future gas production.

At December 31, 2005, we had outstanding natural gas price swaps on total notional volumes of 7.9 Bcf at a weighted average price per Mcf of $6.64 in 2006 and 12.0 Bcf at a weighted average price per Mcf of $6.66 in 2007. Outstanding oil price swaps at December 31, 2005 on 120 MBbls are 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 1.8 Bcf in 2006 for which we paid an average fixed price of $12.71 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 Bcf in 2008 of gas production. The 43.0 Bcf in 2006 has a weighted average floor and ceiling price of $5.47 and $10.13 per Mcf, respectively. The 28.0 Bcf in 2007 has a weighted average floor and ceiling price of $6.64 and $11.91 per Mcf, respectively. The 2.0 Bcf in 2008 has a weighted average floor and ceiling price of $8.00 and $19.40 per Mcf, respectively.

ITEM 4. 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 submissions 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 June 30, 2006. There were no changes in our internal control over financial reporting during the three months ended June 30, 2006 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II

OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS.

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

38

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 briefs on the merits of the case. Should the other party prevail on the appeal, we could be required to pay approximately $2.1 million, plus pre-judgment interest and attorney's fees. Based on an assessment of this litigation by us and our legal counsel, no accrual for loss is currently recorded.

ITEM 1A. RISK FACTORS.

The following risk factor supplements the Company's risk factors as disclosed in Item 1A of Part I of the Company's 2005 Annual Report on Form 10-K:

Some anti-takeover provisions contained in our certificate of incorporation and bylaws, as well as provisions of Delaware law, could impair a takeover attempt.

We have provisions in our certificate of incorporation and bylaws, each of which could have the effect of rendering more difficult or discouraging an acquisition deemed undesirable by our Board of Directors. These include provisions:

-

authorizing blank check preferred stock, which the Company could issue with voting, liquidation, dividend and other rights superior to the common stock;

-

limiting the liability of, and providing indemnification to, the Company's directors and officers;

-

requiring advance notice of proposals by the Company's stockholders for business to be conducted at stockholder meetings and for nominations of candidates for election to the Company s board of directors; and

-

controlling the procedures for the conduct of the Company's board and stockholder meetings and the election, appointment and removal of the Company's directors.

These provisions, alone or together, could deter or delay hostile takeovers, proxy contests and changes in control or management of the Company. As a Delaware corporation, the Company also is subject to provisions of Delaware law, including Section 203 of the Delaware General Corporation Law, which prevents some stockholders from engaging in certain business combinations without approval of the holders of substantially all of the Company s outstanding common stock.

Any provision of our certificate of incorporation or bylaws or Delaware law that has the effect of delaying or deterring a change in control could limit the opportunity for our stockholders to receive a premium for their shares of common stock, and also could affect the price that some investors are willing to pay for common stock.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS.

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES.

Not applicable.

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

The Company held its Annual Meeting of Shareholders on May 25, 2006, for the purpose of electing Directors of the Company for the ensuing year, to ratify the appointment of PricewaterhouseCoopers LLP to serve as the Company s independent registered public accounting firm for 2006, to vote on a proposal to reincorporate the Company from the State of Arkansas to the State of Delaware, and to vote on a proposal to amend the Company s Restated Articles of Incorporation to increase the number of authorized shares of common stock to 540,000,000 shares. Holders of 157,198,896 shares (93.80% of total outstanding shares) voted in total.

The Directors were elected with the number of shares voted as follows:

	Voted For	Withheld
Lewis E. Epley, Jr.	152,737,448	3,359,594
Robert L. Howard	152,160,386	3,936,656
Harold M. Korell	158,144,950	4,563,216
Vello A. Kuuskraa	149,873,053	6,223,989
Kenneth R. Mourton	152,155,142	3,941,900
Charles E. Scharlau	147,439,031	8,658,011

Holders of 156,304,429 shares voted for the proposal to ratify the appointment of PricewaterhouseCoopers LLP to serve as the Company s independent registered public accounting firm for 2006, 751,861 shares voted against and 142,606 shares abstained.

Holders of 85,381,184 shares voted for the proposal to reincorporate the Company from the state of Arkansas to the state of Delaware, 48,435,767 shares voted against, 487,533 shares abstained and 22,894,412 shares were broker non-votes.

Holders of 109,211,888 shares voted for the proposal to amend the Company s Restated Articles of Incorporation to increase the number of authorized shares of common stock to 540,000,000 shares, 22,087,504 shares voted against, 3,005,092 shares abstained and 22,894,412 shares were broker non-votes.

ITEM 5. OTHER INFORMATION.

Not applicable.

ITEM 6. EXHIBITS.

(2.1)

Agreement and Plan of Merger between Southwestern Energy Company, an Arkansas corporation ("SWN Arkansas"), and Southwestern Energy Company, a Delaware corporation, dated June 30, 2006 (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed on June 30, 2006).

(3.1)

Certificate of Incorporation of Southwestern Energy Company (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed on June 30, 2006).

(3.2)

Bylaws of Southwestern Energy Company (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed on June 30, 2006).

(4.1)

First Amendment and Consent dated as of June 29, 2006 among Southwestern Energy Company, various Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on June 30, 2006).

(4.2)

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 SWN Arkansas' Current Report on Form 8-K filed on May 4, 2006).

(4.3)

First Supplemental Indenture dated May 2, 2006 by and among Southwestern Energy Company, NOARK Pipeline Finance, L.L.C., and UMB Bank, N.A. (incorporated by reference to Exhibit 4.2 to SWN Arkansas' Current Report on Form 8-K filed on May 4, 2006).

(4.4)

Second Supplemental Indenture dated as of June 30, 2006 by and between Southwestern Energy Company and UMB Bank, N.A. (as successor to The Bank of New York), as Trustee, supplementing the Indenture, dated June 1, 1998 between NOARK Pipeline Finance L.L.C. and The Bank of New York, as Trustee (as previously supplemented by the First Supplemental Indenture dated May 2, 2006) (incorporated by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K filed on June 30, 2006).

(4.5)

First Supplemental Indenture dated as of June 30, 2006 by and between Southwestern Energy Company and J.P. Morgan Trust Company, N.A. (as ultimate successor to The First National Bank of Chicago), as Trustee supplementing the Indenture, dated as of December 1, 1995 between SWN Arkansas and The First National Bank of Chicago, as trustee (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on June 30, 2006).

(4.6)

Specimen of Common Stock Certificate (incorporated by reference to Exhibit 4.4 to the Company's Current Report on Form 8-K filed on June 30, 2006).

(4.7)

Amendment No. 2, dated as of June 30, 2006, to the Amended and Restated Rights Agreement, dated as of April 12, 1999 between Southwestern Energy Company and Computershare Trust Company, N.A., successor to First Chicago Trust Company of New York, as Rights Agent, which includes as Exhibit A the form of Amended Right Certificate and as Exhibit B the Summary of Rights to Purchase Common Stock (incorporated by reference to Exhibit 4.5 to the Company's Current Report on Form 8-K filed on June 30, 2006).

(10.1)

Stock Purchase Agreement dated May 1, 2006 by and among Southwestern Energy Company and Atlas Pipeline Partners, L.P. (incorporated by reference to Exhibit 10.1 to SWN Arkansas' Current Report on Form 8-K filed on May 4, 2006).

(10.2)

Form of Second Amended and Restated Indemnity Agreement (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on June 30, 2006).

(10.3)

Description of Compensation Payable to Non-Management Director (incorporated by reference to Exhibit 10.1 to SWN Arkansas' Current Report on Form 8-K filed on May 31, 2006).

(10.4)

Resolution of the Board of Directors authorizing the acceleration of the vesting of all incentive awards granted to director John Paul Hammerschmidt under the 2004 Stock Incentive Plan and the 2000 Stock Incentive Plan that were unvested as of April 27, 2006.

(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.

(32.1)

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.

Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

SOUTHWESTERN ENERGY COMPANY
Registrant

Dated:	August 1, 2006	/s/ GREG D. KERLEY Greg D. Kerley Executive Vice President and Chief Financial Officer

---