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NEWS RELEASE

SOUTHWESTERN ENERGY ANNOUNCES 2009 FINANCIAL AND OPERATING RESULTS

Company Reports Production Growth of 54%, Reserve Growth of 67%, Reserve Replacement of 592% and Finding Cost of $0.86 per Mcfe in 2009

Houston, Texas – February 25, 2010...Southwestern Energy Company (NYSE: SWN) today announced its financial and operating results for the fourth quarter and the year ended December 31, 2009. Calendar year 2009 highlights include:

- Gas and oil production of 300.4 Bcfe, up 54% over 2008
- Proved oil and gas reserves of 3,657 Bcfe, up 67% over 2008
- Reserve replacement of 592% in 2009, including reserve revisions, compared to 523% in 2008
- Finding and development cost of $0.86 per Mcfe in 2009, including reserve revisions, compared to $1.53 per Mcfe in 2008
- Net cash provided by operating activities before changes in operating assets and liabilities (a non-GAAP measure reconciled below) of approximately $1.4 billion, up 23% from 2008

"2009 was a year of milestones for Southwestern Energy," remarked Steve Mueller, President and Chief Executive Officer of Southwestern Energy. "It was just five years ago when we announced to the world that we had discovered a new shale play in Arkansas called the Fayetteville Shale and were the first to produce gas from the reservoir. Since that time our results have been dramatically impacted by the Fayetteville Shale, including our results in 2009:

- We again set new records in 2009 for production, reserves, reserve replacement and cash flow in a year where we saw NYMEX gas prices fall more than 50%.
- We have recorded exceptional organic production growth since our discovery of the Fayetteville Shale, as total company production reached 300.4 Bcfe in 2009, compared to 54.1 Bcfe in 2004 when we announced the play.
- Our proved gas and oil reserves have also climbed over this same time period to 3,657 Bcfe in 2009, compared to 646 Bcfe in 2004.
- We celebrated our 5-year anniversary in the Fayetteville Shale play this year while also reaching a production milestone of 1 Bcf per day from the play.
- We drilled and completed our 1,000th well in the Fayetteville Shale, on our way to completing thousands more in the years to come.
- We continued to have an industry-leading low cost structure, as our finding and development cost of $0.86 per Mcfe and lease operating expense of $0.77 per Mcfe in 2009 are among the lowest in our industry.

As we look forward, there remains uncertainty for natural gas prices, so our capital plan will remain flexible. If we see a repeat of the low gas prices we saw in 2009, we will actively manage our capital program and make reductions in our 2010 plan. If gas prices rebound in 2010, we could increase our planned investments and accelerate the development of our Fayetteville Shale play by utilizing additional drilling rigs. However, we know that our disciplined approach to capital investing, focus on organic growth and financial flexibility will keep us extremely well-positioned during both the good and the challenging times. While we are very proud of our accomplishments in 2009 and over the past five years, we also know that we have much more work to do. We are looking forward to what lies ahead in 2010 and in the years to come."

Fourth Quarter of 2009 Financial Results

For the fourth quarter of 2009, Southwestern reported net income of $157.8 million, or $0.45 per diluted share, compared to $104.2 million, or $0.30 per diluted share, for the same period in 2008. The increase was primarily due to higher gas production which more than offset lower realized natural gas prices and increased operating costs and expenses. Net cash provided by operating activities before changes in operating assets and liabilities (a non-GAAP measure; see reconciliation below), was $411.4 million in the fourth quarter of 2009, up 45% from $283.4 million in 2008.

E&P Segment - Operating income from the company's E&P segment was $223.7 million for the fourth quarter of 2009, up from $152.1 million for the same period in 2008. The increase was primarily due to a 55% increase in production volumes which more than offset an 11% decrease in realized natural gas prices and a 30% increase in operating costs and expenses.

Gas and oil production totaled 89.0 Bcfe in the fourth quarter of 2009, up from 57.6 Bcfe in the fourth quarter of 2008, and included 73.9 Bcf from the company's Fayetteville Shale play, up from 44.1 Bcf in the fourth quarter of 2008. Beginning on October 8, 2009, the Fayetteville Lateral of the Texas Gas Transmission Pipeline (Boardwalk Pipeline) was placed back into service after having been shut down since September 1, 2009 due to maintenance and pipeline inspection. The Greenville Lateral of the Boardwalk Pipeline was also placed back into service in October after this shut down. As a result of the repairs, the company is now able to transport to market all of its current production from the Fayetteville Shale.

Including the effect of hedges, Southwestern's average realized gas price in the fourth quarter of 2009 was $5.29 per Mcf, down 11% from $5.93 per Mcf in the fourth quarter of 2008. The company's commodity hedging activities increased its average gas price by $1.51 per Mcf during the fourth quarter of 2009, compared to an increase of $0.79 per Mcf during the same period in 2008. As of February 23, 2010, Southwestern had NYMEX fixed price hedges in place on notional volumes of 36.0 Bcf of its 2010 gas production at a weighted average price of $9.04 per Mcf and collars in place on notional volumes of 30.0 Bcf of its 2010 gas production at an average floor and ceiling price of $6.80 and $8.43 per Mcf, respectively.

Disregarding the impact of commodity price hedges, the company's average price received for its gas production during the fourth quarter of 2009 was approximately $0.39 per Mcf lower than average NYMEX spot prices, compared to approximately $1.80 per Mcf lower during the fourth quarter of 2008. As of February 23, 2010, the company had protected approximately 47 Bcf of its first quarter 2010 expected gas production from the potential of widening basis differentials through hedging activities and sales arrangements at an average basis differential to NYMEX gas prices of approximately $0.20 per Mcf.

The company typically sells its natural gas at a discount to NYMEX spot prices due to locational basis differentials, while transportation charges and fuel charges also reduce the price received. In 2010, the company expects to pay average third-party transportation charges in the range of $0.25 to $0.32 per Mcf and average fuel charges in the range of 0.25% to 1.00% of the company's sales price for natural gas.

Lease operating expenses per unit of production for the company's E&P segment were $0.79 per Mcfe in the fourth quarter of 2009, down from $0.87 per Mcfe in the fourth quarter of 2008. The decrease primarily resulted from the impact that lower natural gas prices had on the cost of compressor fuel in the fourth quarter of 2009.

General and administrative expenses per unit of production were $0.37 per Mcfe in the fourth quarter of 2009, compared to $0.49 per Mcfe in the fourth quarter of 2008. The decrease was primarily due to the effects of the company's increased production volumes which more than offset increased compensation and employee-related costs primarily associated with the expansion of the company's E&P operations in the Fayetteville Shale play.

Taxes other than income taxes per unit of production were $0.14 per Mcfe in the fourth quarter of 2009, compared to $0.06 per Mcfe in the fourth quarter of 2008, as the increase was primarily due to higher severance taxes recognized on Arkansas gas production and the timing of tax refunds recognized in Texas.

The company's full cost pool amortization rate decreased to $1.40 per Mcfe in the fourth quarter of 2009, compared to $1.87 per Mcfe in the fourth quarter of 2008. The decline in the average amortization rate was primarily the result of a $907.8 million non-cash ceiling test impairment recorded in the first quarter of 2009 and the company's lower finding and development costs in 2009. The amortization rate is impacted by the timing and amount of reserve additions and the costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, impairments that result from full cost ceiling tests, proceeds from the sale of properties that reduce the full cost pool and the levels of costs subject to amortization. The future full cost pool amortization rate cannot be predicted with accuracy due to the variability of each of the factors discussed above, as well as other factors.

Midstream Services - Operating income for the company's Midstream Services segment, which is comprised of natural gas gathering and marketing activities, was $42.4 million for the three months ended December 31, 2009, up from $18.9 million in the same period in 2008. The increase in operating income was primarily due to the increase in gathering revenues from the company's Fayetteville Shale play, partially offset by increased operating costs and expenses.

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Full-Year 2009 Financial Results

Southwestern reported a net loss for 2009 of $35.7 million, or $0.10 per diluted share, which resulted from a first quarter $907.8 million non-cash ceiling test impairment ($558.3 million net of taxes) of the company's natural gas and oil properties resulting from lower natural gas and oil prices. Excluding the non-cash impairment, Southwestern's net income for 2009 was $522.7 million (a non-GAAP measure; see reconciliation below), or $1.52 per diluted share, compared to net income of $567.9 million, or $1.64 per diluted share, in 2008. Results for 2008 included an after-tax gain on the sale of the company's utility assets of $35.4 million, or $0.10 per diluted share. Excluding the non-cash impairment, the company's financial results were impacted primarily by lower realized natural gas prices during 2009 and increased operating costs and expenses which were partially offset by significant growth in production volumes.

Net cash provided by operating activities before changes in operating assets and liabilities (a non-GAAP measure; see reconciliation below), was approximately $1.4 billion in 2009, up 23% from approximately $1.2 billion in 2008.

***E&P Segment* -** The company's E&P segment recorded an operating loss of $157.7 million in 2009, as a result of the recognition of the $907.8 million non-cash ceiling test impairment of its natural gas and oil properties recorded for the first three months ended March 31, 2009 due to a significant decline in natural gas and oil prices. Excluding the non-cash ceiling test impairment, operating income from the company's E&P segment was $750.1 million in 2009 (a non-GAAP measure; see reconciliation below), compared to $813.5 million in 2008. The decrease was primarily due to lower realized natural gas prices and increased operating costs and expenses which were partially offset by higher production.

Gas and oil production was 300.4 Bcfe in 2009, up 54% compared to 194.6 Bcfe in 2008, and included 243.5 Bcf from the company's Fayetteville Shale play, up from 134.5 Bcf in 2008. Southwestern's 2010 total gas and oil production guidance is 400 to 410 Bcfe, an increase of approximately 35% over its 2009 production (using the midpoint of targeted 2010 gas and oil production), of which approximately 344 to 352 Bcf is expected to come from the Fayetteville Shale.

Southwestern's average realized gas price was $5.30 per Mcf, including the effect of hedges, in 2009 compared to $7.52 per Mcf in 2008. The company's hedging activities increased the average gas price realized in 2009 by $1.96 per Mcf, compared to a decrease of $0.21 per Mcf in 2008. Disregarding the impact of hedges, the average price received for the company's gas production during 2009 was approximately $0.65 per Mcf lower than average NYMEX spot prices, compared to approximately $1.30 per Mcf lower than NYMEX spot prices in 2008.

Lease operating expenses for the company's E&P segment were $0.77 per Mcfe in 2009, down from $0.89 per Mcfe in 2008. The decrease was primarily the result of the impact that lower natural gas prices had on the cost of compressor fuel in 2009.

General and administrative expenses were $0.35 per Mcfe in 2009, down from $0.41 per Mcfe in 2008. The decrease was primarily due to the effects of the company's increased

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production volumes which more than offset the effects of increased payroll, incentive compensation and other employee-related costs primarily associated with the expansion of the company's operations in the Fayetteville Shale play. Southwestern added 335 new employees during 2009.

Taxes other than income taxes were $0.11 per Mcfe in 2009, compared to $0.13 per Mcfe in 2008, primarily due to lower commodity prices and the change in the mix of the company's production volumes.

The company's full cost pool amortization rate decreased to $1.51 per Mcfe in 2009, compared to $1.99 per Mcfe in 2008, primarily due to the $907.8 million non-cash ceiling test impairment recorded in the first quarter of 2009, the company's lower finding and development costs in 2009 and the sale of natural gas and oil properties in 2008, as the sales proceeds were credited to the full cost pool.

Midstream Services - Operating income for the company's midstream activities was $122.6 million in 2009, compared to $62.3 million in 2008. The increase in operating income was primarily due to increased gathering revenues and an increase in the margin from gas marketing activities related to the Fayetteville Shale play, partially offset by increased operating costs and expenses. At December 31, 2009, the company's midstream segment was gathering approximately 1.3 Bcf per day through 1,137 miles of gathering lines in the Fayetteville Shale play, compared to gathering 802 MMcf per day through 843 miles of gathering lines at December 31, 2008. Gathering volumes, revenues and expenses for this segment are expected to continue to grow as reserves related to the company's Fayetteville Shale play are developed and production increases.

Capital Investments - In 2009, Southwestern invested approximately $1.8 billion, which was nearly flat compared to its capital investments in 2008, and included $1.6 billion invested in its E&P business and $214 million invested in its Midstream Services segment. Of the approximate $1.6 billion invested in its E&P business, $1.3 billion was invested in its Fayetteville Shale play, $167 million in East Texas, $40 million in Appalachia, $40 million in its conventional Arkoma Basin program and $25 million in New Ventures. The company expects that its total capital investments for the full year of 2010 to be approximately $2.1 billion, which includes approximately $1.2 billion invested in its Fayetteville Shale play, $230 million in East Texas, $145 million in Appalachia, $25 million in its conventional Arkoma Basin program, $135 million in New Ventures, $270 million in Midstream Services and $95 million for corporate and other purposes.

Southwestern Reports Record Gas and Oil Reserves

Southwestern's estimated proved gas and oil reserves totaled 3,657 Bcfe at December 31, 2009, up 67% from 2,185 Bcfe at the end of 2008. Approximately 100% of the company's year-end 2009 estimated proved reserves were natural gas and 54% were classified as proved developed, compared to 100% and 62%, respectively, in 2008.

On December 31, 2009, the company implemented certain provisions of Securities and Exchange Commission (SEC) and Financial Accounting Standards Board standards that updated requirements relative to natural gas and oil reserves. Accordingly, the company's estimated proved natural gas and oil reserves as of December 31, 2009 were valued utilizing the average prices in the 12-month period, which is defined, with certain exceptions, as the unweighted arithmetic average of the first-day-of-the-month price for each month within such period, of $3.87 per Mcf for natural gas and $57.65 per barrel for oil. The market prices for natural gas and crude oil used in calculating the value of the company's estimated proved natural gas and oil reserves for 2008 and 2007 were single day prices permitted to be used under the SEC's prior rules, which were $5.71 per Mcf for natural gas and $41.00 per barrel for oil at year-end 2008 and $6.80 per Mcf and $92.50 per barrel at year-end 2007.

In 2009, Southwestern replaced 592% of its production volumes with an increase of 1,685 Bcfe of proved natural gas and oil reserves as a result of its drilling program and net upward revisions of 92.9 Bcfe. Of the reserve additions, 757.6 Bcfe were proved developed and 927.5 Bcfe were proved undeveloped. The net upward reserve revisions during 2009 were primarily due to upward revisions of 384.8 Bcf related to the improved performance of wells in its Fayetteville Shale play, partially offset by downward reserve revisions of 251.5 Bcfe due to a comparative decrease in the average gas price for 2009 as compared to year-end 2008. Additionally, the company had downward performance revisions of 40.6 Bcfe in its East Texas and conventional Arkoma Basin operating areas. In 2008, the company's reserve replacement ratio was 523%, including revisions. For the period ending December 31, 2009, the company's three-year average reserve replacement ratio, including revisions, was 548%. Excluding reserve revisions, the company's 2009 and three-year average reserve replacement ratios were 561% and 512%, respectively.

Southwestern's finding and development cost was $0.86 per Mcfe in 2009, including reserve revisions, compared to $1.53 per Mcfe in 2008. For the period ending December 31, 2009, the company's three-year finding and development cost, including revisions, was $1.34 per Mcfe. Excluding reserve revisions, the company's 2009 and three-year average finding and development costs were $0.91 per Mcfe and $1.43 per Mcfe, respectively (finding and development costs are considered by the SEC to be non-GAAP financial measures and have been computed below).

The following table provides an overall and by category summary of the company's gas and oil reserves, as of fiscal year end 2009 based on average fiscal year prices, and its well count, net acreage and PV-10 as of December 31, 2009 and sets forth 2009 annual information related to production and capital investments for each of its operating areas:

2009 Proved Reserves by Category and Summary Operating Data

	U.S. Exploitation					
	Fayetteville Shale Play	East Texas	Arkoma Basin	Appalachia	New Ventures	Total
Estimated Proved Reserves:						
Natural Gas (Bcf):						
Developed (Bcf)	1,501	280	190	2	-	**1,973**
Undeveloped (Bcf)	1,616	43	18	-	-	**1,677**
	3,117	323	208	2	-	**3,650**
Crude Oil (MMBbls):						
Developed (MMBbls)	-	1	-	-	-	**1**
Undeveloped (MMBbls)	-	-	-	-	-	**-**
	-	1	-	-	-	**1**
Total Proved Reserves (Bcfe)(1):						
Proved Developed (Bcfe)	1,501	287	190	2	-	**1,980**
Proved Undeveloped (Bcfe)	1,616	43	18	-	-	**1,677**
	3,117	330	208	2	-	**3,657**
Percent of Total	85%	9%	6%	-	-	**100%**
Percent Proved Developed	48%	87%	91%	100%	-	**54%**
Percent Proved Undeveloped	52%	13%	9%	-	-	**46%**
Production (Bcfe)	243.5	34.9	22.0	-	-	**300.4**
Capital Investments (millions)(2)	$ 1,259	$ 167	$ 40	$ 40	$ 25	**$ 1,531**
Total Gross Producing Wells	1,428	582	1,193	-	-	**3,203**
Total Net Producing Wells	993	449	583	-	-	**2,025**
Total Net Acreage	763,293(3)	115,199(4)	463,888(5)	149,317(6)	36,125	**1,527,822**
Net Undeveloped Acreage	394,538(3)	61,298(4)	278,927(5)	149,317(6)	36,125	**920,205**

(1) The company has no reserves from synthetic gas, synthetic oil or nonrenewable natural resources intended to be upgraded into synthetic gas or oil. The company's proved reserves increased by 1,685 Bcfe as a result of its drilling program and net upward revisions of 92.9 Bcfe in 2009. Of the reserve additions, 757.6 Bcfe were proved developed and 927.5 Bcfe were proved undeveloped. The company used standard engineering and geoscience methods, or a combination of methods, such as performance analysis, volumetric analysis and analogy to establish the appropriate level of certainty for reserve estimates from the material properties included in its total reserves.

(2) The company's Total and Fayetteville Shale play capital investments exclude $35 million related to its sand facility and the purchase of drilling rig related and ancillary equipment.

(3) Assuming successful wells are not drilled and leases are not extended, leasehold expiring over the next three years will be 120,977 net acres in 2010, 23,722 net acres in 2011 and 34,231 net acres in 2012.

(4) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 21,747 net acres in 2010, 24,594 net acres in 2011 and 2,334 net acres in 2012.

(5) Includes 123,442 net developed acres and 1,960 net undeveloped acres in the Arkoma Basin that are also within the company's Fayetteville Shale focus area but not included in the Fayetteville Shale acreage in the table above. Assuming successful wells are not drilled and leases are not extended, leasehold expiring over the next three years will be 32,434 net acres in 2010, 34,115 net acres in 2011 and 28,153 net acres in 2012.

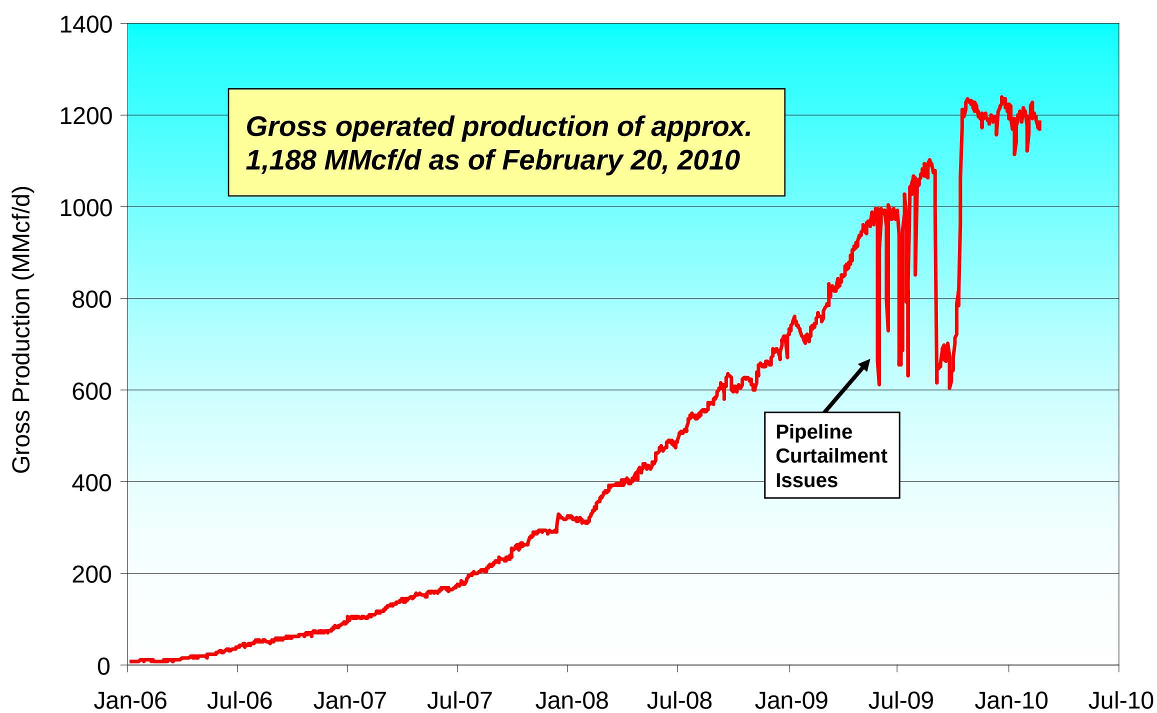
(6) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 1,475 net acres in 2010, 551 net acres in 2011 and 61,133 net acres in 2012.

2009 E&P Operations Review

Southwestern invested a total of approximately $1.6 billion in its E&P business during 2009 and participated in drilling 636 wells, 419 of which were successful, 5 were dry and 212 were in progress at year-end. Of the 212 wells in progress at year-end, 196 were located in the company's Fayetteville Shale play. Of the $1.6 billion invested, approximately $1.3 billion was in exploratory and development drilling and workovers, $82 million for acquisition of properties, $32 million for seismic expenditures and $155 million in capitalized interest and expenses and other technology-related expenditures.

Fayetteville Shale Play - As of December 31, 2009, Southwestern had spud a total of 1,792 wells in the play, 1,437 of which were operated and 355 of which were outside-operated wells. Of the wells spud, 570 were in 2009 compared to 604 wells in 2008. At year-end 2009, 1,288 wells had been drilled and completed, including 1,201 horizontal wells.

Southwestern's net production from the Fayetteville Shale play was 243.5 Bcf in 2009, up 81% from 134.5 Bcf in 2008, as gross production from the company's operated wells in the Fayetteville Shale play increased from approximately 720 MMcf per day at the beginning of 2009 to approximately 1,225 MMcf per day by year-end and was 1,188 MMcf per day at February 20, 2010. When the Boardwalk Pipeline was placed back into service on October 8, 2009, the company's October exit rate was artificially high due to flush production caused by the shut-in period and the fact that Southwestern placed on production 55 wells during that month, the highest ever in one month. Since that time and through February 22, 2010, operational and weather-related field issues have caused approximately 25 fewer wells to be placed on production than originally scheduled. As a result, the company has added two additional drilling rigs and expects to catch up to its original well count schedule during the third quarter of 2010. The graph below provides gross production data from the company's operated wells in the Fayetteville Shale play area through February 20, 2010.



Southwestern invested approximately $1.3 billion in its Fayetteville Shale drilling program during 2009, adding approximately 1.8 Tcf in new reserves at a finding and development cost of $0.69 per Mcf (finding and development costs are considered by the SEC to be non-GAAP financial measures and have been computed below), including positive reserve revisions of approximately 384.8 Bcf due primarily to improved well performance and 147.1 Bcf of negative revisions due to a comparative decrease in gas prices. During 2008, the company added approximately 984 Bcf in new reserves in the Fayetteville Shale play at a finding and development cost of $1.21 per Mcf, including positive reserve revisions of approximately 159.7 Bcf due primarily to improved well performance and 0.8 Bcf of negative revisions due to low year-end gas prices.

Southwestern's total proved net reserves booked in the play at year-end 2009 were 3,117 Bcf from a total of 2,675 locations, of which 1,428 were proved developed producing, 97 were proved developed non-producing and 1,150 were proved undeveloped. Of the 2,675 locations, 2,609 were horizontal. The average gross proved reserves for the undeveloped wells included in the company's year-end reserves was approximately 2.2 Bcf per well, up from 1.9 Bcf per well at year-end 2008. Total proved gas reserves booked in the play in 2008 totaled approximately 1,545 Bcf from a total of 1,508 locations, of which 882 were proved developed producing, 18 were proved developed non-producing and 608 were proved undeveloped.

During 2009, the company continued to improve its drilling practices in the Fayetteville Shale play. The company's horizontal wells had an average completed well cost of $2.9 million per well, average horizontal lateral length of 4,100 feet and average time to drill to total depth of 12 days from re-entry to re-entry. This compares to an average completed well cost of $3.0 million per well, average horizontal lateral length of 3,619 feet and average time to drill to total depth of 14 days from re-entry to re-entry during 2008. Southwestern also continued to improve its completion practices, as wells placed on production during 2009 averaged initial production rates of 3,478 Mcf per day, up 25% from average initial production rates of 2,777 Mcf per day in 2008.

Since 2007, improvements in the company's completion practices and longer lateral lengths have resulted in improvements in average initial production rates of operated wells placed on production. During 2009, Southwestern placed 60 wells on production with initial production rates over 5.0 MMcf per day, including 6 wells that exceeded 6.0 MMcf per day and the play's highest rate well, the Arklan, Inc. 09-11 #4-32H located in Cleburne County, with an initial production rate of approximately 7.6 MMcf per day. Results from the company's drilling activities from 2007 through 2009, by quarter, are shown below.

Time Frame	Wells Placed on Production	Average IP Rate (Mcf/d)	30th-Day Avg Rate (# of wells)	60th-Day Avg Rate (# of wells)	Average Lateral Length
1st Qtr 2007	58	1,261	1,066 (58)	958 (58)	2,104
2nd Qtr 2007	46	1,497	1,254 (46)	1,034 (46)	2,512
3rd Qtr 2007	74	1,769	1,510 (72)	1,334 (72)	2,622
4th Qtr 2007	77	2,027	1,690 (77)	1,481 (77)	3,193
1st Qtr 2008	75	2,343	2,147 (75)	1,943 (74)	3,301
2nd Qtr 2008	83	2,541	2,155 (83)	1,886 (83)	3,562
3rd Qtr 2008	97	2,882	2,560 (97)	2,349 (97)	3,736
4th Qtr 2008(1)	74	3,350(1)	2,722 (74)	2,386 (74)	3,850
1st Qtr 2009(1)	120	2,992(1)	2,537 (120)	2,293 (120)	3,874
2nd Qtr 2009	111	3,611	2,833 (111)	2,556 (111)	4,123
3rd Qtr 2009	93	3,604	2,640 (92)	2,275 (92)	4,100
4th Qtr 2009	122	3,757	2,679 (121)	2,421 (85)	4,303

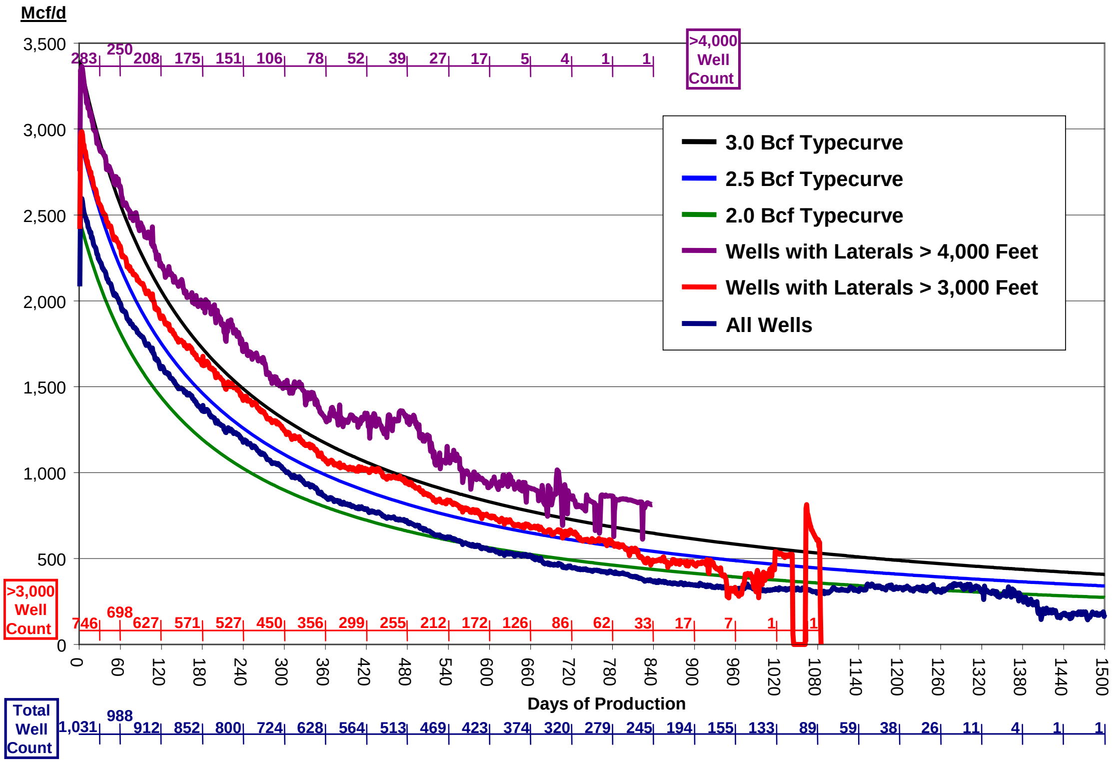
Note: Results as of December 31, 2009.
(1) The significant increase in the average initial production rate for the fourth quarter of 2008 and the subsequent decrease for the first quarter of 2009 primarily reflected the impact of the delay in the Boardwalk Pipeline. Wells that were placed on production in January and February of 2009 had average initial production rates of 2,806 Mcf per day and 2,749 Mcf per day,

respectively, while wells placed on production during March 2009 had average initial production rates of 3,353 Mcf per day.

During the fourth quarter of 2009, the company's horizontal wells had an average completed well cost of $3.0 million per well, average horizontal lateral length of 4,303 feet and average time to drill to total depth of 12 days from re-entry to re-entry. This compares to an average completed well cost of $2.9 million per well, average horizontal lateral length of 4,100 feet and average time to drill to total depth of 12 days from re-entry to re-entry in the third quarter of 2009. The company currently has 22 drilling rigs running in its Fayetteville Shale play area, 16 that are capable of drilling horizontal wells and 6 smaller rigs that are used to drill the vertical portion of the wells.

Beginning in late 2008 and through 2009, the company began drilling wells to test tighter well spacing. At December 31, 2009, Southwestern had placed over 300 wells on production that have well spacing of 700 feet or less, representing approximately 65-acre spacing or less, with encouraging results. In areas tested to date, Southwestern expects to drill between 10 and 12 wells per section in the Fayetteville Shale, pending additional well data and analyses. The company will continue to focus on optimizing the well spacing for the play and plans to test over 20 different pilot areas with well spacings that will range from 300 to 600 feet apart as part of its 2010 drilling program.

The graph below provides normalized average daily production data through December 31, 2009, for the company's horizontal wells using slickwater and crosslinked gel fluids. The "dark blue curve" is for horizontal wells fracture stimulated with either slickwater or crosslinked gel fluid. The "red curve" indicates results for the company's wells with lateral lengths greater than 3,000 feet, while the "purple curve" indicates results for the company's wells with lateral lengths greater than 4,000 feet. The normalized production curves are intended to provide a qualitative indication of the company's Fayetteville Shale wells' performance and should not be used to estimate an individual well's estimated ultimate recovery. The 2.0, 2.5 and 3.0 Bcf typecurves are shown solely for reference purposes and are not intended to be projections of the performance of the company's wells.



Notes: Data as of December 31, 2009 and excludes wells with mechanical problems (28).
"Wells with Laterals > 3,000 Feet" curve excludes the last 184 days of production for the Guinn 09-15 #2-06H due to positive response to offset frac which may not be typical.

At December 31, 2009, Southwestern held approximately 889,000 net acres in the play area (including 125,402 net acres in the traditional Fairway portion of the Arkoma Basin). In 2010, Southwestern plans to invest approximately $1.2 billion in the Fayetteville Shale play, which includes participating in approximately 650 to 680 horizontal wells, 475 to 500 of which will be operated by the company.

East Texas - At December 31, 2009, Southwestern had approximately 330 Bcfe of reserves in East Texas, representing approximately 9% of total reserves, compared to 351 Bcfe at year-end 2008. In 2009, the company invested approximately $167 million in East Texas and participated in 46 wells, of which 33 were successful and 13 were in progress at year-end, resulting in a 100% success rate and adding new reserves of 94 Bcfe. This area recorded negative revisions of approximately 55.3 Bcfe primarily due to a comparative decrease in the average 2009 gas price from the year-end 2008 gas price and 25.5 Bcfe due to negative performance revisions. Net production from East Texas was 34.9 Bcfe in 2009, compared to 31.6 Bcfe in 2008.

The company's 2009 drilling program was primarily focused on developing the James Lime formation in its Jebel prospect area located in Shelby County, Texas, and it initiated drilling in the Haynesville Shale in Shelby and San Augustine Counties with good success. At December 31, 2009, Southwestern had participated in 77 James Lime horizontal wells, 51 of which were operated. Of those, 43 wells that were operated were placed on production at an average gross initial production rate of 9.8 MMcfe per day, resulting in net production from the James Lime of approximately 48 MMcf per day at December 31, 2009.

In the second quarter of 2008, the company signed a 50/50 joint venture agreement with a private company targeting the Haynesville and Middle Bossier Shale intervals in Shelby and

San Augustine Counties. Since that time, the company has drilled six wells with initial production rates shown below. In total, Southwestern has approximately 42,300 net acres it believes are prospective for the Haynesville and Middle Bossier Shales and the company's average gross working interest is approximately 61%.

Well Name	County	Formation	Completion Date	Average Lateral Length	IP Rate (MMcf/d)
Red River 877 #1	Shelby	Haynesville	1st Qtr 2009	2,765	7.2
Red River 164 #1	San Augustine	Haynesville	2nd Qtr 2009	3,892	13.4
Red River 619 #1	San Augustine	Haynesville	3rd Qtr 2009	4,144	16.7
Burrows GU #1-H	San Augustine	Haynesville	4th Qtr 2009	3,828	21.0
Red River 257 #1	San Augustine	Haynesville	4th Qtr 2009	4,728	18.1
Red River 257 #2	San Augustine	Middle Bossier	4th Qtr 2009	4,062	11.3

In 2010, Southwestern expects to invest approximately $230 million and participate in approximately 50 to 60 gross wells in East Texas, 22 to 27 of which will be operated. Of the wells planned in 2010, 21 to 26 wells will be targeting the Haynesville or Middle Bossier Shales and 29 to 34 wells will be targeting the James Lime, Pettet or Cotton Valley formations.

Conventional Arkoma Basin - (Outside the Fayetteville Shale play area) At December 31, 2009, Southwestern had approximately 208 Bcf of reserves which were attributable to its conventional Arkoma properties, representing approximately 6% of total reserves, compared to 281 Bcf at year-end 2008. In 2009, the company invested approximately $40 million in its conventional Arkoma drilling program and participated in 20 wells, of which 15 were successful and 3 were in progress at year-end, resulting in an 88% success rate and adding new reserves of 14 Bcf. This area recorded negative reserve revisions of approximately 49.1 Bcf primarily due to a comparative decrease in the gas price and 15.1 Bcfe due to negative performance revisions. Net production from the company's conventional Arkoma properties was 22.0 Bcf in 2009, compared to 24.4 Bcf in 2008. In 2010, Southwestern plans to invest approximately $25 million in its conventional Arkoma program and participate in approximately 15 to 20 wells.

Appalachia - The company began leasing in northeastern Pennsylvania in 2007 in an effort to gain a position in the emerging Marcellus Shale play. At December 31, 2009, Southwestern had approximately 149,000 net acres in Pennsylvania under which it believes the Marcellus Shale is prospective. The company's undeveloped acreage position as of December 31, 2009 had an average remaining lease term of 5 years, an average royalty interest of 13% and was obtained at an average cost of approximately $594 per acre. During 2009, Southwestern invested approximately $40 million in Pennsylvania, almost all of which was for acquisition of acreage. In 2010, the company plans to invest approximately $145 million in Appalachia, which includes drilling with one operated rig in the Marcellus Shale play in Pennsylvania and participating in a total of 35 to 40 wells, 21 to 24 of which will be operated.

New Ventures - At December 31, 2009, Southwestern held approximately 36,000 net undeveloped acres in the United States outside of its core operating areas in connection with New Ventures. In 2009, the company invested approximately $25 million in its New

Ventures program and, in 2010, it plans to invest approximately $135 million in various unconventional, exploration and New Ventures projects.

Explanation and Reconciliation of Non-GAAP Financial Measures

We report our financial results in accordance with accounting principles generally accepted in the United States of America ("GAAP"). However, management believes certain non-GAAP performance measures may provide users of this financial information additional meaningful comparisons between current results and the results of our peers and of prior periods.

One such non-GAAP financial measure is net cash provided by operating activities before changes in operating assets and liabilities. Management presents this measure because (i) it is accepted as an indicator of an oil and gas exploration and production company's ability to internally fund exploration and development activities and to service or incur additional debt, (ii) changes in operating assets and liabilities relate to the timing of cash receipts and disbursements which the company may not control and (iii) changes in operating assets and liabilities may not relate to the period in which the operating activities occurred.

Additional non-GAAP financial measures we may present from time to time are net income attributable to Southwestern Energy, diluted earnings per share attributable to Southwestern Energy stockholders and our E&P segment operating income, all which exclude certain charges or amounts. Management presents these measures because (i) they are consistent with the manner in which the Company's performance is measured relative to the performance of its peers, (ii) these measures are more comparable to earnings estimates provided by securities analysts, and (iii) charges or amounts excluded cannot be reasonably estimated and guidance provided by the Company excludes information regarding these types of items. These adjusted amounts are not a measure of financial performance under GAAP.

See the reconciliations below of GAAP financial measures to non-GAAP financial measures for the three and twelve months ended December 31, 2009 and December 31, 2008. Non-GAAP financial measures should not be considered in isolation or as a substitute for the Company's reported results prepared in accordance with GAAP.

	12 Months Ended Dec. 31, 2009	12 Months Ended Dec. 31, 2008
	(in thousands)	
Net income (loss) attributable to Southwestern Energy:		
Net income (loss) attributable to Southwestern Energy	$ (35,650)	$ 567,946
Add back:		
Impairment of natural gas and oil properties (net of taxes)	558,305	--
Net income attributable to Southwestern Energy, excluding impairment of natural gas and oil properties	$ 522,655	$ 567,946

	12 Months Ended Dec. 31, 2009	12 Months Ended Dec. 31, 2008
Diluted earnings per share:		
Net income (loss) per share attributable to Southwestern Energy stockholders	$ (0.10)	$ 1.64
Add back:		
Impairment of natural gas and oil properties (net of taxes)	1.62	--
Net income per share attributable to Southwestern Energy stockholders, excluding impairment of natural gas and oil properties	$ 1.52	$ 1.64

	3 Months Ended Dec. 31, 2009	3 Months Ended Dec. 31, 2008
	(in thousands)	
Cash flow from operating activities:		
Net cash provided by operating activities	$ 369,850	$ 194,102
Add back (deduct):		
Change in operating assets and liabilities	41,554	89,306
Net cash provided by operating activities before changes in operating assets and liabilities	$ 411,404	$ 283,408

	12 Months Ended Dec. 31, 2009	12 Months Ended Dec. 31, 2008
	(in thousands)	
Cash flow from operating activities:		
Net cash provided by operating activities	$ 1,359,376	$ 1,160,809
Add back (deduct):		
Change in operating assets and liabilities	81,652	6,685
Net cash provided by operating activities before changes in operating assets and liabilities	$ 1,441,028	$ 1,167,494

	12 Months Ended Dec. 31, 2009	12 Months Ended Dec. 31, 2008
	(in thousands)	
E&P segment operating income:		
E&P segment operating income (loss)	$ (157,725)	$ 813,504
Add back:		
Impairment of natural gas and oil properties	907,812	--
E&P segment operating income, excluding impairment of natural gas and oil properties	$ 750,087	$ 813,504

Finding and development costs - Finding and development (F&D) costs are computed by dividing acquisition, exploration and development capital costs incurred for the indicated period by reserve additions, including reserves acquired, for that same period. The following computes F&D costs using information required by GAAP for the periods ending December 31, 2009 and December 31, 2008, and three years ending December 31, 2009.

	For the 12 Months Ending December 31, 2009	For the 12 Months Ending December 31, 2008	For the 3 Years Ending December 31, 2009	Fayetteville Shale Play 2009	Fayetteville Shale Play 2008
Total exploration, development and acquisition costs incurred ($ in thousands)	$ 1,529,876	$ 1,559,995	$ 4,460,747	$ 1,259,151	$ 1,191,558
Reserve extensions, discoveries and acquisitions (MMcfe)	1,685,191	920,181	3,113,227	1,576,980	824,706
Finding & development costs, excluding revisions ($/Mcfe)	$ 0.91	$ 1.70	$ 1.43	$ 0.80	$ 1.44
Reserve extensions, discoveries, acquisitions and reserve revisions (MMcfe)	1,778,045	1,018,281	3,335,156	1,814,665	983,635
Finding & development costs, including revisions ($/Mcfe)	$ 0.86	$ 1.53	$ 1.34	$ 0.69	$ 1.21

The company believes that providing a measure of F&D costs is useful for investors as a means of evaluating a company's cost to add proved reserves, on a per thousand cubic feet of natural gas equivalent basis. These measures are provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in Southwestern's financial statements prepared in accordance with GAAP (including the notes thereto). Due to various factors, including timing differences and the SEC's 2009 adoption of a number of revisions to its oil and gas reporting disclosure requirements, F&D costs do not necessarily reflect precisely the costs associated with particular reserves. For example, exploration costs may be recorded in periods prior to the periods in which related increases in reserves are recorded and development costs, including future development costs for proved undeveloped reserve additions, may be recorded in periods subsequent to the periods in which related increases in reserves are recorded. In addition, changes in commodity prices can affect the magnitude of recorded increases in reserves independent of the related costs of such increases. As a result of the foregoing factors and various factors that could materially affect the timing and amounts of future increases in reserves and the timing and amounts of future costs, including factors disclosed in Southwestern's filings with the SEC, future F&D costs may differ materially from those set forth above. Further, the methods used by Southwestern to calculate its F&D costs may differ significantly from methods used by other companies to compute similar measures and, as a result, Southwestern's F&D costs may not be comparable to similar measures provided by other companies.

Southwestern will host a teleconference call on Friday, February 26, 2010, at 10:00 a.m. Eastern to discuss the company's fourth quarter and year-end 2009 results. The toll-free number to call is 877-407-8035 and the international toll-free number is 201-689-8035. The teleconference can also be heard "live" on the Internet at http://www.swn.com.

Southwestern Energy Company is an integrated company whose wholly-owned subsidiaries are engaged in oil and gas exploration and production, natural gas gathering and marketing. Additional information on the company can be found on the Internet at http://www.swn.com.

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All statements, other than historical financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for the company's future operations, are forward-looking statements. Although the company believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance and actual results or developments may differ materially from those in the forward-looking statements. The company has no obligation and makes no undertaking to publicly update or revise any forward-looking statements. You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect the company's operations, markets, products, services and prices and cause its actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause the company's actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to: the timing and extent of changes in market conditions and prices for natural gas and oil (including regional basis differentials); the company's ability to transport its production to the most favorable markets or at all; the timing and extent of the company's success in discovering, developing, producing and estimating reserves; the economic viability of, and the company's success in drilling, the company's large acreage position in the Fayetteville Shale play, overall as well as relative to other productive shale gas plays; the company's ability to fund the company's planned capital investments; the impact of federal, state and local government regulation, including any legislation relating to hydraulic fracturing, the climate or over the counter derivatives; the company's ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation; the costs and availability of oil field personnel services and drilling supplies, raw materials, and equipment and services; the company's future property acquisition or divestiture activities; increased competition; the financial impact of accounting regulations and critical accounting policies; the comparative cost of alternative fuels; conditions in capital markets, changes in interest rates and the ability of the company's lenders to provide it with funds as agreed; credit risk relating to the risk of loss as a result of non-performance by the company's counterparties and any other factors listed in the reports the company has filed and may file with the Securities and Exchange Commission (SEC). For additional information with respect to certain of these and other factors, see the reports filed by the company with the SEC. The company disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Financial Summary Follows

# # #

The Right People doing the Right Things, wisely investing the cash flow from our underlying Assets, will create Value+®

OPERATING STATISTICS (Unaudited)
Southwestern Energy Company and Subsidiaries

	Three Months		Twelve Months	
Periods Ended December 31	**2009**	2008	**2009**	2008
Exploration & Production				
Production				
Gas production (Bcf)	**88.9**	57.4	**299.7**	192.3
Oil production (MBbls)	**29**	40	**124**	385
Total equivalent production (Bcfe)	**89.0**	57.6	**300.4**	194.6
Commodity Prices				
Average gas price per Mcf, including hedges	**$ 5.29**	$ 5.93	**$ 5.30**	$ 7.52
Average gas price per Mcf, excluding hedges	**$ 3.78**	$ 5.14	**$ 3.34**	$ 7.73
Average oil price per Bbl	**$ 72.52**	$ 61.64	**$ 54.99**	$ 107.18
Operating Expenses per Mcfe				
Lease operating expenses	**$ 0.79**	$ 0.87	**$ 0.77**	$ 0.89
General & administrative expenses	**$ 0.37**	$ 0.49	**$ 0.35**	$ 0.41
Taxes, other than income taxes	**$ 0.14**	$ 0.06	**$ 0.11**	$ 0.13
Full cost pool amortization	**$ 1.40**	$ 1.87	**$ 1.51**	$ 1.99

Midstream				
Gas volumes marketed (Bcf)	**108.6**	76.8	**382.5**	258.0
Gas volumes gathered (Bcf)	**119.7**	71.1	**387.1**	224.1

STATEMENTS OF OPERATIONS (Unaudited)

Southwestern Energy Company and Subsidiaries

Periods Ended December 31	Three Months **2009**	Three Months 2008	Twelve Months **2009**	Twelve Months 2008
	(in thousands except share/per share amounts)			
Operating Revenues				
Gas sales	**$ 468,205**	$ 333,005	**$ 1,578,256**	$ 1,500,408
Gas marketing	**132,011**	151,877	**488,663**	719,909
Oil sales	**2,163**	2,424	**6,843**	41,240
Gas gathering	**23,410**	11,614	**74,281**	41,748
Other	**(1,296)**	1,157	**(2,264)**	8,247
	624,493	500,077	**2,145,779**	2,311,552
Operating Costs and Expenses				
Gas purchases – midstream services	**129,513**	149,639	**482,836**	710,129
Gas purchases – gas distribution	**—**	—	**—**	61,439
Operating expenses	**39,965**	29,674	**136,541**	107,577
General and administrative expenses	**37,767**	31,423	**122,618**	101,959
Depreciation, depletion and amortization	**137,670**	113,930	**493,658**	414,408
Impairment of natural gas and oil properties	**—**	—	**907,812**	—
Taxes, other than income taxes	**13,317**	4,479	**37,280**	29,272
	358,232	329,145	**2,180,745**	1,424,784
Operating Income (Loss)	**266,261**	170,932	**(34,966)**	886,768
Interest Expense				
Interest on debt	**13,910**	14,202	**55,581**	61,152
Other interest charges	**997**	535	**3,266**	2,284
Interest capitalized	**(8,296)**	(12,937)	**(40,209)**	(34,532)
	6,611	1,800	**18,638**	28,904
Other Income	**361**	1,874	**1,449**	4,404
Gain on Sale of Utility Assets	**—**	—	**—**	57,264
Income (Loss) Before Income Taxes	**260,011**	171,006	**(52,155)**	919,532
Provision (Benefit) for Income Taxes				
Current	**(8,765)**	14,500	**(64,969)**	122,000
Deferred	**110,984**	52,267	**48,606**	228,999
	102,219	66,767	**(16,363)**	350,999
Net income (loss)	**157,792**	104,239	**(35,792)**	568,533
Less: net income (loss) attributable to noncontrolling interest	**(34)**	40	**(142)**	587
Net Income (Loss) Attributable to Southwestern Energy	**$ 157,826**	$ 104,199	**$ (35,650)**	$ 567,946
Earnings Per Share				
Net income (loss) attributable to Southwestern Energy stockholders - Basic	**$ 0.46**	$ 0.30	**$ (0.10)**	$ 1.66
Net income (loss) attributable to Southwestern Energy stockholders - Diluted	**$ 0.45**	$ 0.30	**$ (0.10)**	$ 1.64
Weighted Average Common Shares Outstanding				
Basic	**344,410,199**	342,366,075	**343,420,568**	341,621,814
Diluted	**349,268,735**	346,342,212	**343,420,568**	346,245,938

BALANCE SHEETS (Unaudited)

Southwestern Energy Company and Subsidiaries

December 31	**2009**	2008
	(in thousands)	
ASSETS		
Current Assets	**$ 564,501**	$ 883,263
Property and Equipment	**7,154,021**	5,328,914
Less: Accumulated depreciation, depletion and amortization	**3,026,768**	1,615,307
	4,127,253	3,713,607
Other Assets	**78,496**	163,288
	$ 4,770,250	$ 4,760,158
LIABILITIES AND EQUITY		
Current Liabilities [1]	**$ 536,416**	$ 780,397
Long-Term Debt	**997,500**	674,200
Deferred Income Taxes	**811,902**	721,707
Long-Term Hedging Liability	**3,057**	5,934
Other Liabilities	**80,394**	59,957
Commitments and Contingencies		
Equity		
Common stock, $.01 par value; authorized 540,000,000 shares, issued 346,081,210 shares in 2009 and 343,624,956 in 2008	**3,461**	3,436
Additional paid-in capital	**833,494**	811,492
Retained earnings	**1,414,327**	1,449,977
Accumulated other comprehensive income	**84,276**	247,665
Common stock in treasury, 203,830 shares in 2009 and 225,050 in 2008	**(4,333)**	(4,740)
Total Southwestern Energy stockholders' equity	**2,331,225**	2,507,830
Noncontrolling interest	**9,756**	10,133
Total equity	**2,340,981**	2,517,963
	$ 4,770,250	$ 4,760,158

(1) Current Liabilities include $1.2 million in 2009 and $61.2 million in 2008 of Senior Notes.

STATEMENTS OF CASH FLOWS (Unaudited)

Southwestern Energy Company and Subsidiaries

	Twelve Months	
Periods Ended December 31	**2009**	2008
	(in thousands)	
Cash Flows From Operating Activities		
Net income (loss)	**$ (35,792)**	$ 568,533
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	**495,291**	416,151
Impairment of natural gas and oil properties	**907,812**	—
Deferred income taxes	**48,606**	228,999
Gain on sale of utility assets	**—**	(57,264)
Unrealized loss on derivatives	**5,309**	4,644
Stock-based compensation expense	**12,749**	7,952
Impairment of natural gas inventory and other	**7,053**	(1,521)
Change in assets and liabilities	**(81,652)**	(6,685)
Net cash provided by operating activities	**1,359,376**	1,160,809
Cash Flows From Investing Activities		
Capital investments	**(1,780,165)**	(1,755,888)
Proceeds from sale of property and equipment	**818**	750,310
Net proceeds from sale of utility assets	**—**	213,721
Other items	**(1,257)**	(221)
Net cash used in investing activities	**(1,780,604)**	(792,078)
Cash Flows From Financing Activities		
Payments on short-term debt	**(61,200)**	(1,200)
Payments on revolving long-term debt	**(1,371,700)**	(1,843,600)
Borrowings under revolving long-term debt	**1,696,200**	1,001,400
Proceeds from issuance of long-term debt	**—**	600,000
Debt issuance costs and revolving credit facility costs	**—**	(8,895)
Excess tax benefit for stock-based compensation	**—**	43,107
Change in bank drafts outstanding	**(30,920)**	31,397
Proceeds from exercise of common stock options	**5,755**	3,505
Net cash provided by (used in) financing activities	**238,135**	(174,286)
Increase (decrease) in cash and cash equivalents	**(183,093)**	194,445
Cash and cash equivalents at beginning of year[1]	**196,277**	1,832
Cash and cash equivalents at end of year	**$ 13,184**	$ 196,277

(1) Cash and cash equivalents at the beginning of the year for 2008 include $1.1 million classified as “held for sale.”

SEGMENT INFORMATION (Unaudited)

Southwestern Energy Company and Subsidiaries

	Exploration & Production	Midstream Services	Other[1]	Eliminations	Total
			(in thousands)		
Quarter Ending December 31, 2009					
Revenues	**$ 471,431**	**$ 512,483**	**$ 112**	**$ (359,533)**	**$ 624,493**
Gas purchases	**—**	**439,468**	**—**	**(309,955)**	**129,513**
Operating expenses	**70,510**	**18,920**	**—**	**(49,465)**	**39,965**
General & administrative expenses	**32,683**	**5,178**	**19**	**(113)**	**37,767**
Depreciation, depletion & amortization	**132,094**	**5,707**	**(131)**	**—**	**137,670**
Taxes, other than income taxes	**12,447**	**844**	**26**	**—**	**13,317**
Operating Income (Loss)	**$ 223,697**	**$ 42,366**	**$ 198**	**$ —**	**$ 266,261**
Capital Investments [2]	**$ 379,041**	**$ 46,766**	**$ 15,109**	**$ —**	**$ 440,916**
Quarter Ending December 31, 2008					
Revenues	$ 343,387	$ 445,717	$ 231	$ (289,258)	$ 500,077
Gas purchases	—	405,290	—	(255,651)	149,639
Operating expenses	49,875	13,294	—	(33,495)	29,674
General & administrative expenses	28,068	3,452	15	(112)	31,423
Depreciation, depletion & amortization	109,807	3,816	307	—	113,930
Taxes, other than income taxes	3,536	933	10	—	4,479
Operating Income	$ 152,101	$ 18,932	$ (101)	$ —	$ 170,932
Capital Investments [2]	$ 440,803	$ 49,476	$ 8,868	$ —	$ 499,147
Twelve Months Ending December 31, 2009					
Revenues	**$ 1,593,231**	**$ 1,603,332**	**$ 687**	**$ (1,051,471)**	**$ 2,145,779**
Gas purchases	**—**	**1,375,824**	**—**	**(892,988)**	**482,836**
Operating expenses	**230,447**	**64,129**	**—**	**(158,035)**	**136,541**
General & administrative expenses	**105,017**	**17,989**	**60**	**(448)**	**122,618**
Depreciation, depletion & amortization	**474,014**	**19,213**	**431**	**—**	**493,658**
Impairment of natural gas and oil properties	**907,812**	**—**	**—**	**—**	**907,812**
Taxes, other than income taxes	**33,666**	**3,557**	**57**	**—**	**37,280**
Operating Income (Loss)	**$ (157,725)**	**$ 122,620**	**$ 139**	**$ —**	**$ (34,966)**
Capital Investments [2]	**$ 1,565,450**	**$ 214,208**	**$ 29,459**	**$ —**	**$ 1,809,117**
Twelve Months Ending December 31, 2008					
Revenues	$ 1,491,302	$ 2,173,971	$ 118,399	$ (1,472,120)	$ 2,311,552
Gas purchases	—	2,043,417	79,120	(1,350,969)	771,568
Operating expenses	173,692	40,382	14,139	(120,636)	107,577
General & administrative expenses	80,215	13,522	8,737	(515)	101,959
Depreciation, depletion & amortization	399,159	11,402	3,847	—	414,408
Taxes, other than income taxes	24,732	2,899	1,641	—	29,272
Operating Income	$ 813,504	$ 62,349	$ 10,915	$ —	$ 886,768
Capital Investments [2]	$ 1,595,828	$ 183,021	$ 17,319	$ —	$ 1,796,168

(1) The twelve-month period ended December 31, 2008 includes operating results and capital investments associated with our natural gas distribution subsidiary, Arkansas Western Gas, for the first six months of 2008. On July 1, 2008, we closed the sale of Arkansas Western Gas and, as a result, we no longer have any natural gas distribution operations.

(2) Capital investments include increases of $24.6 million and $12.2 million for the three- and twelve-month periods ended December 31, 2009, respectively, and increases of $29.2 million and $36.2 million for the three- and twelve-month periods ended December 31, 2008, respectively, relating to the change in accrued expenditures between periods.