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NEWS RELEASE

SOUTHWESTERN ENERGY ANNOUNCES SECOND QUARTER 2011 FINANCIAL AND OPERATING RESULTS

Continued Strong Well Results from Marcellus Shale
Company Unveils New Venture Play; First Well To Be Drilled in Third Quarter

Houston, Texas – July 28, 2011...Southwestern Energy Company (NYSE: SWN) today announced financial and operating results for the second quarter of 2011. Highlights include:

- Natural gas and crude oil production of 122.8 Bcfe, up 25% over the same period in 2010
- Record net cash provided by operating activities before changes in operating assets and liabilities of $448.2 million (a non-GAAP measure reconciled below), up 30% from the same period in 2010
- Net income of $167.5 million, up 37% from the same period in 2010

For the second quarter of 2011, Southwestern reported net income of $167.5 million, or $0.48 per diluted share, compared to $122.1 million, or $0.35 per diluted share, for the prior year period. Net cash provided by operating activities before changes in operating assets and liabilities (a non-GAAP measure; see reconciliation below) was a record $448.2 million for the second quarter of 2011, up 30% from $345.7 million for the same period in 2010.

"We had a great second quarter," stated Steve Mueller, President and Chief Executive Officer of Southwestern Energy. "Our production continues to grow, primarily driven by our Fayetteville Shale operations. However, we are also beginning to see the impact of our Marcellus Shale activities on our production, as we placed several strong wells on-line during the quarter. Our current gross operated production from the Marcellus Shale is over 100 MMcf per day from 17 horizontal wells. Also in the second quarter, we closed the transaction we previously announced for the sale of our Haynesville and Middle Bossier properties in East Texas for approximately $108 million, before adjustments. Finally, we have announced a potential new unconventional horizontal oil play and hope to get two test wells drilled and completed by year-end."

For the first six months of 2011, Southwestern reported net income of $304.1 million, or $0.87 per diluted share, compared to $293.9 million, or $0.84 per diluted share, for the first six months of 2010. Net cash provided by operating activities before changes in operating assets and liabilities (a non-GAAP measure; see reconciliation below) was $839.7 million for the first six months of 2011, up 10% compared to $763.5 million for the same period in 2010.

Second Quarter 2011 Financial Results

E&P Segment - Operating income from the company's E&P segment was $222.5 million for the second quarter of 2011, up 37% from $162.5 million for the same period in 2010. The increase was primarily due to higher production volumes which were only partially offset by increased operating costs and expenses.

Gas and oil production totaled 122.8 Bcfe in the second quarter of 2011, up 25% from 98.3 Bcfe in the second quarter of 2010, and included 107.4 Bcf from the company's Fayetteville Shale play, up from 83.6 Bcf in the second quarter of 2010.

Including the effect of hedges, Southwestern's average realized gas price in the second quarter of 2011 was $4.30 per Mcf, compared to $4.27 per Mcf in the second quarter of 2010. The company's commodity hedging activities increased its average gas price by $0.46 per Mcf during the second quarter of 2011, compared to an increase of $0.58 per Mcf during the same period in 2010. At July 28, 2011, Southwestern had approximately 160 Bcf of its remaining 2011 projected natural gas production hedged through fixed price swaps and collars at a weighted average floor price of $5.21 per Mcf. The company also had approximately 266 Bcf of its 2012 forecasted gas production hedged at an average floor price of $5.16 per Mcf and approximately 185 Bcf of its 2013 forecasted gas production hedged at an average floor price of $5.06 per Mcf.

The company typically sells its natural gas at a discount to NYMEX settlement prices. This discount includes a basis differential, third-party transportation charges and fuel charges. Disregarding the impact of commodity price hedges, the company's average price received for its gas production during the second quarter of 2011 was approximately $0.47 per Mcf lower than average monthly NYMEX settlement prices, compared to approximately $0.40 per Mcf lower during the second quarter of 2010. In 2011, the company expects its total gas sales discount to NYMEX to be $0.45 to $0.50 per Mcf. As of July 28, 2011, the company had protected approximately 72 Bcf of its third quarter 2011 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 ($0.02) per Mcf, excluding transportation and fuel charges.

Lease operating expenses per unit of production for the company's E&P segment were $0.80 per Mcfe in the second quarter of 2011, compared to $0.85 per Mcfe in the second quarter of 2010. The decrease was primarily due to a decrease in salt water disposal costs in the company's Fayetteville Shale operations.

General and administrative expenses per unit of production were $0.27 per Mcfe in the second quarter of 2011, compared to $0.31 per Mcfe in the second quarter of 2010. The decrease was primarily due to the effects of the company's increased production volumes which more than offset increased payroll, incentive compensation and other employee-related costs primarily associated with the expansion of the company's operations due to the Fayetteville Shale play.

Taxes other than income taxes per unit of production were $0.11 per Mcfe in the second quarter of 2011, compared to $0.09 per Mcfe in the second quarter of 2010. Taxes other than income taxes vary due to changes in severance and ad valorem taxes that result from the mix of the company's volumes and fluctuations in commodity prices.

The company's full cost pool amortization rate was $1.28 per Mcfe in the second quarter of 2011, down from $1.33 per Mcfe in the second quarter of 2010. The decline in the average amortization rate was primarily the result of lower finding and development costs, combined with the sale of certain East Texas oil and natural gas leases and wells in the second quarter of 2010, as the proceeds from the sale were appropriately credited to the full cost pool. 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 $59.6 million for the second quarter of 2011, up 36% from $43.8 million for the second quarter of 2010. The increase in operating income was primarily due to the increase in gathering revenues from the company's Fayetteville and Marcellus Shale properties, partially offset by increased operating costs and expenses.

At July 28, 2011, the company's midstream segment was gathering approximately 2.0 Bcf per day through 1,696 miles of gathering lines in the Fayetteville Shale play area, up from approximately 1.6 Bcf per day through 1,367 miles of gathering lines a year ago. 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 and as it develops its Marcellus Shale properties.

<u>First Six Months of 2011 Financial Results</u>

E&P Segment **-** Operating income from the company's E&P segment was $400.8 million for the six months ended June 30, 2011, compared to $412.9 million for the same period in 2010. The decrease was primarily due to lower average realized gas prices and increased operating costs and expenses which were mostly offset by higher production volumes.

Gas and oil production was 237.8 Bcfe in the first six months of 2011, up 26% compared to 188.3 Bcfe in the first six months of 2010, and included 208.5 Bcf from the company's Fayetteville Shale play, up from 159.1 Bcf in the first six months of 2010.

Southwestern's average realized gas price was $4.21 per Mcf, including the effect of hedges, in the first six months of 2011 compared to $4.82 per Mcf in the first six months of 2010. The company's hedging activities increased the average gas price realized during the first six months of 2011 by $0.45 per Mcf, compared to an increase of $0.57 per Mcf during the first six months of 2010. Disregarding the impact of hedges, the average price received for the company's gas production during both the first six months of 2011 and 2010 was approximately $0.45 per Mcf lower than average monthly NYMEX settlement prices.

Lease operating expenses for the company's E&P segment were $0.83 per Mcfe in the first six months of 2011, compared to $0.81 per Mcfe in the first six months of 2010. The increase was primarily due to increased gathering and treating costs related to the company's Fayetteville Shale play.

General and administrative expenses were $0.27 per Mcfe in the first six months of 2011, compared to $0.30 per Mcfe in the first six months of 2010. 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 were $0.11 per Mcfe during the first six months of 2011, compared to $0.11 per Mcfe during the first six months of 2010.

The company's full cost pool amortization rate decreased to $1.30 per Mcfe in the first six months of 2011, compared to $1.37 per Mcfe in the first six months of 2010, primarily due to the sale of certain East Texas oil and natural gas leases and wells in the second quarter of 2010, as the proceeds from the sale were appropriately credited to the full cost pool, combined with lower finding and development costs.

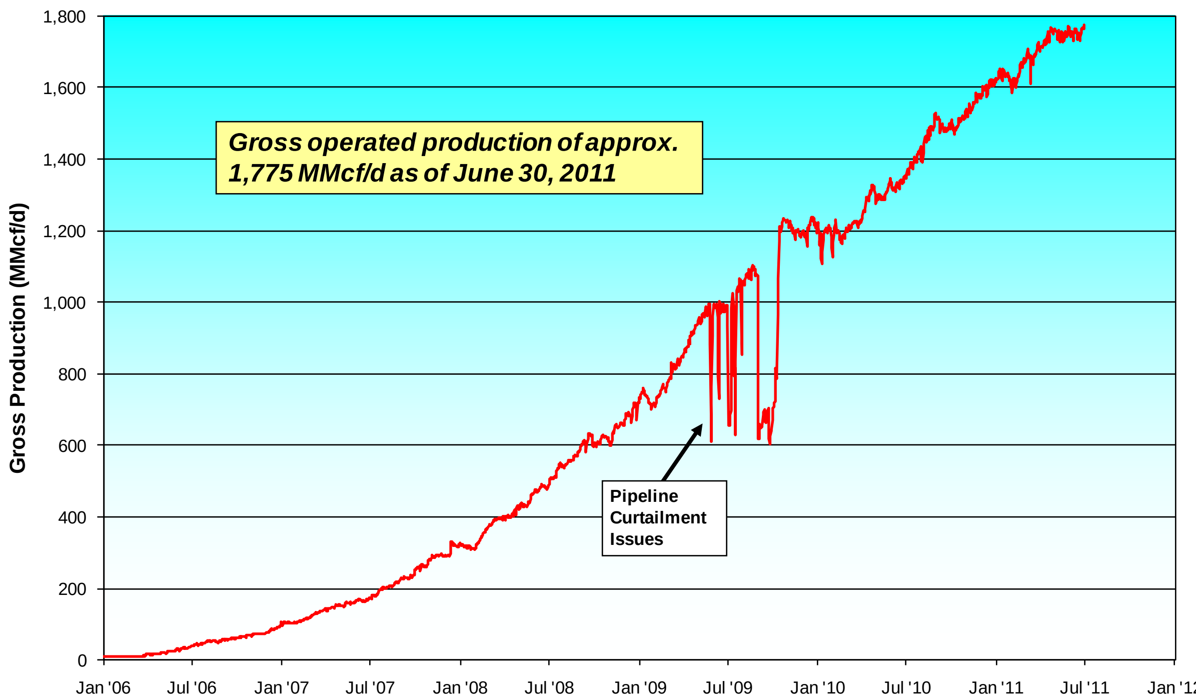
Midstream Services - Operating income for the company's midstream activities was $113.6 million in the first six months of 2011, up 40% compared to $81.4 million in the first six months of 2010. The increase in operating income was primarily due to increased gathering revenues related to the company's Fayetteville and Marcellus Shale properties, partially offset by increased operating costs and expenses.

Capital Structure and Investments - At June 30, 2011, the company had approximately $1.2 billion in long-term debt and its long-term debt-to-total capitalization was 27%.

For the first six months of 2011, Southwestern invested a total of approximately $1.1 billion, compared to $1.0 billion during the first six months of 2010, which included $944 million invested in its E&P business and $106 million invested in its Midstream Services activities. Of the $944 million invested in its E&P business, approximately $682 million was invested in its Fayetteville Shale play, $110 million in Appalachia, $80 million in New Ventures and $65 million in East Texas and its conventional Arkoma Basin program. Southwestern's total capital investments program for 2011 is expected to be approximately $2.0 billion.

E&P Operations Review

Fayetteville Shale Play – During the second quarter of 2011, Southwestern placed a total of 149 operated wells on production in the Fayetteville Shale play, all of which were horizontal wells fracture stimulated using slickwater. At July 25, 2011, the company's gross production rate from the Fayetteville Shale play was approximately 1.8 Bcf per day, up from approximately 1.4 Bcf per day a year ago. The company is currently utilizing 18 drilling rigs in its Fayetteville Shale play, including 12 that are capable of drilling horizontal wells and 6 smaller rigs that are used to drill the vertical portion of the wells. The graph below provides gross production data from the company's operated wells in the Fayetteville Shale play area through July 25, 2011.



During the second quarter of 2011, the company's horizontal wells had an average completed well cost of $2.8 million per well, average horizontal lateral length of 4,839 feet and average time to drill to total depth of 8.2 days from re-entry to re-entry. This compares to an average completed well cost of $2.8 million per well, average horizontal lateral length of 4,985 feet and average time to drill to total depth of 8.4 days from re-entry to re-entry in the first quarter of 2011. In the second quarter of 2011, the company had 10 operated wells placed on production which had average times to drill to total depth of 5 days or less from re-entry to re-entry. In total, the company has had a total of 55 wells drilled to total depth of 5 days or less from re-entry to re-entry.

The company's wells placed on production during the second quarter of 2011 averaged initial production rates of 3,014 Mcf per day, down 7% from average initial production rates of 3,231 Mcf per day in the first quarter of 2011, primarily due to shorter lateral lengths, increased well density and locational differences in the mix of wells. Results from the company's drilling activities from 2007 by quarter are shown below.

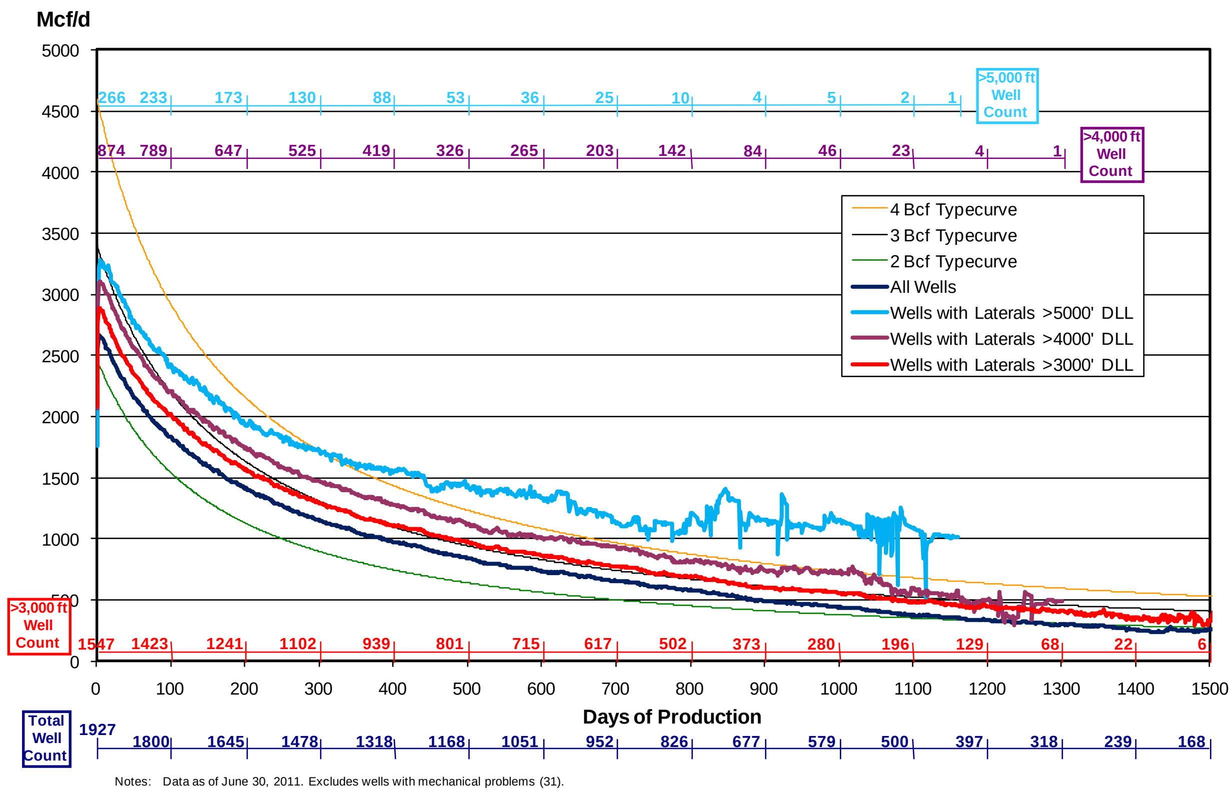
Time Frame	Wells Placed on Production	Average IP Rate (Mcf/d)	30th-Day Avg Rate (# of wells)	60th-Day Avg Rate (# of wells)	Average Lateral Length
1st Qtr 2007	58	1,261	1,066 (58)	958 (58)	2,104
2nd Qtr 2007	46	1,497	1,254 (46)	1,034 (46)	2,512
3rd Qtr 2007	74	1,769	1,510 (72)	1,334 (72)	2,622
4th Qtr 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	3,727	2,674 (122)	2,360 (120)	4,303
1st Qtr 2010(2)	106	3,197(2)	2,388 (106)	2,123 (106)	4,348
2nd Qtr 2010	143	3,449	2,575 (141)	2,329 (141)	4,532
3rd Qtr 2010	145	3,281	2,448 (145)	2,202 (144)	4,503
4th Qtr 2010	159	3,472	2,678 (159)	2,294 (159)	4,667
1st Qtr 2011	137	3,231	2,604 (137)	2,260 (135)	4,985
2nd Qtr 2011	149	3,014	2,303 (133)	1,943 (79)	4,839

Note: Results as of June 30, 2011.

(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.

(2) In the first quarter of 2010, the company's results were impacted by the shift of all wells to "green completions" and the mix of wells, as a large percentage of wells were placed on production in the shallower northern and far eastern borders of the company's acreage.

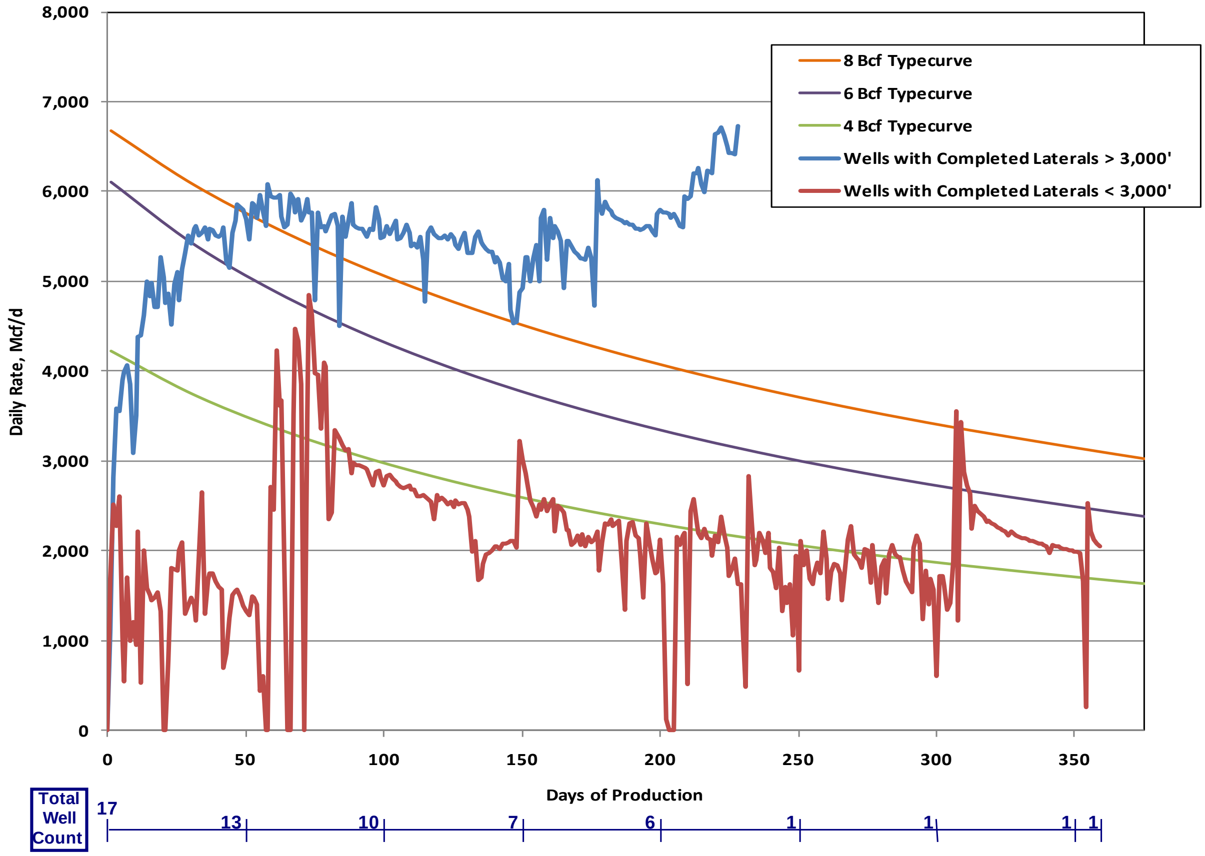
The graph below provides normalized average daily production data through June 30, 2011, for the company's horizontal wells using slickwater and crosslinked gel fluids. The "dark blue curve" is for horizontal wells fracture stimulated with either slickwater or crosslinked gel fluid. The "red curve" indicates 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 and the "light blue curve" indicates results for the company's wells with lateral lengths greater than 5,000 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, 3 and 4 Bcf typecurves are shown solely for reference purposes and are not intended to be projections of the performance of the company's wells.



Appalachia – Southwestern has participated in a total of 28 wells in northeast Pennsylvania, of which 18 were successful and 10 were in progress at June 30, 2011. The producing wells are all operated Marcellus Shale wells located in its Greenzweig area in Bradford County. Net production from the area was 5.1 Bcf in the second quarter of 2011, compared to 2.8 Bcf in the first quarter of 2011 and 0.8 Bcf in the fourth quarter of 2010. The company is currently running one drilling rig and is moving in another rig which will begin drilling in Susquehanna County in August.

Of the four wells put on production in June, of particular note is the Ball Myer 1H well located in Bradford County. This well had a completed lateral of 4,502 feet and was fracture stimulated in 19 stages and is currently producing at a tubing constrained rate of approximately 7.8 MMcf per day at a flowing tubing pressure of 1,396 psi after 33 days of production. Previous to this well, the company's horizontal wells have had average lateral lengths of approximately 3,900 feet and have averaged 10 stages of completion. Gross operated production from the area is currently approximately 104 MMcf per day.

The graph below provides normalized average daily production data through June 30, 2011, for the company's horizontal wells in the Marcellus Shale. The "red curve" indicates results for one well with a lateral length less than 3,000 feet, while the "blue curve" indicates results for the company's wells with lateral lengths greater than 3,000 feet. The normalized production curves are intended to provide a qualitative indication of the company's Marcellus Shale wells' performance and should not be used to estimate an individual well's estimated ultimate recovery. The 4, 6 and 8 Bcf typecurves are shown solely for reference purposes and are not intended to be projections of the performance of the company's wells.



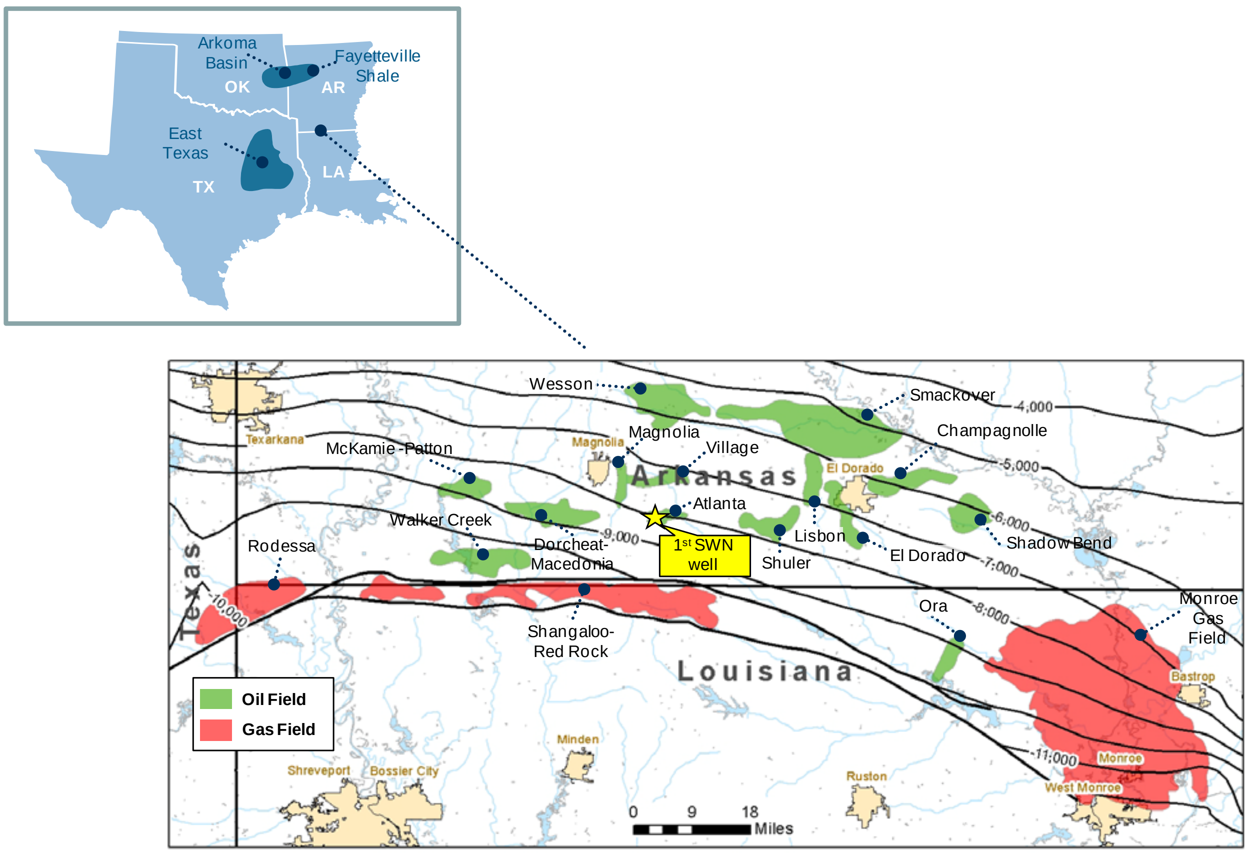
Notes: Data as of June 30, 2011.
Red curve represents production from one well.

***Other Areas* –** Total net production from the company's East Texas and conventional Arkoma Basin properties was 21.4 Bcfe during the first six months of 2011, compared to 29.2 Bcfe in the first six months of 2010. The company participated in drilling 5 wells in these areas during the first six months of 2011, 3 of which were operated.

In the second quarter of 2011, Southwestern sold certain oil and natural gas leases, wells and gathering equipment in Shelby, San Augustine and Sabine Counties in East Texas for approximately $108.1 million, before customary purchase price adjustments. This divestiture included only the producing rights to the Haynesville and Middle Bossier Shale intervals in this acreage with net production of approximately 7.0 MMcf per day as of May 25, 2011 and proved net reserves of approximately 25.1 Bcf at December 31, 2010. At closing, the company deposited $85 million of proceeds from this sale with a qualified intermediary to facilitate potential like-kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code.

New Ventures – At June 30, 2011, Southwestern held 2,518,518 net undeveloped acres which were located in New Brunswick, Canada and approximately 835,000 net undeveloped acres in connection with other New Ventures prospects. In New Brunswick, the company is currently in the acquisition phase of approximately 410 miles of 2-D data and plans to have that finished in September. The company is also in the second phase of surface geochemical sampling which will provide more information on potential hydrocarbon presence.

Included in the approximately 835,000 net acres are 460,000 net acres where the company will begin testing a new unconventional horizontal oil play. Late in the third quarter, the company plans to spud its first test well targeting the Lower Smackover Brown Dense formation, an unconventional oil reservoir found in southern Arkansas and northern Louisiana. The formation, which ranges in vertical depths from 8,000 to 11,000 feet, appears to be laterally extensive over a large area ranging in thickness from 300 to 550 feet. The company's investment in undeveloped acreage in the play area to date is approximately $150 million and its leases currently have an 82% average net revenue interest and an average primary lease term of 4 years with 4-year extensions. Below is a map indicating the company's general area of interest in the play.



"We are very excited to announce our position in the Lower Smackover Brown Dense play which we have been working on for over two years. The formation is an Upper Jurassic age, kerogen-rich carbonate source rock found across the Gulf Coast region of the southern United States from Texas to Florida. We extensively reviewed the Brown Dense across the region and have indications that the right mix of reservoir depth, thickness, porosity, matrix permeability, sealing formations, thermal maturity and oil characteristics are found in the area of Southern Arkansas and Northern Louisiana. This region of Arkansas and Louisiana has produced oil and gas from the Upper Smackover since the 1920s. The Brown Dense formation is the source rock for these Upper Smackover fields. It has the critical properties necessary to be a successful play and compares favorably to other productive oil plays in the United States. However, it has never been exploited with horizontal drilling technology until now," stated Mueller.

"We hope to receive a permit to drill our first well in Columbia County, Arkansas, in August and will spud later in the third quarter. This well is planned to drill to a vertical depth of approximately 8,900 feet and has a planned horizontal lateral length of 3,500 feet. The well will be extensively logged and a full core will be obtained over the entire Brown Dense interval before the well is completed. Our second well is planned to spud later this year with a total vertical depth of approximately 10,700 feet and a 6,000-foot horizontal lateral in Claiborne Parish, Louisiana. We plan to drill up to 10 additional wells as we continue to test the concept in 2012. If our testing yields positive results, we expect that our activity in the play could increase significantly over the next several years.

"I am very proud of our New Ventures team which has worked on this play for over two years now, analyzing log data on literally thousands of wells across the play area and thousands of miles of 2-D seismic data. While its commerciality is still to be determined, we believe that our position could have a significant positive impact on our company. We are also working on other New Ventures ideas and will provide updates on those in the future. In the meantime, we're poised to have a very successful year in 2011 and believe that the combination of our Fayetteville, Marcellus and New Venture programs will continue to provide significant value creation for our shareholders."

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 with 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.

See the reconciliations below of GAAP financial measures to non-GAAP financial measures for the three and six months ended June 30, 2011 and June 30, 2010. 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.

	3 Months Ended June 30,	
	2011	**2010**
	(in thousands)	
Cash flow from operating activities:		
Net cash provided by operating activities	$ 460,451	$ 391,474
Add back (deduct):		
Change in operating assets and liabilities	(12,237)	(45,744)
Net cash provided by operating activities before changes in operating assets and liabilities	$ 448,214	$ 345,730

	6 Months Ended June 30,	
	2011	**2010**
	(in thousands)	
Cash flow from operating activities:		
Net cash provided by operating activities	$ 856,930	$ 809,053
Add back (deduct):		
Change in operating assets and liabilities	(17,184)	(45,558)
Net cash provided by operating activities before changes in operating assets and liabilities	$ 839,746	$ 763,495

Southwestern will host a teleconference call on Friday, July 29, 2011, at 10:00 a.m. Eastern to discuss the company's second quarter 2011 results. The toll-free number to call is 877-407-8035 and the international dial-in 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

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