

**UPLIFTING**

$$\frac{R^2}{A} = V^+ \text{®}$$

**SWN**  
Southwestern Energy®

---

**August 2012 Update**

---

**NYSE: SWN**

## • General Information •

Southwestern Energy Company is an independent natural gas company whose wholly-owned subsidiaries are engaged in natural gas and oil exploration and production and natural gas gathering and marketing.

## • Market Data as of August 1, 2012 •

NYSE: SWN

Shares of Common Stock Outstanding – 349,110,361

Market Capitalization – \$11,520,000,000

Institutional Ownership – 90.2%

Management and Board Ownership – 2.8%

52-Week Price Range – \$25.82 (6/13/12) – \$44.21 (10/28/11)

## • Investor Contacts •

**Greg D. Kerley**

Executive Vice President and Chief Financial Officer

Phone: (281) 618-4803 Fax: (281) 618-4820

**Brad D. Sylvester, CFA**

Vice President, Investor Relations

Phone: (281) 618-4897 Fax: (281) 618-4820

All statements, other than historical facts and 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 fund the company's planned capital investments; 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 impact of government regulation, including any increase in severance or similar taxes, legislation relating to hydraulic fracturing, the climate and over the counter derivatives; the costs and availability of oilfield personnel, services and drilling supplies, raw materials, and equipment, including pressure pumping equipment and crews; the company's ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation; the company's future property acquisition or divestiture activities; the impact of the adverse outcome of any material litigation against the company; the effects of weather; increased competition and regulation; 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.

The SEC has generally permitted oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We use the terms "estimated ultimate recovery," "EUR," "probable," "possible," and "non-proven" reserves, reserve "potential" or "upside" or other descriptions of volumes of reserves potentially recoverable through additional drilling or recovery techniques that the SEC's guidelines may prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being actually realized by the company.

The contents of this presentation are current as of August 2, 2012.

- **Focused on exploration and production of natural gas.**
  - *5.9 Tcfe of reserves; 11.8 R/P at year-end 2011.*
- **E&P strategy built on organic growth through the drillbit.**
  - *Over 80% of planned E&P capital allocated to drilling in 2012.*
- **Track record of adding significant reserves at low costs.**
  - *From 2006 to 2011, we've averaged over 40% annual production and reserve growth and annually replaced over 400% of our production at an F&D cost of \$1.31 per Mcfe.*
- **Proven management team has increased Southwestern's market capitalization from \$187 million at year-end 1998 to over \$11 billion today.**
- **Strategy built on the Formula:**

$$\frac{R^2}{A} \rightarrow V^+ \text{®}$$

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

- **First Six Months of 2012 Highlights**

- *Production of 270.8 Bcfe, up 14%, due to strong Fayetteville and Marcellus results.*
- *Currently drilling on 3 New Ventures ideas – the Lower Smackover Brown Dense formation in southern Arkansas and northern Louisiana, the Marmaton/Atoka oil play in Colorado and the Bakken/Three Forks play in Montana.*
- *One of the lowest cost operators in the industry – finding and development costs<sup>(1)</sup> of \$1.31 per Mcfe and cash operating costs<sup>(2)</sup> of \$1.20 per Mcfe.*
- *Strong balance sheet and financial position as of June 30, 2012:*
  - *Net debt-to-book capitalization ratio of 30%.*
  - *Nothing drawn on unsecured revolving credit facility of \$1.5 billion.*
  - *Cash on hand of approximately \$41 million; restricted cash of approximately \$144 million.*

- **Strong Growth and Low-Cost Operations Set the Stage for a Record 2012**

- *2012 projected capital investment program of \$2.1 billion.*
- *2012 production projected to grow 13%.*

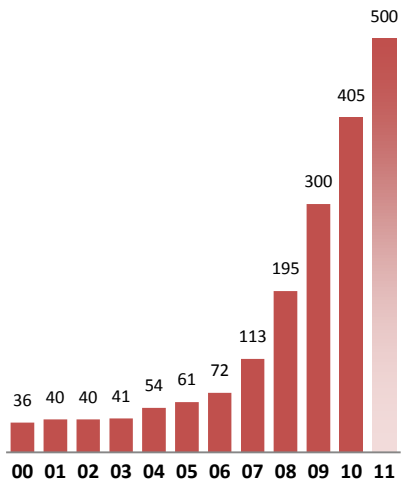
(1) Finding and development costs for the twelve months ended December 31, 2011 includes reserve revisions and excludes capital investments in our sand facility, drilling rig related and ancillary equipment of approximately \$21 million. Excluding revisions and capital investments in our sand facility, drilling rig related and ancillary equipment, our finding and development cost was \$1.34/Mcfe.

(2) Cash operating costs for the three months ended June 30, 2012, include lease operating expenses (\$0.79/Mcfe), general and administrative expenses (\$0.27/Mcfe), taxes other than income taxes (\$0.08/Mcfe) and net interest expense (\$0.06/Mcfe).

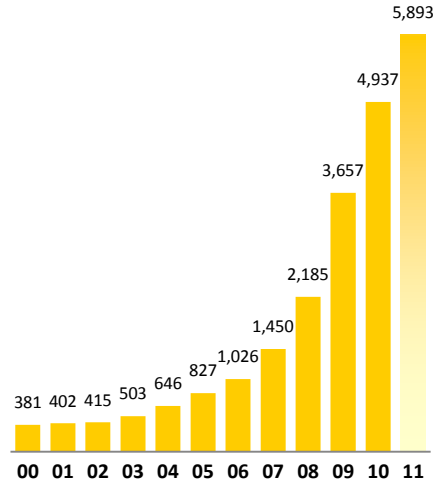
# Proven Track Record

For the Periods Ended December 31

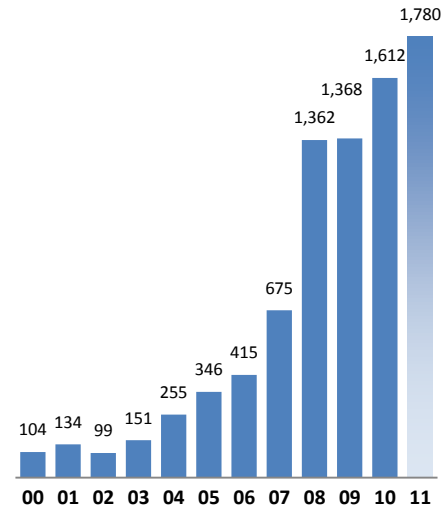
**Production (Bcfe)**



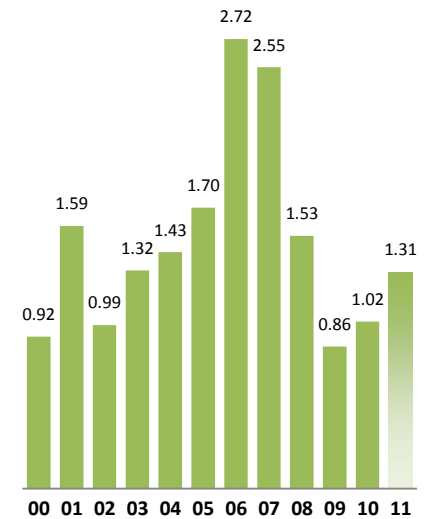
**Proved Reserves (Bcfe)**



**EBITDA (\$MM) (1)**

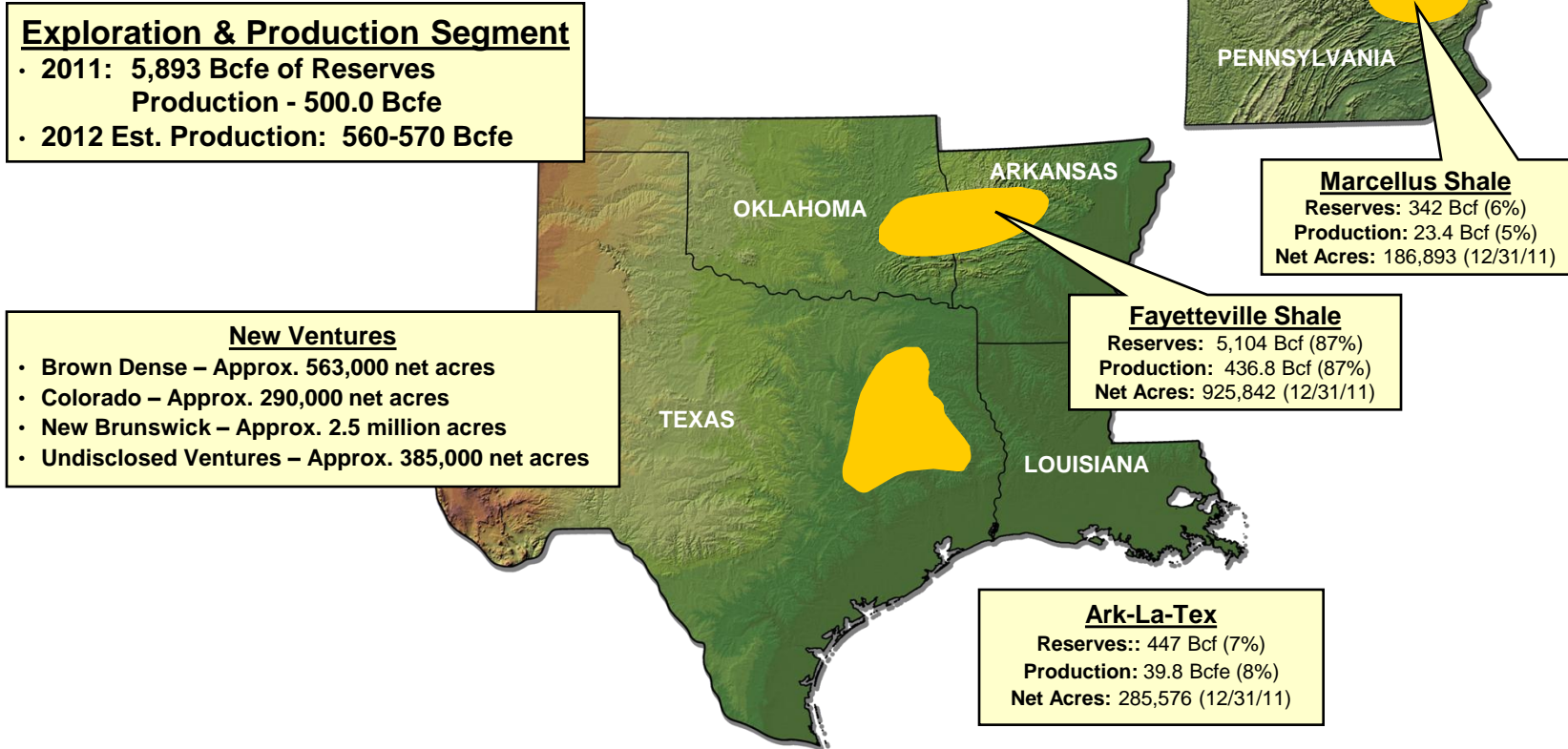


**F&D Cost (\$/Mcf)**



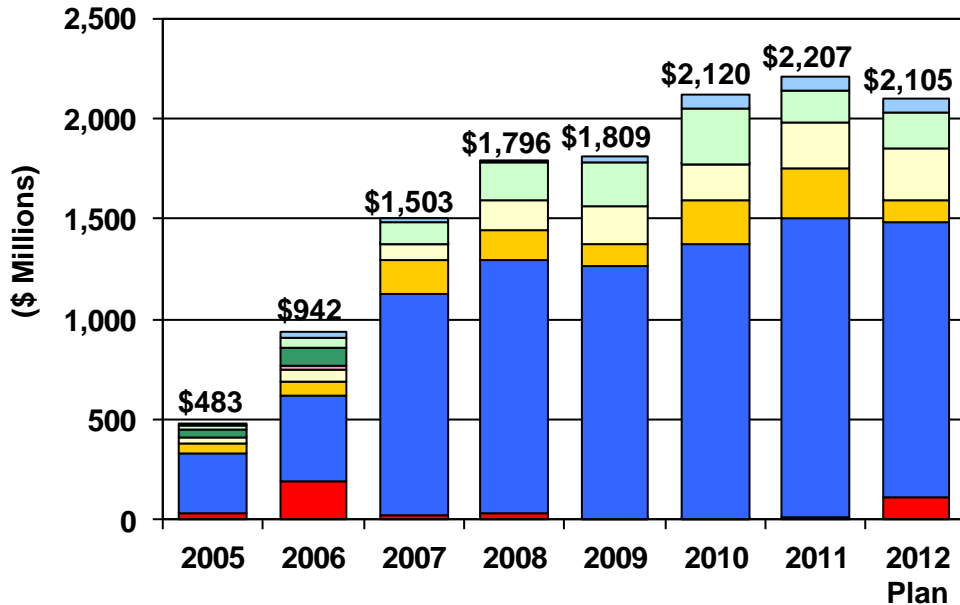
Note: Reserve data includes reserve revisions and excludes capital investments in our sand facility, drilling rig related and ancillary equipment.

(1) EBITDA is a non-GAAP financial measure. See explanation and reconciliation of EBITDA on page 34.

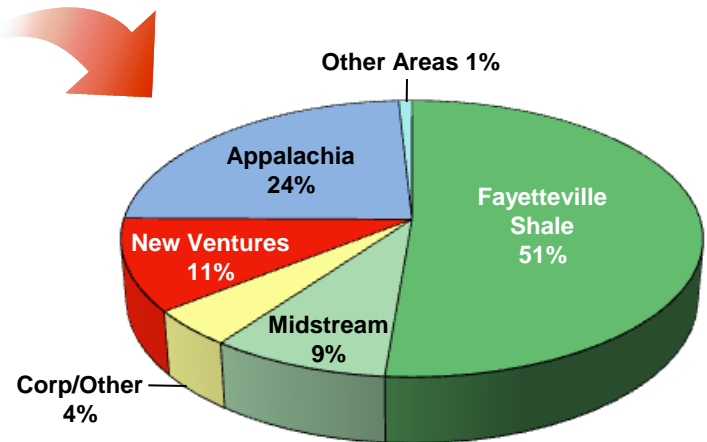


- Southwestern’s E&P segment operates in Arkansas, Texas, Pennsylvania, Louisiana, Oklahoma and New Brunswick.
- Midstream Services segment provides marketing and gathering services for the E&P business.

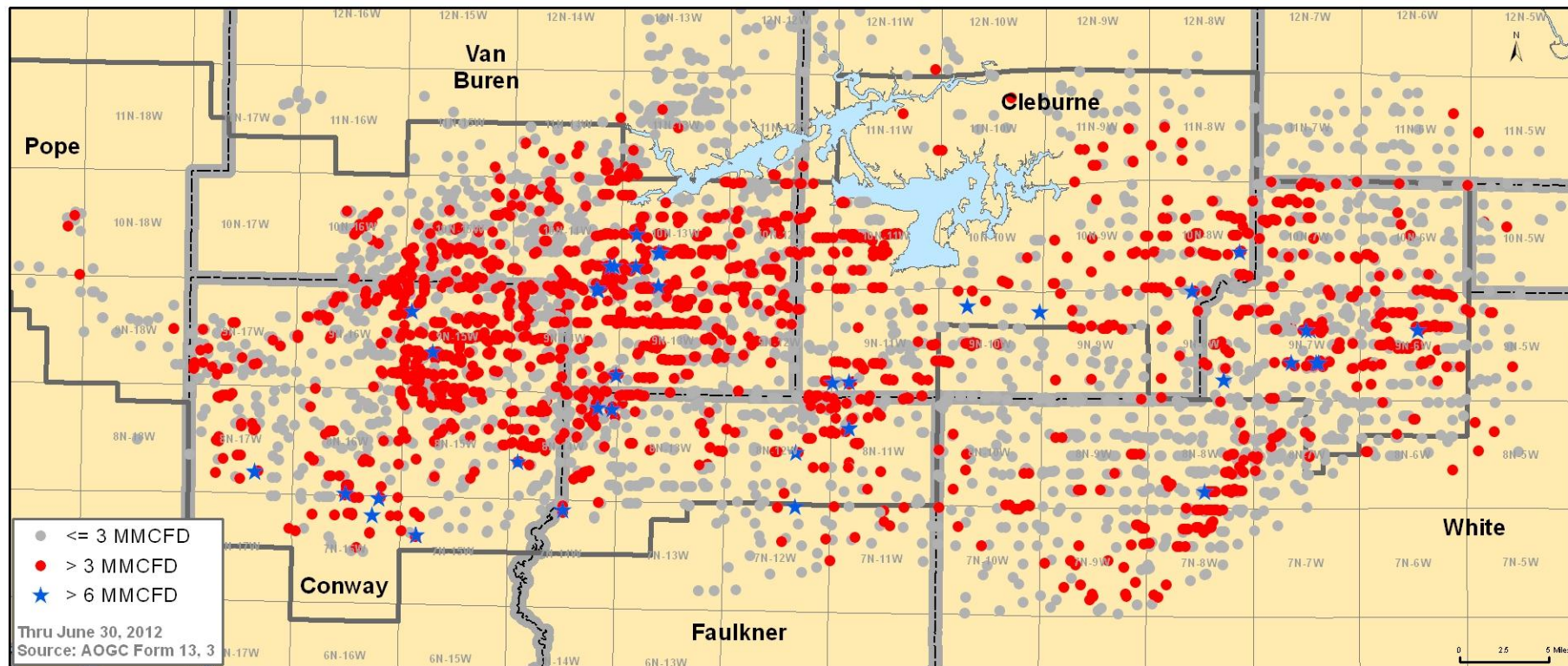
Notes: ArkLaTex acreage excludes 125,056 net acres in the conventional Arkoma Basin operating area that are also within the company’s Fayetteville Shale focus area. Reserves and acreage as of December 31, 2011. Production is a total annual amount for 2011.



- E&P capital program heavily weighted to low-risk development drilling in 2012.
- Plan to invest approximately \$1.2 billion in the Fayetteville Shale and \$600 million in the Marcellus Shale (including Midstream) in 2012.



# Fayetteville Shale Focus Area

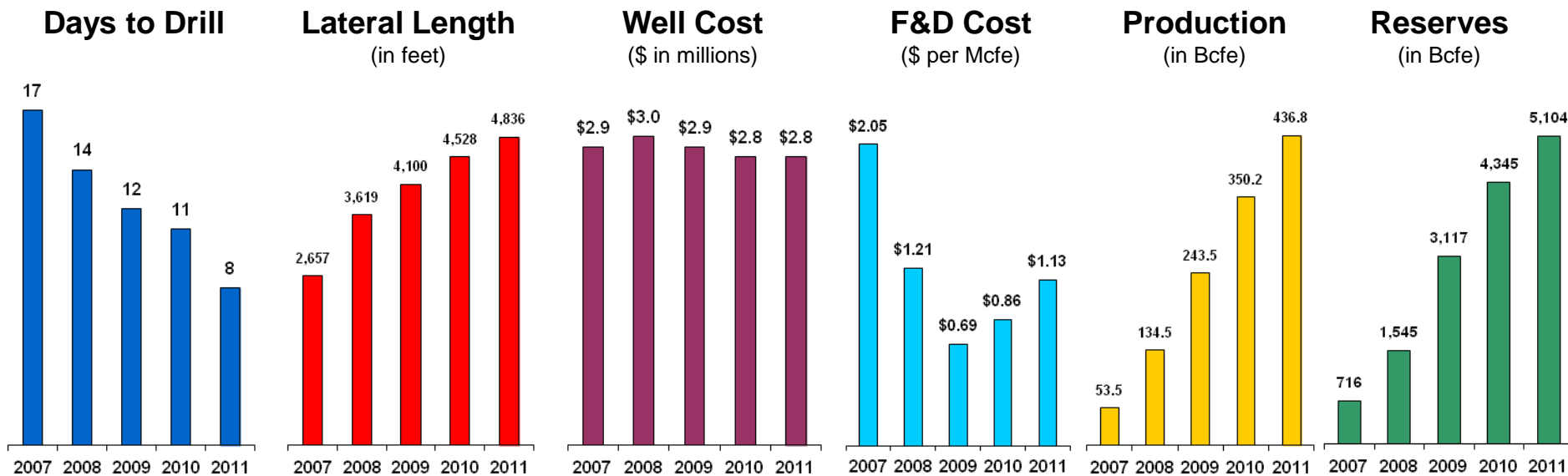


- SWN holds approx. 925,000 net acres in the Fayetteville Shale play (approx 1,400 sq. miles).
- Mississippian-age shale, geological equivalent of the Barnett Shale in north Texas.
- SWN discovered the Fayetteville Shale and has first mover advantage – average acreage cost of \$253 per acre with a 15% royalty and average working interest of 74%.
- We plan to drill approximately 430-440 operated wells in 2012.

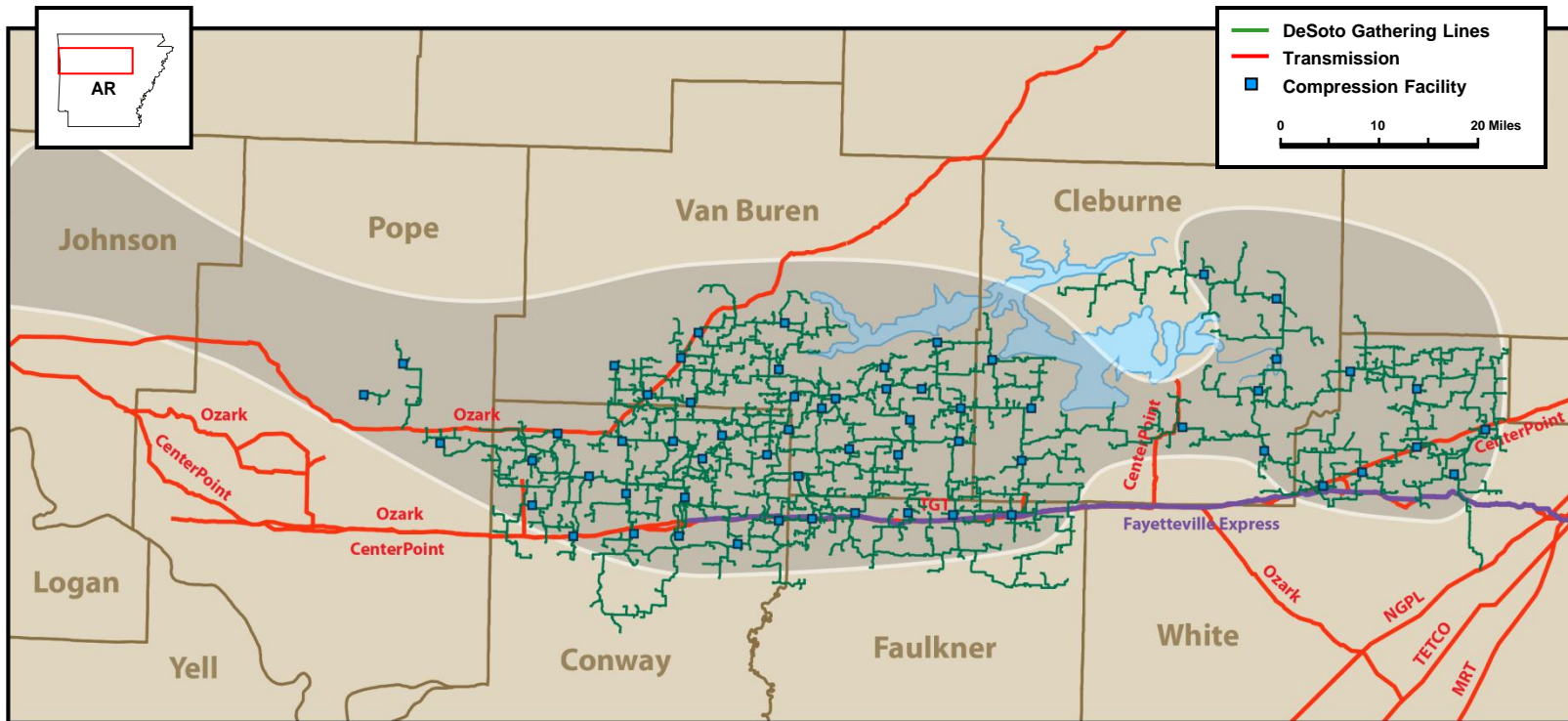
Notes: Rates are AOGC Form 13 and Form 3 test rates.

Forward-Looking Statement

# Fayetteville Shale - Continuous Improvement



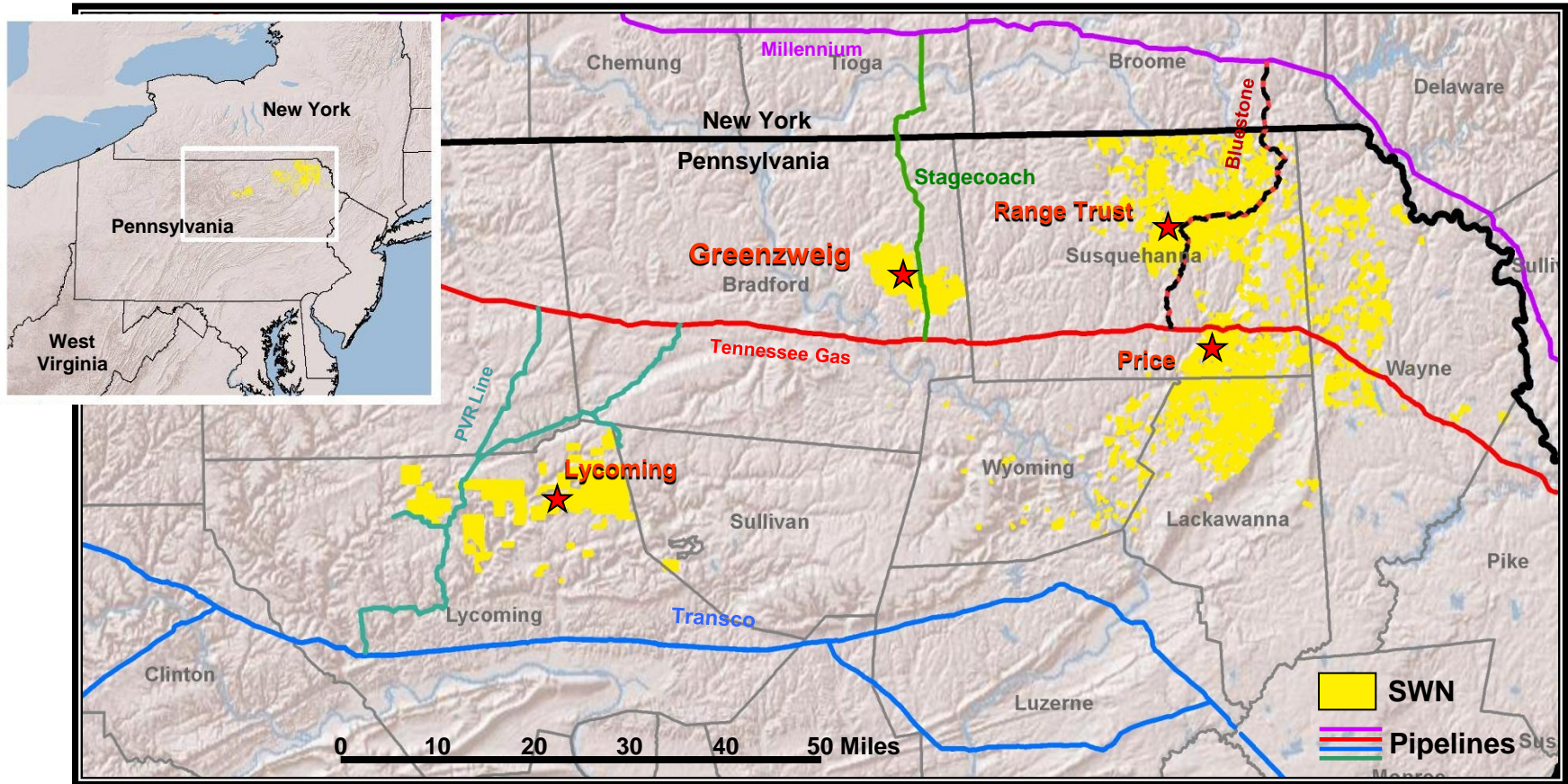
- **Continuous improvement in our Fayetteville Shale operations – completed lateral length has increased 82% over the last four years while holding total well costs flat.**
- **Vertical integration and contiguous acreage position allow us significant economies of scale and operating flexibility.**



- SWN's Fayetteville Shale gathering system is one of the largest in the U.S.
- At June 30, 2012, gathering approximately 2.1 Bcf per day through 1,829 miles of gathering lines, up from approximately 2.0 Bcf per day the same time a year ago.
- SWN has total firm transportation for the Fayetteville Shale of 2.0 Bcf per day.
- Midstream total EBITDA in 2011 was \$285 million. Projected EBITDA of \$310-\$315 million in 2012.

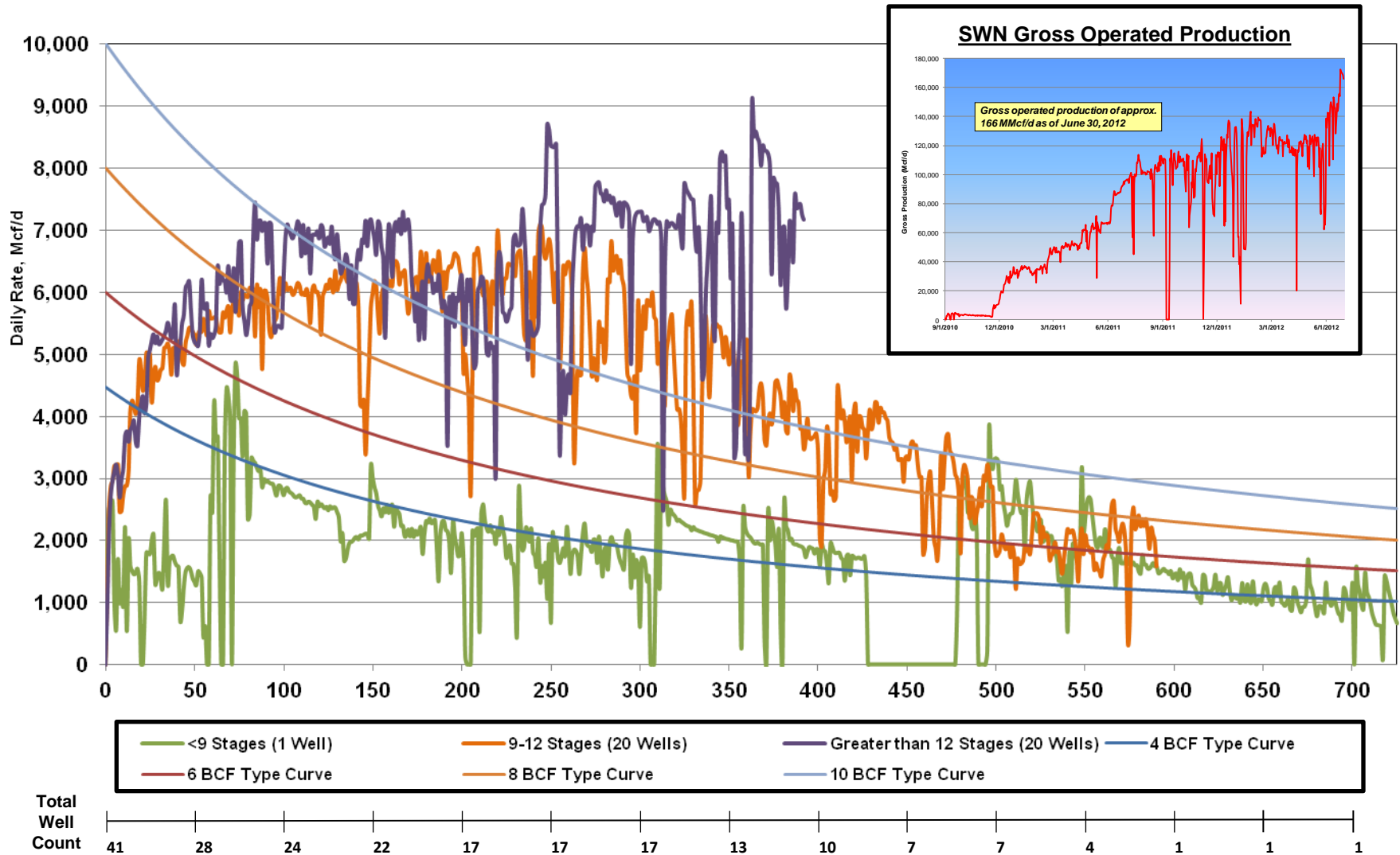
Note: Map as of June 30, 2012.

(1) EBITDA is a non-GAAP financial measure. See explanation and reconciliation of EBITDA on page 34.



- We hold approximately 187,000 net acres in Northeast Pennsylvania.
- At June 30, 2012, we had 41 operated Marcellus Shale horizontal wells on production in Bradford and Susquehanna Counties. Daily gross operated production was approximately 166 MMcf per day.
- Currently running 3 operated rigs with plans to drill up to 60-70 wells in 2012.

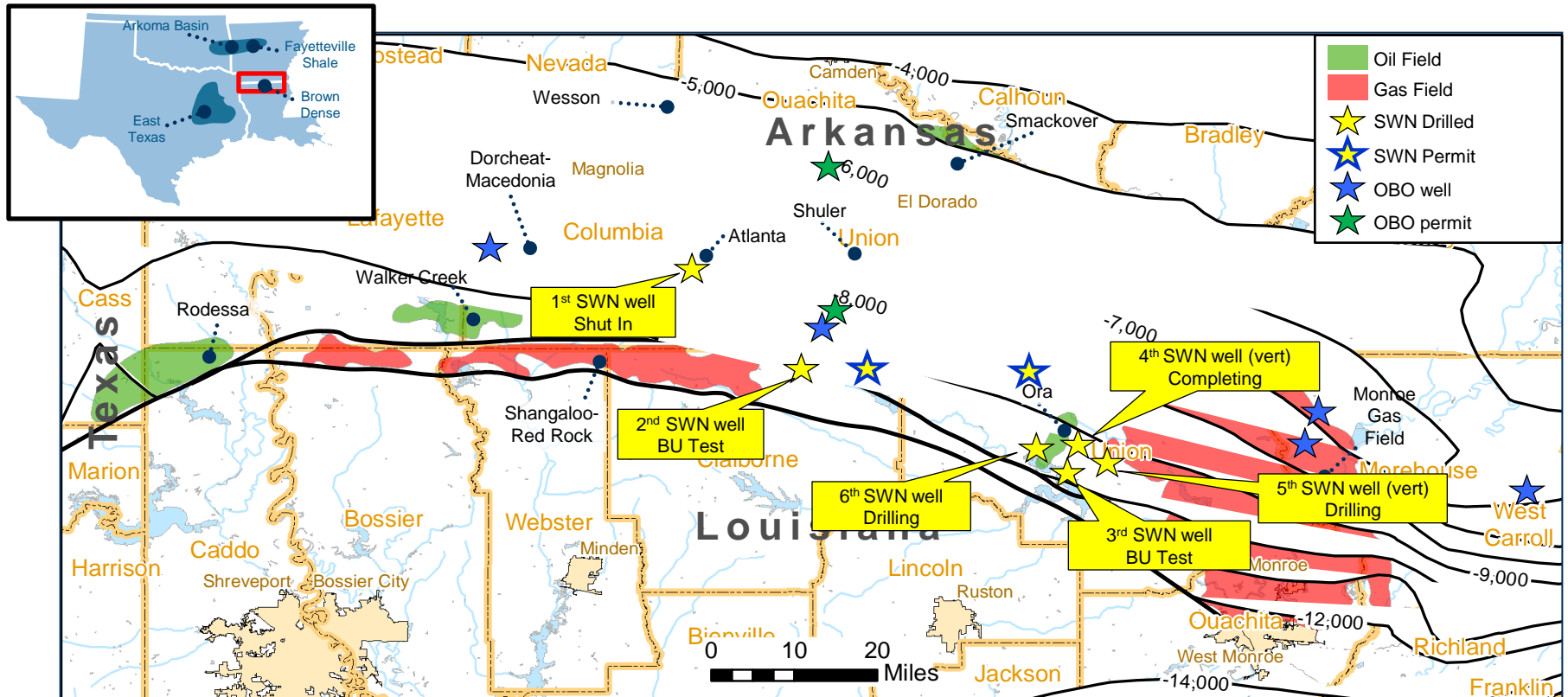
# Marcellus Shale - Horizontal Well Performance



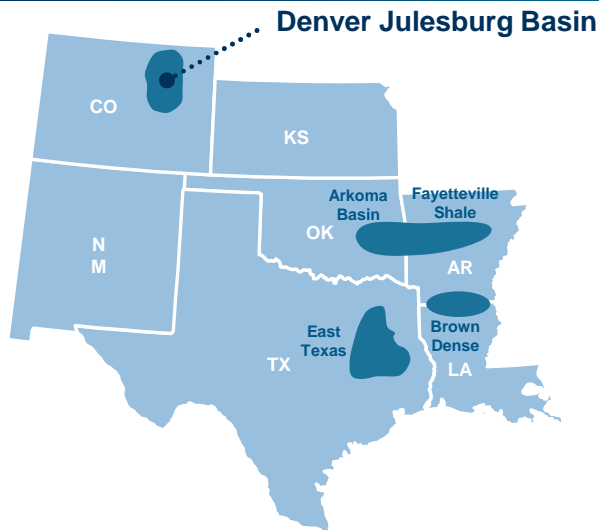
Notes: Data as of June 30, 2012.

$\frac{R^2}{A} \rightarrow V^+$

# Brown Dense Exploration Project

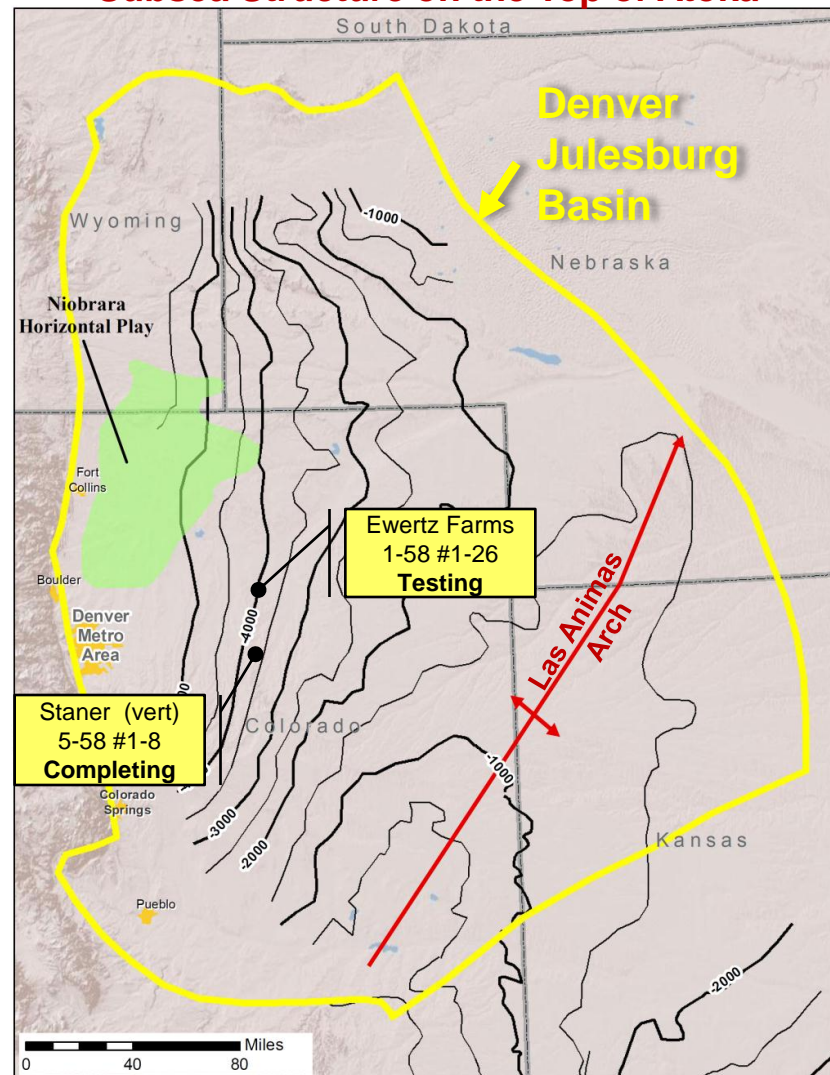


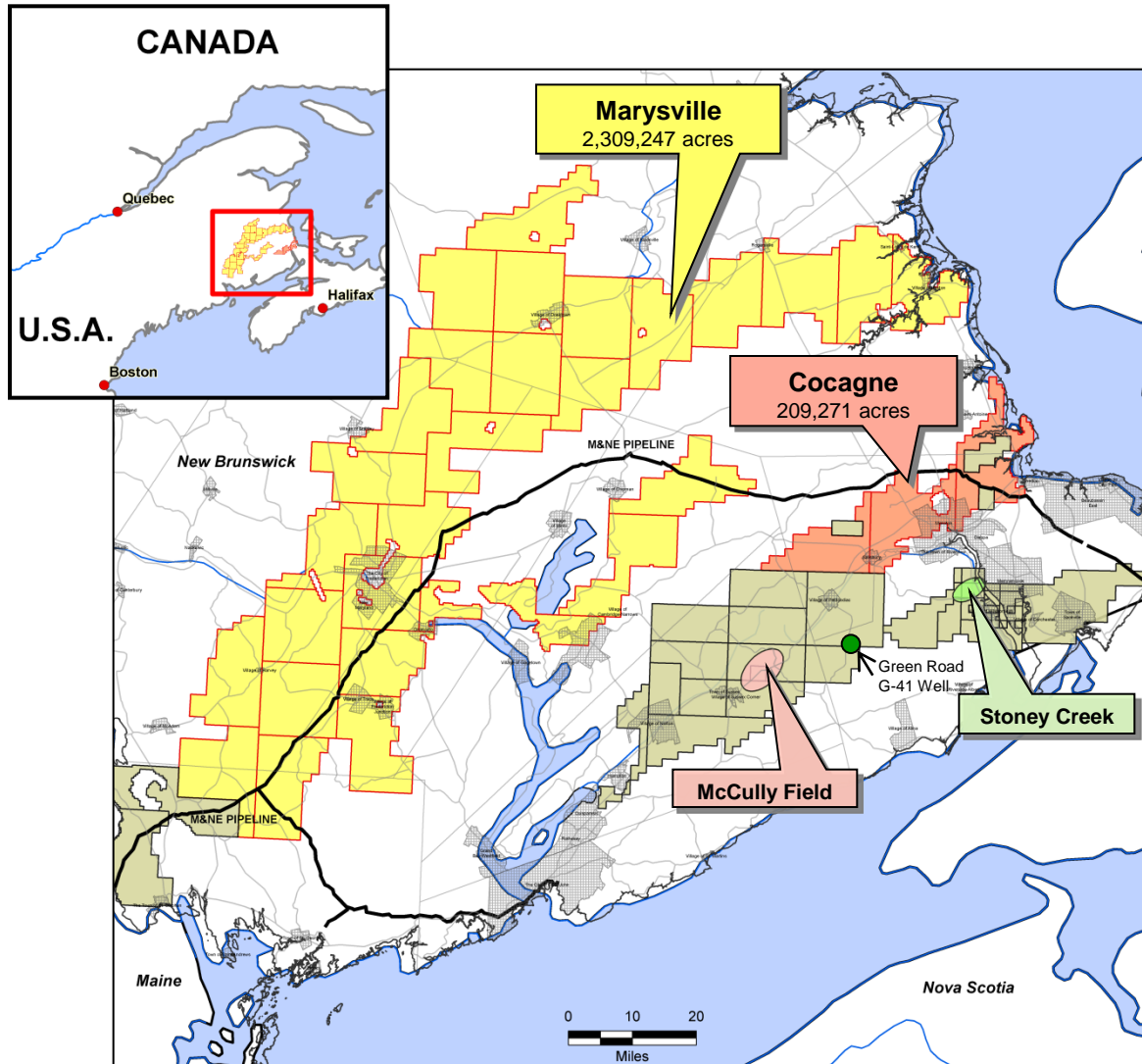
- **SWN currently holds 563,000 net acres in Lower Smackover Brown Dense play. Total land cost of approx. \$398 per acre; 82% NRI; leases have 4-year terms and 4-year extensions.**
- **Targeting oil window in Upper Jurassic age, kerogen-rich carbonate in southern Arkansas and northern Louisiana with horizontal drilling.**
  - *Targeting 300 to 550 feet thick section at depths of 8,000 - 11,000 feet.*
- **Currently performing operations on 6 wells.**



- SWN held 290,000 net acres at 6/30/12 with a total land cost of approx. \$170 per acre; 85% NRI; leases with 5-year terms and 3-year extensions.
- Targeting unconventional oil in late Pennsylvanian-age carbonates and shales with thicknesses of 300 - 750 feet at depths of 8,000 - 10,500 feet.
- Currently performing operations on 2 wells.

## Subsea Structure on the Top of Atoka





- SWN currently holds exploration licenses to over 2.5 million acres within the Maritimes Basin
- Principal targets are the conventional and unconventional sandstone and shale reservoirs of the Horton Group (Frederick Brook Shale)
- Oil and gas production from fields along southern flank:
  - McCully – reserves 190 bcfg
  - Stoney Creek – cum 800,000 bo, 30 bcfg
- 3-year initial exploration license to complete work program
  - Total \$47MM work commitment with options of multiple 5-yr extension leases

- Production target of 560-570 Bcfe in 2012 (estimated growth of ~13%).

	2011 Actual	2012 Guidance		
		NYMEX Price Assumption		
	\$4.04 Gas \$94.01 Oil	\$2.50 Gas \$95.00 Oil	\$2.75 Gas \$95.00 Oil	\$3.00 Gas \$95.00 Oil
➤ Adj. Net Income	\$637.8 MM	\$410-\$420 MM <sup>(1)</sup>	\$450-\$460 MM <sup>(1)</sup>	\$490-\$500 MM <sup>(1)</sup>
➤ Adj. Diluted EPS	\$1.82	\$1.17-\$1.20 <sup>(1)</sup>	\$1.29-\$1.32 <sup>(1)</sup>	\$1.40-\$1.43 <sup>(1)</sup>
➤ EBITDA <sup>(2)</sup>	\$1,779.6 MM	\$1,510-\$1,520 MM	\$1,580-\$1,590 MM	\$1,650-\$1,660 MM
➤ Net Cash Flow <sup>(2)</sup>	\$1,766.0 MM	\$1,480-\$1,490 MM	\$1,550-\$1,560 MM	\$1,620-\$1,630 MM
➤ CapEx	\$2,207.2 MM	\$2,105 MM	\$2,105 MM	\$2,105 MM
➤ Debt %	25%	31%-33% <sup>(3)</sup>	30%-32% <sup>(3)</sup>	29%-31% <sup>(3)</sup>

(1) Adjusted net income and adjusted diluted EPS for 2012 excludes a \$578.9 million after-tax non-cash ceiling test impairment and both are non-GAAP financial measures. See explanation and reconciliation on page 33.

(2) Net cash flow is net cash flow before changes in operating assets and liabilities. Net cash flow and EBITDA are non-GAAP financial measures. See explanation and reconciliation of non-GAAP financial measures on pages 32 and 34.

(3) 2012 projected book capitalization includes the effect of the \$578.9 million after-tax non-cash ceiling test impairment in the second quarter of 2012.

- **Invest in the Highest PVI Projects.**
- **Flexibility in 2012 Capital Program.**
- **Maintain Strong Balance Sheet.**
- **Deliver the Numbers.**
  - **Production and Reserves.**
  - **Maximize Cash Flow.**
- **Continue to Tell Our Story.**

# *Appendix*

# Financial & Operational Summary

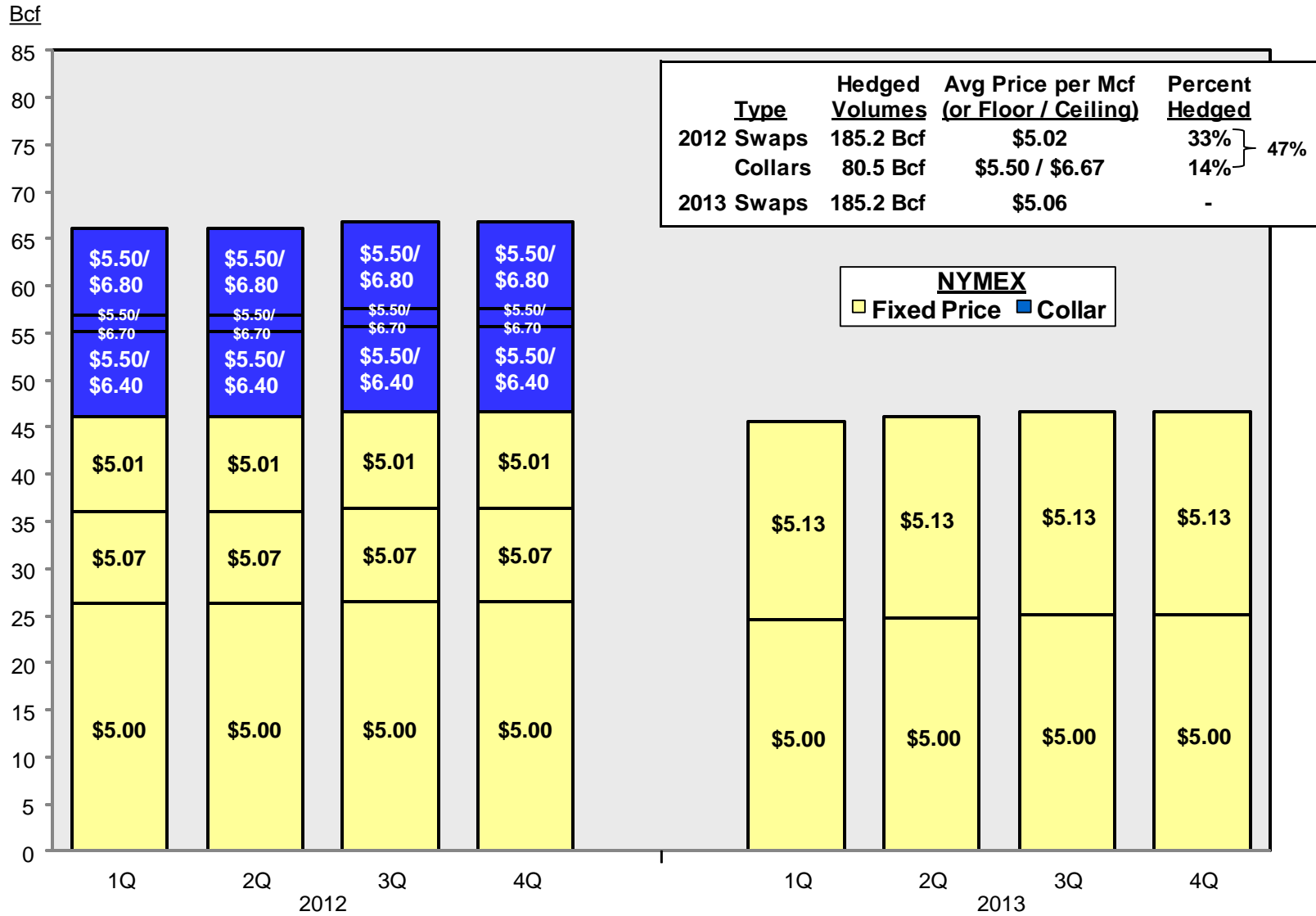
	Six Months Ended June 30		Year Ended December 31,		
	2012	2011	2011	2010	2009
	(\$ in millions, except per share amounts)		(\$ in millions, except per share amounts)		
Revenues	\$1,256.2	\$1,441.5	\$2,952.9	\$2,610.7	\$2,145.8
EBITDA <sup>(1)</sup>	738.1	850.7	1,779.6	1,612.3	1,368.1
Adjusted Net Income	198.5 <sup>(2)</sup>	304.1	637.8	604.1	522.7 <sup>(2)</sup>
Net Cash Flow <sup>(1)</sup>	725.3	839.7	1,766.0	1,579.7	1,441.0
Adjusted Diluted EPS	\$0.57 <sup>(2)</sup>	\$0.87	\$1.82	\$1.73	\$1.52 <sup>(2)</sup>
Diluted CFPS <sup>(1)</sup>	\$2.08	\$2.40	\$5.05	\$4.52	\$4.13
Production (Bcfe)	270.8	237.8	500.0	404.7	300.4
Avg. Gas Price (\$/Mcf)	\$3.30	\$4.21	\$4.19	\$4.64	\$5.30
Avg. Oil Price (\$/Bbl)	\$104.41	\$95.86	\$94.08	\$76.84	\$54.99
Finding Cost (\$/Mcf) <sup>(3)</sup>			\$1.31	\$1.02	\$0.86
Reserve Replacement (%) <sup>(3)</sup>			299%	430%	592%
Net Debt/Proved Reserves (\$/Mcf)			\$0.23	\$0.22	\$0.27
Net Debt/Avg. Daily Production (\$/Mcf)	\$997	\$851	\$969	\$972	\$1,197
Net Debt/Total Capitalization	30%	25%	25%	27%	30%

(1) Net cash flow is net cash flow before changes in operating assets and liabilities. Net cash flow, EBITDA and diluted CFPS are non-GAAP financial measures. See explanation and reconciliation of non-GAAP financial measures on pages 32 and 34.

(2) Adjusted net income and adjusted diluted EPS in 2012 exclude a \$578.9 million after-tax non-cash ceiling test impairment and the same measures in 2009 exclude a \$558.3 million after-tax non-cash ceiling test impairment and both are non-GAAP financial measures. See explanation and reconciliation of adjusted net income and adjusted diluted EPS on page 33.

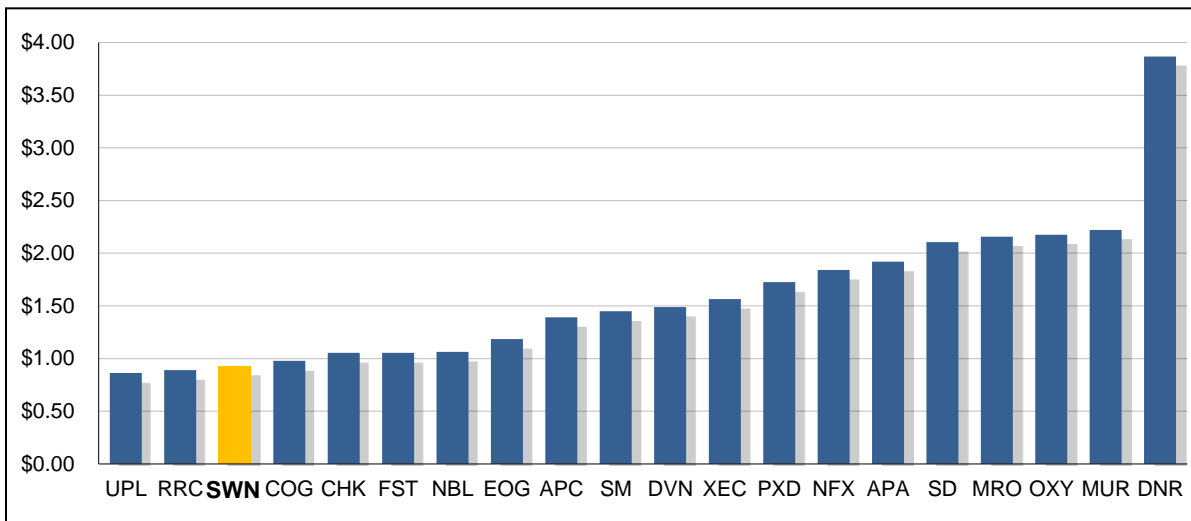
(3) Includes reserve revisions and excludes capital investments in our sand facility, drilling rig related and ancillary equipment.

# Gas Hedges in Place Through 2013

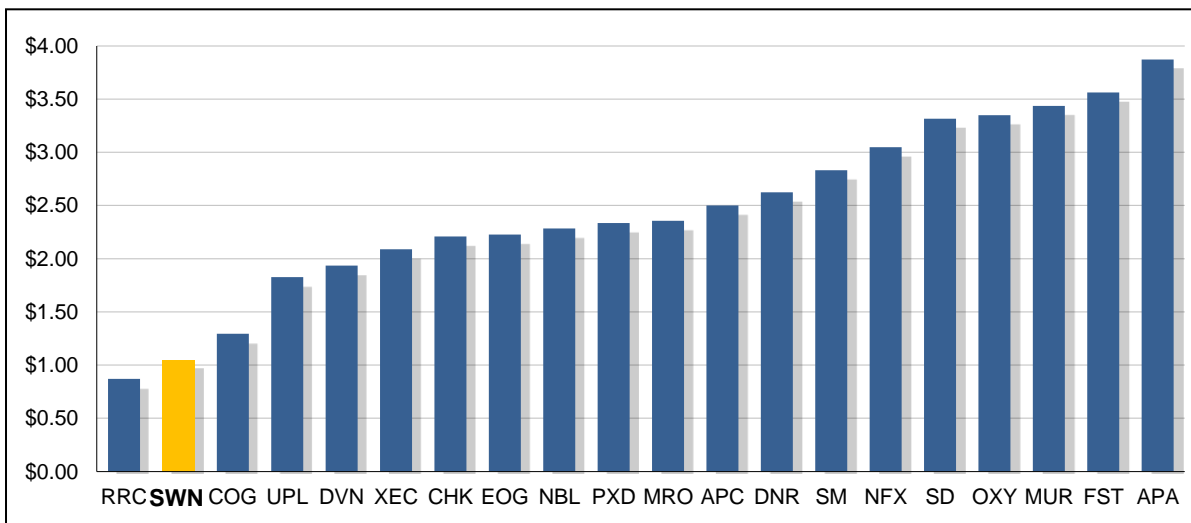


# SWN is One of the Lowest Cost Operators

**Lifting Cost**  
per Mcfe of Production  
(3 year average)



**Finding & Development Cost**  
per Mcfe  
(3 year average)



Source: Public filings

Note: All data as of December 31, 2009, 2010 and 2011. APC - Anadarko Petroleum, APA - Apache, COG - Cabot Oil & Gas, CHK - Chesapeake Energy, XEC - Cimarex Energy, DNR - Denbury Resources, DVN - Devon Energy, EOG - EOG Resources, FST - Forest Oil, MRO - Marathon Oil, MUR - Murphy Oil, NFX - Newfield Exploration, NBL - Noble Energy, OXY - Occidental Petroleum, PXD - Pioneer Natural Resources, RRC - Range Resources, SD - Sandridge Energy, SM - SM Energy, SWN - Southwestern Energy, UPL - Ultra Petroleum.

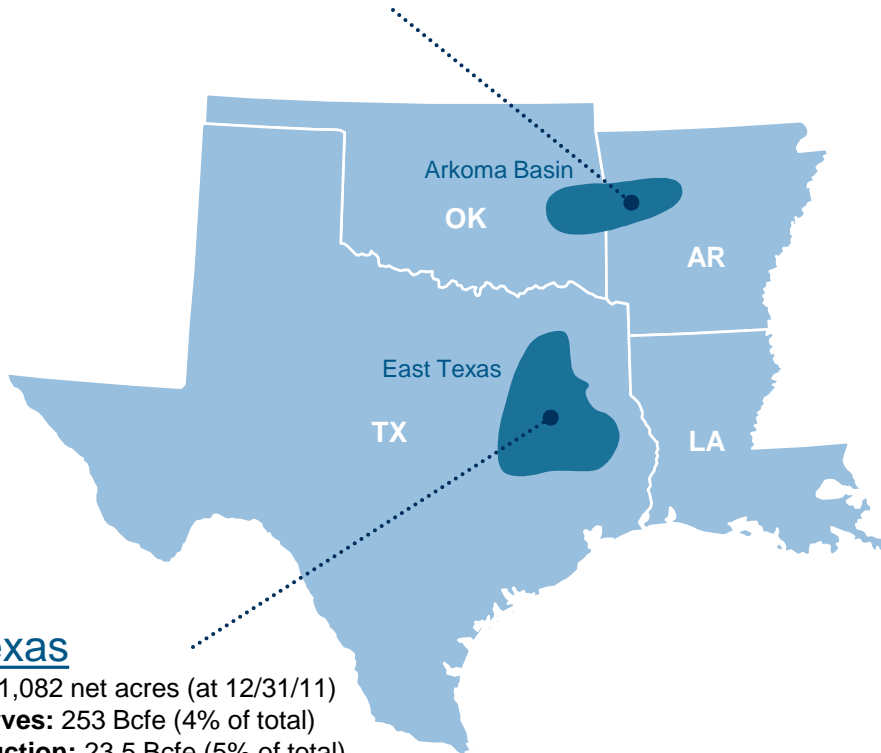
Lifting Cost per Mcfe defined as lease operating expenses plus production taxes divided by production.

F&D Cost per Mcfe defined as the three-year sum of costs incurred in natural gas and oil exploration and development divided by the three-year sum of reserve additions from extensions and discoveries, improved recovery, revisions and purchases.



## Arkoma Basin

**Acreage:** 194,494 net acres (at 12/31/11)  
**2011 Reserves:** 194 Bcf (3% of total)  
**2011 Production:** 16.3 Bcf (3% of total)



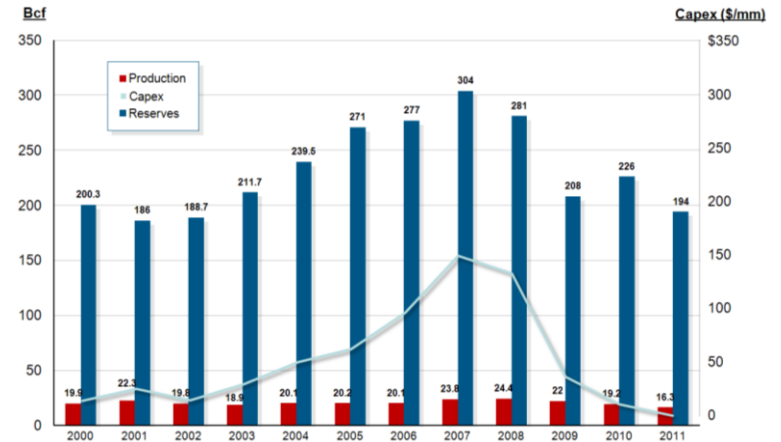
## East Texas

**Acreage:** 91,082 net acres (at 12/31/11)  
**2011 Reserves:** 253 Bcfe (4% of total)  
**2011 Production:** 23.5 Bcfe (5% of total)

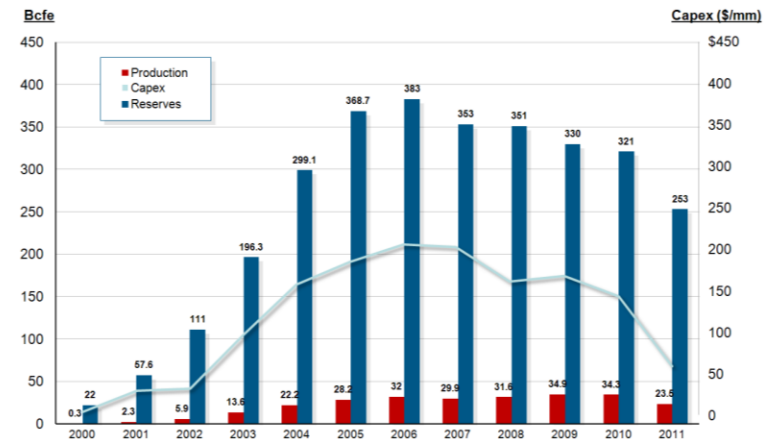
- Sold Overton Field in May 2012 (24 MMcfe/d and 143 Bcfe).

Notes: Conventional Arkoma acreage excludes 125,056 net acres in the conventional Arkoma Basin operating area that are also within the company's Fayetteville Shale focus area.  
 Overton Field production as of May 2012; total reserves as of December 2011.

## Arkoma Basin



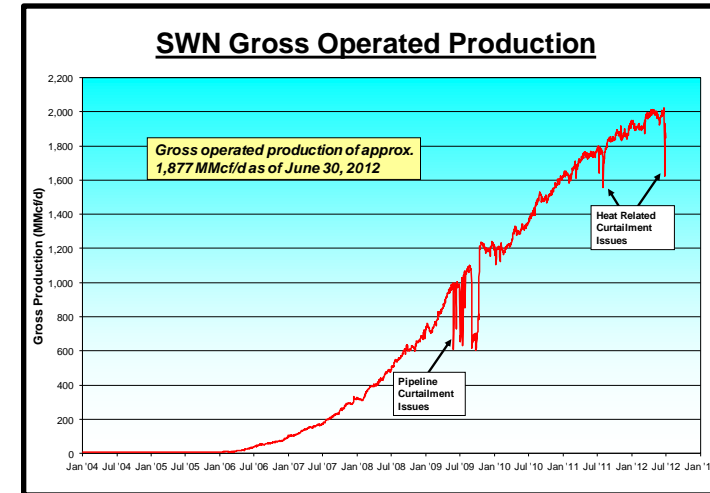
## East Texas



*R<sup>2</sup> → V<sup>+</sup>  
A*

# Fayetteville Shale - Horizontal Well Performance

Time Frame	Wells Placed on Production	Average IP Rate (Mcf/d)	30th-Day Avg Rate (# of wells)	60th-Day Avg Rate (# of wells)	Avg 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 <sup>(1)</sup>	74	3,350 <sup>(1)</sup>	2,722 (74)	2,386 (74)	3,850
1st Qtr 2009 <sup>(1)</sup>	120	2,992 <sup>(1)</sup>	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	2,624 (93)	2,255 (93)	4,100
4th Qtr 2009	122	3,727	2,674 (122)	2,360 (120)	4,303
1st Qtr 2010 <sup>(2)</sup>	106	3,197 <sup>(2)</sup>	2,388 (106)	2,123 (106)	4,348
2nd Qtr 2010	143	3,449	2,554 (143)	2,321 (142)	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)	2,238 (137)	4,985
2nd Qtr 2011	149	3,014	2,328 (149)	1,991 (149)	4,839
3rd Qtr 2011	132	3,441	2,666 (132)	2,372 (132)	4,847
4th Qtr 2011	142	3,646	2,606 (142)	2,243 (142)	4,703
1st Qtr 2012	146	3,319	2,421 (146)	2,131 (146)	4,743
2nd Qtr 2012	131	3,500	2,454 (121)	2,003 (77)	4,840



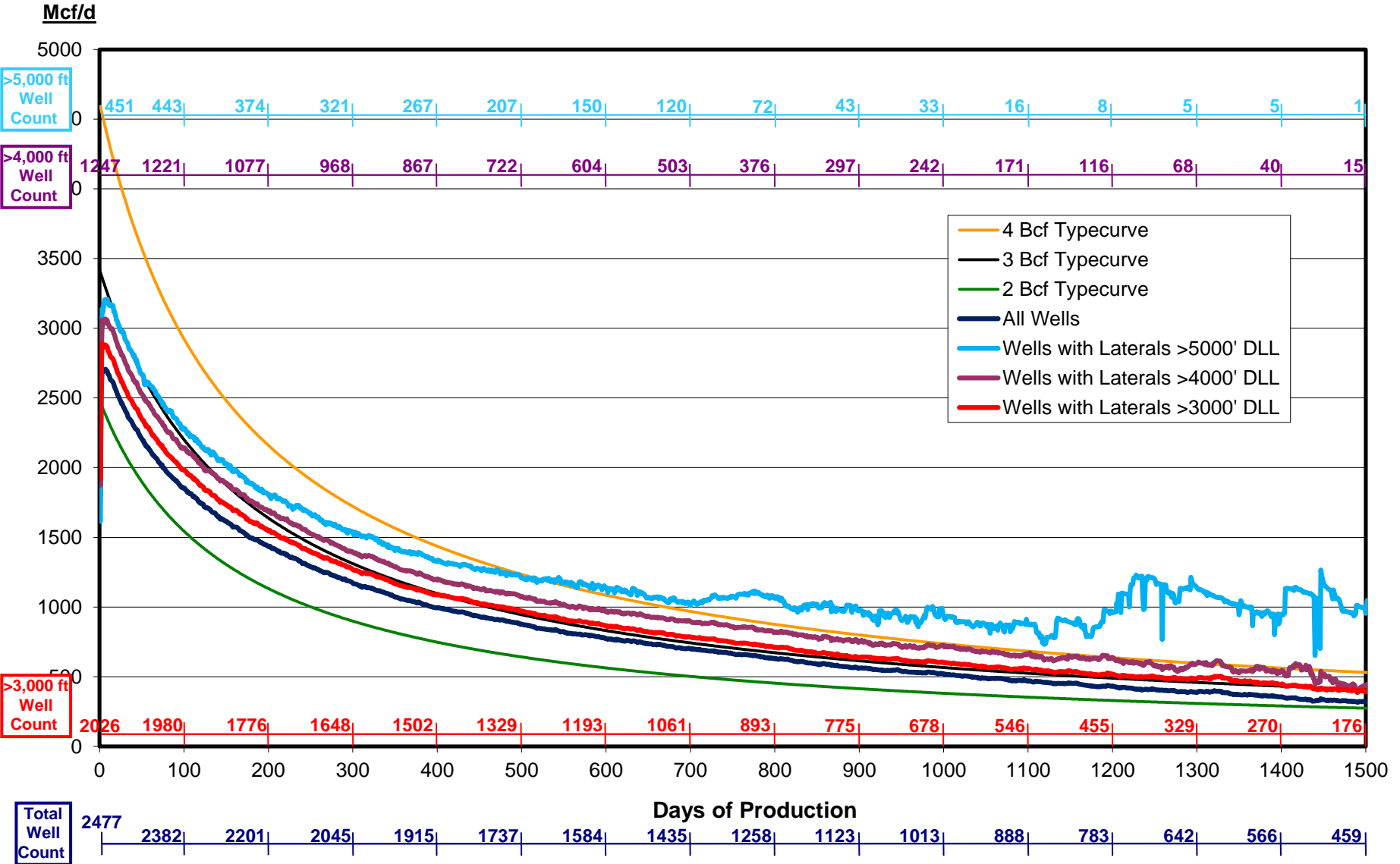
- Gross operated production of approx. 1,877 MMcf/d as of June 30, 2012.
- 2011 Fayetteville Shale F&D cost of \$1.13/Mcf.

Note: Data as of June 30, 2012.

- (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.

R<sub>2</sub> → V<sup>+</sup>  
A

# Fayetteville Shale – Horizontal Well Performance



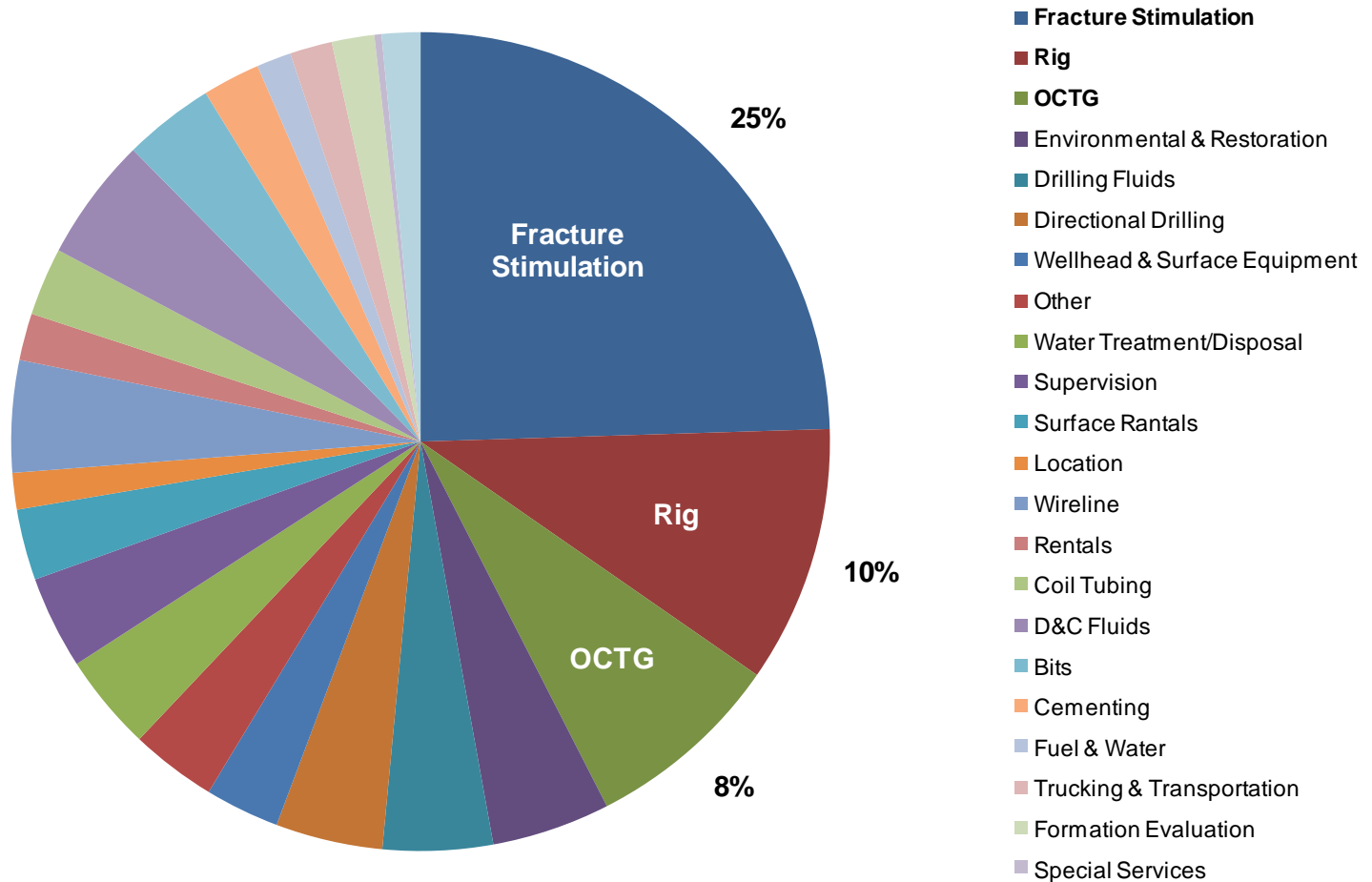
Notes: Data as of June 30, 2012. Excludes wells with mechanical problems (31).

$\frac{R^2}{A} \rightarrow V^+$

# Drilling & Completion Major Cost Categories

Average 2012 Fayetteville Shale Well Cost Estimate

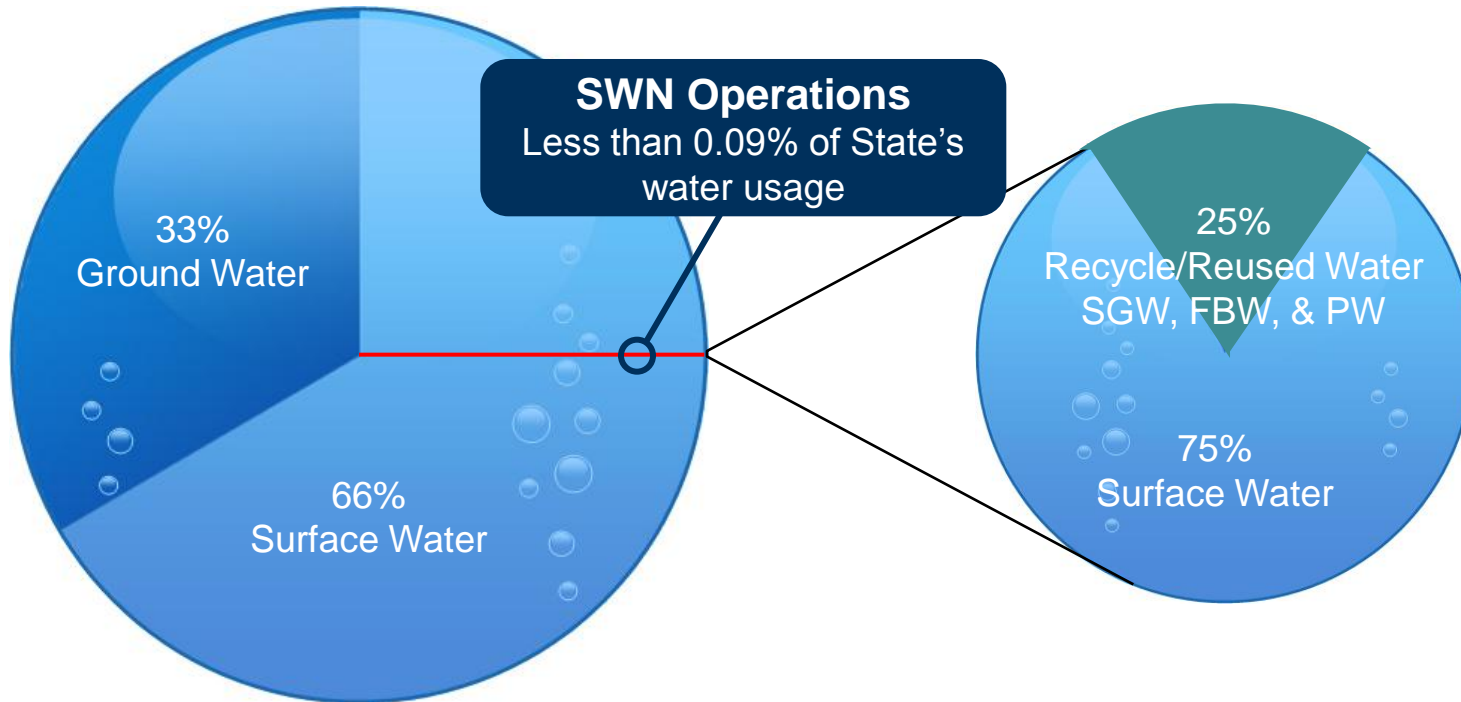
## Major Cost Categories - \$2,808M



# Water Demand: Perspective

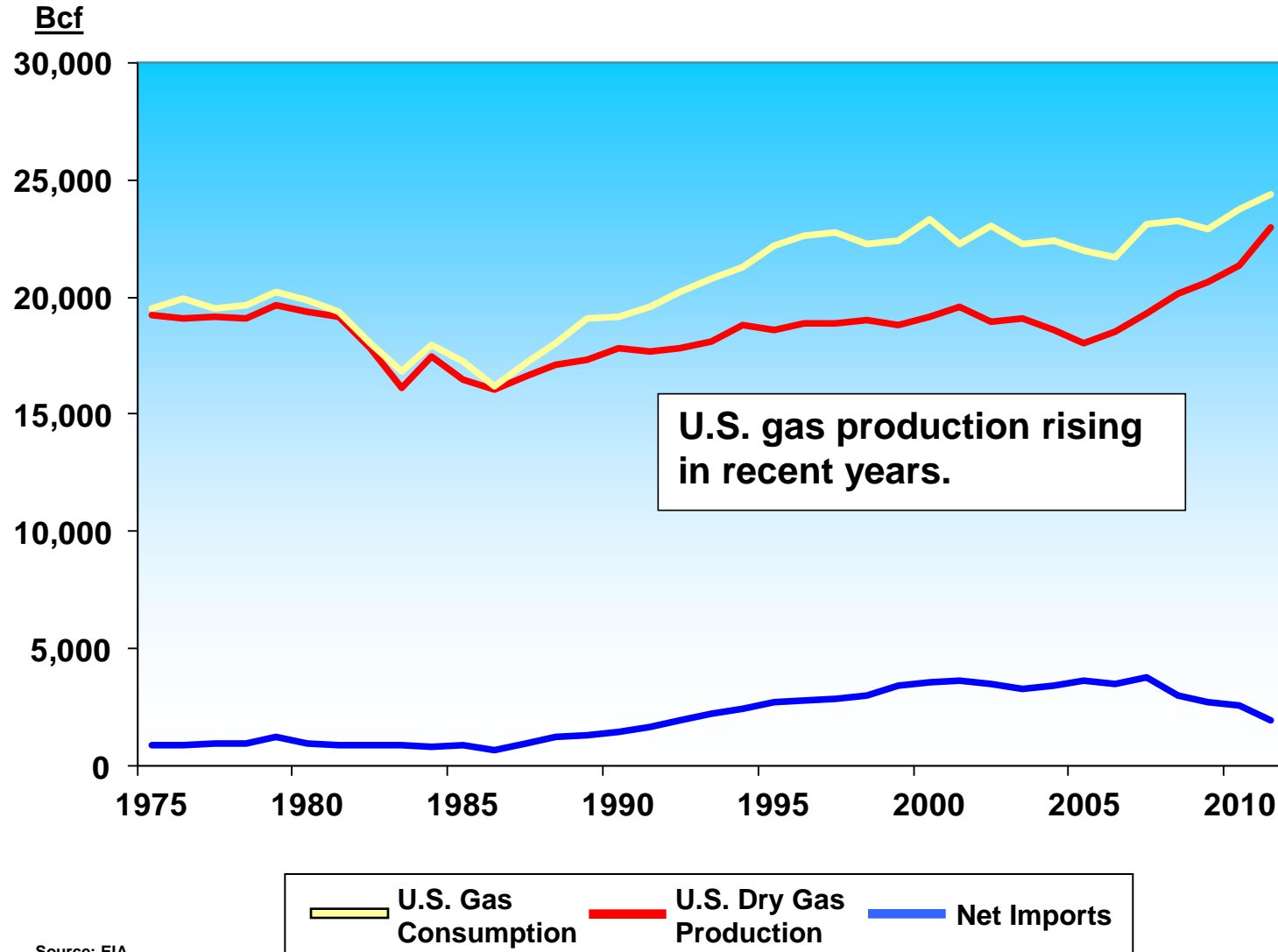
Statewide Demand:  
11,500 million gallons/day

SWN Operations Demand:  
10 million gallons/day (600 Wells/year)



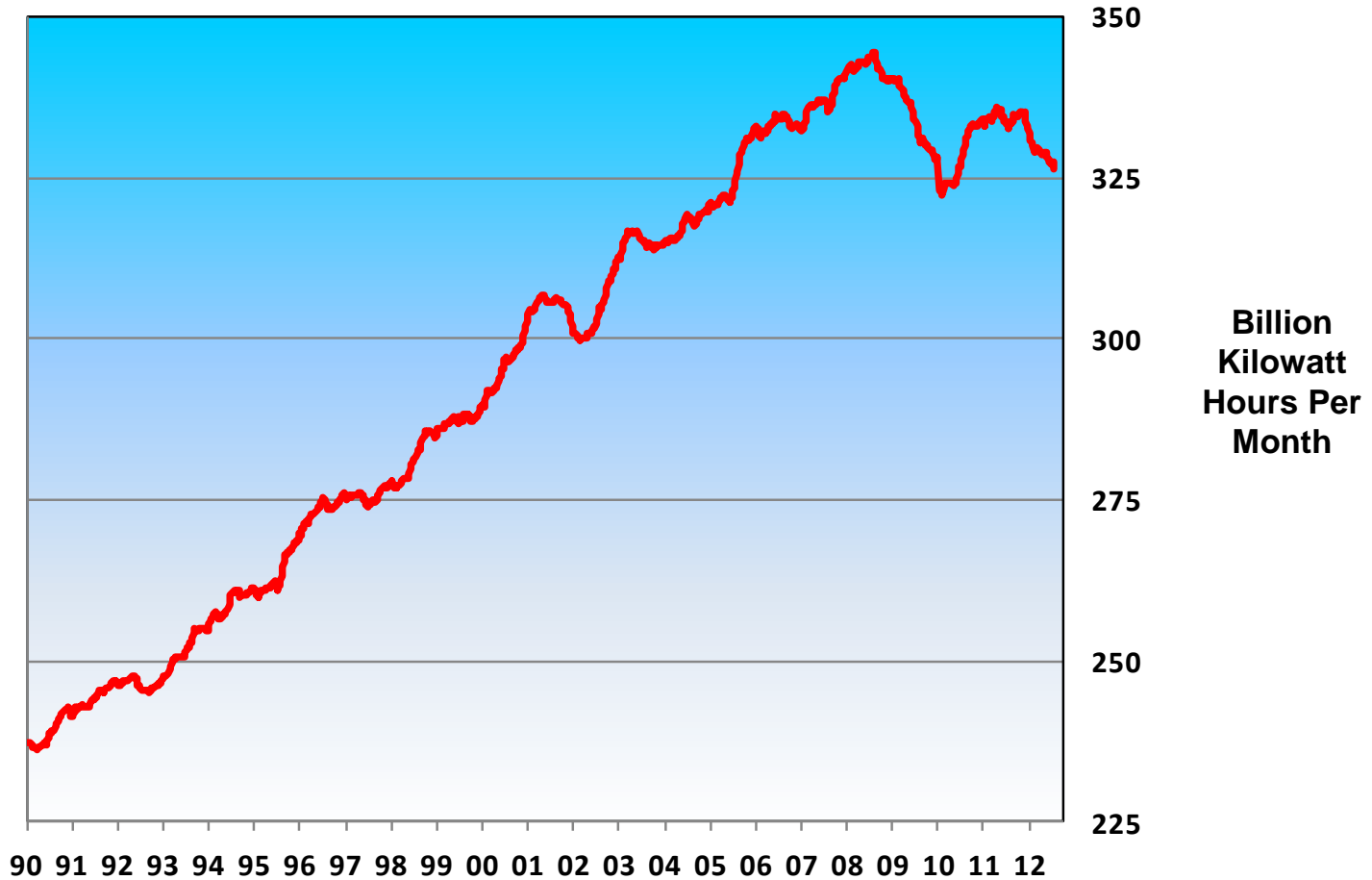
Source: U.S. Geological Survey, Central Arkansas Water, Southwestern Energy Company estimates.  
Shallow Ground Water (SGW) – Ground water recovered from shallow formations during the air drilling process.  
Flow Back Water (FBW) – Frac Fluid that is recovered from the well after the fracture stimulation.  
Produced Water (PW) – Natural formation water that is returned to the surface throughout the producing life of the well.

# U.S. Gas Consumption and Sources



Source: EIA

# U.S. Electricity Consumption

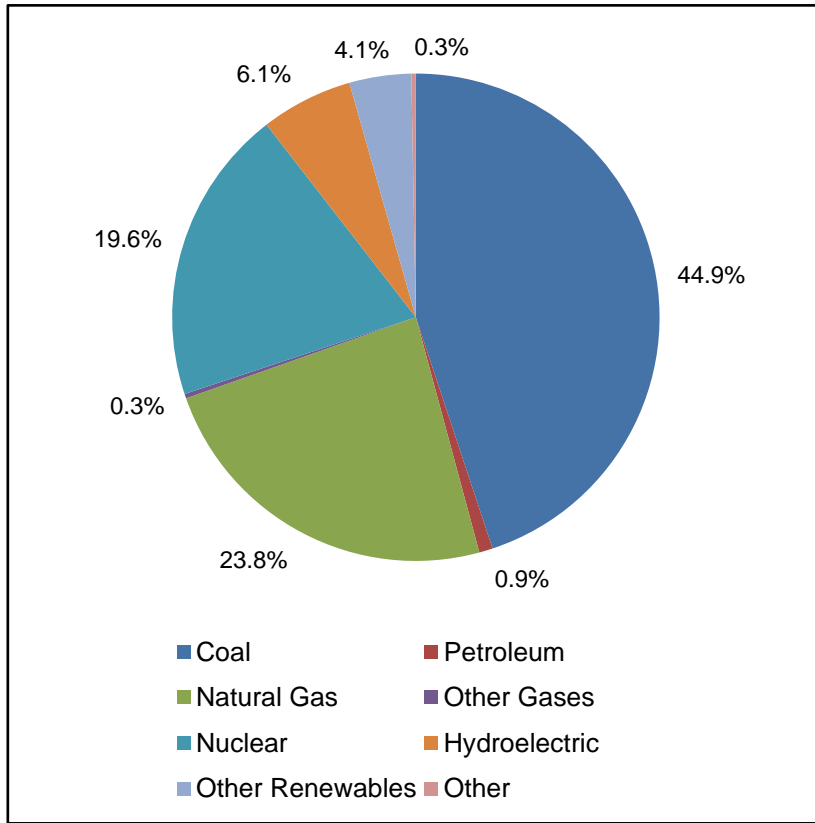


Source: Edison Electric Institute



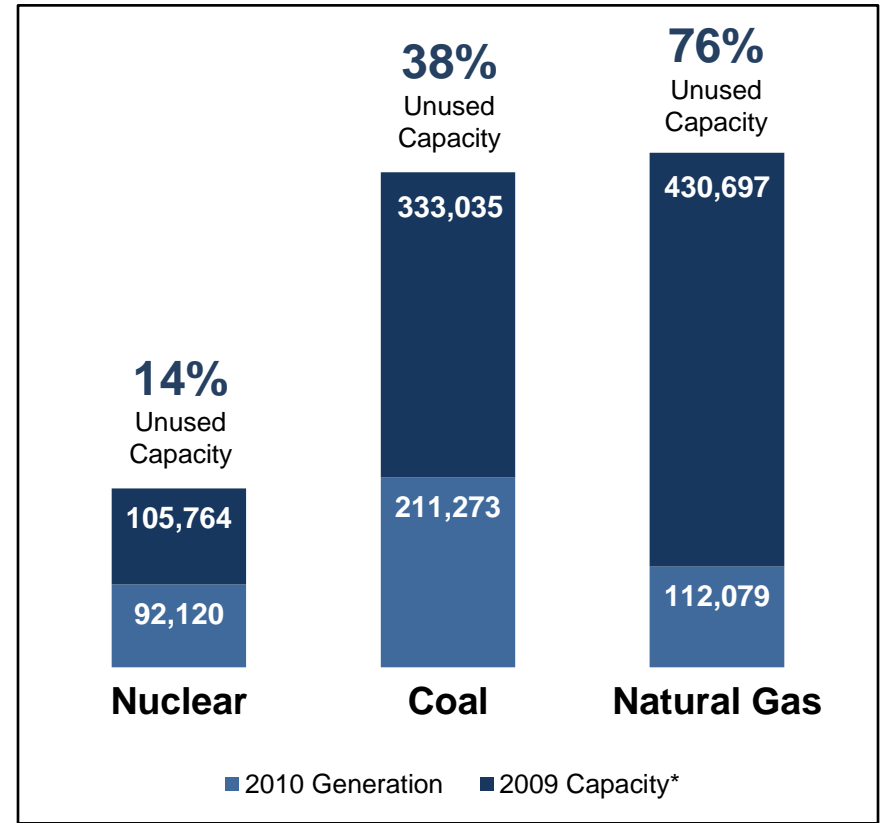
## Electricity Generation by Energy Source

Total 4,120 Billion kWh in 2010.



## Electricity Generation Capacities

While coal and nuclear power plants operate at very high capacity, natural gas power plants are only running at 24% of their capacity.



\* Excludes standby units  
SOURCE: EIA

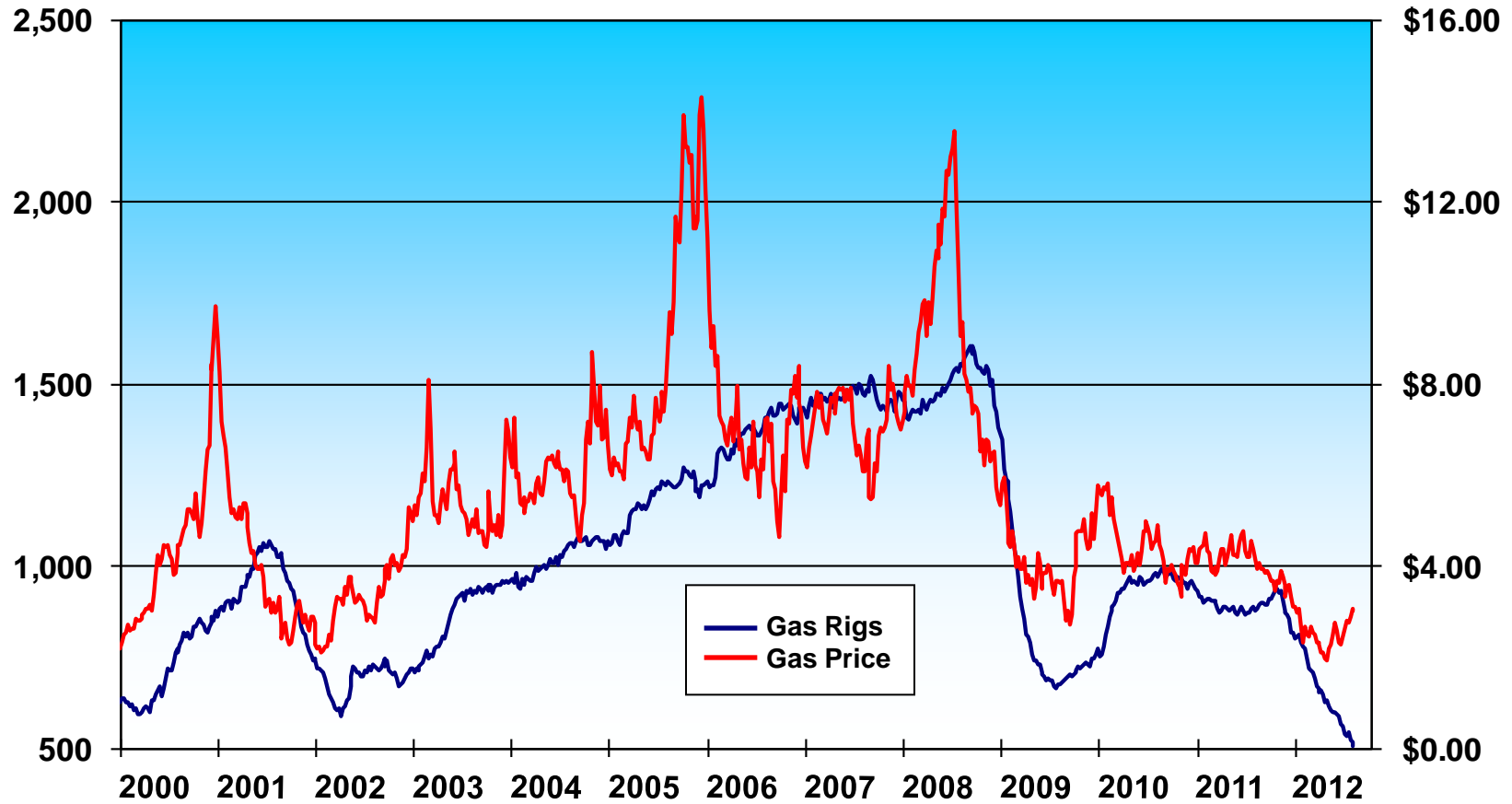
SOURCE: EIA



# U.S. Gas Drilling and Prices

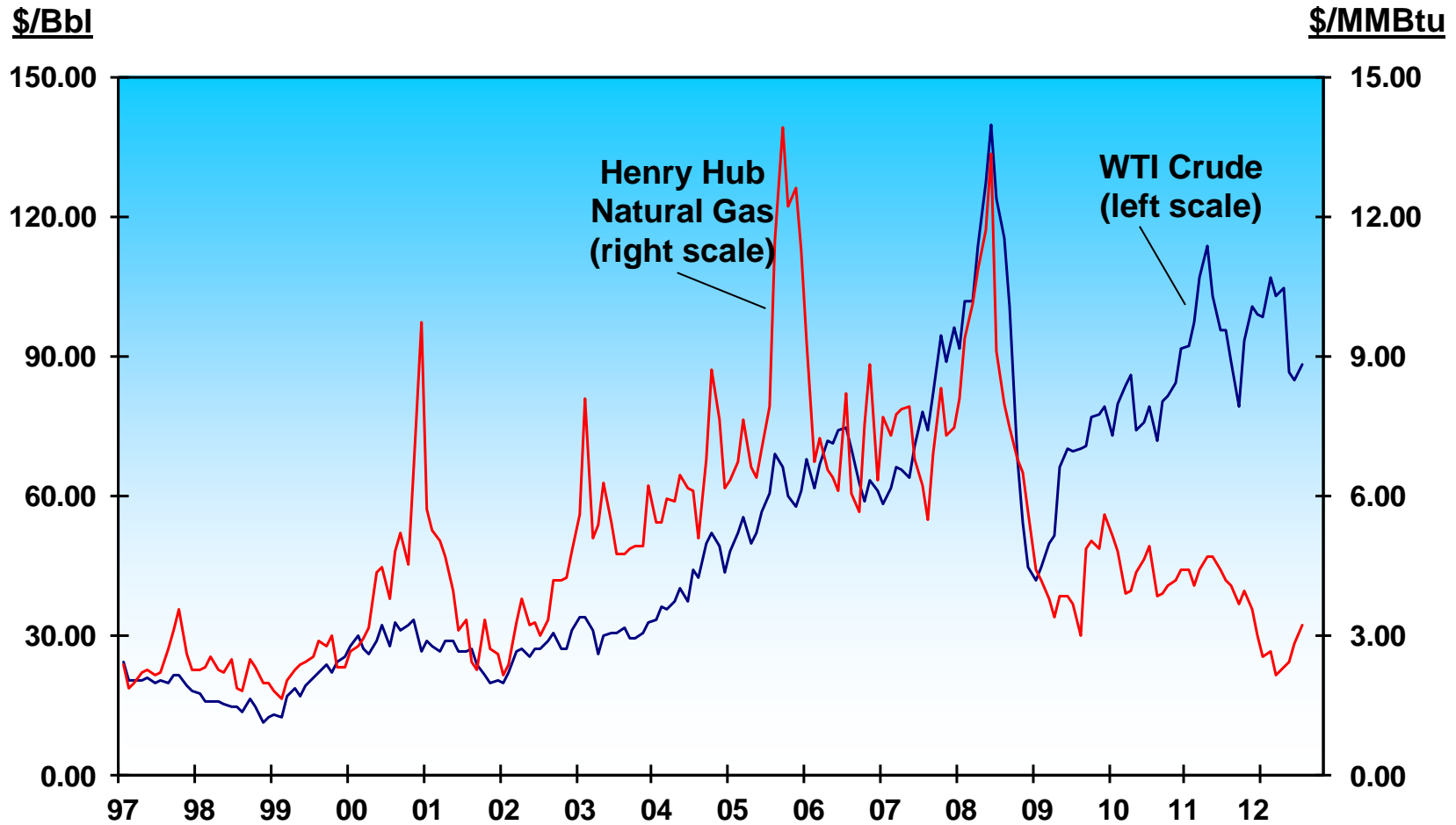
**Gas Rigs  
Drilling**

**Gas Price  
\$/MMBtu**



Source: Baker Hughes, Bloomberg

# Oil and Gas Price Comparison



Source: Bloomberg

# Explanation and Reconciliation of Non-GAAP Financial Measures: Net Cash Flow

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 flow. 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. These adjusted amounts are not a measure of financial performance under GAAP.

	<b>6 Months Ended June 30,</b>		<b>12 Months Ended December 31,</b>		
	<b>2012</b>	<b>2011</b>	<b>2011</b>	<b>2010</b>	<b>2009</b>
				(in thousands)	
Net cash provided by operating activities	\$837,390	\$ 856,930	\$ 1,739,817	\$ 1,642,585	\$ 1,359,376
Add back (deduct):					
Change in operating assets and liabilities	(112,043)	(17,184)	26,201	(62,906)	81,652
Net cash flow	<u>\$ 725,347</u>	<u>\$ 839,746</u>	<u>\$ 1,766,018</u>	<u>\$ 1,579,679</u>	<u>\$ 1,441,028</u>

	<b>2012 Guidance</b>		
	<b>NYMEX Commodity Price Assumption</b>		
	<b>\$2.50 Gas</b> <b>\$95.00 Oil</b>	<b>\$2.75 Gas</b> <b>\$95.00 Oil</b>	<b>\$3.00 Gas</b> <b>\$95.00 Oil</b>
			(\$ in millions)
Net cash provided by operating activities	\$1,480-\$1,490	\$1,550-\$1,560	\$1,620-\$1,630
Add back (deduct):			
Assumed change in operating assets and liabilities	--	--	--
Net cash flow	<u>\$1,480-\$1,490</u>	<u>\$1,550-\$1,560</u>	<u>\$1,620-\$1,630</u>

# Explanation and Reconciliation of Non-GAAP Financial Measures: Adjusted Net Income

Additional non-GAAP financial measures we may present from time to time are net income attributable to Southwestern Energy and diluted earnings per share attributable to Southwestern Energy stockholders, both of 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.

	<b>6 Months Ended June 30, 2012</b>		<b>12 Months Ended December 31, 2009</b>	
	(\$ in thousands)	(per share)	(\$ in thousands)	(per share)
Net loss attributable to SWN	\$ (380,396)	\$ (1.09)	\$ (35,650)	\$ (0.10)
Add back:				
Impairment of natural gas & oil properties (net of taxes)	578,879	1.66	558,305	1.62
Adjusted net income	<u>\$ 198,483</u>	<u>\$ 0.57</u>	<u>\$ 522,655</u>	<u>\$ 1.52</u>

The table below reconciles forecasted adjusted net income with GAAP net income for 2012, assuming various NYMEX price scenarios and the corresponding estimated impact on the company's results for 2012, including current hedges in place:

	<b>2012 Guidance</b>		
	<b>Overall Corporate</b>		
	<b>NYMEX Commodity Price Assumption</b>		
	<b>\$2.50 Gas \$95.00 Oil</b>	<b>\$2.75 Gas \$95.00 Oil</b>	<b>\$3.00 Gas \$95.00 Oil</b>
	(\$ in millions)		
Net income (loss)	(\$169)-(\$159)	(\$129)-(\$119)	(\$89)-(\$79)
Add back: Impairment of natural gas & oil properties (net of taxes)	579	579	579
Adjusted net income	<u>\$410-\$420</u>	<u>\$450-\$460</u>	<u>\$490-\$500</u>
	<b>2012 Guidance</b>		
	<b>Overall Corporate</b>		
	<b>NYMEX Commodity Price Assumption</b>		
	<b>\$2.50 Gas \$95.00 Oil</b>	<b>\$2.75 Gas \$95.00 Oil</b>	<b>\$3.00 Gas \$95.00 Oil</b>
	(per share)		
Diluted earnings per share	(\$0.49)-(\$0.46)	(\$0.37)-(\$0.34)	(\$0.26)-(\$0.23)
Add back: Impairment of natural gas & oil properties (net of taxes)	1.66	1.66	1.66
Adjusted diluted earnings per share	<u>\$1.17-\$1.20</u>	<u>\$1.29-\$1.32</u>	<u>\$1.40-\$1.43</u>

# Explanation and Reconciliation of Non-GAAP Financial Measures: EBITDA

EBITDA is defined as net income plus interest, income tax expense, depreciation, depletion and amortization. Southwestern has included information concerning EBITDA because it is used by certain investors as a measure of the ability of a company to service or incur indebtedness and because it is a financial measure commonly used in the energy industry. EBITDA should not be considered in isolation or as a substitute for net income, net cash provided by operating activities or other income or cash flow data prepared in accordance with generally accepted accounting principles or as a measure of the company's profitability or liquidity. EBITDA as defined above may not be comparable to similarly titled measures of other companies. Net income is a financial measure calculated and presented in accordance with generally accepted accounting principles. The table below reconciles historical EBITDA with historical net income.

	6 Months Ended June 30,		12 Months Ended December 31,											
	2012	2011	2011 (4)	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000
Net income (loss)	\$ (380,396) (1)	\$ 304,063	\$ 637,769	\$ 604,118	\$ (35,650) (5)	\$ 567,946	\$ 221,174	\$ 162,636	\$ 147,760	\$ 103,576	\$ 48,897	\$ 14,311	\$ 35,324	\$ 20,461 (9)
Add back:														
Net interest expense	15,699	13,606	24,075	26,163	18,638	28,904	23,873	679	15,040	16,992	17,311	21,466	23,699	24,689
Provision (benefit) for income taxes	(234,607) (2)	197,967	413,221	391,659	(16,363) (6)	350,999	135,855	99,399	86,431	59,778	28,372 (8)	8,708	21,917	11,457
Depreciation, depletion and amortization	1,337,355 (3)	335,067	704,511	590,332	1,401,470 (7)	414,460	294,500	151,795	96,641	74,919	56,833	54,095	53,003	47,505
EBITDA	\$ 738,051	\$ 850,703	\$ 1,779,576	\$ 1,612,272	\$ 1,368,095	\$ 1,362,309	\$ 675,402	\$ 414,509	\$ 345,872	\$ 255,265	\$ 151,413	\$ 98,580	\$ 133,943	\$ 104,112 (9)

(1) Net income (loss) includes the after tax \$578.9 million non-cash ceiling impairment of our natural gas and oil properties recorded in Q2 2012.

(2) Provision (benefit) for income taxes includes the (\$357.0) million income tax benefit related to the non-cash ceiling impairment of our natural gas and oil properties recorded in Q2 2012.

(3) Depreciation, depletion and amortization includes the \$935.9 million non-cash ceiling impairment of our natural gas and oil properties recorded in Q2 2012.

(4) Net income for the Midstream Services segment was \$142,591, depreciation, depletion and amortization was \$37,261, net interest expense was \$15,049 and provision for income taxes was \$90,221.

(5) Net income (loss) includes the after tax \$558.3 million non-cash ceiling impairment of our natural gas and oil properties recorded in Q1 2009.

(6) Provision (benefit) for income taxes includes the (\$349.5) million income tax benefit related to the non-cash ceiling impairment of our natural gas and oil properties recorded in Q1 2009.

(7) Depreciation, depletion and amortization includes the \$907.8 million non-cash ceiling impairment of our natural gas and oil properties recorded in Q1 2009.

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

(9) 2000 amounts exclude unusual items of \$109.3 million for the Hales judgment and \$2.0 million for other litigation.

The table below reconciles forecasted EBITDA with forecasted net income for 2012, assuming various NYMEX price scenarios and the corresponding estimated impact on the company's results for 2012, including current hedges in place:

	2012 Guidance			
	Overall Corporate			
	NYMEX Commodity Price Assumption			Midstream Services Segment (1)
	\$2.50 Gas	\$2.75 Gas	\$3.00 Gas	
\$95.00 Oil	\$95.00 Oil	\$95.00 Oil		
	(\$ in millions)			
Net income (loss)	\$(169)-\$(159) (2)			\$(89)-\$(79) (2)
Add back:				
Provision (benefit) for income taxes	(111)-(104) (3)			(85)-(78) (3)
Interest expense	26-28			26-28
Depreciation, depletion and amortization	1,740-1,750 (4)			1,740-1,750 (4)
EBITDA	<u>\$1,510-\$1,520</u>			<u>\$1,580-\$1,590</u>
	<u>\$1,650-\$1,660</u>			<u>\$310-\$315</u>

(1) Midstream Services segment results assume NYMEX commodity prices of \$2.75 per Mcf for natural gas and \$95.00 per barrel for crude oil for 2012.

(2) Net income (loss) includes the after tax \$578.9 million full cost ceiling impairment of our natural gas and oil properties recorded in Q2 2012.

(3) Provision (benefit) for income taxes includes the (\$357.0) million income tax benefit related to the full cost ceiling impairment of our natural gas and oil properties recorded in Q2 2012.

(4) Depreciation, depletion and amortization includes the \$935.9 million full cost ceiling impairment of our natural gas and oil properties recorded in Q2 2012.