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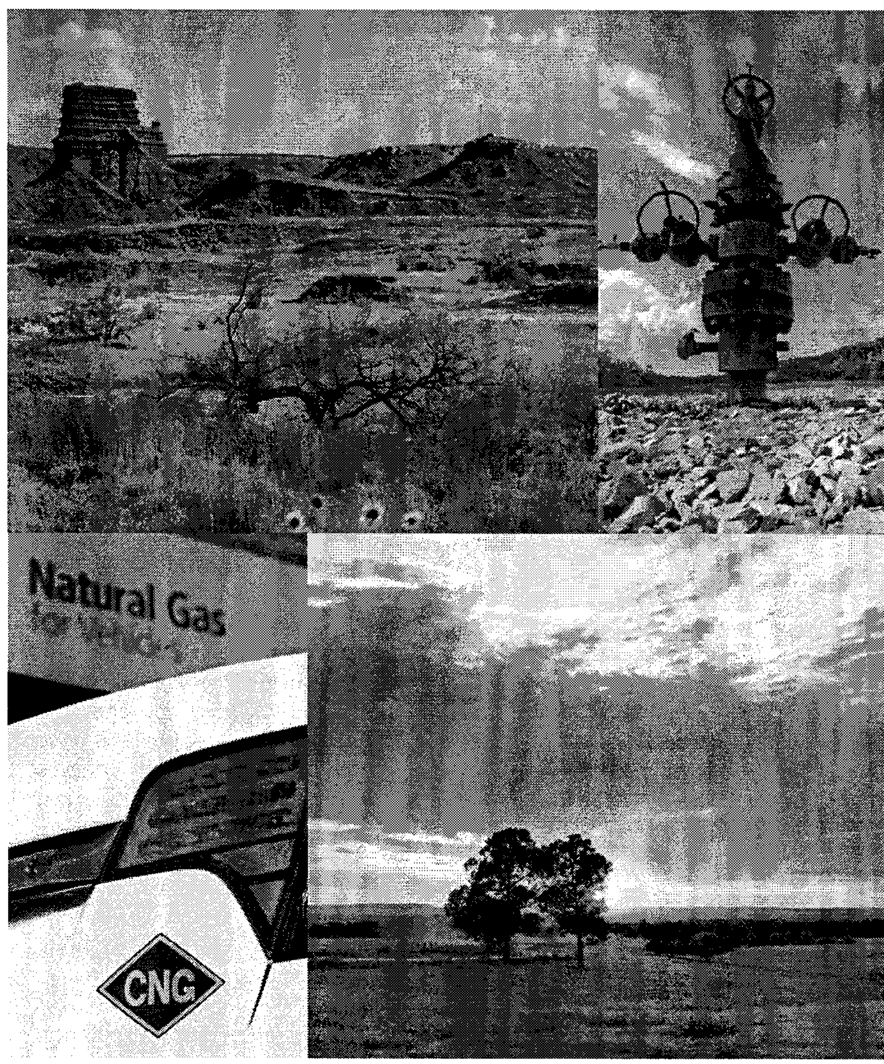
CHESAPEAKE ENERGY CORPORATION • 2009 ANNUAL REPORT

Chesapeake
ENERGY

6100 NORTH WESTERN AVENUE
OKLAHOMA CITY, OK 73118
WWW.CHK.COM



CORPORATE INFORMATION

CORPORATE HEADQUARTERS
6100 North Western Avenue
Oklahoma City, OK 73118
(405) 935-8000

INTERNET ADDRESS
Company financial information, public disclosures and other information are available through Chesapeake's web site at www.chk.com.

COMMON STOCK
Chesapeake Energy Corporation's common stock is listed on the New York Stock Exchange (NYSE) under the symbol CHK. As of March 31, 2010, there were approximately 455,000 beneficial owners of our common stock.

COMMON STOCK DIVIDENDS
During 2009, the company declared a cash dividend of $0.075 per share on March 17, June 15, September 24 and December 18 for a total dividend declared of $0.30 per share.

INDEPENDENT PUBLIC ACCOUNTANTS
PricewaterhouseCoopers LLP
6120 South Yale, Suite 1850
Tulsa, OK 74136
(918) 524-1200

STOCK TRANSFER AGENT AND REGISTRAR
Communication concerning the transfer of shares, lost certificates, duplicate mailings or change of address notifications should be directed to our transfer agent:
Computershare Trust Company, N.A.
250 Royall Street
Canton, MA 02021
(800) 884-4225

TRUSTEE FOR THE COMPANY'S SENIOR NOTES
The Bank of New York Mellon Trust Company, N.A.
101 Barclay Street, 8th Floor
New York, NY 10286

FORWARD-LOOKING STATEMENTS
This report includes "forward-looking statements" that give our current expectations or forecasts of future events. They include estimates of natural gas and oil reserves, expected production, assumptions regarding future natural gas and oil prices, and planned drilling activity and capital expenditures, as well as statements concerning anticipated cash flow and liquidity, business strategy and other plans and objectives for future operations.

Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties.

Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in Item 1A of our 2009 Annual Report on Form 10-K included in this report. We caution you not to place undue reliance on forward-looking statements, and we undertake no obligation to update this information. We urge you to carefully review and consider the disclosures made in this report and our other filings with the Securities and Exchange Commission regarding the risks and factors that may affect our business.

The SEC requires natural gas and oil companies, in filings made with the SEC, to disclose proved reserves and, beginning with filings reporting year-end 2009 reserves, permits the optional disclosure of probable and possible reserves. While Chesapeake has elected not to report probable and possible reserves in its filings with the SEC, we have provided estimates in this report of what we consider to be our "total resource base." This term includes our estimated proved reserves as well as "risked and unrisked unproved resources," which represent Chesapeake's internal estimates of volumes of natural gas and oil that are not classified as proved reserves but are potentially recoverable through exploratory drilling or additional drilling or recovery techniques. Our estimates of unproved resources are not intended to correspond to probable and possible reserves, as defined by SEC regulations, 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.

2010	High	Low	Last
First Quarter	$ 29.22	$ 22.10	$ 23.64

2009	High	Low	Last
Fourth Quarter	$ 30.00	$ 22.06	$ 25.88
Third Quarter	29.49	16.92	28.40
Second Quarter	24.66	16.43	19.83
First Quarter	20.13	13.27	17.06

2008	High	Low	Last
Fourth Quarter	$ 35.46	$ 9.84	$ 16.17
Third Quarter	74.00	31.15	35.86
Second Quarter	68.10	45.25	65.96
First Quarter	49.87	34.42	46.15

2007	High	Low	Last
Fourth Quarter	$ 41.19	$ 34.90	$ 39.20
Third Quarter	37.55	31.38	35.26
Second Quarter	37.75	30.88	34.60
First Quarter	31.83	27.27	30.88

CHK
LISTED
NYSE

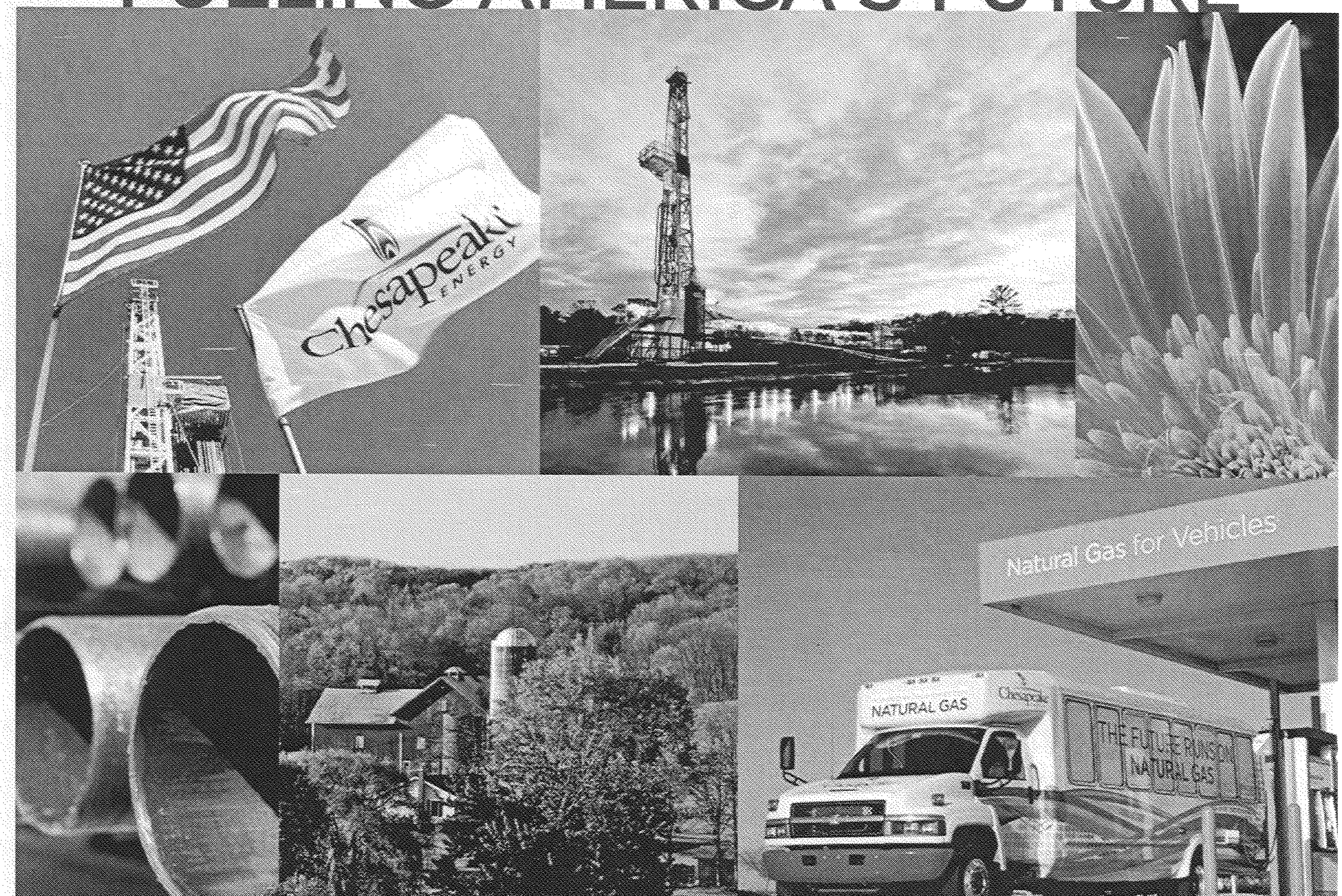
TWITTER.COM/CHESAPEAKE

FACEBOOK.COM/CHESAPEAKE

YOUTUBE.COM/CHESAPEAKEENERGY

Chesapeake
ENERGY

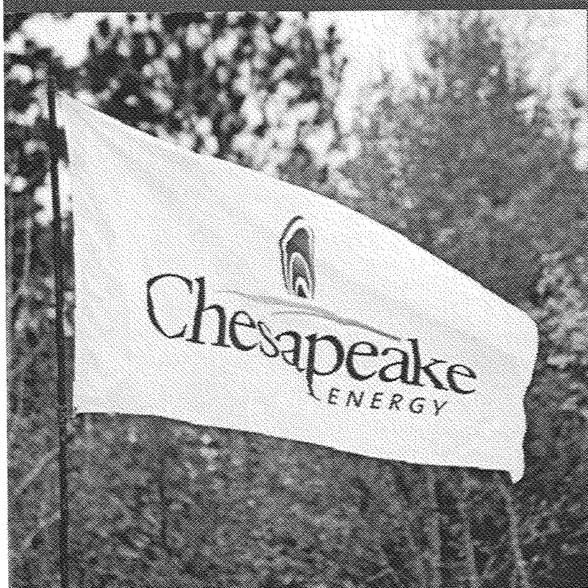
NATURAL GAS:
FUELING AMERICA'S FUTURE



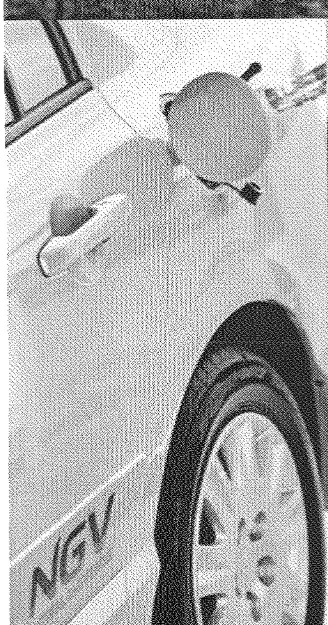
2009 ANNUAL REPORT • CHESAPEAKE ENERGY CORPORATION

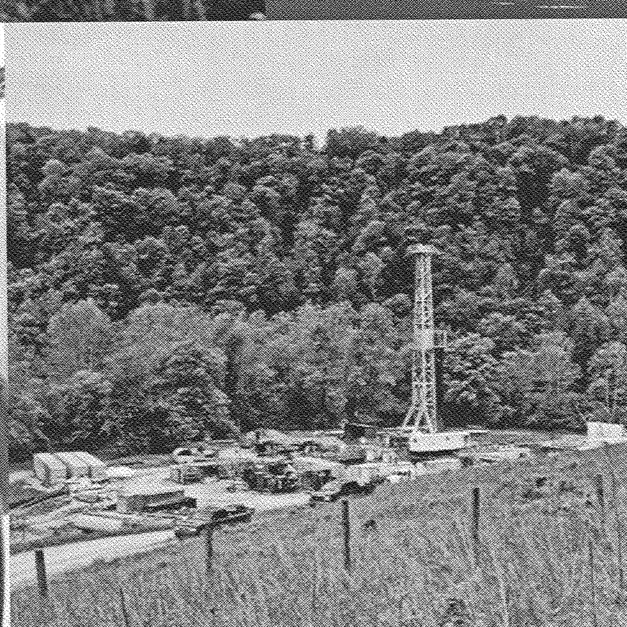
CORPORATE PROFILE

Chesapeake Energy Corporation is the second-largest producer of natural gas and the most active driller of new wells in the U.S. Headquartered in Oklahoma City, the company's operations are focused on discovering and developing unconventional natural gas and oil fields onshore in the U.S. Chesapeake owns leading positions in the Barnett, Fayetteville, Haynesville, Marcellus and Bossier natural gas shale plays and in the Eagle Ford, Granite Wash and various other unconventional oil plays. The company has also vertically integrated its operations and owns substantial midstream, compression, drilling and oilfield service assets. Chesapeake's stock is listed on the New York Stock Exchange under the symbol CHK. Further information is available at **www.chk.com**.



ON THE COVER
Scenes from the field to the natural gas fueling station depict how Chesapeake explores for, produces and advocates the expanded use of natural gas — the clean, affordable, abundant energy resource that is *Fueling America's Future*.





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FINANCIAL REVIEW

($ in millions, except per share data)

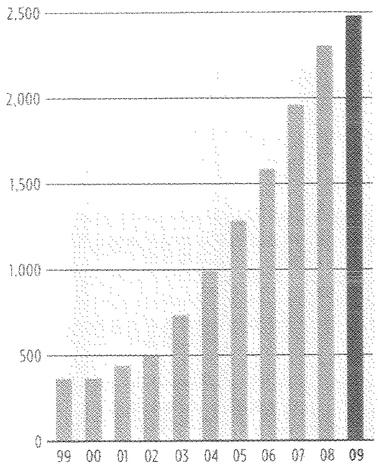
	Years Ended December 31												Six Months Ended December 31	Years Ended June 30				
Financial and Operating Data	**2009**	**2008**	**2007**	**2006**	**2005**	**2004**	**2003**	**2002**	**2001**	**2000**	**1999**	**1998**	**1997**	**1997**	**1996**	**1995**	**1994**	**1993**
Revenues																		
Natural gas and oil sales	$ 5,049	$ 7,858	$ 5,624	$ 5,619	$ 3,273	$ 1,936	$ 1,297	$ 568	$ 820	$ 470	$ 280	$ 257	$ 96	$ 193	$ 111	$ 57	$ 22	$ 12
Midstream and service operations revenue	2,653	3,771	2,176	1,707	1,392	773	420	171	149	158	75	121	58	76	35	9	7	5
Total revenues	$ 7,702	$ 11,629	$ 7,800	$ 7,326	$ 4,665	$ 2,709	$ 1,717	$ 739	$ 969	$ 628	$ 355	$ 378	$ 154	$ 269	$ 146	$ 66	$ 29	$ 17
Operating costs																		
Production expenses	876	889	640	490	317	205	138	98	75	50	46	51	8	11	6	3	2	3
Production taxes	107	284	216	176	208	104	78	30	33	25	13	8	2	4	2	1	2	—
General and administrative expenses	349	377	243	139	64	37	24	18	15	13	13	20	6	9	5	4	3	3
Midstream and service operations expenses	2,498	3,648	2,063	1,590	1,358	755	410	166	144	152	72	119	58	75	33	8	5	4
Depreciation, depletion and amortization	1,615	2,144	1,988	1,462	945	611	386	235	182	109	103	155	63	107	54	27	10	5
Impairments and other	11,202	2,830	—	55	—	5	6	—	—	—	—	881	110	236	—	—	—	1
Total operating costs	16,647	10,172	5,150	3,912	2,892	1,717	1,042	547	449	349	247	1,234	247	442	100	43	22	16
Income (loss) from operations	(8,945)	1,457	2,650	3,414	1,773	992	675	192	520	279	108	(856)	(93)	(173)	46	23	7	1
Other income (expense)	(28)	(11)	15	26	10	5	1	7	3	3	8	4	79	11	4	2	1	1
Interest expense	(113)	(271)	(401)	(316)	(221)	(167)	(154)	(112)	(98)	(86)	(81)	(68)	(18)	(18)	(14)	(7)	(3)	(2)
Miscellaneous gains (losses)	(202)	(184)	83	117	(70)	(25)	(21)	(20)	(63)	—	—	(14)	—	(7)	—	—	—	—
Total other income (expense)	(343)	(466)	(303)	(173)	(281)	(187)	(174)	(125)	(158)	(83)	(73)	(78)	61	(14)	(10)	(5)	(2)	(1)
Income (loss) before income taxes and cumulative effect of accounting change	(9,288)	991	2,347	3,241	1,492	805	501	67	362	196	35	(934)	(32)	(187)	36	18	5	—
Income tax expense (benefit):																		
Current	4	423	29	5	—	—	5	(2)	4	—	—	—	—	—	—	—	—	—
Deferred	(3,487)	(36)	863	1,242	545	290	185	29	141	(260)	2	—	—	(4)	13	6	1	—
Net income (loss) before cumulative effect of accounting change, net of tax	(5,805)	604	1,455	1,994	947	515	311	40	217	456	33	(934)	(32)	(183)	23	12	4	—
Net (income) loss attributable to noncontrolling interest	(25)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Cumulative effect of accounting change, net of tax	—	—	—	—	—	—	2	—	—	—	—	—	—	—	—	—	—	—
Net Income (loss)	$ (5,830)	$ 604	$ 1,455	$ 1,994	$ 947	$ 515	$ 313	$ 40	$ 217	$ 456	$ 33	$ (934)	$ (32)	$ (183)	$ 23	$ 12	$ 4	—
Preferred stock dividends	(23)	(35)	(94)	(89)	(42)	(40)	(22)	(10)	(2)	(9)	(16)	(12)	—	—	—	—	—	(1)
Gain (loss) on redemption of preferred stock	—	(67)	(128)	(10)	(26)	(36)	—	—	—	7	—	—	—	—	—	—	—	—
Net Income (loss) available to common stockholders	$ (5,853)	$ 504	$ 1,233	$ 1,895	$ 879	$ 439	$ 291	$ 30	$ 215	$ 454	$ 17	$ (946)	$ (32)	$ (183)	$ 23	$ 12	$ 4	$ (1)
Earnings per common share – basic:																		
Income (loss) before cumulative effect of accounting change	$ (9.57)	$ 0.94	$ 2.70	$ 4.76	$ 2.73	$ 1.73	$ 1.36	$ 0.18	$ 1.33	$ 3.52	$ 0.17	$ (9.97)	$ (0.45)	$ (2.79)	$ 0.43	$ 0.22	$ 0.08	$ (0.02)
Cumulative effect of accounting change	—	—	—	—	—	—	0.02	—	—	—	—	—	—	—	—	—	—	—
EPS – basic	$ (9.57)	$ 0.94	$ 2.70	$ 4.76	$ 2.73	$ 1.73	$ 1.38	$ 0.18	$ 1.33	$ 3.52	$ 0.17	$ (9.97)	$ (0.45)	$ (2.79)	$ 0.43	$ 0.22	$ 0.08	$ (0.02)
Earnings per common share – assuming dilution:																		
Income (loss) before cumulative effect of accounting change	$ (9.57)	$ 0.93	$ 2.63	$ 4.33	$ 2.51	$ 1.53	$ 1.20	$ 0.17	$ 1.25	$ 3.01	$ 0.16	$ (9.97)	$ (0.45)	$ (2.79)	$ 0.40	$ 0.21	$ 0.08	$ (0.02)
Cumulative effect of accounting change	—	—	—	—	—	—	0.01	—	—	—	—	—	—	—	—	—	—	—
EPS – assuming dilution	$ (9.57)	$ 0.93	$ 2.63	$ 4.33	$ 2.51	$ 1.53	$ 1.21	$ 0.17	$ 1.25	$ 3.01	$ 0.16	$ (9.97)	$ (0.45)	$ (2.79)	$ 0.40	$ 0.21	$ 0.08	$ (0.02)
Cash provided by (used in) operating activities (GAAP)	$ 4,356	$ 5,357	$ 4,974	$ 4,843	$ 2,407	$ 1,432	$ 939	$ 429	$ 478	$ 315	$ 145	$ 95	$ 139	$ 84	$ 121	$ 55	$ 19	$ (1)
Operating cash flow (non-GAAP) *	$ 4,333	$ 5,299	$ 4,675	$ 4,040	$ 2,426	$ 1,403	$ 897	$ 409	$ 443	$ 306	$ 139	$ 118	$ 68	$ 161	$ 88	$ 46	$ 16	$ 4
Balance Sheet Data (at end of period)																		
Total assets	$ 29,914	$ 38,593	$ 30,764	$ 24,413	$ 16,114	$ 8,245	$ 4,572	$ 2,876	$ 2,287	$ 1,440	$ 851	$ 813	$ 953	$ 949	$ 572	$ 277	$ 126	$ 79
Long-term debt, net of current maturities	12,295	13,175	10,178	7,187	5,286	3,075	2,058	1,651	1,329	945	964	919	509	509	268	146	48	14
Total equity (deficit)	$ 12,341	$ 17,017	$ 12,624	$ 11,366	$ 6,299	$ 3,163	$ 1,733	$ 908	$ 767	$ 313	$ (218)	$ (249)	$ 280	$ 287	$ 178	$ 45	$ 31	$ 31
Other Operating and Financial Data																		
Proved reserves in natural gas equivalents (bcfe)	14,254	12,051	10,879	8,956	7,521	4,902	3,169	2,205	1,780	1,355	1,206	1,091	448	403	425	243	142	137
Future net natural gas and oil revenues discounted at 10% **	$ 9,449	$ 15,601	$ 20,573	$ 13,647	$ 22,934	$ 10,504	$ 7,333	$ 3,718	$ 1,647	$ 6,046	$ 1,089	$ 661	$ 467	$ 437	$ 547	$ 188	$ 141	$ 142
Natural gas price used in reserve report (per mcf)	$ 3.13	$ 5.12	$ 6.19	$ 5.41	$ 8.76	$ 5.65	$ 5.68	$ 4.28	$ 2.51	$ 10.12	$ 2.25	$ 1.68	$ 2.29	$ 2.12	$ 2.41	$ 1.60	$ 1.98	$ 2.43
Oil price used in reserve report (per bbl)	$ 56.72	$ 41.60	$ 90.58	$ 56.25	$ 56.41	$ 39.91	$ 30.22	$ 30.18	$ 18.82	$ 26.41	$ 24.72	$ 10.48	$ 17.62	$ 18.38	$ 20.90	$ 17.41	$ 18.27	$ 18.71
Natural gas production (bcf)	835	775	655	526	422	322	240	161	144	116	109	94	27	62	52	25	7	3
Oil production (mmbbl)	11.8	11.2	9.9	8.7	7.7	6.8	4.7	3.5	2.9	3.1	4.1	6.0	1.9	2.8	1.4	1.1	0.5	0.3
Production (bcfe)	906	843	714	578	469	363	268	181	161	134	133	130	38	79	60	32	10	4
Sales price per mcfe ***	$ 6.22	$ 8.38	$ 8.40	$ 8.86	$ 6.90	$ 5.23	$ 4.79	$ 3.61	$ 4.56	$ 3.50	$ 2.10	$ 1.97	$ 2.49	$ 2.45	$ 1.84	$ 1.78	$ 2.21	$ 2.68
Production expense per mcfe	$ 0.97	$ 1.05	$ 0.90	$ 0.85	$ 0.68	$ 0.56	$ 0.51	$ 0.54	$ 0.47	$ 0.37	$ 0.35	$ 0.39	$ 0.20	$ 0.15	$ 0.11	$ 0.11	$ 0.21	$ 0.67
Production taxes per mcfe	$ 0.12	$ 0.34	$ 0.30	$ 0.31	$ 0.44	$ 0.29	$ 0.29	$ 0.17	$ 0.20	$ 0.19	$ 0.10	$ 0.06	$ 0.07	$ 0.05	$ 0.03	$ 0.03	$ 0.15	—
General and administrative expense per mcfe	$ 0.38	$ 0.45	$ 0.34	$ 0.24	$ 0.14	$ 0.10	$ 0.09	$ 0.10	$ 0.09	$ 0.10	$ 0.10	$ 0.15	$ 0.15	$ 0.11	$ 0.08	$ 0.11	$ 0.31	$ 0.84
Depreciation, depletion and amortization expense per mcfe	$ 1.78	$ 2.55	$ 2.78	$ 2.53	$ 2.02	$ 1.69	$ 1.44	$ 1.30	$ 1.12	$ 0.81	$ 0.77	$ 1.19	$ 1.63	$ 1.36	$ 0.90	$ 0.85	$ 0.99	$ 1.09
Number of employees (full-time at end of period)	8,152	7,649	6,219	4,883	2,885	1,718	1,192	866	677	462	424	481	360	362	344	325	250	150
Cash dividends declared per common share	$ 0.30	$ 0.2925	$ 0.2625	$ 0.23	$ 0.195	$ 0.17	$ 0.135	$ 0.06	—	—	—	$ 0.04	$ 0.04	$ 0.02	—	—	—	—
Stock price (at end of period – split adjusted)	$ 25.88	$ 16.17	$ 39.20	$ 29.05	$ 31.73	$ 16.50	$ 13.58	$ 7.74	$ 6.61	$ 10.12	$ 2.38	$ 0.94	$ 7.50	$ 9.81	$ 29.52	$ 5.64	$ 0.85	$ 1.18

* See page 13 for definition of this non-GAAP measure.

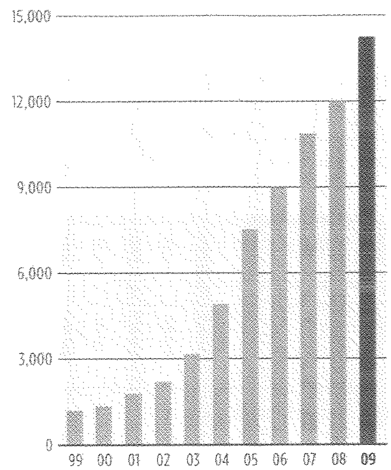
** PV-10 is the present value (10% discount rate) of estimated future gross revenues to be generated from the production of proved reserves, net of production and future development costs, using assumed prices and costs. Please see page 129 of our Form 10-K for information on the standardized measure of discounted future net cash flows.

*** Excludes unrealized gains (losses) on natural gas and oil hedging.

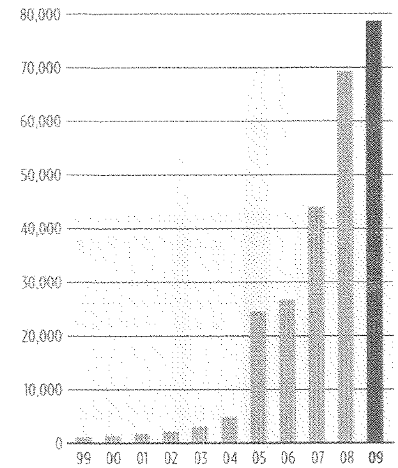
PRODUCTION GROWTH
Average mmcfe per day for year



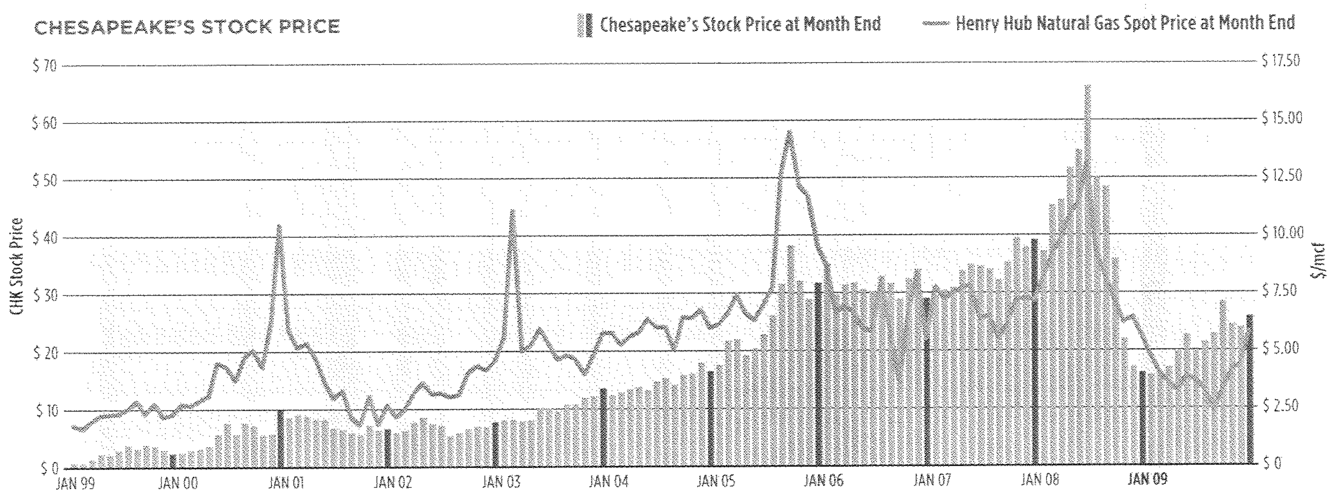
PROVED RESERVE GROWTH
Bcfe at end of year



TOTAL RESOURCE BASE GROWTH
Bcfe at end of year



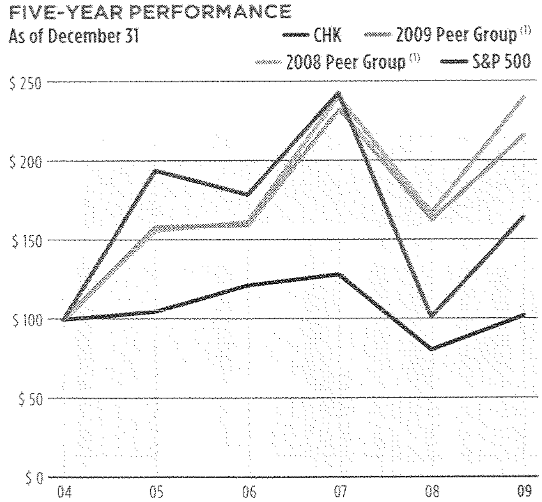
CHESAPEAKE'S STOCK PRICE



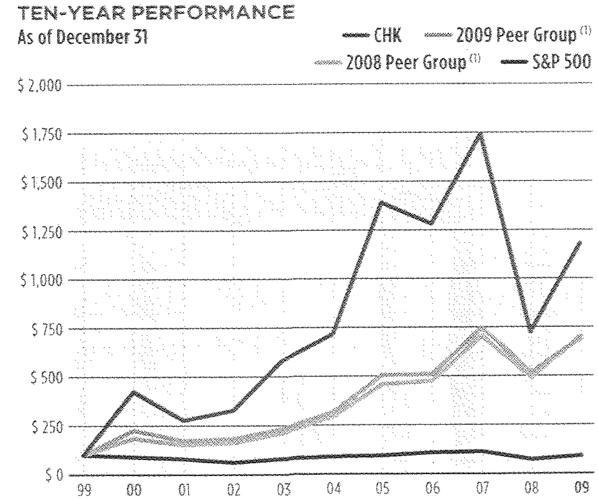
CHESAPEAKE'S FIVE-YEAR AND TEN-YEAR COMMON STOCK PERFORMANCE

The graphs below compare the performance of our common stock to the S&P 500 Stock Index and two groups of peer companies for the past five and 10 years. The graph on the left assumes an investment of $100 on December 31, 2004 and the reinvestment of all dividends. The graph on the right assumes an investment of $100 on December 31, 1999 and the reinvestment of all dividends. The graphs show the value of the investment at the end of each year.

FIVE-YEAR PERFORMANCE
As of December 31



TEN-YEAR PERFORMANCE
As of December 31



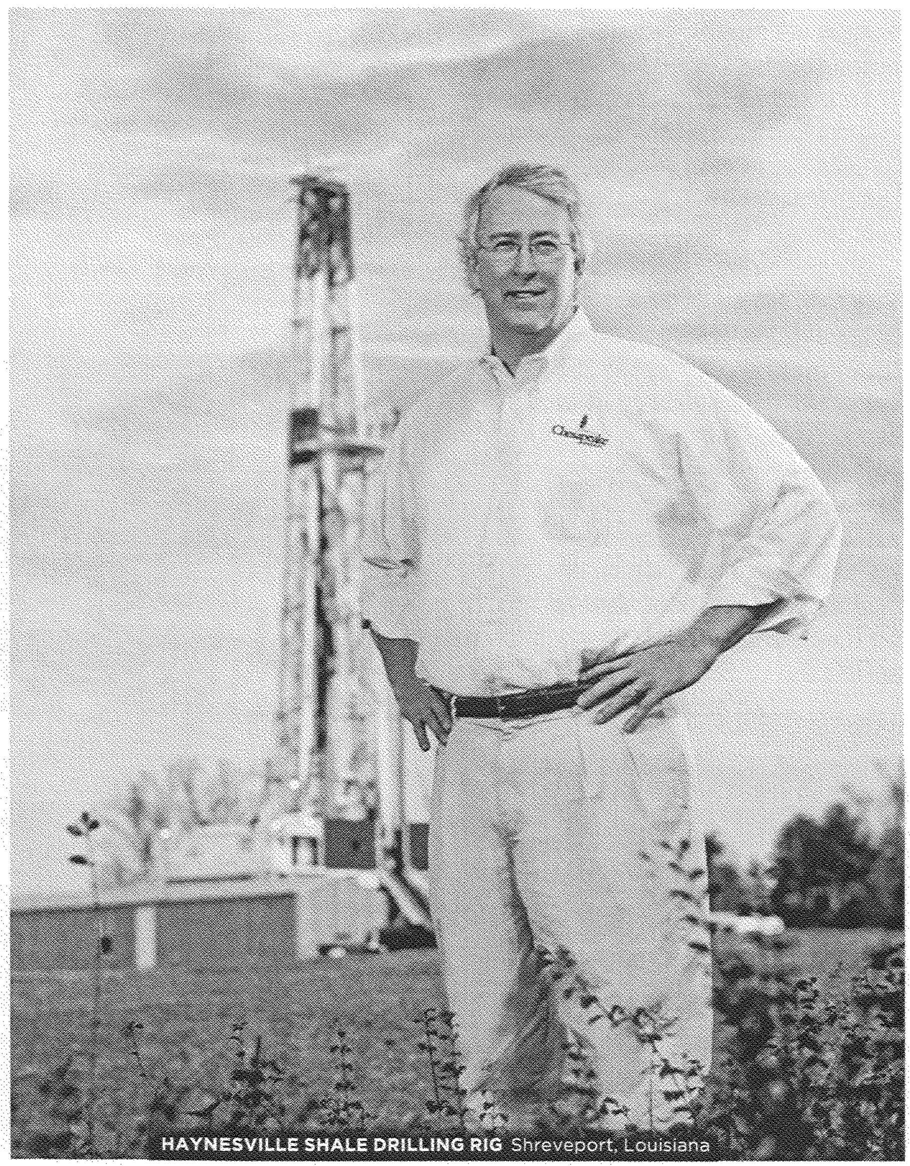
(1) The 2009 peer group is comprised of Anadarko Petroleum Corporation, Apache Corporation, Devon Energy Corporation, Encana Corporation, EOG Resources, Inc. and XTO Energy, Inc. The 2008 peer group was comprised of Anadarko Petroleum Corporation, Apache Corporation, Cabot Oil & Gas Corporation, Devon Energy Corporation, EOG Resources, Inc., Forest Oil Corporation, Newfield Exploration Company, Noble Energy, Inc., Occidental Petroleum Corporation, Pioneer Natural Resources Company, Quicksilver Resources, Inc., Range Resources Corporation, Southwestern Energy Company, St. Mary Land & Exploration Company and XTO Energy, Inc. The change in peer group composition was made in order to show the returns of Chesapeake vs. other North American gas-focused large-cap E&P companies.

LETTER TO SHAREHOLDERS

Dear Fellow Shareholders,

Marking the 20th anniversary since our founding, 2009 was a very successful year for Chesapeake, even though average natural gas prices fell 56% in 2009 compared to 2008:

Aubrey K. McClendon,
Co-Founder, Chairman
and Chief Executive Officer



HAYNESVILLE SHALE DRILLING RIG Shreveport, Louisiana

- **Average daily natural gas and oil production increased 8% from 2.3 billion cubic feet of natural gas equivalent (bcfe) in 2008 to 2.5 bcfe in 2009;**
- **Proved natural gas and oil reserves increased 18% in 2009, from 12.1 trillion cubic feet of natural gas equivalent (tcfe) to 14.3 tcfe;**
- **Reserve replacement for the year reached 343% at a drilling and net acquisition cost of only $0.74 per thousand cubic feet of natural gas equivalent (mcfe)[1];**
- **Cash hedging gains were $2.3 billion;**
- **Our stock price increased 60% in 2009, from $16.17 to $25.88;**
- **Revenues totaled $7.7 billion;**
- **Adjusted ebitda[2] was $4.4 billion;**
- **Operating cash flow[2] totaled $4.3 billion; and**
- **Adjusted earnings per fully diluted share[2] were $2.55.**

THE PAST AS PROLOGUE

In May 1989, I co-founded Chesapeake to take advantage of a newly developed technology called horizontal drilling. At the time, my business partner Tom Ward and I were two self-employed landmen working together to develop prospects for other companies to drill. These prospects were located in southern Oklahoma and in South Texas where we assembled large land positions that were underlain by fractured carbonates — reservoirs which were not at the time considered economic to develop using conventional vertical drilling technologies.

Convinced the conventional wisdom about these formations was wrong, we started developing the prospects ourselves using horizontal drilling. We didn't know it then, but those prospects today would be called unconventional reservoirs (so-called because they are generally nonproductive without the implementation of advanced horizontal drilling and fracture stimulation technologies). To us, it was simply a very logical way to combine a new technology with our land acquisition skills to crack the code for economically developing large scale projects that could be company-makers.

Ironically, that is precisely what Chesapeake does today — uses its cutting-edge technological capabilities and industry-leading land acquisition skills to develop new unconventional reservoirs that have recently become some of the largest, most active and most highly valued natural gas development projects in the world.

While I am proud of our humble beginnings, I am also proud that during its 20-year existence, Chesapeake has built an unparalleled asset portfolio, an industry-leading technological position and a deep sense of environmental stewardship to become the nation's second-largest natural gas producer, most active driller of new wells and most vocal proponent of natural gas as the best way to fuel America's clean energy future.

OUR POWERFUL ASSETS

What will drive Chesapeake's strong growth in the future? It will be our industry-leading position in the "Big 6" major natural gas shale plays in the U.S. — the Barnett, Fayetteville, Haynesville, Marcellus, Bossier and Eagle Ford shales — plus our emerging unconventional oil plays. The Big 6 shale plays form the foundation of the American natural gas shale revolution and they will create substantial value for Chesapeake's shareholders for decades to come. And because those key shale plays are dominated by only 15 or so public companies, we believe this group of shale pioneers will emerge as the industry's biggest winners in the years ahead. Chesapeake's Top 2 position in five of the Big 6 shale plays (with no other company having more than one Top 2 position) should ensure that Chesapeake will emerge as the biggest winner of all from the Big 6 shale land rush.

BARNETT SHALE

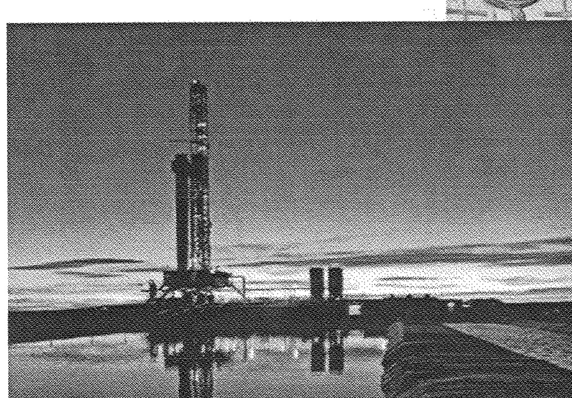
Discovered in the 1990s, the Barnett is the granddaddy of all shale plays. Chesapeake acquired its first assets in the Barnett in 2001, but did not fully appreciate the potential significance of the play until early 2004. We then made our first two property acquisitions in Johnson County and set our sights on what we called the "doughnut hole" — Tarrant County, the home of Fort Worth and more than 60 other municipalities.

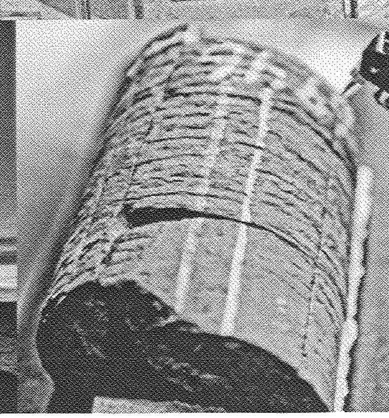
Most in the industry knew Tarrant County lay above the best Barnett rock in the entire play. What was unclear was how to develop it beneath a metropolitan area of almost two million people. After analyzing the challenges and opportunities of urban and suburban drilling, we concluded that while most of our competitors would not want to deal with these complexities, Chesapeake's operational and land acquisition skills would be especially well suited for successful urban development in the Barnett.

Consequently, in 2005 we began leasing in earnest in Tarrant County, and today we own approximately 200,000 leases, on which we estimate we could drill up to 2,400 future net wells in addition to our 1,100 net wells currently producing.

Our most exciting development in the Barnett Shale during 2009 was the signing of our fourth natural gas shale joint venture agreement. This agreement closed in January 2010 and involved Chesapeake selling 25% of its assets in the Barnett to Paris-based Total, S.A., the world's fifth-largest oil company. Total paid $2.25 billion in cash and drilling carries for its 25% stake in the Barnett and we are extremely proud to welcome Total as one of our four highly valued joint venture partners.

Hard work, high-tech drilling rigs and gas-laden shale provide a formula for success. Employees of Nomac Drilling, a Chesapeake subsidiary, operate the largest rig fleet in the exploration and production industry as they drill for natural gas in America's Big 6 shale plays.





FAYETTEVILLE SHALE

The Fayetteville Shale of central Arkansas emerged as the second important U.S. shale play in early 2005. Chesapeake had already developed a presence in the Woodford Shale of southeastern Oklahoma in 2004, so when we learned in 2005 of initial success in the Fayetteville, we aggressively jumped into Arkansas, acquiring approximately 550,000 net acres of prime Fayetteville acreage by mid-year 2008. Our drilling success came quickly in the Fayetteville as our knowledge of shale development from the Barnett and Woodford plays helped establish Chesapeake as the second-largest player in the Fayetteville.

A key to Chesapeake's Fayetteville success has been our September 2008 joint venture with London-based BP, the world's second-largest oil company. In this joint venture, we sold 25% of our assets in the Fayetteville to BP for $1.9 billion in cash and drilling carries. Today, we are producing from more than 500 net wells in the Fayetteville on our 460,000 net acres and estimate we could drill up to 5,200 additional net wells in the years ahead.

HAYNESVILLE SHALE

The Haynesville Shale in Northwest Louisiana and East Texas is the shale play of which we are most proud because it was discovered by Chesapeake's own geoscientists and engineers. We began our geoscientific investigation of the Haynesville in 2005–06 and tested our theories through drilling in 2007. In 2008, we formed an innovative joint venture with our well-respected industry partner, Houston-based Plains Exploration & Production Company, to which we sold 20% of our Haynesville assets for $3.2 billion in cash and drilling carries.

The Haynesville Shale is now the nation's second-largest producing shale play. It is so large (more than twice the size of the Barnett core area) and so over-pressured (holding more gas in place per square mile than the Barnett) that we believe it will likely surpass the Barnett by 2014 to become the largest natural gas producing field in the U.S. Ultimate recoveries from the Haynesville could exceed 250 tcfe, making it potentially one of the five largest natural gas fields in the world. Today, we are producing from more than 200 net wells in the Haynesville on our 520,000 net leasehold acres and estimate we could drill up to 6,500 additional net wells in the years ahead.

The Haynesville Shale in Northwest Louisiana and East Texas is the shale play of which we are most proud because it was discovered by Chesapeake's own geoscientists and engineers.

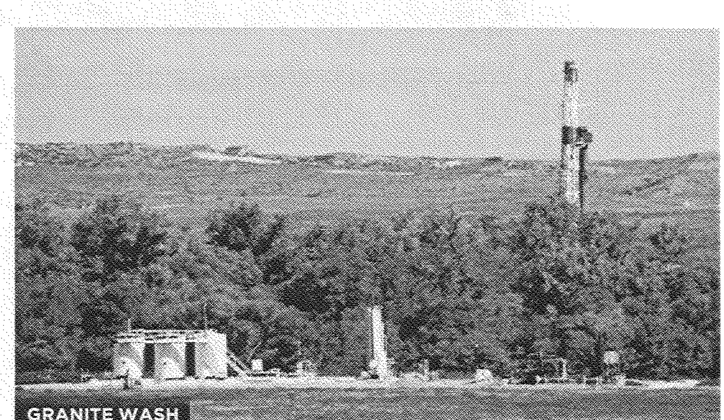
GRANITE WASH
High-volume natural gas with a bonus of oil and natural gas liquids give the Granite Wash outstanding returns.

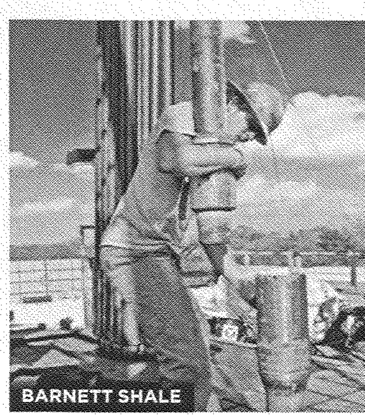
BARNETT SHALE
The massive Barnett in north-central Texas is the granddaddy of all natural gas shale plays.

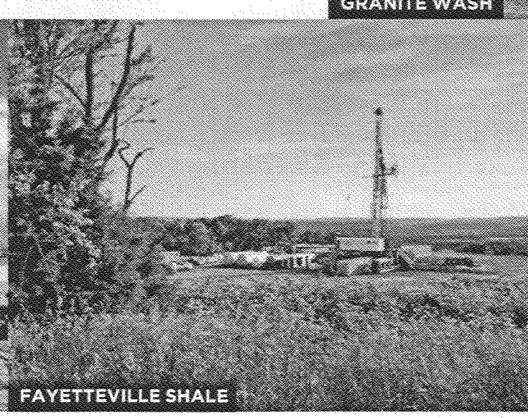
FAYETTEVILLE SHALE
Scenic central Arkansas is home to the prolific Fayetteville Shale.

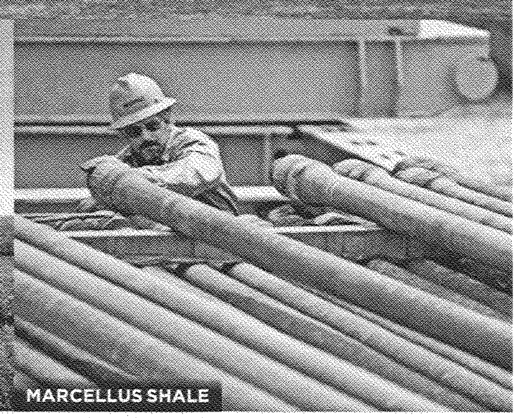
MARCELLUS SHALE
Deep beneath northern Appalachia, Marcellus Shale natural gas will revitalize the region.

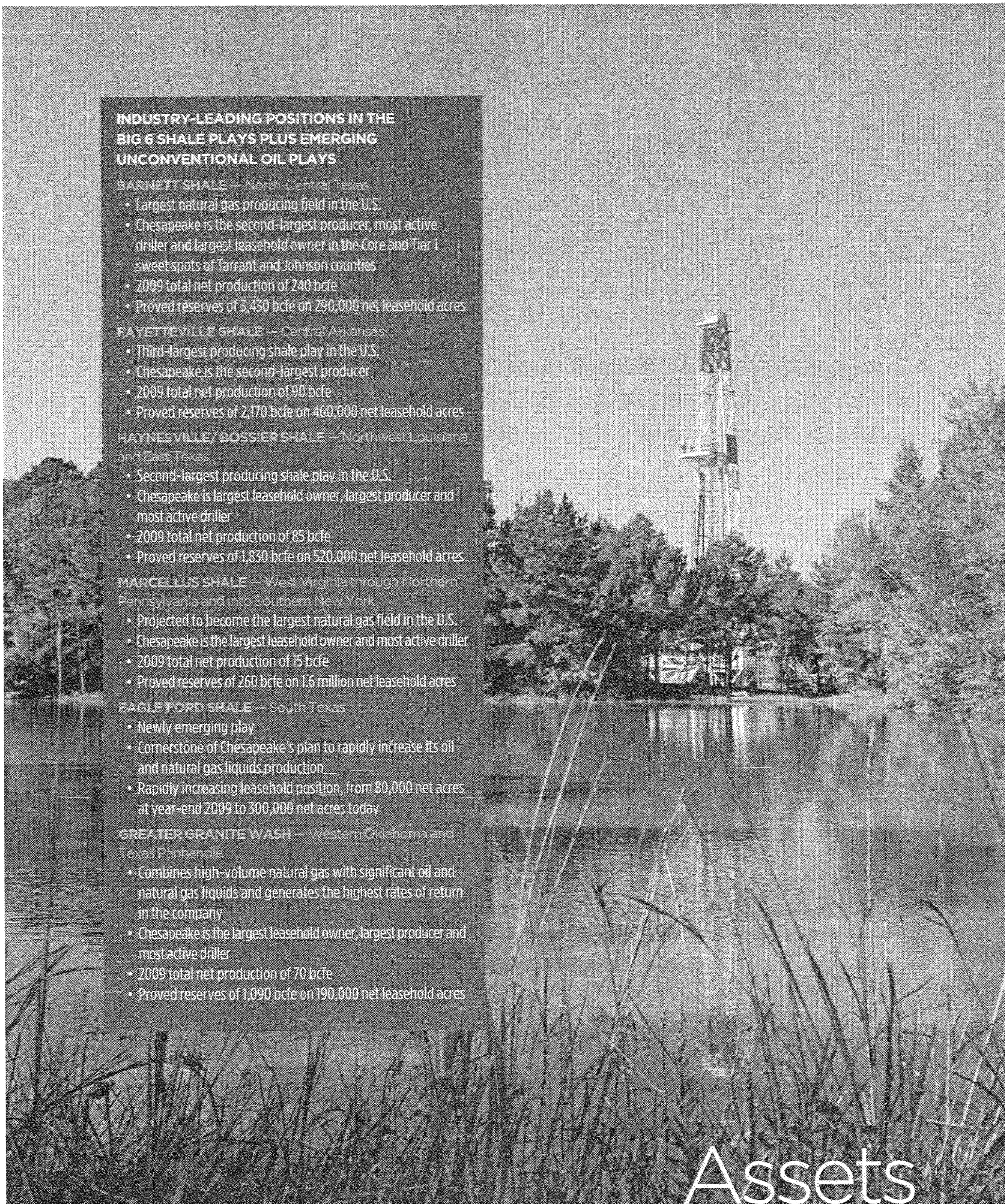
HAYNESVILLE SHALE
Chesapeake's discovery of the Haynesville makes the play's success even sweeter.


GRANITE WASH


BARNETT SHALE


FAYETTEVILLE SHALE


MARCELLUS SHALE



INDUSTRY-LEADING POSITIONS IN THE BIG 6 SHALE PLAYS PLUS EMERGING UNCONVENTIONAL OIL PLAYS

BARNETT SHALE — North-Central Texas
- Largest natural gas producing field in the U.S.
- Chesapeake is the second-largest producer, most active driller and largest leasehold owner in the Core and Tier 1 sweet spots of Tarrant and Johnson counties
- 2009 total net production of 240 bcfe
- Proved reserves of 3,430 bcfe on 290,000 net leasehold acres

FAYETTEVILLE SHALE — Central Arkansas
- Third-largest producing shale play in the U.S.
- Chesapeake is the second-largest producer
- 2009 total net production of 90 bcfe
- Proved reserves of 2,170 bcfe on 460,000 net leasehold acres

HAYNESVILLE/BOSSIER SHALE — Northwest Louisiana and East Texas
- Second-largest producing shale play in the U.S.
- Chesapeake is largest leasehold owner, largest producer and most active driller
- 2009 total net production of 85 bcfe
- Proved reserves of 1,830 bcfe on 520,000 net leasehold acres

MARCELLUS SHALE — West Virginia through Northern Pennsylvania and into Southern New York
- Projected to become the largest natural gas field in the U.S.
- Chesapeake is the largest leasehold owner and most active driller
- 2009 total net production of 15 bcfe
- Proved reserves of 260 bcfe on 1.6 million net leasehold acres

EAGLE FORD SHALE — South Texas
- Newly emerging play
- Cornerstone of Chesapeake's plan to rapidly increase its oil and natural gas liquids production
- Rapidly increasing leasehold position, from 80,000 net acres at year-end 2009 to 300,000 net acres today

GREATER GRANITE WASH — Western Oklahoma and Texas Panhandle
- Combines high-volume natural gas with significant oil and natural gas liquids and generates the highest rates of return in the company
- Chesapeake is the largest leasehold owner, largest producer and most active driller
- 2009 total net production of 70 bcfe
- Proved reserves of 1,090 bcfe on 190,000 net leasehold acres

HAYNESVILLE SHALE

Assets

MARCELLUS SHALE

We first became aware of the Marcellus in 2005 when we were negotiating our $2.2 billion acquisition of Appalachia's second-largest natural gas producer, Columbia Natural Resources, LLC (CNR). Although CNR was not actively developing the Marcellus at the time of our acquisition, Chesapeake's geoscientists recognized that CNR's industry-leading leasehold position in Appalachia would overlay a significant portion of the Marcellus in northwestern West Virginia and southern New York (CNR had unfortunately previously sold its Pennsylvania assets). In 2007, we aggressively accelerated our Marcellus leasehold acquisition efforts in Pennsylvania and began to prepare for our first drilling activities. By early 2008, we had determined the Marcellus could be prospective over an area of approximately 15 million net acres (approximately five times larger than the prospective Haynesville core area and 10 times larger than the Barnett core area).

After acquiring 1.8 million net acres, we entered into a joint venture in late 2008 with Oslo, Norway-based Statoil, one of the largest and most respected European energy companies. In this transaction, we sold Statoil 32.5% of our Marcellus assets for $3.375 billion in cash and drilling carries. In addition, we have joined with Statoil in the search for other shale plays around the world in a 50/50 partnership. We are excited by the opportunity to extend our natural gas shale expertise from the U.S. to other parts of the world through our Statoil joint venture. Today, we are producing from more than 150 net wells in the Marcellus on our 1.6 million net acres and estimate we could drill up to 20,000 additional net wells in the years ahead.

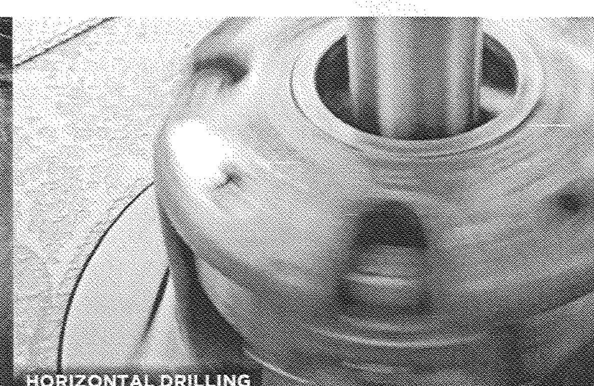
BOSSIER SHALE

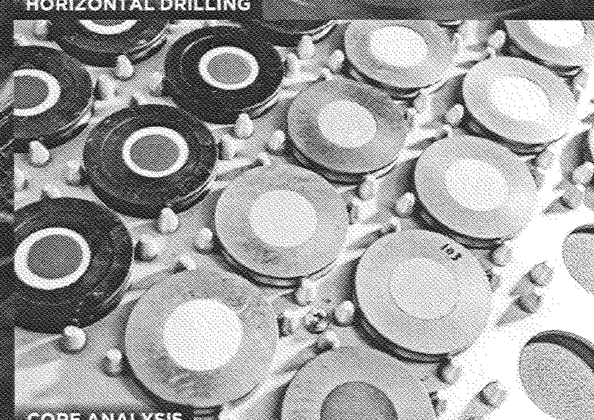
The Bossier Shale is one of the two new shale plays that expanded our "Big 4" shale plays from 2008 into the "Big 6" of 2009. The Bossier overlays a portion of the Haynesville Shale and is perhaps the "sleeper" of the Big 6 shale plays. The reason is that in Louisiana, leases often restrict the lessee (i.e., the producer) to only holding future drilling rights down through the deepest formation drilled. Because the Bossier

TECHNOLOGY
Associate Geologist Emiko Bogard takes a closer look at the microscopic qualities of shale.

HORIZONTAL DRILLING
Chesapeake's expertise in horizontal drilling has been a key factor in its success.

CORE ANALYSIS
Scientists in the company's Reservoir Technology Center study core samples to unlock the secrets of shale gas.





lies above the Haynesville, horizontal wells drilled just to the Bossier may not always hold Haynesville rights. Therefore, Chesapeake and other producers are drilling aggressively to hold all rights through the Haynesville before the typical three-year-term initial leases expire, so not much Bossier drilling is yet underway. However, once our leases are HBP (held by production) by Haynesville drilling, we will begin developing the Bossier Shale more aggressively in 2013. In the Bossier play, we own 180,000 net acres on which we estimate we could drill up to 2,250 net wells in the years ahead.

EAGLE FORD SHALE

The Eagle Ford Shale of South Texas was the second addition to our Big 6 inventory in 2009. The Eagle Ford is different from the other Big 6 shale plays because it has three distinct elements: a dry gas play, an oil play and a wet gas play. Chesapeake has acquired approximately 300,000 net acres to date, all of which are in the oil and wet gas portions of the play. Given that oil and natural gas liquids are valued much more highly than natural gas, we are focusing all of our Eagle Ford leasing efforts in the oil and wet gas portions of the play. Our first three wells have been successful, and we expect to accelerate our drilling in the Eagle Ford in 2010 and beyond. Our leasehold position could support the drilling of up to 2,000 additional net wells.

LOOKING FOR MORE OIL

In addition to further developing our Big 6 natural gas shale plays, another important goal of the company in 2010 is to find more oil. Oil comprised only 8% of Chesapeake's 2009 production, and with oil prices more than 3.5 times higher today than natural gas prices on an energy equivalent basis, it makes powerful economic sense to increase our efforts toward finding, leasing and developing large scale unconventional oil projects using the skills we have developed in unconventional natural gas projects.

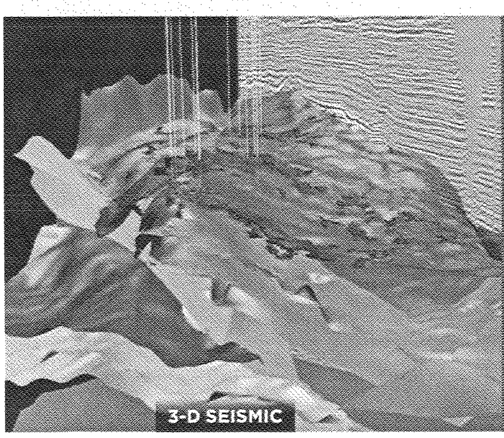
This challenge is especially difficult because oil molecules and wet natural gas molecules are larger than dry natural gas molecules and therefore much more difficult to produce from ultra-tight unconventional reservoirs.

In addition to further developing our Big 6 natural gas shale plays, another important goal of the company in 2010 is to find more oil.

We kicked off this "gas to oil" initiative two years ago, and to date, have already had initial success in 10 new oil plays. We also are working on additional oil play concepts. If these plays and concepts prove commercial on a large scale, then we believe Chesapeake owns more than four billion barrels of unrecognized oil resources that will substantially increase the company's value as they are developed.

Because early drilling results need to remain confidential as we acquire more leasehold in these new oil plays, we are being guarded with our oil drilling results disclosures. As 2010 progresses, however, we look forward to revealing more about the potential of Chesapeake's oil upside. I believe these oil discoveries could prove to be the most significant value creation uplift for the company since our gas shale discoveries of the past few years.

3-D SEISMIC This rapidly advancing technology has been critical in enabling Chesapeake's geoscientists to steer our horizontal wells into the best shale rock.



INNOVATIVE TECHNOLOGY AND SHARED KNOWLEDGE

In the natural gas exploration and production business, success is predicated on knowledge: knowing where to drill, how to complete and how to transfer the expertise gained in one play to the next.

Using 3-D seismic, Chesapeake's geoscientists and reservoir engineers study the geologic structures of plays and potential drillsites. They also collaborate with world class petrophysicists in our unique Reservoir Technology Center to analyze core samples and evaluate the most effective completion techniques to maximize recovery of each well.

Chesapeake is among the few industry participants with an internal technology group that works with engineering, unconventional, petrophysical, reservoir and asset management teams to leverage the experience and knowledge gained in one big play to the next — optimizing and improving performance in every area in which we operate.

GRANITE WASH PLAYS

The Colony and Texas Panhandle Granite Wash plays provide insight into what could happen if Chesapeake is successful in finding new unconventional oil plays. As good as the per-well Big 6 gas shale economics are, the economics are even better in the Colony Wash and Texas Panhandle Granite Wash plays because they possess the best of both worlds: high-volume natural gas production as in the Big 6 gas shale plays, along with significant volumes of oil and natural gas liquids that dramatically increase investment returns. For example, while our per-well economics for Big 6 shale wells generally provide returns of 20–60%, wells drilled in these two Granite Wash plays provide returns of 100–150% and generally reach payout in less than a year.

> We are already producing from approximately 100 net Granite Wash wells and estimate we could drill up to 1,200 additional net wells on our 190,000 net acres of leasehold in the years ahead.

We are already producing from approximately 100 net Granite Wash wells and estimate we could drill up to 1,200 additional net wells on our 190,000 net acres of leasehold in the years ahead. Based on current NYMEX futures prices for natural gas and oil, each Granite Wash well should generate approximately $8–11 million of present value per well (or $10–13 billion for all 1,200 wells), making it obvious that finding, leasing and developing more oil plays with Granite Wash-type returns will be Chesapeake's number one priority for 2010.

OUR PEOPLE

Great assets would not and cannot exist without great people, so we take great pride in hiring, training, motivating, rewarding and retaining great people. From our beginning 20 years ago with 10 employees in Oklahoma to employing 8,600 people in 16 states today, Chesapeake has always focused on

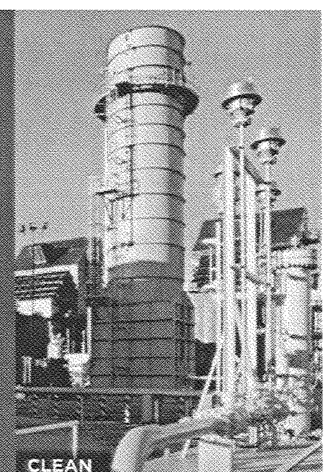
CLEAN The growing number of natural gas-powered electrical generation plants is testimony to their environmental and economic advantages.
AFFORDABLE Consumers filling their tanks with compressed natural gas (CNG) often save 50% over the cost of gasoline.
ABUNDANT Natural gas pipelines transport America into the "Age of Natural Gas" with almost a 200-year supply.
AMERICAN Workers like Aaron Harris, Nomac Derrickman, help supply approximately 90% of America's natural gas needs from domestic sources.

ANGA: A NEW NATIONAL VOICE FOR NATURAL GAS

In March 2009, Chesapeake joined with a group of the nation's leading independent producers to create one dynamic voice for increasing demand for American natural gas. The mission of America's Natural Gas Alliance (ANGA) is to increase understanding and appreciation for the environmental, economic and national security benefits of clean, abundant, dependable and cost-efficient American natural gas. Its 34 members represent more than 40% of the total U.S. natural gas supply, producing about nine trillion cubic feet per year.

Chesapeake has long been a champion for natural gas. We are proud to be a founding member of ANGA and share its core belief that America's clean energy future will increasingly be fueled by the enormous domestic natural gas resources now available to generate electricity, power industry, provide energy for heating and cooking, and offer a cleaner, more affordable fuel for transportation vehicles.

For more information, please visit www.anga.us.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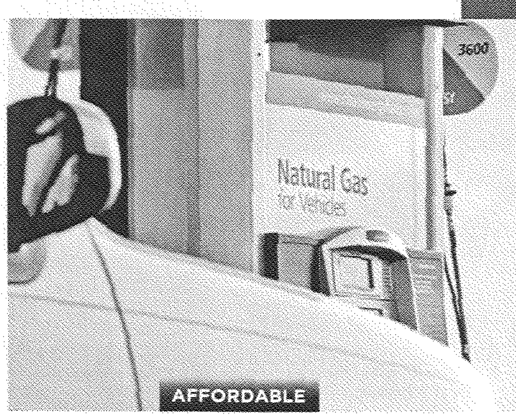

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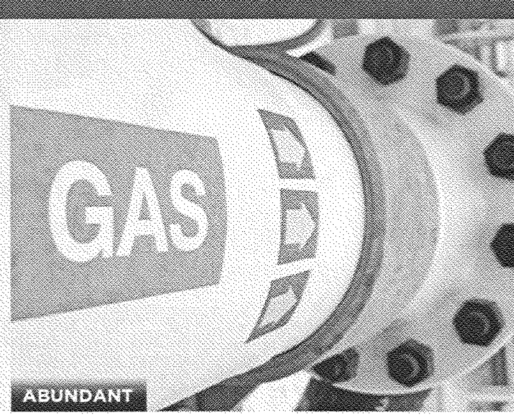


ABUNDANT


AMERICAN

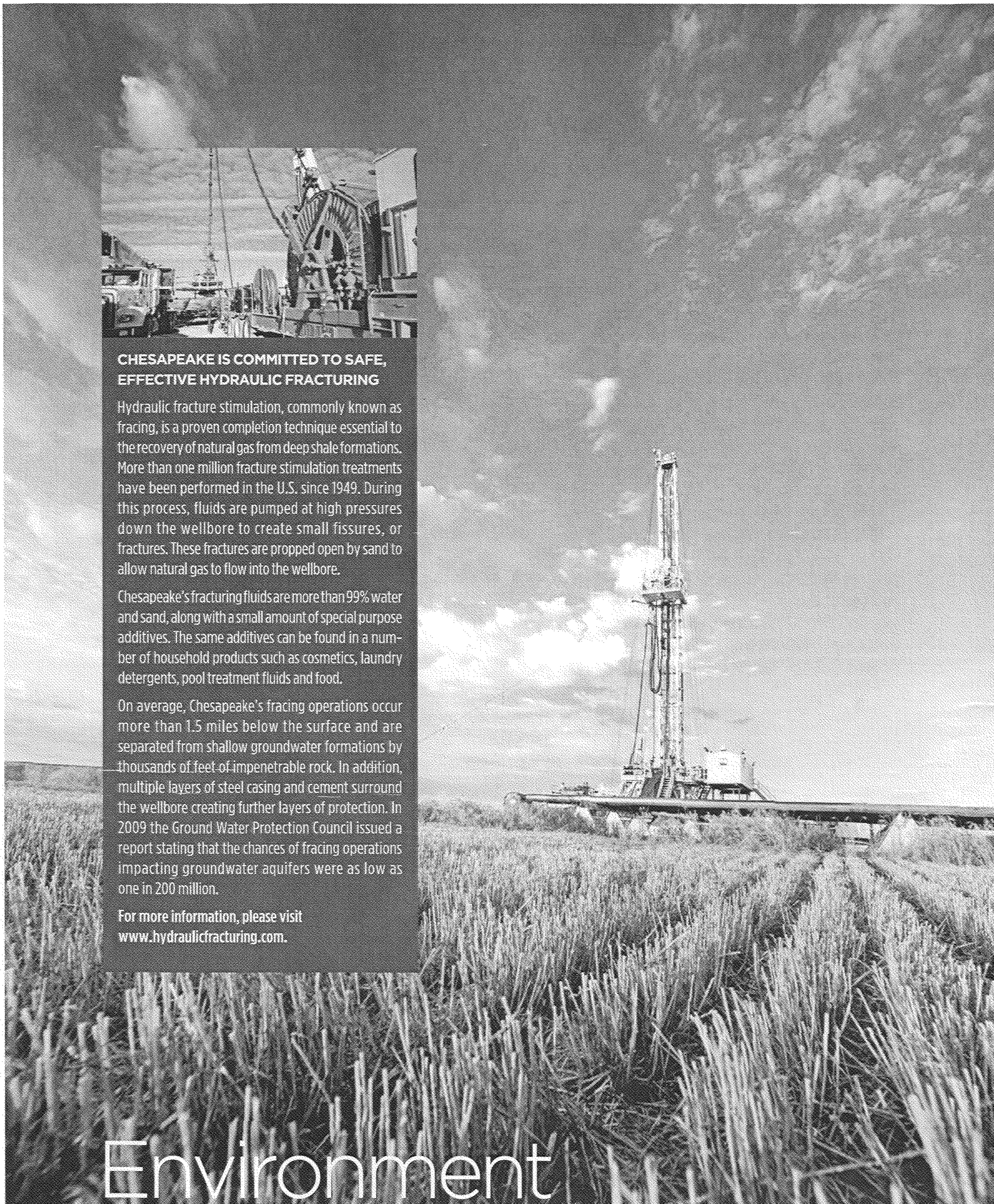
building a first class human resource team within a distinctive corporate culture. Talk to Chesapeake employees and you will sense genuine pride and great enthusiasm about the company and the vital role we play in delivering our high-quality product to consumers across the country.

Chesapeake employees are distinctive in other ways as well. They are much younger than the industry average, with 50% of our 3,300 Oklahoma City-based headquarters employees 34 years old or younger. Their enthusiasm and willingness to learn create an atmosphere of vitality and energy at Chesapeake, important ingredients of our unique culture. These attributes, along with a very attractive corporate headquarters campus, low levels of bureaucracy and a well-executed corporate strategy, have combined to create our culture of success and innovation.

This has generated extremely positive external feedback as Chesapeake was recently recognized for the third consecutive year as one of the FORTUNE 100 Best Companies to Work For®[(3)]. In addition, we were honored in December 2009 at the 11th Annual Platts Global Energy Awards as the Energy Producer of the Year. We also received the Industry Leadership Award and were a finalist for CEO of the Year, Deal of the Year and Community Development Program of the Year. Chesapeake was one of only two companies to receive multiple awards this year and one of only three companies selected as a finalist in five or more categories. This was the second time in three years that Platts has named Chesapeake Producer of the Year. Chesapeake was also recognized in 2009 with *Oil and Gas Investor* magazine's Best Corporate Citizen Award.

From our beginning 20 years ago with 10 employees in Oklahoma to employing 8,600 people in 16 states today, Chesapeake has always focused on building a first class human resource team within a distinctive corporate culture.

Chesapeake is proud to be the nation's second-largest producer of natural gas — and the most vocal proponent for natural gas *Fueling America's Future.*



CHESAPEAKE IS COMMITTED TO SAFE, EFFECTIVE HYDRAULIC FRACTURING

Hydraulic fracture stimulation, commonly known as fracing, is a proven completion technique essential to the recovery of natural gas from deep shale formations. More than one million fracture stimulation treatments have been performed in the U.S. since 1949. During this process, fluids are pumped at high pressures down the wellbore to create small fissures, or fractures. These fractures are propped open by sand to allow natural gas to flow into the wellbore.

Chesapeake's fracturing fluids are more than 99% water and sand, along with a small amount of special purpose additives. The same additives can be found in a number of household products such as cosmetics, laundry detergents, pool treatment fluids and food.

On average, Chesapeake's fracing operations occur more than 1.5 miles below the surface and are separated from shallow groundwater formations by thousands of feet of impenetrable rock. In addition, multiple layers of steel casing and cement surround the wellbore creating further layers of protection. In 2009 the Ground Water Protection Council issued a report stating that the chances of fracing operations impacting groundwater aquifers were as low as one in 200 million.

For more information, please visit www.hydraulicfracturing.com.

Environment

FUELING AMERICA'S CLEAN ENERGY FUTURE

Because of a series of insights into the future, followed by good decisions and hard work, Chesapeake has grown from a small startup company 20 years ago into an industry leader today. Along the way, we have built the industry's highest quality asset base in the Big 6 natural gas shale plays. These shale plays have dramatically changed how we can solve our nation's most important energy and environmental challenges in the years ahead, while also creating millions of truly green jobs that pay well and do not need taxpayer or ratepayer subsidies. They also can improve America's national security by reducing our dependence on foreign oil.

There has never really been any debate about whether natural gas is a good fuel — its carbon-light molecular structure guarantees that. The issue has always been whether there is enough of it to begin moving our electrical generation system more aggressively away from dirty coal and whether it is the right time to begin moving our transportation system away from expensive foreign oil. With the enormity of the Big 6 natural gas shale plays now more fully understood, it should become increasingly clear that the U.S. has a huge competitive advantage in the world.

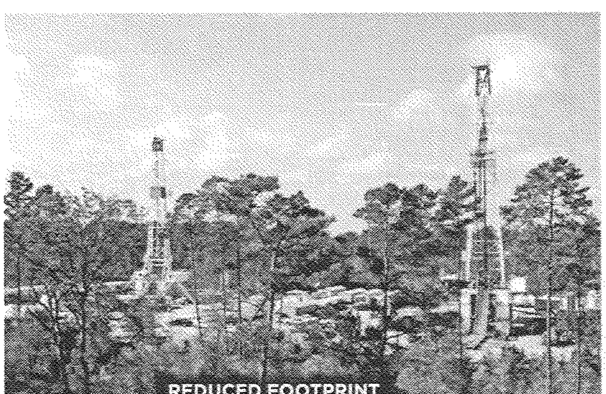
On the economic front, U.S. natural gas prices are among the lowest in the industrialized world and are likely to remain so for an extended period because of the discovery of the Big 6 shale natural gas resources. On the environmental front, the U.S. can regain its leadership in environmental best practices by burning more clean natural gas and less dirty coal to make our electricity. And finally, natural gas can enable the U.S. to transition its transportation system away from dangerous and expensive foreign oil to cheaper and cleaner American natural gas.

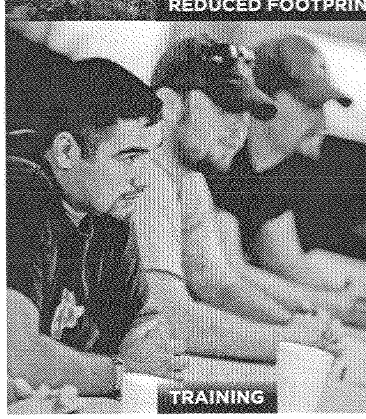
To capture the important advantages the Big 6 shale plays can provide, U.S. leaders must recognize the "Age of Natural Gas" has arrived and that it will remain with us for decades to come. A better, brighter and more prosperous future awaits us if we pursue the full potential of natural gas for *Fueling America's Future.*

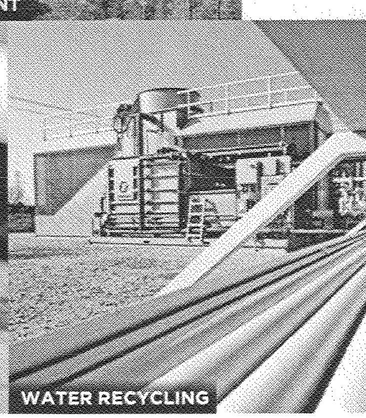
Best regards,

Aubrey K. McClendon

Aubrey K. McClendon
Chairman and Chief Executive Officer
March 31, 2010







(1) Reserve replacement is calculated by dividing net reserve additions from all sources by actual production for the corresponding period. We calculate drilling and net acquisition cost per mcfe by dividing total drilling and net proved property acquisition costs incurred during the year (excludes certain costs primarily related to net unproved property acquisitions, geological and geophysical costs and deferred taxes related to corporate acquisitions) by total proved reserve additions excluding price-related revisions.

(2) A non-GAAP financial measure, as defined below. Please refer to the Investors section of our website at www.chk.com for reconciliations of non-GAAP financial measures to comparable financial measures calculated in accordance with generally accepted accounting principles.
- Adjusted ebitda is net income (loss) before interest expense, income tax expense (benefit), and depreciation, depletion and amortization expense, as adjusted to remove the effects of certain items that management believes affect the comparability of operating results.
- Operating cash flow is cash provided by operating activities before changes in assets and liabilities.
- Adjusted earnings per fully diluted share is net income (loss) per share available to Chesapeake common stockholders, assuming dilution, as adjusted to remove the effects of certain items that management believes affect the comparability of operating results.

(3) FORTUNE 100 Best Companies to Work For® listed in the magazine's February 8, 2010 issue.

REDUCED FOOTPRINT Two drilling rigs on one superpad help minimize the footprint of operations in the Haynesville Shale.
TRAINING Trainees Vincent Sandoval, Jayson Pihajlic and Mark O'Byrne learn to work safely, efficiently and with respect for the environment at the Nomac Drilling training facility in Searcy, Arkansas.
WATER RECYCLING One facet of Chesapeake's innovative AquaRenew™ program recycles produced water into clean water vapor.
LOW EMISSIONS Seth Unruh, EHS Field Representative, inspects a valve to decrease venting, reduce emissions and increase gas volumes.

FUELING AMERICA'S FUTURE

Aubrey McClendon on the Potential of Natural Gas in the 21st Century

The enormous potential of the 21st century's "Age of Natural Gas" is now fully in view. Vast new reserves of natural gas in shale reservoirs deep beneath our country have been discovered in the past five years. These shale reservoirs are now estimated to contain more than two quadrillion cubic feet of natural gas, more than doubling America's previously estimated natural gas reserves, and giving us close to a 200-year supply of clean, affordable, American natural gas. These unconventional reservoirs are a remarkable addition to America's bountiful natural resource endowment.

They are also essential to retaining our nation's prosperity. Because of our reliance on dangerous and expensive foreign oil to power our cars and trucks and on dirty coal to produce 50% of our electricity, America's position of global economic and environmental leadership for the next century is unfortunately in doubt. It need not be. Underneath many parts of the U.S. lies a buried treasure of natural gas that is quickly becoming the envy of the world — it's clean, affordable, abundant, American, and brought to you by public independent natural gas producers such as Chesapeake.

Two quadrillion cubic feet of America's natural gas represent more energy than Saudi Arabia's 200 billion barrels of oil reserves — but America's natural gas is much cleaner and 70% cheaper than Saudi oil. In 2009, the U.S. passed Russia as the biggest producer of natural gas in the world, but how many Americans realize this remarkable achievement? Our political leadership must begin to acknowledge and celebrate this tremendous accomplishment and to recognize the strategic and practical benefits of more aggressively using our enormous new reserves of natural gas.

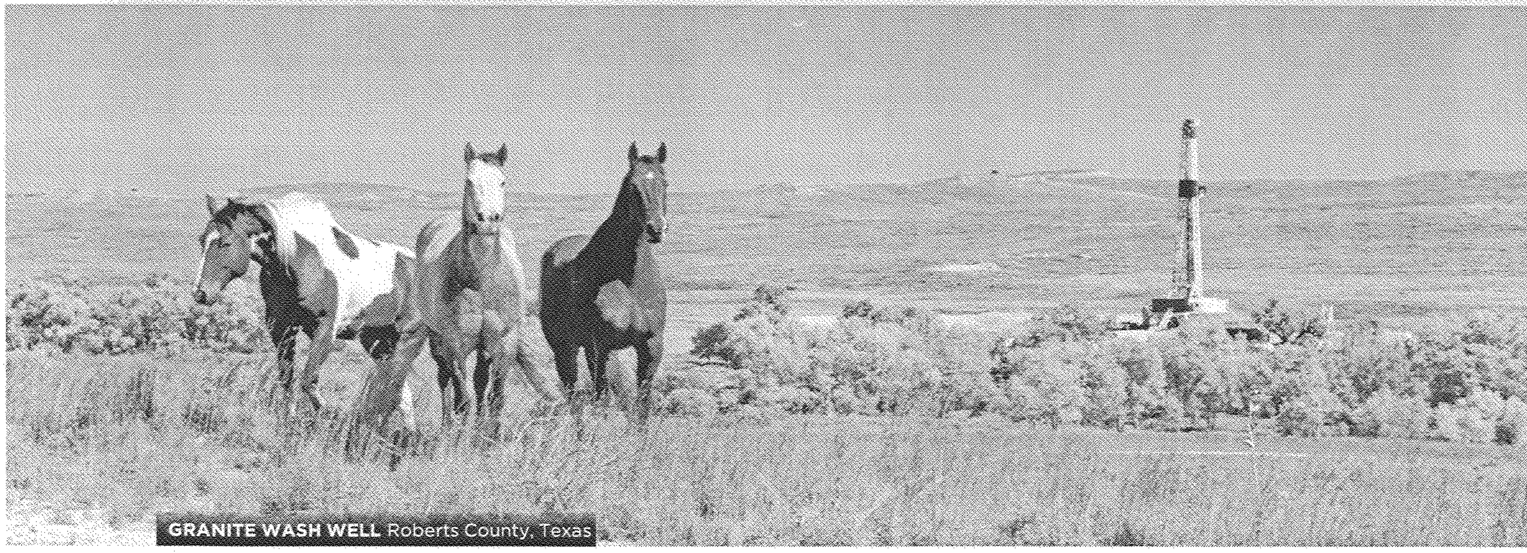
NATURAL GAS IS THE BEST SUBSTITUTE FOR FOREIGN OIL

The U.S. imports approximately 60% of the oil that we consume — a dangerous addiction that costs our country $1 billion per day. This percentage will likely rise in the years ahead as oil prices inevitably increase to choke off demand in the industrialized countries to make room for burgeoning oil demand from rapidly developing countries in Asia, the Middle East and in South America. This is an addiction America cannot afford in good economic times and certainly not in the tough economic times the nation is facing today.

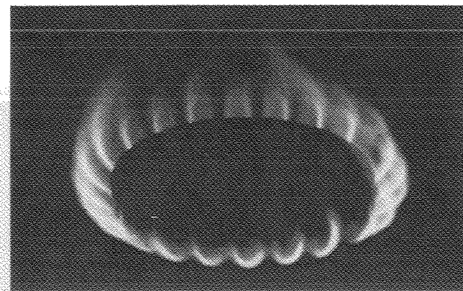
But if our political leadership would awaken and recognize that this addiction could be overcome by converting some of the current demand for foreign oil to new demand for domestic natural gas, America's economic future would be much stronger and our environmental outlook would be brighter. Natural gas has only 50% of the carbon that gasoline has, but more importantly, natural gas vehicles emit little to no harmful pollutants such as carbon monoxide (CO), nitrogen oxide (NOx), and toxic volatile organic compounds (VOCs) that gasoline and diesel consumption currently produce.

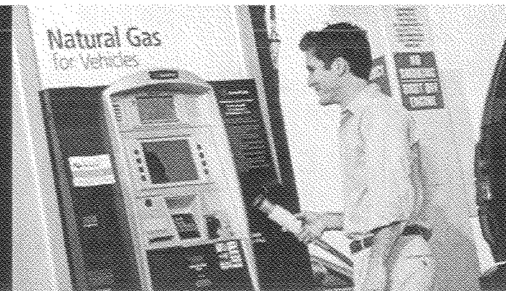
The best way to begin breaking this foreign oil addiction is to endorse the NAT GAS Act (H.R. 1835 and S. 1408) now pending in Congress. For details on these bills, please visit www.cngnow.com. These bills would gradually and efficiently introduce clean, American natural gas as the fuel of choice for heavy-, medium- and light-duty truck fleets in the U.S., replacing diesel refined from expensive foreign oil.

Once truck fleets have been converted to natural gas (in the form of liquefied natural gas, or "LNG") and natural gas refueling pumps have been added to many of our nation's truck stops, we can then begin converting passenger cars to natural gas (in the form of compressed natural gas, or "CNG"). This conversion process would save American consumers billions of dollars because natural gas is 70% cheaper than oil. Americans also would



GRANITE WASH WELL Roberts County, Texas





enjoy the added benefits of cleaner air and water and greater national security.

Speaking of national security, let's not forget that the real price of oil is far more than the $85 per barrel that it costs today. When the American military's cost of defending the world's oil shipping lanes and fighting wars in the Middle East and nearby areas is considered, some experts say the true cost of oil to Americans may be over $200 per barrel. The current practice of spending $1 billion per day to import 11 million barrels of oil from foreign countries is simply not sustainable — it's a dangerous, dirty and expensive habit that must be curtailed.

I drive a converted Chevy Tahoe that runs on natural gas from my home, and I can assure you it feels great to refuel my vehicle at $1.00 per gallon with a clean fuel that is made in America and creates American jobs. My goal is to make sure all Americans one day have the opportunity to enjoy that same great feeling.

We must demand that our leadership begins acting now to make the transition to clean, affordable, abundant, American natural gas before oil reaches $150 per barrel (bringing the price of gasoline to $4.50–5.00 per gallon) and we find ourselves right back in another recession, or perhaps even worse, a depression. These are serious issues, and our nation does not have one day to waste in beginning the transition to a transportation system based on natural gas rather than on expensive foreign oil.

NATURAL GAS IS THE BEST SUBSTITUTE FOR DIRTY COAL

A recent survey Chesapeake commissioned showed that most Americans believe their electricity comes from coal, nuclear or wind — very few people know that natural gas provides 22% of America's electricity. It is critical for Americans to realize how their electricity is generated. As more Americans take responsibility for the environmental impact they create through their electricity consumption, they need to know there are alternatives to burning dirty coal besides constructing new nuclear power plants or new wind and solar facilities. Nuclear plants are prohibitively expensive and time consuming to build. Wind and solar facilities are not economic without taxpayer or ratepayer subsidies. They also cannot provide baseload power because of the lack of sunshine at night and on cloudy days and because of the unpredictability of the wind. These alternatives also require the enormous expense of building unsightly power lines over long distances.

The only scalable, affordable alternative to burning dirty coal is to burn clean natural gas. And the best news is that it would be relatively easy to shut down the dirtiest 33% of America's coal plants (better known at Chesapeake as the "Filthy 100") and replace their electrical output with natural gas-fired electricity. That is because coal plants generally run about 75% of the time while natural gas power plants only run about 25% of the time. The U.S. has enough natural gas to ramp up natural gas power plants to run at least 50% of the time so that we can decommission the Filthy 100.

Doing so would eliminate the following annual estimated pollution: 600 million tons of carbon dioxide (implicated in global warming concerns); 700,000 tons of nitrogen oxide (exacerbates respiratory and heart diseases); 1.5 million tons of sulfur dioxide (the main ingredient of acid rain); 19,000 tons of mercury (one of the deadliest toxins known to mankind, and nonexistent in natural gas); and millions of tons of particulates (which the American Lung Association says kill 24,000 Americans per year).

Confronted with these facts, the coal industry responds with two claims: first, that natural gas is more expensive, and second, that coal can be made clean. Natural gas today sells for around $4 per mcf, making it nearly equivalent in cost to coal, but far cheaper when you factor in the social and environmental costs from coal pollution. And to say that coal is clean or can be made clean is extremely misleading. No scalable, affordable technology exists today to make coal clean. It remains an expensive fantasy on a distant horizon.

In addition, so-called "clean coal" still retains 50% of coal's original carbon, which ironically would place "clean coal" at a carbon level equivalent to natural gas. So why not just use the reality of clean natural gas today and save hundreds of billions of dollars and several decades of time associated with the daunting challenge of trying to make coal clean? And remember, the carbon removed from coal to make it "clean" doesn't just go away — it has to be disposed of somewhere. Right now the "clean coal" plan is to pump more than 100 million gallons of liquid carbon dioxide underneath the ground every day and hope it stays there. That process is expensive, unproven and is projected to consume about 30–35% of a typical power plant's electrical output. No wonder the coal industry favors the "clean coal" idea so much — it would actually increase coal consumption by 30–35%! This insanity must stop! Our country needs to recognize that the future should belong to clean, affordable, practical energy sources — and natural gas is the only ready-to-go, scalable alternative to dirty coal.

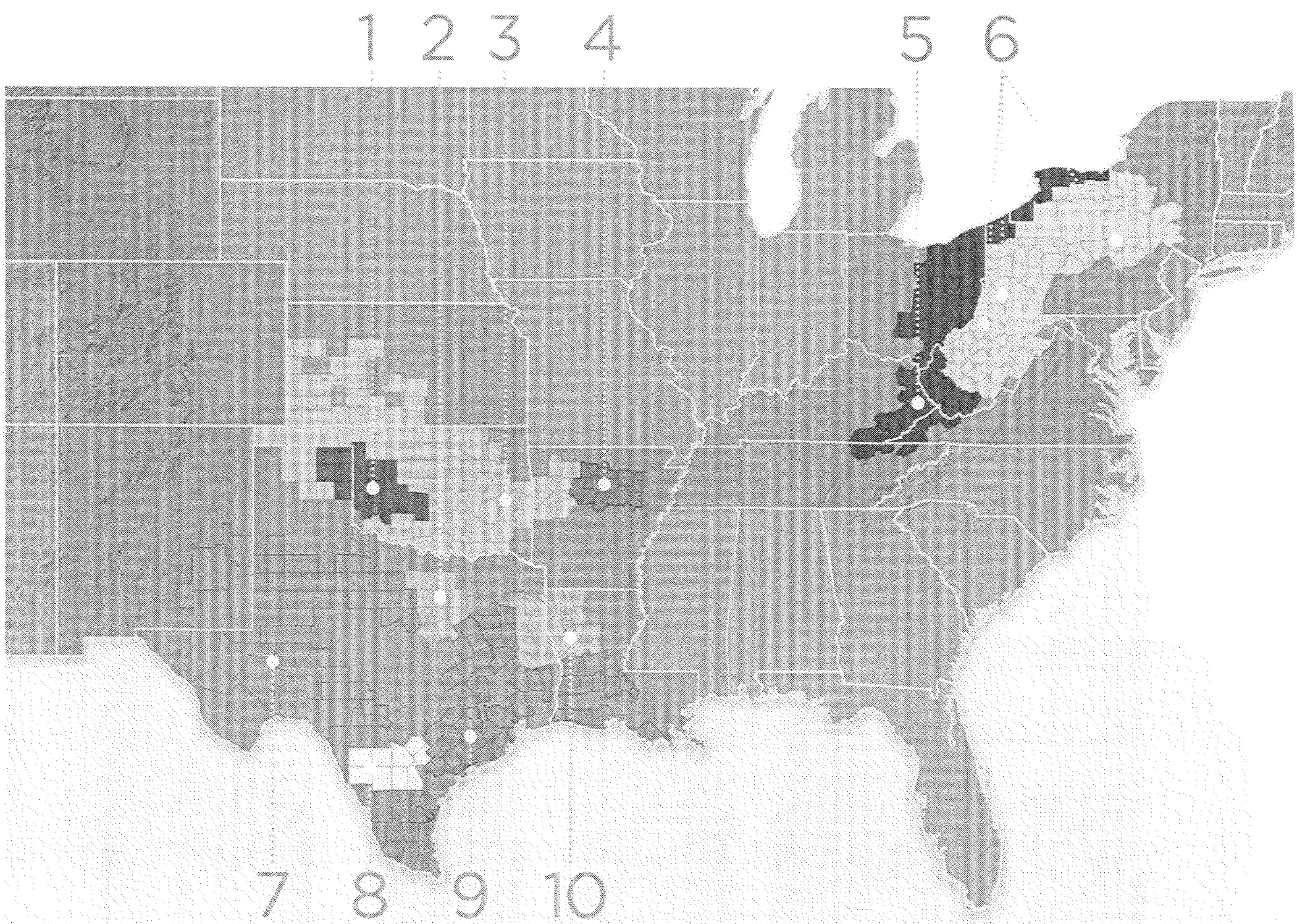
Natural gas provides an affordable, environmentally friendly substitute for foreign oil and dirty coal — while also stimulating America's economy and strengthening its energy security. Let's embrace a clean and prosperous energy future through the substitution of American natural gas for foreign oil and dirty coal. **The time for action is NOW!**

Let's embrace a clean and prosperous energy future through the substitution of American natural gas for foreign oil and dirty coal.
The time for action is NOW!

OPERATING AREAS

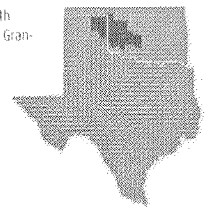
Chesapeake is the second-largest producer of U.S. natural gas and has built the nation's largest natural gas resource base with high-quality U.S. shale assets within the Big 6 shale plays: the Barnett, Fayetteville, Haynesville, Marcellus, Bossier and Eagle Ford. Our unique position in these six shale plays, as well as the liquids-rich Granite Wash plays of western Oklahoma and the Texas Panhandle, will provide us competitive advantages for decades to come. No other company in the industry has amassed a leading position in each of the low-cost, low-risk Big 6 shale plays.

We own interests in approximately 44,100 producing natural gas and oil wells, and in 2009 we produced 906 bcfe for an average of 2.5 bcfe per day. At year-end 2009, our proved reserves were 14.3 tcfe, of which 95% were natural gas and all of which were onshore in the U.S. We have also captured the nation's largest inventory of future drilling opportunities on approximately 13 million net acres of total leasehold in the U.S. The map below highlights Chesapeake's ownership position in our key operating areas.



1 Granite Wash

Chesapeake is the largest leaseholder in the Granite Wash plays with 190,000 net acres. We have generated particularly strong drilling results from our Colony Granite Wash discovery in Washita and Custer counties, Oklahoma, and from the Texas Panhandle Granite Wash in Hemphill, Wheeler and Roberts counties, Texas, where rates of return in these plays are the highest in our company. We estimate we could drill up to 1,200 net wells on our Granite Wash acreage in the future and plan to utilize an average of 13 operated rigs in 2010 to further develop our Granite Wash leasehold.



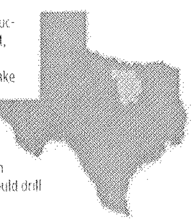
2009 Total Production:
70 bcfe, +40%*, 8%**

12/31/09 Proved Reserves:
1,090 bcfe, +419%*, 8%**

12/31/09 Net Leasehold Acres:
190,000, +217%*, 1%**

2 Barnett Shale

The Barnett Shale in North Texas is currently the largest natural gas producing field in the U.S. and is producing approximately half of all shale gas in the U.S. In the Barnett, Chesapeake is the second-largest producer of natural gas, the most active driller and the largest leasehold owner in the Core and Tier 1 sweet spots of Tarrant and Johnson counties. In January 2010, Chesapeake completed a $2.25 billion Barnett Shale joint venture transaction with Total S.A. (NYSE:TOT, FP:FP) (Total), whereby Total acquired a 25% interest in Chesapeake's upstream Barnett Shale assets. Total paid Chesapeake approximately $800 million in cash at closing and will pay a further $1.45 billion by funding 60% of Chesapeake's share of drilling and completion expenditures until the $1.45 billion obligation has been funded, which Chesapeake expects to occur by year-end 2012. We anticipate using an average of 25 operated rigs in 2010 to further develop our leasehold. On our acreage, we estimate we could drill up to 2,400 net wells in the years to come.



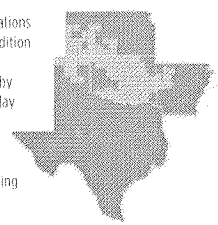
2009 Total Production:
240 bcfe, +33%, 26%

12/31/09 Proved Reserves:
3,430 bcfe, +17%, 24%

12/31/09 Net Leasehold Acres:
290,000, -6%, 2%

3 Other Mid-Continent

Chesapeake's Other Mid-Continent area includes operations in Oklahoma, the Texas Panhandle, southwestern Kansas and western Arkansas. In addition to various conventional plays in this area, our activities currently focus on the massive Sahara unconventional natural gas resource project in northwestern Oklahoma, where Chesapeake is by far the dominant operator with nearly 950,000 net leasehold acres. Sahara is a multi-county play with excellent low-risk, shallow natural gas production and an emerging horizontally drilled oil opportunity in the Mississippian formation. In the Anadarko Basin area of the Mid-Continent, we are developing multiple horizontal unconventional oil plays, with a significant presence in the emerging Cleveland and Tonkawa tight sand oil plays, in which we are leveraging what we have learned from our horizontal Granite Wash discoveries.



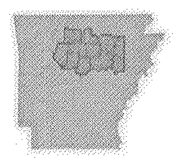
2009 Total Production:
235 bcfe, -23%, 26%

12/31/09 Proved Reserves:
3,010 bcfe, -29%, 21%

12/31/09 Net Leasehold Acres:
4,330,000, -9%, 33%

4 Fayetteville Shale

The Fayetteville is currently the third most productive shale play in the U.S. and one of the nation's 10 largest natural gas fields of any type. Chesapeake owns the industry's second-largest acreage position in the core area of the Fayetteville Shale play in Arkansas, totaling nearly 460,000 net acres. We estimate we could drill up to 5,200 net wells on our Fayetteville acreage in the years ahead and plan to utilize an average of 10 operated rigs in 2010 to further develop our leasehold. During 2009, $600 million of Chesapeake's drilling costs in the Fayetteville were paid for by its joint venture partner, BP America (NYSE:BP). During the fourth quarter 2009, BP paid Chesapeake the remaining balance of its drilling carry obligations and Chesapeake and BP each then began paying its proportionate working interest costs.



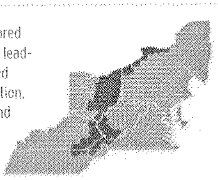
2009 Total Production:
90 bcfe, +64%, 10%

12/31/09 Proved Reserves:
2,170 bcfe, +229%, 15%

12/31/09 Net Leasehold Acres:
460,000, +10%, 4%

5 Appalachian Basin

Often referred to as America's most drilled but least explored area, Appalachia presents abundant growth opportunities through the introduction of leading-edge exploration, drilling and production technologies, in which Chesapeake is a recognized industry leader, into a basin largely ignored by the industry since the 1940s. Our leasehold position, excluding our Marcellus position, includes 1.2 million net acres in the Lower Huron Shale play and an additional 1.7 million net acres in other conventional and unconventional plays in the region. We have developed multiple deep exploration prospects in Appalachia that we plan to test once natural gas prices recover to higher levels.



2009 Total Production:
30 bcfe, -14%, 3%

12/31/09 Proved Reserves:
1,160 bcfe, -24%, 8%

12/31/09 Net Leasehold Acres:
2,930,000, -7%, 22%

Note: Figures may not add to company totals due to rounding in each area.
* Compared to last year
** % of company total
NM Not meaningful

6 Marcellus Shale

Chesapeake is the largest leasehold owner and most active driller in the Marcellus Shale play that spans from northern West Virginia across much of Pennsylvania into southern New York. The Marcellus is located near the highest gas-consuming region of the U.S. and therefore receives the best natural gas prices in the U.S. We estimate we could drill up to 20,000 net wells on our Marcellus acreage in the future and plan to utilize an average of 31 operated rigs in 2010 to further develop our 1.6 million net acres of Marcellus leasehold. During 2009, approximately $160 million of Chesapeake's drilling costs in the Marcellus were paid for by its joint venture partner, Statoil (NYSE:STO, OSE:STL). During 2010 through 2012, 75% of Chesapeake's drilling costs (approximately $2.0 billion) in the Marcellus will be paid for by STO. We remain very active in acquiring additional leasehold in the Marcellus and expect that over time, it will become the largest natural gas field in the U.S. and the second largest in the world.

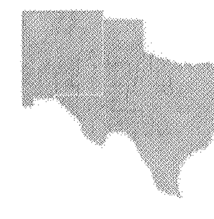
2009 Total Production:
15 bcfe, +200%, 2%

12/31/09 Proved Reserves:
260 bcfe, +550%, 2%

12/31/09 Net Leasehold Acres:
1,620,000, +30%, 12%

7 Permian and Delaware Basins

In the northern portion of the Permian Basin, Chesapeake has focused on discovering and developing various shallow- to medium-depth horizontal oil plays and also operates a number of secondary recovery oil projects. We plan to utilize an average of six operated rigs in 2010 to further develop our 2.15 million net acres of leasehold in the Permian and Delaware Basins. Our new horizontal oil projects in this area, including the Avalon Shale and the Bone Spring Sand, have the potential to deliver significant upside as we move towards substantially increasing our oil production in the years ahead.



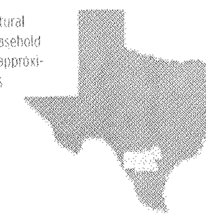
2009 Total Production:
75 bcfe, -6%, 8%

12/31/09 Proved Reserves:
740 bcfe, -20%, 5%

12/31/09 Net Leasehold Acres:
2,150,000, -23%, 16%

8 Eagle Ford Shale

As part of a growing emphasis on increasing its oil and natural gas liquids production, Chesapeake has recently built one of the top five industry leasehold positions in the Eagle Ford Shale play in South Texas. At year-end 2009, the company owned approximately 80,000 net acres of Eagle Ford leasehold and now has 300,000 net acres. Our focus has been on the oil and wet gas prone portions of the play and we plan to utilize an average of four operated rigs in 2010 to further develop our growing Eagle Ford leasehold position.



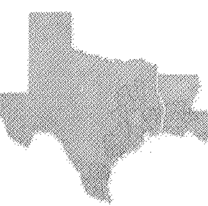
2009 Total Production:
0 bcfe, NM, NM

12/31/09 Proved Reserves:
0 bcfe, NM, NM

12/31/09 Net Leasehold Acres:
80,000, NM, 1%
(300,000 as of 3/31/10)

9 East Texas, Gulf Coast, South Texas and Louisiana

In East Texas, Chesapeake owns significant vertical natural gas production from wells that produce from various tight natural gas sand formations in medium to deep horizons, including the Pettet, Travis Peak and Cotton Valley formations. In addition, we are a major leasehold owner in the Deep Bossier Sand play. We have established a significant presence in a number of counties along the prolific Texas Gulf Coast, where we utilize 3-D seismic data to delineate structural and stratigraphic traps, primarily in the Frio, Yegua and Wilcox formations. This area has been de-emphasized as we move our drilling away from legacy vertical natural gas drilling to horizontal natural gas and oil drilling in unconventional plays.



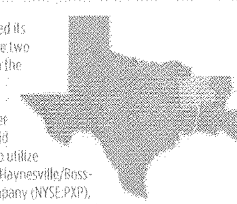
2009 Total Production:
65 bcfe, -38%, 7%

12/31/09 Proved Reserves:
560 bcfe, -51%, 4%

12/31/09 Net Leasehold Acres:
610,000, -48%, 5%

10 Haynesville/Bossier Shales

In early 2008, Chesapeake announced its discovery of the Haynesville Shale, a reservoir that likely will become one of the two largest natural gas fields in the U.S. (along with the Marcellus) and one of the five largest in the world. The Haynesville Shale is now the nation's second-largest producing shale play. The Bossier Shale lies above and overlaps much of our Haynesville prospective leasehold. We are the largest leasehold owner and most active driller of new wells in the Haynesville/Bossier shale play, which is located in northwestern Louisiana and East Texas. We estimate we could drill up to 8,750 net wells on our Haynesville/Bossier Shale acreage in the future and plan to utilize an average of 35 operated rigs in 2010 to further develop our 520,000 net leasehold acres of Haynesville/Bossier Shale. Chesapeake and its 20% joint venture partner, Plains Exploration & Production Company (NYSE:PXP), are producing from more than 200 net wells in the Haynesville play and continue to experience outstanding drilling results. PXP paid us approximately $400 million in drilling carries in 2009 and paid $1.1 billion in September 2009 as a result of an amendment to our joint venture agreement that eliminated PXP's future carry obligations.



2009 Total Production:
85 bcfe, +183%, 10%

12/31/09 Proved Reserves:
1,830 bcfe, +408%, 13%

12/31/09 Net Leasehold Acres:
520,000, +13%, 4%

Skilled crews keep Chesapeake rigs turning to the right every day. Pictured here are Michael Smith and Brandon Winsett, Roughnecks on Nomac rig 12 in the Northern Mid-Continent District.

INVESTOR Q&A

What is CHK doing to increase its percentage of oil and natural gas liquids production?

STEVE DIXON: While the exact timing of a peak in worldwide oil production remains a great debate, the vast majority of investors and industry professionals would agree that a peak in worldwide natural gas production is much further away. We believe this is reflected in the current market price of oil relative to natural gas – today, oil is priced more than 3.5 times higher than natural gas on an energy equivalent basis. Compared to natural gas, oil is harder to find and even more challenging to move through and produce from tight reservoir rocks. One of the few strategic weaknesses of Chesapeake is the relatively small percentage of our production that comes from oil and natural gas liquids – that, however, is on the verge of changing.

Over the past two years, Chesapeake's world class unconventional resource teams have been quietly working to develop oil-focused projects in the U.S. where our expertise in identifying, analyzing and commercializing unconventional natural gas reservoirs could be transferred to tight rock oil reservoirs. Innovative horizontal drilling and well completion techniques enable our geoscientists and engineers to extract oil and natural gas liquids from pore spaces in rocks that are more than 300 times smaller in diameter than a human hair.

Our efforts to crack the code on these difficult, but very lucrative, liquids-rich plays have greatly benefited from our state-of-the-art Reservoir Technology Center (RTC). This unique, proprietary core laboratory has enabled us to quickly analyze rock properties, model completion techniques and assess fluid movement properties in multiple tight rock formations. It has also helped Chesapeake minimize resources and capital spent on leasing and drilling programs in many plays that are likely to prove uneconomic.

The company has now established a strong leasehold position and made substantial progress in commercializing 10 liquids-rich plays, including the Eagle Ford Shale in South Texas, the Niobrara and Frontier plays in Wyoming, the Texas Panhandle and Colony Granite Washes, the Cleveland, Tonkawa and Mississippian plays in western Oklahoma and the Bone Spring and Avalon shale plays in the Permian Basin. In each of these 10 plays, we have drilled successful wells and established very large leasehold positions. We are now in the process of reallocating capital expenditures from some of our natural gas plays and increasing drilling activity in each of these emerging liquids-rich plays.

These new plays could enable Chesapeake to substantially increase its percentage of production of liquids from 8% in 2009 to perhaps as much as 20% over the next few years. If we are able to achieve this objective, our percentage of revenue from liquids production could approach the 50% balance we are seeking.

What makes CHK a great place to work?

MARTHA BURGER: There's not a set formula for creating a great place to work. Instead, it evolves out of a corporate culture which demonstrates commitment to making and keeping its employees happy and motivated. At Chesapeake, we work hard to create an environment where people feel valued, are challenged and are part of something special.

Chesapeake provides a wide array of benefits to employees. To name a few, we have: an on-site health and dental clinic at our headquarters, a 72,000-square-foot best-in-class fitness center, stock and bonuses awarded twice a year, a generous 401(k) match of up to 15% of pay, adoption and fertility benefits and a flexible work week schedule.

We believe the Chesapeake culture is unique. It starts from the top and disseminates throughout the organization. New employees experience this very quickly during the company's New Employee Orientation program, which is a half-day session led by our CEO Aubrey McClendon. Our employees are empowered to make decisions without getting caught up in bureaucracy and are encouraged to create innovation along the way.

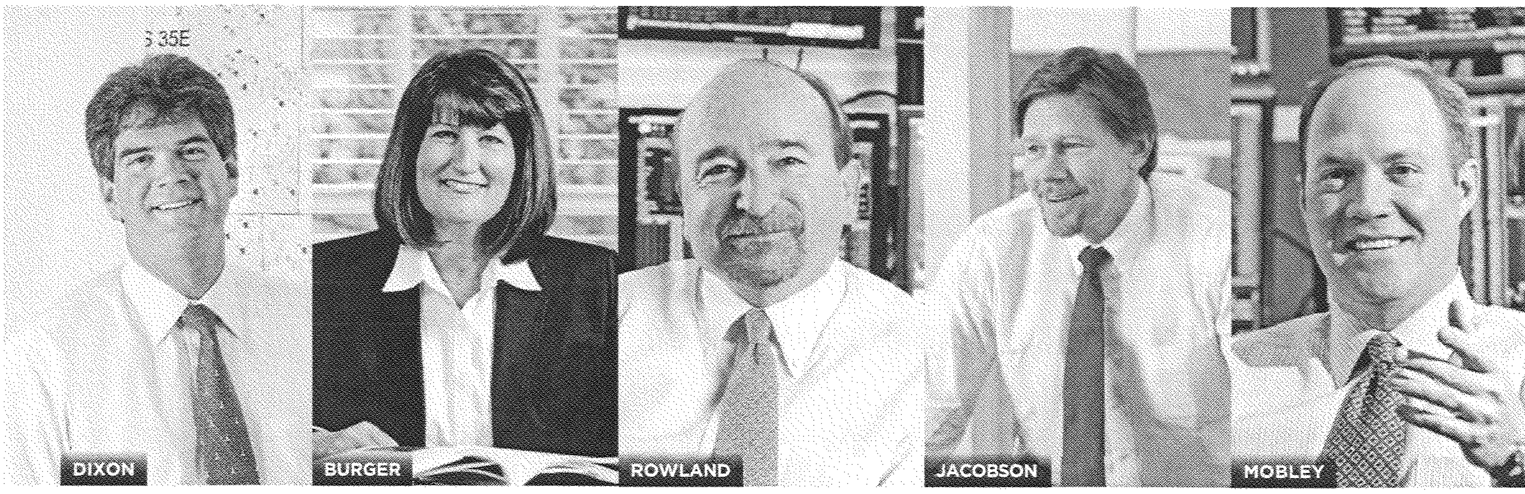
We expect industry-leading performance and results from employees, and that means that we must do our part by providing them with the best tools, a motivating environment and the space to grow and learn. Employees at Chesapeake have access to first-class resources, such as large dual-screen monitor work stations in every office, the safest, most modern trucks, rigs and equipment in the field. This commitment inspires our employees to perform to the best of their ability.

We pride ourselves on our efforts to be a great neighbor, employer and corporate citizen. Chesapeake's campus is a landmark in Oklahoma City with immaculate landscaped grounds, three full-service restaurants, a reservoir technology center and an athletic field for team sports and individual exercise. The company's high work environment standards extend beyond its corporate headquarters to every wellsite, field and subsidiary office.

For the third consecutive year, Chesapeake has been named to FORTUNE magazine's 100 Best Companies to Work For® list. This year the company jumped from #73 to #34. Two-thirds of a company's score is based on an extensive third-party administered employee survey, which is sent to a random sample of employees. The survey asks questions related to employee attitudes about management's credibility, job satisfaction and corporate culture. We are thrilled again to be awarded this prestigious honor because it reaffirms that our employees believe Chesapeake is one of the best places to work in America.

Why does CHK monetize assets and what additional opportunities are possible?

MARC ROWLAND: Chesapeake has always been a growth company and has amassed an abundance of attractive investment opportunities that will keep us growing for years to come. To fully benefit from these opportunities, we make substantial capital investments each year and work proactively to arrange the most attractive funding alternatives for these investments. We reinvest our operating cash flow primarily in our drilling program and in our midstream, compression, drilling and oilfield service subsidiaries. We also make investments for fu-



ture growth largely in new leasehold in emerging plays and to further solidify our leasehold position in our existing plays. As part of our program to fund our leasehold investments while reducing our financial leverage, we periodically sell or monetize non-core assets. Our goal is to secure proceeds from asset sales well in excess of our reinvestment needs in order to provide cash for debt reduction. We believe this financial strategy will enable Chesapeake to become an investment-grade company.

In just the past two years, we have successfully monetized $10.7 billion of assets (in which our cost basis was only $2.7 billion) by selling minority joint venture interests in four of our shale plays. In addition, we have sold producing assets through volumetric production payment transactions and also smaller packages of non-core assets that did not compete well for capital in our overall investment program. We plan to pursue similar asset sales in the years ahead, possibly including a joint venture in the Eagle Ford Shale, additional volumetric production payments and partial monetization of our mid-stream and other non-E&P assets.

Why have world-class energy companies chosen to do joint ventures with CHK?

DOUG JACOBSON: Chesapeake's industry-leading position in U.S. shale gas plays has attracted the interest of numerous world class energy companies, including three European integrated oil companies: London-based BP, Oslo-based Statoil and Paris-based Total, which have a combined market capitalization of $400 billion. We believe these joint ventures are also great investments for our joint venture partners, who benefit from Chesapeake's expertise in identifying and leasing prime shale gas assets, our industry-leading drilling program that efficiently converts leasehold to producing assets, our scale and purchasing power with service providers and our vertically integrated operations. Our partners are also able to make substantial low-risk investments over multi-year periods with minimal commitment of their own personnel. These benefits have enabled Chesapeake to secure premium valuations for its assets though joint venture transactions and generate attractive returns for Chesapeake's shareholders.

Will shale gas plays permanently oversupply U.S. natural gas markets?

JEFF MOBLEY: The rise of shale gas plays in the U.S. has led to substantial growth in natural gas supplies and much lower natural gas prices for consumers. More importantly, this new abundant and affordable resource provides consumers with long-term supply visibility and reliability to meet market demands and dampen price volatility. However, shale gas only accounts for approximately 15% of total U.S. natural gas production. Currently, 85% of U.S. natural gas production comes from non-shale plays, the vast majority of which have substantially higher finding and development costs than the major U.S. shale gas plays. Without new drilling, production from virtually all natural gas fields declines approximately 20% or more per year through normal depletion. Chesapeake believes this depletion, combined with reduced drilling activity in high-cost, non-shale gas fields will make way for further growth in production from the low-cost shale plays to perhaps as much as 30–40% of total U.S. natural gas production over the next few years.

Will this lead to a permanent oversupply? We don't believe so. Rather, the market will be balanced over time through reduced drilling on marginal, high-cost production, probably in the range of $6–7 per mcf. The abundance of low-cost shale gas will likely lead to a lower ultimate cost of gas supplies to consumers, but we believe that natural gas prices will be sustained at high enough levels to profitably develop shale gas.

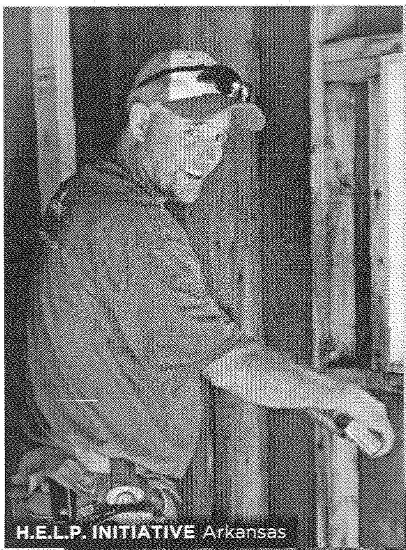
Chesapeake was early to recognize this structural change in the natural gas industry and strategically invested to capture the largest leasehold position in the Big 6 shale plays. This unique position in the industry should make Chesapeake one of the greatest beneficiaries of the shale gas revolution and the more stable price of natural gas in the future.

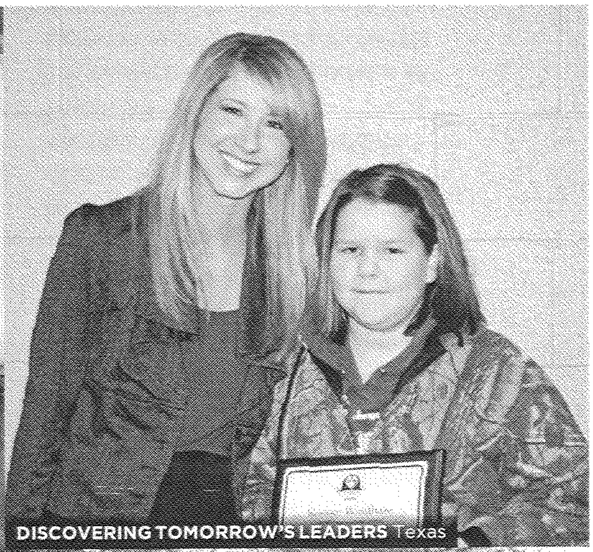
STEVEN C. DIXON Executive Vice President – Operations and Geosciences and Chief Operating Officer
MARTHA A. BURGER Senior Vice President – Human and Corporate Resources
MARCUS C. ROWLAND Executive Vice President and Chief Financial Officer
DOUGLAS J. JACOBSON Executive Vice President – Acquisitions and Divestitures
JEFFREY L. MOBLEY Senior Vice President – Investor Relations and Research

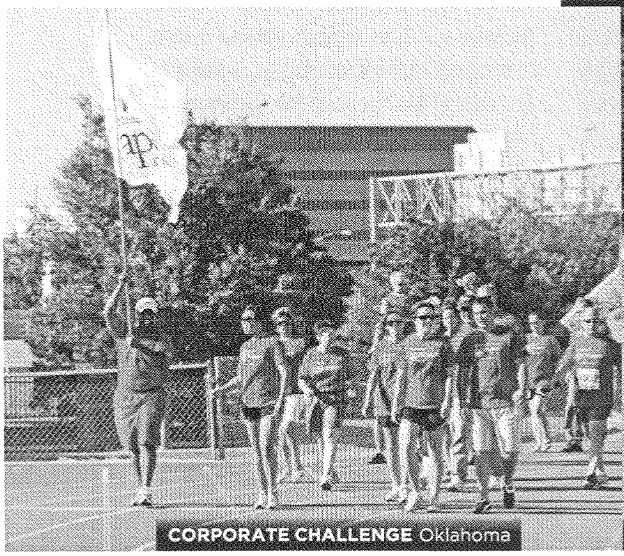
SOCIAL RESPONSIBILITY

We believe the true success of our company extends beyond our reserve report, income statement and balance sheet to our employees, neighbors, partner communities and the environment.

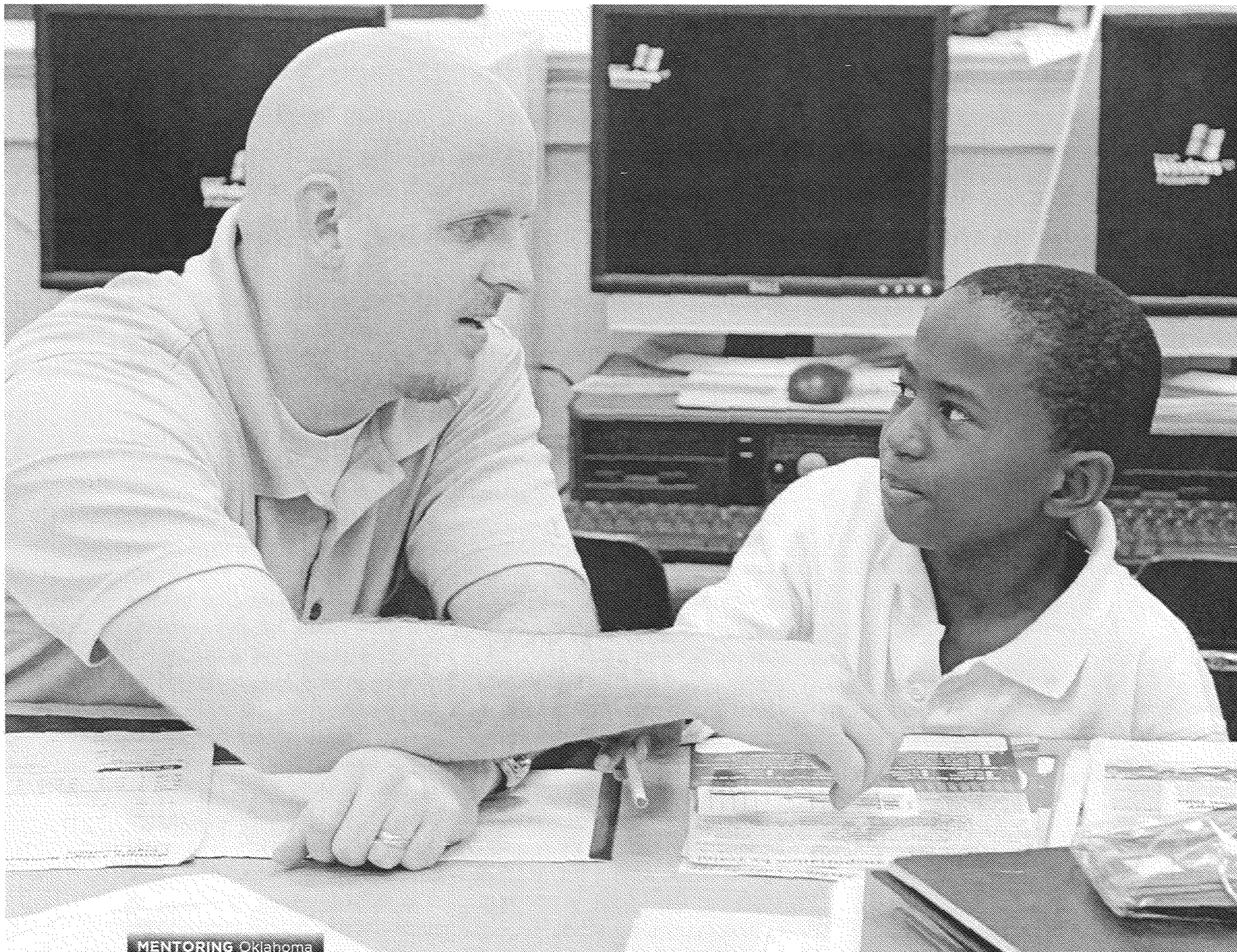
H.E.L.P. INITIATIVE Roustabout Sean Cook trades his drilling tools for building tools as part of his team's community service project in Arkansas. **DISCOVERING TOMORROW'S LEADERS** Katie McCullin, Coordinator – Administration, with an honoree from East Texas. The program recognizes students for leadership and community service. **CORPORATE CHALLENGE** From track and field events to basketball tournaments, this business-to-business athletic challenge encourages health and team building. **H.E.L.P. INITIATIVE** Blue-shirted H.E.L.P. volunteers take a break after renovating a West Virginia playground.


H.E.L.P. INITIATIVE Arkansas


DISCOVERING TOMORROW'S LEADERS Texas


CORPORATE CHALLENGE Oklahoma


H.E.L.P. INITIATIVE West Virginia



MENTORING Oklahoma

REBUILDING TOGETHER Oklahoma

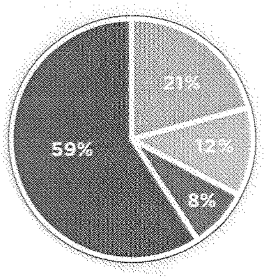
H.E.L.P. INITIATIVE Louisiana

MENTORING Reservoir Engineer Brian Bounds mentors a student at Horace Mann Elementary in Oklahoma City.
REBUILDING TOGETHER Applications Developer/ Analyst Diane Cloud carries her share of the load in the annual event that repairs homes for the needy.
H.E.L.P. INITIATIVE Nick Sentell, Field Technician, helps renovate the home of a 74-year-old woman in Sligo, Louisiana.

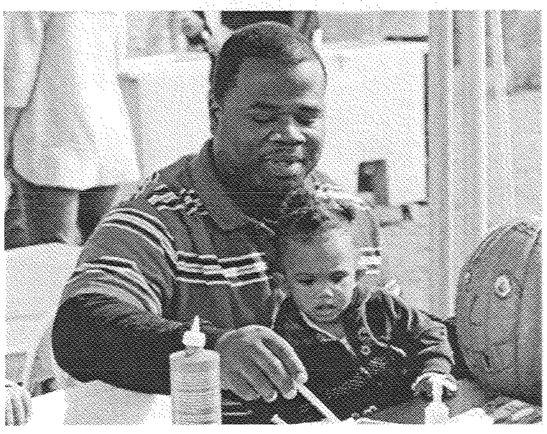
Community Relations

As Chesapeake continues *Fueling America's Future* with clean, affordable, abundant American natural gas, we also place a priority on fueling the communities where we live, work and play. In 2009 we gave more than $21 million to charitable organizations and projects across our operating areas, primarily focusing on community development, education, health and medical and social services.

CHESAPEAKE'S $21 MILLION OF CHARITABLE GIVING IN 2009



Painting pumpkins at Fall Fest on the Chesapeake campus in Oklahoma City are Associate Help Desk Specialist Branden Killingsworth and his daughter Bryelle. The event, which was open to the community, raised funds for United Way with carnival games and a hay maze.



FUELING THE ECONOMY

While most of the country has been experiencing a slow economy, the natural gas industry has remained steady and even grown in some regions. As the country's most active driller of new wells, Chesapeake's presence in an area increases business activity and creates well-paying jobs that improve people's lives and stimulate local economies.

In addition to our activities' impact on local economies, the company's tax contributions are substantial: in 2009, Chesapeake paid more than $730 million in total state and local taxes, including ad valorem, severance, sales and use, employee withholding and unemployment, corporate income and franchise taxes. These taxes are used for building and maintaining schools, recreational facilities, parks and roads — and at a time when state and local governments are feeling the pinch of recession. We are proud to support America's economy with our growth while we also help to reduce the country's dependence on expensive foreign oil.

In addition to stimulating the economy, Chesapeake makes strategic donations to help improve lives and local economies in cities where we operate. In 2009 the company announced a donation of $5 million to build a four-story Finish Line Tower in the Boathouse District of downtown Oklahoma City. We led the way in developing this emerging area of the city with the completion of the first boathouse on the Oklahoma River in 2005. Today, there are several more boathouses under construction, and upon their completion, five state-of-the-art boathouses will confirm Oklahoma City's international recognition as the nation's premier canoeing, rowing and kayaking venue. Recently, USA Canoe/Kayak moved its headquarters to Oklahoma City. With the Oklahoma River serving as an official U.S. Olympic Training site, Oklahoma City is now a strong contender for the upcoming 2012 Olympic canoe/kayak trials.

FUELING THE NEXT GENERATION

Preparing tomorrow's leaders today is imperative to building and sustaining a competitive work force. In 2009, Chesapeake supported universities, schools, academic chairs, scholarships and other educational programs with contributions of $4.5 million. The backbone of a strong country in today's competitive economy is education, and by investing in it today, we are fueling a brighter future for the next generation.

More than $1.3 million of the company's educational contributions helped fund higher education tuition for nearly 400 students. Chesapeake scholarships help recruit the best and brightest students and provide educational opportunities in communities where we operate.

In Northwest Louisiana, for example, we provided scholarships to 25 students at five universities and colleges based on need and community leadership. To increase diversity in the energy industry, Chesapeake partnered with the Fort Valley State University's (Fort Valley, Georgia) Cooperative Developmental Energy Program (CDEP) to award scholarships to minority students pursuing geoscience and petroleum engineering degrees. Last year, over 50 students benefited from our CDEP contributions.

In Texas, Chesapeake established a new scholarship program, which will benefit qualified Johnson County high school graduates through five annual gifts totaling $125,000, available to qualifying seniors through 2013. With another foundation matching Chesapeake's contributions, a total of $250,000 will be available to support Johnson County scholars.

We also award scholarships to students pursuing degrees in energy-related fields such as geology, engineering, land and law. Through the Peak Program in Oklahoma, junior- and senior-level scholarship recipients are paired with Chesapeake employee mentors who help develop students' knowledge and provide career advice. There are currently 30 mentors and 39 scholarship recipients participating in the Peak Program. These numbers are expected to increase in the upcoming years as the program is extended to universities outside Oklahoma.

University science departments are centers for research to find the best approaches for meeting society's energy needs while reducing environmental costs. To further such efforts, the company funded $1.5 million to endow two Chesapeake Energy Chairs in the field of Climate Studies in the School of Meteorology of the University of Oklahoma College of Atmospheric and Geographic Sciences. For the past five years, Chesapeake's meteorological team in Chicago has provided the company with long-range forecasting that has been very helpful to the success of its natural gas hedging program.

FUELING OUR COMMUNITIES

Volunteerism has always been at the core of the company's culture. In 2009 as part of Chesapeake's 20th anniversary celebration, a company-wide project was launched through an employee volunteer program — the H.E.L.P. Initiative (Helping Energize Local Progress). Many employees volunteer year-round, but this past summer employees were challenged to complete 20,000 hours of community service in five weeks. Chesapeake also permitted employees to use four hours of company time to complete this task. From renovating playgrounds in West Virginia to building a Habitat for Humanity house in Texas, employees responded in full force. In just five weeks, Chesapeake employees exceeded the company's goal by 30%, donating 26,134 hours of service to 575 organizations in more than 70 communities across the country. The hours they worked would be comparable to a full-time employee working 40 hours a week for 13 years! Employees and communities responded with such enthusiasm that the volunteer push will become an annual event.

We listen to our communities to ensure we are providing services they really need. In addition to the more than $21 million in charitable donations given last year, we also made numerous in-kind donations of computers, reconditioned Chesapeake fleet vehicles and subsidized office space. With the slow economy affecting monetary donations, many nonprofit groups found themselves struggling to meet basic administrative costs with some on the verge of closing. To alleviate this burden, we opened the Chesapeake Community Plaza in Oklahoma City, providing more than 67,000 square feet of office space at low monthly rates. To date, 10 nonprofit groups ranging from the Oklahoma Visual Arts Coalition to Citizens Caring for Children have relocated offices to the space and are now more able to focus on their mission rather than worry about how to pay rent.

Chesapeake partners with other companies and groups in hundreds of communities to meet basic needs. One example is in North Texas where we partnered with eye care companies to provide vision screenings, exams and glasses to children in Tarrant County public schools. So far 2,700 students have been tested with many receiving prescription glasses at no cost.

Regardless of the size of our contributions, Chesapeake and its employees are honored to work in local communities and partner with nonprofit groups and organizations to make a difference — fueling development and improving the communities that our employees, royalty owners and contractors all call home.

(Upper right) Production Assistant Julie Miller carries food as part of her team's volunteer work with Operation Blessing in Cleburne, Texas. (Lower left) Monica Stroman, Compliance Analyst, mentors students at Horace Mann Elementary in Oklahoma City. (Far right) Andrew Sprouse, Senior Applications Developer/Analyst, is one of more than 200 Chesapeake volunteers who helped out at last year's Rebuilding Together workday in Oklahoma City.

Environmental, Health & Safety

Chesapeake's commitment to fueling America's clean energy future is reflected in every aspect of what we do — from our corporate dedication to that of our employees and extending to the clean, affordable, abundant American natural gas that we produce every day to improve lives across our country and enhance our nation's future well-being.

PRODUCING ENVIRONMENTALLY FRIENDLY FUEL

Chesapeake employees are proud to be *Fueling America's Future* by exploring for and producing clean, affordable, abundant American natural gas. With almost a 200-year supply located in the U.S., natural gas can help reduce the nation's dependence on foreign oil and dirty coal, while creating jobs and revenue to fuel state and local economies. It also provides an environmentally friendly source of power and a viable transportation alternative to foreign oil. Selling for less than half the cost of a gallon of gasoline, compressed natural gas (CNG) powers vehicles that are among the greenest transportation options on the planet. A recent study completed on behalf of the California Energy Commission concluded that CNG vehicles produce up to 30% less greenhouse gas emissions than comparable gasoline vehicles and up to 22% less than comparable diesel vehicles.

Dave Gum, Production Foreman, checks fluid level readings at the Elk Valley Disposal in Braxton County, West Virginia. With its automated two-pump filtering and monitoring systems, the facility can safely and efficiently work year-round.

In fact, natural gas is the earth's cleanest and most efficient hydrocarbon. Emissions from its combustion contain approximately 50% less carbon dioxide than coal and up to 30% less than oil products. It's also one of the most efficient supplies for power. On average, 50% of the natural gas piped into a natural gas power plant is converted to electricity, compared to only 33% in coal- and nuclear-fueled power plants. Furthermore, natural gas used for power generation creates 85% less nitrogen oxides, 50% less particulate matter, 97% less sulfur dioxide and 100% less mercury than a comparable modern pulverized coal-fired plant.

PROTECTING THE ENVIRONMENT

We realize the way a product is produced can be as important as the product itself. Protecting the beauty and resources of the areas where we operate is our goal from the day we spud a well until the day a depleted well is plugged and the well location restored to its natural state.

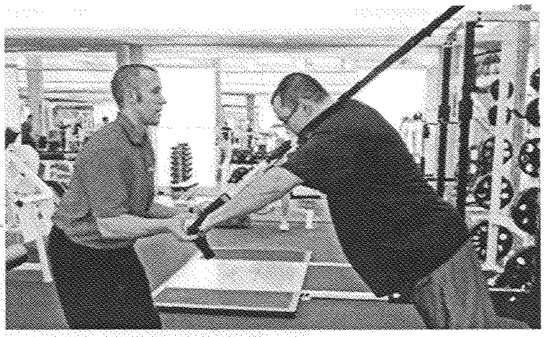
The company evaluates every potential drillsite to identify any possible operational or environmental issues, ensuring that the best possible location is selected. This kind of careful planning allows Chesapeake to utilize multiwell padsites to drill up to 12 wells on a single location, greatly reducing the impact of the company's drilling and production activities. Using the latest horizontal and directional drilling technology, we are also able to place wells at a safe distance from homes, schools and businesses.

As an industry leader, Chesapeake merges experience with state-of-the-art technology to create remarkable sites like its Elk Valley Disposal facility in Braxton County, West Virginia. Designed by Dave Gum, Chesapeake's Production Foreman for the Victory Prospect in the Marcellus Shale, the facility is one of the most advanced and efficient produced water disposal facilities in existence, according to the West Virginia Department of Environmental Protection (DEP), and has become a popular tour stop for the DEP in showing off a best-practice approach to produced water.

"All of Chesapeake's sites are good, but I was really impressed with this one," said Jamie Peterson, West Virginia DEP Environmental Resource Specialist and Permitting. "It's a model of how an underground injection control facility should be done."

Serving as a DEP example is not the only way Chesapeake collaborates with environmental organizations. An active member of the Environmental Protection Agency's (EPA) Natural Gas Star Program, the company has hosted a number of events at its Oklahoma City headquarters, including most recently a Producers Technology Transfer Workshop. In addition, we work closely with a number of nonprofit and government organizations such as the American Clean Skies Foundation, The Nature Conservancy, the Groundwater Protection Council and various environmental organizations to design and pursue best practices.

We also strive to educate the public and policymakers about our industry and the environmental advantages of natural gas. Chesapeake is a proud member of the newly formed America's Natural Gas Alliance (ANGA), which is comprised of 34 of America's top independent natural gas producers. We also host regular town hall meetings in our operating areas to meet with our neighbors and address their questions and concerns about natural gas and environmental issues. We strive to provide clear, accurate answers about natural gas and its production and consumption on our websites at www.askchesapeake.com, www.hydraulicfracturing.com and www.cngnow.com. We also feature extensive, timely information about our industry and company on our corporate website at www.chk.com.



Toby Fullbright, Senior Landman, participates in the Fitness Center's award-winning Live Better Forever Program with Chesapeake Trainer Landon Dean.

PROTECTING OUR PEOPLE

Chesapeake approaches the safety of our employees with the same intensity we have for drilling for natural gas. We work hard to ensure that all of our employees are properly educated to meet the company's high safety standards. Last year we offered approximately 500 online and instructor-led operational training sessions. Additional training and field safety drills ensure that employees in every phase of our drilling, completion and production activities are knowledgeable of and committed to safe work practices.

Chesapeake's intranet is an important tool used in our efforts to promote company-wide safety, and employees receive regular safety alerts about potential issues. In addition, quarterly newsletters highlight pertinent environmental, health and safety news and recognize the safety achievements and milestones of our field employees.

Like most companies in our industry, Chesapeake employs a number of contract service companies for specialized tasks and projects. The safety of these contract employees is also of great importance to us, and we begin by selecting contractors with a safety commitment that matches our own. In 2009, we began using ISNetworld to objectively manage contractor prequalification requirements for safety and health programs. This allows us to make educated contractor selections by reviewing a potential contractor's history and performance.

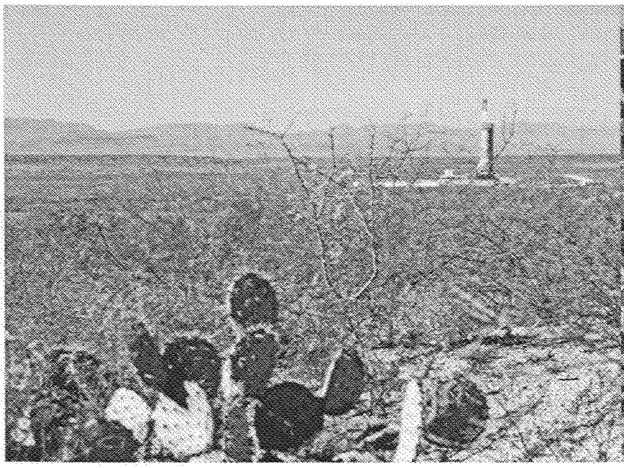
"Contractors are an extension of the company, and it's important that we only partner with organizations that demonstrate the same high standards of safety and operational excellence that we do," said Greg Dykes, Senior Director – Corporate EHS Compliance.

At Chesapeake, protecting employees' safety and health does not end at the jobsite. We encourage our employees to live healthy lives through a number of amenities and incentive programs. The company's distinctive health promotion program, Living Well, allows employees to earn cash rewards for maintaining a healthy, active lifestyle throughout the year. In addition, on-site health screenings are offered at least once a year at all office locations and Wellness Dollar benefits pay for preventive screenings and care.

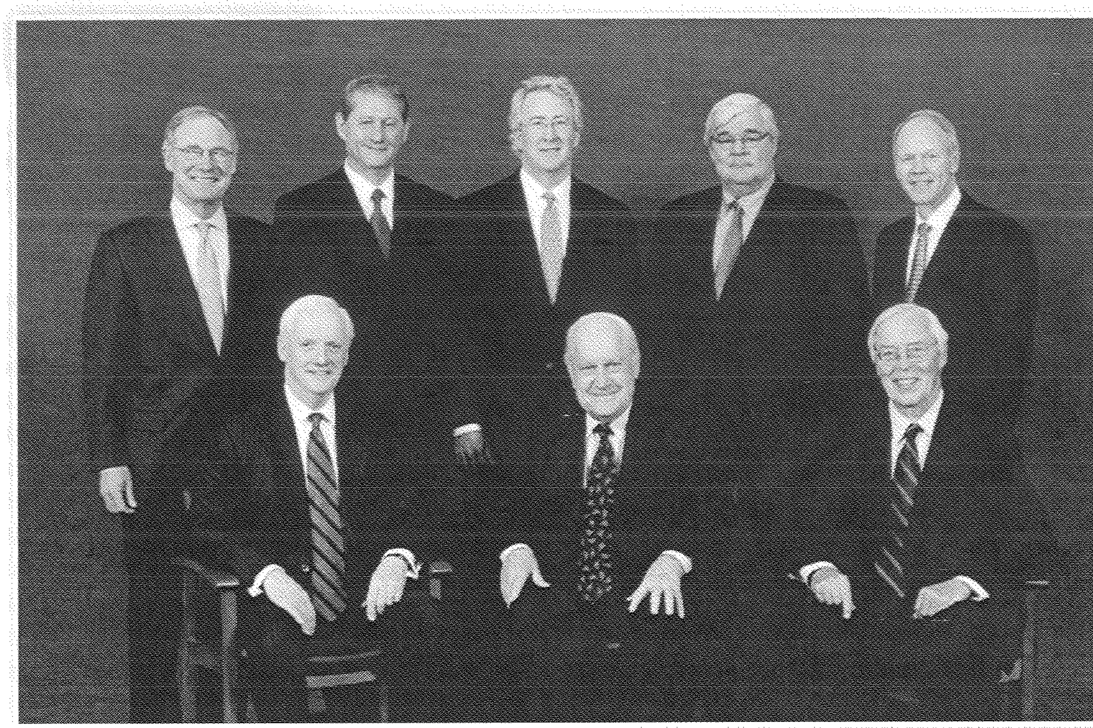
The company's corporate campus includes the 72,000-square-foot Chesapeake Fitness Center, which features a swimming pool; volleyball, basketball, racquetball and squash courts; a rock climbing wall and a variety of cardio and weight lifting equipment. Subsidized memberships are available for employees and family members. With more than 100 group exercise classes offered every week, the facility serves as a testament to Chesapeake's commitment to our employees' health. A fully equipped on-site gym is also available at our Fort Worth regional headquarters, while field office employees are reimbursed for individual and family memberships at local fitness facilities.

The Chesapeake Health Center, also located on our Oklahoma City campus, provides employees and their families with primary and urgent care and chronic disease management. The company also partners with health organizations such as Weight Watchers to provide free or reimbursed memberships to employees. We also hold a variety of internal health-related classes throughout the year including CPR training, healthy cooking classes and educational Lunch and Learn sessions, as well as programs such as Live Better Forever, a year-long program for employees who have serious medical or health-related issues. In addition, the company launched the Your Life Matters campaign in 2010 to help educate employees about mental health issues and work/life balance.

(Left) Chesapeake works to ensure each of its sites, like this one in Reeves County, Texas, meet the highest environmental standards. (Right) Crews like that of Nomac rig 36 merge state-of-the-art drilling techniques with hard work to produce American natural gas.



BOARD OF DIRECTORS



STANDING (LEFT TO RIGHT)

V. BURNS HARGIS [1]
President
Oklahoma State University
Stillwater, Oklahoma

RICHARD K. DAVIDSON [1]
Former CEO and Chairman
Union Pacific Corporation
Bonita Springs, Florida

AUBREY K. McCLENDON
Chairman of the Board
and Chief Executive Officer
Chesapeake Energy Corporation
Oklahoma City, Oklahoma

MERRILL A. "PETE" MILLER, JR. [1]
Chairman, President and CEO
National Oilwell Varco, Inc.
Houston, Texas

DON L. NICKLES [3]
Former U.S. Senator, Oklahoma
Founder and President
The Nickles Group
Washington, D.C.

SEATED (LEFT TO RIGHT)

FRANK KEATING [2,3]
Former Governor, Oklahoma
President and CEO
American Council of Life Insurers
Washington, D.C.

FREDERICK B. WHITTEMORE [2,3]
Advisory Director
Morgan Stanley
New York, New York

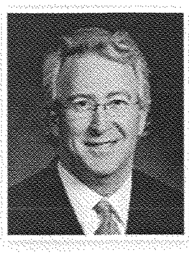
CHARLES T. MAXWELL [2]
Senior Energy Analyst
Weeden & Co.
Greenwich, Connecticut

(1) Audit Committee
(2) Compensation Committee
(3) Nominating and Corporate Governance Committee

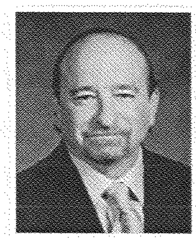
Governance

Our Board of Directors is responsible to our shareholders for the oversight of the company and for the implementation and operation of an effective and sound corporate governance environment. We believe that effective corporate governance contributes to long-term corporate performance. An effective governance structure should reinforce a culture of corporate integrity, foster the company's pursuit of long-term strategic goals of growth and profit and ensure quality and continuity of corporate leadership. Our directors will continue to be diligent in their efforts to preserve the public trust while fostering the long-term success of the company.

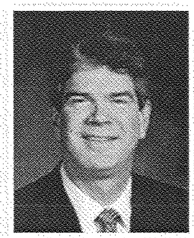
OFFICERS



AUBREY K. McCLENDON
Chairman of the Board
and Chief Executive Officer

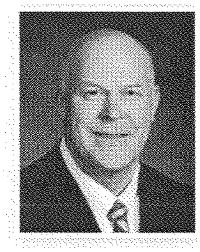


MARCUS C. ROWLAND
Executive Vice President
and Chief Financial Officer



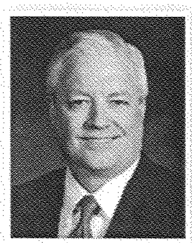
STEVEN C. DIXON
Executive Vice President –
Operations and Geosciences
and Chief Operating Officer

DOUGLAS J. JACOBSON
Executive Vice President –
Acquisitions and Divestitures

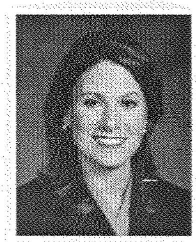


J. MARK LESTER
Executive Vice President –
Exploration
(retired January 2010)

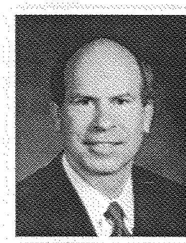
MARTHA A. BURGER
Senior Vice President –
Human and Corporate Resources



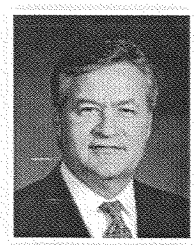
JEFFREY A. FISHER
Senior Vice President –
Production



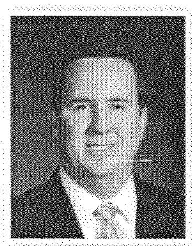
JENNIFER M. GRIGSBY
Senior Vice President,
Treasurer and
Corporate Secretary



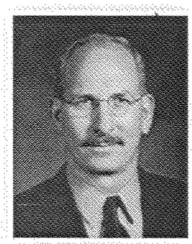
HENRY J. HOOD
Senior Vice President –
Land and Legal and
General Counsel



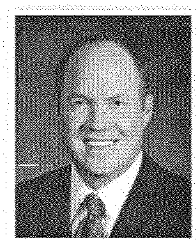
JAMES C. JOHNSON
Senior Vice President –
Energy Marketing



MICHAEL A. JOHNSON
Senior Vice President –
Accounting, Controller
and Chief Accounting Officer



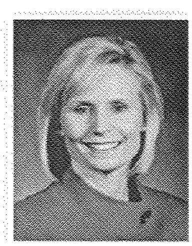
STEPHEN W. MILLER
Senior Vice President –
Drilling



JEFFREY L. MOBLEY
Senior Vice President –
Investor Relations and Research

THOMAS S. PRICE, JR.
Senior Vice President –
Corporate Development
and Government Relations

J. MIKE STICE
Senior Vice President –
Natural Gas Projects and
Chief Executive Officer
Chesapeake Midstream
Partners, L.P.



CATHY L. TOMPKINS
Senior Vice President –
Information Technology
and Chief Information Officer

EMPLOYEES

Chesapeake is pleased to list all 8,152 of its talented, hard-working employees who contributed to our company's success in 2009. Because we think they are the best team in the industry, we want Chesapeake to be the best employer in the industry, with a corporate culture that rewards their efforts and inspires their future. In 2009, Chesapeake was honored to be included as #34 in the FORTUNE 100 Best Companies to Work For® list, our third consecutive year for this prestigious award.

1989 (4)
Mark Lester
Kinney Louthan
Aubrey McClendon
Patsy Watters

1990 (3)
Kevin Decker
David Higgins
Cindi Williams

1991 (5)
Steve Dixon
Marilyn Pollard
Patti Schlegel
John Striplin
Julie Washam

1992 (2)
Tom Price
Melanie Weaver

1993 (6)
Ralph Ball
David DeSalvo
Mike Johnson
Randy Pierce
Marc Rowland
Dave Wittman

1994 (15)
Barbara Bale
Martha Burger
Michael Coles
Traci Cook
Ron Goff
Greg Knight
Dan LeDonne
Steve W. Miller
Tommy Morphew
Pat Pope
Danny Rutledge
Stephanie Shedden
Ronnie Ward
Shelly White
Gerald Zgabay

1995 (29)
Richey Albright
Paula Asher
Eric Ashmore
Randy Borlaug
Shelli Butler
Melissa Chambers
Dale Cook
Ted Davis
Mandy Duane
Steve Gaskins
Jennifer Grigsby
Gayle Harris
Henry Hood
Lorrie Jacobs
Mike Johnston
Barry Langham
Cindy LeBlanc
Leland Murray
Fred Portillo
John Qualls
Pat Rolla
Hank Scheel
Charles W. Scholz
Charles Smith
Stan Stinnett
Brenda Stremble
Greg Weinschenk
Brian Winter
Jim Wright

1996 (29)
Heather L. Anderson
Jamie Carter
Jasen Davis
George Denny
Tim Denny
Gary Dunlap
Laurie Eck
Jan Fair
Barbara Frailey
Linda Gardner
Charlene Glover
Randy Goben
Jim Gomez
Melissa Gruenewald
Doug Johnson
Jim Johnson
Taylor Kemp
Mike Lebsack
Steve Lepretre
Larry Lunardi
John Marks
Sandi Michalicka
Liz Muskrat
Angela Ports
Tommy Putz
Bryan Sagebiel
Kurt Schrantz
Phyllis Trammell
Allan Waldroup

1997 (32)
Linda Allen
Karla Allford
Sara Caldwell
Steve Cody
Kristine Conway
Randy Cornelsen
Michelle Cullen
Bruce Dixon
Greg Drwenski
Mark Evans
Joy Franklin
Rob Gilkes
Shane Hamilton
Michael Horn
Eric Hughes
David B. Jones
Carolyn Lindmark
Mike Ludlow
Sarah Lumen
Lauren Matlock
Sam McCaskill
Bob Neely
Bob Pope
Erick Porter
Jolene Schur
April Smith
Wilma Smith
Frank Unsicker
Ivajean Wallace
Craig White
Dori Williams
Curtis Williford

1998 (65)
Stephen Adams
Crae Barr
Francy Beesley
Joel Bennett
Leonard Berry Jr.
Susan Bradford
Mark Brown
Randy Brown
Lori Budde
Terry Caldwell
Bob Campbell
Ted Campbell
Jesse Canaan
Sherri Childers
Tana Clark
Jennifer Copeland
David Craycraft
Iris Drake
Mac Drake
Gary Egger
Steve Emick
Dan Estes
Dennis Frick
Randy Gasaway
Stacy Gilbert
Jim Gowens
Kelsey Hammit
Tresa Hammond
Jeff L. Harris
Debbie Hulett
Julie Ingram
Tammy Kelln
Rose Kim
Steve King
Mike Lancaster
Chris Lee
Carrie Lewis-Crawford
Craig Madsen
John Marshall
Kim Massey
Allen May
Dennis McGee
Allen Miller
Bill Miller
Carey Milligan
David Mobley
Wesley Myers
Bud Neff Jr.
Kathy Nowlin
Don Pannell
Michael Park
Mandy Pena
Matt Rockers
Kelly Ruminer
Dan Scott
Greg Small
Bill Snyder
George Soto
Dan Sparks
Linda Steen
Becky Thomas
Jennifer Van Meir
Rusty Walker
Lynn Whipple
Mandy Whipple

1999 (23)
Jonathan Ball
Mel Barker
Sue Black
Dory Douglas
Mark Edge
Jenny Ferguson
Jeanie Fuller
Dan Garvey
Susan Green
Yamei Hou
Doug Jacobson
Jim Kelley
Lynn Looper
Dea Mengers
Michael J. Miller
Tammy Nguyen
LaCosta Rawls
Larry Shipley
Michelle Smith
Connie Turner
Courtney Tyson
Tonya Vallerand
Tobin Yocham

2000 (43)
Shellie Ashworth
Johnnie Bartlett
Doug Bellis
Jan Benton
Bobby Bolton
Jeff Brooks
Becky Cassel
Rachel Clapp
Debbie Curtis
Jennifer Dees
Tammy Fields
Pam Ford
Robin Gonzalez
Annie Hamilton
Mary Hartman
Twila Hines
Eric Hoffman
Ronnie Howell
Jim Kuhlman
Don Lee
Debbie Lloyd
Jay May Jr.
Andrea McCall
Cindy McClintock
Collin McElrath
Courtney Moad
Georgia Moller
Chantelle Porter
Edward Puffinbarger
Mike Sawatzky
Cindy Schwieger
Brent Scruggs
Vance Shires
Stuart Skelton
David W. Smith
Catherine Stairs
Jerry Townley
Nick Wavers
Brenda Wheeler
Bob Whitman
David Whitten
Brent Williams
Bob Woodside

2001 (103)
Jerry Aebi
Karen Albornoz Cranford
Jeremy Allison
David Anderson
Terry Ashton
Betsy Ball
Gloria Bates
Michelle Bender
Bruce Boeckman
Boyce Boelen
Sharon Bradford
Von Brinkley
Deanne Brooks
Marty Byrd
Carlos Caraveo
Biff Carter
John Carter
Keith Case
Marika Chambers
Kristi Clemmens
John Cook
Tim Cook
Juanita Cooper
Jim Corsoro
Leigh Ann Crain
Brian Cunningham
Garry Curry
Shawn Downey
Jeff Eager
Richard Easterly
Tommy Edler
Amanda Elam
Brian Exline
Alex Gallardo Jr.
Matt Gambill
Roy Gentry
Suzie Goolsby
Randy Grayson
Richard D. Green
Kajsa Greenhoward
Jackie Gross
Johnny Harris
Jeremiah Jackson
Krista Jacobson
Justin Johnson
Keith Johnson
Rob Jones
John Kapchinske
Ginni Kennedy
Edward Killen
Julie Knox
Daniel Koehn
Kennetta Lee
Jeff Lenocker
Julia Lillard
Darwin Lindenmuth
Travis Long
Peter Manter
Rita Marple
Jim Mazza
Jim McHenry
Debbie McKee
Don Messerly
J. C. Morris
Melinda Neher
Lee Nelson
Kevin Newberry
Tim Newville
Deborah O'Neal
Ricky Petty
Dianne Pickard
Catherine Ratliff
Lynn Regouby
Gina Romano
John Romine
Larry Ross
Mike Rossiter
Don Rozzell
Larry Settle
Dee Smith Jr.
Patrick Smith
Chris Sorrells
Dennis Splan
Jason Stamper
Cindy Stevens
Bill Stillwell
Gary Stoner
Howard Stout
Lisa Strackbein
Tim N. Taylor
Jason Thaxton
Alvin Thomas
Rudy Thomas
James Thrash
Larry Watters
Paige Whitehead
Connie Williams
Freda Williams
Dawn Wilson
Brandon Winsett
Marvin Winter Jr.
Larry Woodruff
Amanda Young

2002 (142)
Paula Abla
Nicole Adams
Jenny Adkins
Roger Aldrich
Jimmy Alexander
Brian Babb
Charlie Bagley
Bob Baker
Lynard Barrera
Cindy Barrios
Shane Barron
Dennis Bass
James Beavers
Randy Bergen
Leonard Blackwill
Paul Bowyer
Troy Bradford
Robert Bradley
Don Bredy
Jim Brock
Cindy Brown
Kathy Brown
Lynn Broyles
Jason Budde
Greg Burchett
Aaron Bush
Ernest Byrd
Chris Carter
Paul Childers
Jackie Cooper Jr.
Lori Crabtree
Cary Crusinbery Jr.
James Davis
Kurt Davis
Cathy DeGiusti
Trent Delano
Cheryl Delzer
Larry Dill
Sherry Dixon
Christopher Dudgeon
Stephanie Dugan
Eldon Eagan
Eric Edwards
Michael Falen
Mark Falk
Shawn Fields
Tom Flesher
Viel Flores
Justin Foust
Adam Gaskill
Tamara Gathers
Fred Gipson
Lisa Glover
Cornelio Gomez
David Gouker
Steve Hall
Melvin Harper
John Henry
Kathy Henry
John R. Hornsby
John Hurst
Todd Ice
Rhonda Ingle
Bud Jackson
Jay Jarvis
Danny Jech
Jim Jinkins
Gary Johnson
William D. Johnson
Chris Jones
Joe Jones
Mike Kee
Dax Kimble
Nancy Knox
Greg Kochenower
Jeremie Koehn

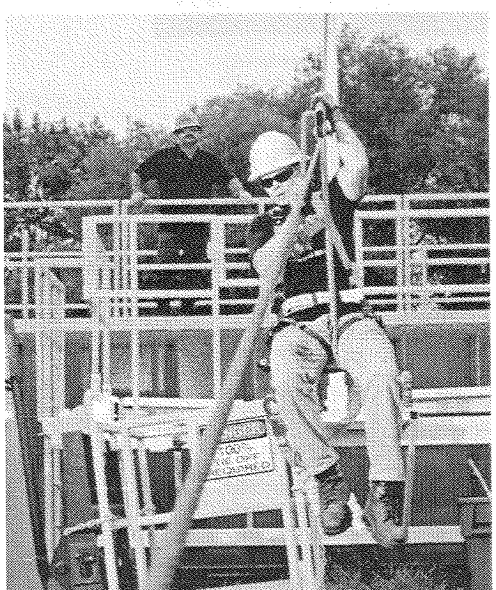
Spencer Land
Steve Larman
Ricky Laster
Casidy Lee
Ken Leedy
Stephen Lobaugh
Billy Long
Shawn Marsh
Richard Martinez
Andrew McCalmont
Mitch McNeill
Richard Mieser
Steve Mills
Sidney Mitchell
Claudia Molina
Nathan Morrison
Todd Murphy
Cindy Murray
Jeff Newby
Rick Nunley
John Ortiz
David Parker
Robert Pennel
Ryan Phillips
Sharon Pool
Bob Portman
Eric Powell
Mike L. Reddick
Ronald Reidle
Martin Robertson II
A.D. Robison
Randy Rodrigue
Vern Roe Jr.
Danny Schmidt
Kary Schneberger
Stacy Settles
Dewayne Shaw
Michael Sherwood
Will Shisler
Jim Shoptaw
Greg Skiles
Chad Smith
Jesse Smith
Robin Smith
Duff Snow
Maria Strain
Josh Swift
Oscar Thiems
Chris Townsend
Michelle Townsend
Ryan Turner
Rodney Vaeth
Fred Vasquez
Ruben Vega Jr.
Al Warner
James Warner
Michael Weese
Hazel Welch
Leslie Wertz
Eddie Whitehead
John Wilken
Gary Willeford
Mark Willson
Jerry Wilson
Robert Wilson
Roy Wilson

2003 (226)
Ronald Aaron
Pat Abla
Lisa Bagwell
Corky Baker
Staci Barentine-Bogle
Charlie Bateman
Mike Bechtel
John Biggs
Bruce Boyd
Tammi Bradford
George Bradley
Kim Brady
Serena Branch
David Brannen
Jerry Bray
Aron Bridges
Ronald Bromlow
Jennifer Broomfield
Bryan Brown
Jeff Brown
Heather Brunker
Kenneth Brunson
John Bullard
Bayley Burns
Cyndy Burris
Buster Burton Jr.
Ara Bush
Lori Byrd
Keith Cameron
Bob O. Campbell
Pat Carson
Gary Carter
Dennis Cerny
David Chisum
Mike Churchwell
Tony Clark
Michael Clinton
Matthew Colbert
Tom Corley
Brian Cox Jr.
Bryan Cox
Michael Cramer
Ann Croan
Jarod Cunningham
Wendy Cunningham
John Davis
Jon Davis
Ryan Dean
Scott Dickson
Dennis Dix
Derek Dixon
Steve Donley
Shanon Dunlap
Jody Dunn
Gary Durkee
Jack Elliott
Jimmy Embery
Charlene Ernest
Keith Ervin
Jim Fansher
Ursula Faus
Carol Fehrenbacher
Mark Ferbrache
Jeff Fisher
Mitch Floresca
Tommy Foust
T. R. Fox
Justin Froehlich
Edd Gabbart
Fred Gagliardi
Tim Gallegly
Travis George
B.K. Gibson
Kenneth Gideon
Dana Ginanni
John Gist
Randy Gladden
David Godsey
Jeff Gorton
Jim Govenlock
Larry Grey
Pablo Hadzeriga Jr.
Paul Hagemeier
Buck Hall
Michael Hall
Ronnie Haney
Jessie Hardin
Graham Harris
Roger Harrod
Rich Hearst
Pancho Hendricks
Tara Henry
Glen Hensley
Sue Ann Henthorn
Catherine Hester
Lanny Holman
Misty Holtgrefe
Paul House
Brian L. Howard
Roy Howe
Donna Huff
Rosie Hutton
Angela Ingargiola
James Inman
John Jackson
Dave Johns
Tommy Johnson
Joseph Kennedy
David Kerrigan
Melissa Ketchum
Joe Kidwell
Neil Kincade
Danny King
Melvin Kingcade
Matthew Klaassen
Jennifer Knott
Pete Lane Jr.
Jeff Lasater
Al Lavenue
Kathy Leasure
Dustin Lenhart
Nick Little
Dustin Locke
George Loman
Clint Lord
Jason Lowrey
Jack Lowry
Sergio Lujan
Shane Lukasek Jr.
Sharon Luttrell
Lewis Lynch
Mark Mabe
Ali Mallett
Jeremy Marple
Shelly Martin
Alfredo Martinez
Alex McCalmont
Kenneth McGuire Sr.
Menecca McHone
Carol McKenzie
Ryan Meacham
Randy Mefferd II
Eddie Merkel
R.T. Miller
Brent Mills
Jay Monroe
Alfredo Montiel
Lucretia Morris
Huey Morton
Larry Mossman
Paul Munding
Maureen Nelson
Jason Nichols
Tal Oden
Tony Olivier
Rena Owen
Ashley Paine
Tobin Paris
Nancy Parker
Gary Parks
Gale Parman
Kellie Patterson
Donnie Patton Sr.
Andrea Patzkowsky
Michael Phillips
Ronnie Pitts
Brent Pletcher
Jerry Preston
Jennifer Pryse
Regan Raff
Ken Rechlin
Wes Redding
Jim Reisch
Mindi Richardson
Matt Roberts
Jody Robertson
Anita Robinson
Kristen Rogstad
Doug Romero
Mark Russo
Beverly Sampson
Larry Savage
Bob Schmicker
Dave Schoonmaker
Kim Scott
Kily Seaman
Janet Selling
Keith Shahan
Clay Shamblin
Kelly Shipley
Aaron Siemers
Stacy Smith
Blake Stacy
Joyce Stanmire
Scott Stearman
Rick Stong
Marla Strack
Luke Strickland
Michelle Surratt
Blake Surrell
Danielle Sydnor
Jaime Tatro
Amber Thomas
Chevy Thomason
Jerry Todd
Scottie Trejo
Seth Unruh
Julio Vasquez
Larry Ventris
Johnny Voth
Keith Wagnon
Marty Wall
Josh Wangler
Brad Watkins
Noel Way
Dan Welch
David Wernli
De Ann Williams
Nicole Williams
David B. Willis
Bill Wince Jr.
Martin Wise
James Worsham Jr.
Todd Wright
Linn Yousey
Lori Zang

2004 (353)
Greg Adams
Justin Adams
Carol Adler
Gary Allen
Stephanie Allsbury
Tim Andrews
Chad Anton
Ronald Babers
Kristi Bacon
Jeffrey Bailey
Bobby Baker
Jeff Ballard
Eric Barbee
Paul Baresel
Tina Barnhill
Damon Beasley
Geoff Beaulieu
Terrye Bell
Curtis Blake
Lorraine Blanchard
Bradley Blevins
Lee Blevins
Aaron Bloedow
Courtney Blood
Deborah Bond
Brian Booker
Tad Boone
Kristin Bottom
Thomas Boucher
Angela Boulware
David Bowes
Darrel Branson
Rudy Bravo Jr.
Avis Bray
Jeff Bray
Dustin Brinkley
Jeff Brinlee
Terri Bristow
Darren Brittain
Anita Brodrick
Donald Bromlow
Brad Brown
Dan Brown
Diana Brown
Harlan Brown
Jason Brown
Pamela S. Brown
Ronnie Brown
Travis Brown
Aaron Buchanan
Craig Buck
Kingsley Burke
Jackie Burks
Josh Burris
Tim Butkus
Amber Butler
Juan Calbillo
Mike Campbell
Christopher Cantrell
Randy Cantwell

20,000 VOLUNTEER HOURS Oklahoma
Keeping score, corporate staff employees celebrate 26,134 hours of service donated to organizations in more than 70 communities throughout the company's operating areas as part of its 20th anniversary festivities.

Larry Carter
Lupe Castro
Jana Cathers
Michael Chester
Yong Cho
Tony Churchill
Cherokee Clark
Justin Clark
Carolyn Coble
Brenda Coffman
Rich Colbert
Paul Coleman
Craig Collins
Andrea Conner
Hershel Conrad
Jennifer Cooksey
Melissa Costello
Danielle Costilla
Lorrie Cottam
Cole Courson
Patrick Crain
Sharon Crain
Tim Crissup
Kizzy Crowell
Justin Cruse
Cathy Curtis
Ryan Curtis
Glenn Cushenbery
Clint Daily
Evelyn Daniel
Jennifer Davis
Robbie Dean
Luke Del Greco
David DeLaO
Alene Do
Kelly Dobbs
Johna Dodson
Kirk Dougherty
Dustin Drew
Chuck Duginski
Peggi Elliott
Brian Ellithorp
Carlos Evans
Robin Evans
Sheila Even
Ron Everett
Libby Fanning
Erik Fares
Fred Ferbrache
Dustin Fick
Jeremy Finefrock
Jeff Finnell
Jarod Fite
Walter Fletcher
Tommy Ford Jr.
Anville Francis
Linda Fries
Terry Frohnapfel
Gary Garrison
John Garrison
Guy Gaskill
Paul Geisinger
Ronnie Givens
Josh Glancy
John Glynn
Linda Good
Michael Goossen
Jennifer Granger
Angie Green
Coty Greer
Bonnie Griggs
Mark Hadlock
Victor Haley
Mark Hamilton
Katy Hampton
Rachael Hanoch
Andrew Hanscom
Joel Harris
Robert Hart
Melanie Harvey
Linda Havrilla
Heather Hawkins
Rebecca Henderson
Tim Henley
Chris Henry
Francisco Hernandez
Randy Herring
J. D. Hertweck
Melissa Heusel
Holly Hicks-Black
Alvin Highfill
Kevin Hill
Danny Hink
Randy Hodge
Buz Holloway
Latania Holt
Alan Horton
Doug Howeth
Will Hubbard
Lauren Humphrey
Cristy Hutchens
Adam Hutchinson
Mark Hylton
Jamie Jackson
Randy Jackson
Jeff James
Ryan Jameson
Jayson Janes
Amanda Jeantet
Sam Johnson
Jeffrey L. Jones
Steven Jones
John Keeling
Shamara Keith
Lindsay Keller
Bill Kerby
Jason Kneedy
Brenda Knight
Brett Knight
Josh Komarek
Matt Kopf
Pam Koscinski
Jennifer Landers
James Lardner
Kelsey Latta
Cory Lewis
Shea Lewis
Brent Lightsey
Melvin Like
Richard Loftin
Harold Lopez
Justin Lucas
Barbara Lydick
Luke Lyons
Stanley Major
Michael Marker
Tara Martin
Lolo Martinez
Rogelio Martinez
Bill McBrayer
John McCartney
Kelly McConnell
Duane McDowell
Mike McGinnis
Donna McGriff
Natalie McNeil
Ryan McNeil
Cliff Merritt
Matthew Milledge
Pat Mills
Sheldon Mills
Rodolfo Molina
Elton Monroe
Kendra Monroe
Penny Montgomery
Dana Moore
Steve Moore
Adria Morgan
Sim Morgan
Jimmy Morris
Elisa Mount
Mark Murray
Tim Murray
Chuck Myers
Todd Nance
Michael New
Rich Newton
Matthew Nowlin



NOMAC TRAINING FACILITY Arkansas Lanny Hotaling, Floorhand, benefits from Chesapeake's hands-on approach to training at the company's fieldhand training facility in Searcy.

Karyn Olschesky
Timothy Olson
Shery Orahood
Steven Owen
Regan Paquette
Lindsey Pargeter
Glenn Parker
Ryan Parman
Walter Patten
Deone Pearcy
Chris Pennel
Andrea Penner
Raymond Perez
Dwain Peterson
Randall Pierce
Debbie Piette
Dennis Plemons
Keitha Plumlee
Bryan Potter
Janae Power
Kelly Price
John Priest
Flo Prieto
Josh Purcell
Odie Quigley
Shelly Quimby
Cary Ragsdale
Loren Raley
Brad Ralstin
Juan Ramirez
Jeff Ramsdell
Tom Reasnor
Shannon Reed
Doug Reuss
Jack Rhine
Dusty Rhoads
Tiffany Rhodes
Jerry Rhymes
Renee Riebe
Gary Robbins
Bill Roberts
Chip Roemisch Jr.
Richard Rosencrans
Kelly Rother
Mary Ann Sanders
Larry Satterfield Jr.
Perry Scheffler
Terry Scifres

Heather Scoggins
Joel Scott
John Seldenrust
Juan Serna
Steve Serna
Auggie Setiadarma
John Sharp
Jack Shaver
Paul Shelite
Gene Shepard
Kyle Shipley
Paul Skelton Jr.
Stacy Slater
Julie Slaton
Clay Smith
Mark Smith
Monte Smith
Jewel Sneed
Gail Spencer
Robert Sperandio
Terry Stafford
Daryl Stallings
Steve Steadham
Joe Stewart
Pete Stewart
David Stone
Travis Stout
John Stoute Jr.
Tom Stovall
Bob Streeter
Kelsey Swinford
Mark Syzemore
Barry Tarman
Ray Taylor
Jon Terrell
Gerald Thomas
Randall Thomas
Renee Thomas
Robert Thompson
Kelly Thomsen
Ryan Thomsen
Cathy Tompkins
T.J. Treece IV
Tom Treece
Billy Trent
Mike Turner
John Uhlenhake
Billy Uptigrove

Anji VonTungeln
Aaron Vrbenec
Fred Wanker
Bryce Ward
Kyle Welcher
Patrick Whitman
Amanda Whitmire
Tom Wible
Jackie Wicks
Andy Widmer
Leon Wildman
Chase Williams
Randy Williams
Antoine Wilson
Kelly Wilson
Dave Winchester
Jeff Wolf
Jerry Womack
Dana Woo
Carla Wood
Harold Wooley
Landon Worth
Jill Wray
Jose Yanez
Mark Yeisley
Becky Young
Josh Young
David Zerger
Steve Zmek

2005 (794)

Daniel Abeyta Jr.
Jim Adams
Julius Adams
Robert Adams
Tony Adams
Ronald Addington
Christa Adkins
Jamie Adkins
Jeff A. Adkins
Jeff J. Adkins
Wayne Adkins
Nancy Aguilar
Reford Alcorn
Bill Allbright
Cindy Allen
Claude Allen
Erin Allen
Sandy Alvarado
Fred Amburgey
David D. Anderson
Jeff Anderson
Gary Anthony
Randy Anthony
Linda Arambula
Dawn Arismendez
Lee Arnold
David Atha
Matt Atkins
Jeffrey Atteberry
Ryan Atwell
Rebecca Avant
Brian Bailey
Leigh Ann Bailey
Marty Bain
Kyle Baker
Melvin Baldridge
Mills Bale
Gary Barnard
Rick Barnes
Mark Barringer
Shawn Barron
Karen Bartley
Cody Barton
Bob Bary
Bob Baxendale
Dustin Baxter
Traci Bean
Lyndal Beasley
Thomas Beaty
Joe Beaudoin
Tyler Beaver
John Beckwith
William Bennett
Cornelius Birmingham
Andrew Black
Kenneth Blackburn
Ron Bliss
Dot Blythe

Buddy Boeckman Jr.
Nick Boeckman
Charlie Boggs
Timothy Bohannan
Raymond Bohnet
K.P. Boland
Corey Bolding
Rachel Bolen
Ronnie Bonnett
Adam Bos
Tim Bostick
Mark Bottrell
Stacie Boyd
Joe Bradford
Everett Bradley
Kenny Bragg
David Branham
Debra Branham
Gail Branham
Del Brazeal
Chris Brennan
Jordan Brim
Ronald Brisendine
Brent Bromlow
Wilfred Broussard
Donna Brown
Richard Brown
Kathy Buckley
Nichole Buersmeyer
Vicki Bumpas
Kara Burch
Rodney Burgess
Steve Burnett
Abiel Buruato
Ronnie Bynum
Gavan Byrd
Skye Callantine
Deric Canary
Michelle Cantrell
Steve Cantrell
Silas Carnes
Dennis Carpenter
Krista Carpenter
Mendy Carpenter
Shannon Carrion
Cathy Carter
Kyle Carter
Zulema Casas
Cassie Casto
LuAnn Chance
Darrel Chandler
Donald Chaney
Mike Chapman
Richard Chin
Nikki Church Lemon
Cathy Clark
Charles Clark
Linda Clark
James Clay
Dana Clayton
Elizabeth Clem
Jack Clement Jr.
Bryan Clevinger
Paul Coffey
Jackie Cole
JC Coleman
Robert W. Coleman
Kevin Collins
Tiffany Collins
Christian Combs
Douglas Combs
Gary Compton
Michele Compton
Bill Connard
Paul Conway
Stephen Cook
Phyllis Copley
Curtis Corcoran
Mike Cornette
Geron Cottam
Tim Cottrell
A.J. Cox
Elsie Cox
Marisa Craig
Dennis Crisp
Vernon Crumm III
Joshua Crystal
Charlotte Cullifer
Larry Cunningham

Ronnie Cunningham
Arthur Curry
Billy Curry
David Cutright
Irene Da Rocha
Bo Daniel
Christy Dare
Fred Daugherty
Donald Davey
Emily Davis
Jacob Davis
Khari Davis
Lisa Davis
Rod Davis
Ricky Daw
Scott Delaney
Mario Delao
Jeremy Denton
Aletha Dewbre-King
Hank DeWitt
Brent Dixon
Darrell Dollens
Pete Dominguez
Tyler Doolen
Barney Dosier
Stephen DuBois
Dane Dunegan
Dustin Durkee
Houston Eagleston
Joe Earley
Anthony Earnest
Nate Easter
Mike Edwards
William Edwards
Travis Egner
Eric Eller
Robert Elliott
Bryan Ellis
Linda Ellis
Kay Elrod
Alan Elswick
Ricky Endicott
Angie England
Ranulfo Escamilla
David Eudey
Sara Everett
Stacy Evett
Deanna Farmer
K.C. Ferguson
Mark Ferman
Cori-Dawn Fields
Grover Fields
Brad Finley
Donald Fisher
Doyle Fisher
Jeff L. Fisher
Marc Fleischer
Adam Flores
Lendel Flournoy
Meara Foreman
Darcie Foster
Jason Fournier
Ricky French
Victor Frias
Bret Frie
Rachel Friedman
Scott Friedman
Mike Friend
Rodney Friend
Mindi Friese
Andy Fritsch
Rachael Fugate
Toby Fullbright
Dennis Gagliardi
Michael Gallo
Beau Galloway
Cleab Gamble
Alma Garcia
Lori Garcia
Tonya Garrett
Fred Gates
Liz Gerhard
Loretta Gibelyou
Josh E. Gibson
John Gilbert
Rhonda Giles
David Gilliam
Keith Glasgow
David Glass

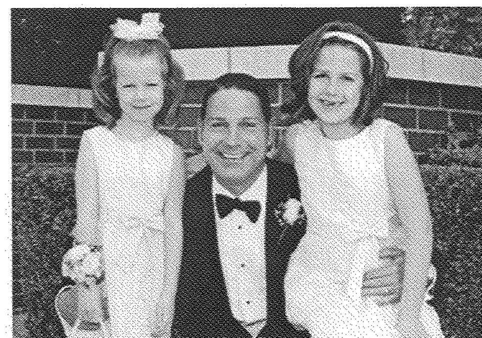
Zane Glasscock
Jason Glassey
Mitch Goble
Dave Gocke
Brian Goins
Heather Gomez
Alex Gonzalez
Martin Gonzalez
Paula Grace
Brian Graefnitz
Daniel Graham
Henry Granados
Jay Gray
Kenneth Gray
Stephen Gray
Rodney Greathouse
Marcus Green
Shane Green
Tracy Green
Brady Greer
Eddy Grey
David Griffith
Greg Gromadzki
Ronnie Guerrero
Dave Gum
Todd Gum
Jim Gumm
Rodney Gunter
Roberto Gutierrez
Jarad Guynes
John Gwynn
Patty Haffey
Lea Hain
Ronald Halbert
Donny Hale
Garrett Hale
Paul Hale
Barb Hall
Bridgette Hall
Don Hall
Marcus Hall
Mike Hall
Joe Halstead
Wheeler Hammit
Dave Hancock
Buddy Harbison
Rusty Hardin
Lonnie Harl
Dewey Harless
Mike Harless
Nathan Harless
Shanna Harmon
Earl Harris
Michelle Harris
Phyllis Harris
Tom Harris
Denise Hart
Kenneth Hartfield
Steve Harvath
Randy Hatfield
Melissa Hatfield-Atkinson
Daniel Hattaway
Gaylon Havel
Tyler Hawkins
Joe Hays
William Hays
Brian Heckert
Fred Hein
Justin Heinken
Jill Heitert
Darin Herndon
Craig Hicks
Eric Higgins
John Highfield
Donna Hilderbrandt
Rick Hill
Kay Hillabold
Juan Hinojosa
Arthur Hoehne
Gary Hohenberger
Ray Holden
Thomas Holland
Nathan Holloway
Pat Holman
Alfred Hooper Jr.
Randy Hooper
Drew Hopkins
Joann Horn
Jimmy House

Tim J. House
Tim M. House
Lindsay Houston
Brian D. Howard
Doyle Howard
Kelli Howard
Greg Howell
Sonny Hloon
Paul Hudgins
Jeff Huelskamp
Christine Hughes
Larry Hughes
Rodney Hughes
Zachary Humphrey
Amy Hutchinson
Jason Ille
Betsy Ireson
William Ireson
Johnny Ison
Bryan Jackson
Mike Jackson
Kris Janzen
Bobbi Johnson
Brent Johnson
Bruce Johnson
George Johnson
Mark Johnson
P.J. Johnson
Steve S. Johnson
Kevin Johnston
Lonnie Johnston
David S. Jones
Fred Jones
Mark Jones
Pat Jones
Greg Jordan
Jessica Jorns
Frances Jowers
Joe Juarez
Larry Justice
Erin Kaiser
Brandon Kammerer
Kevin Kappes
Earl Karickhoff
Robert Keenan
John Keller
Earnest Kelough
Kate Kelser
Brad Kemp
Ron Kendrick
Mike Key
Tommy Kidd
Donna King
Gary W. King
Ryan Klein
Mark Knapp
Brad Knight
Andrew Kock
George Kohlhofer III
Jennifer Kraszewski
Rusty Kreizenbeck
Kim Kremer
Kris Kuehn
Linda Kurtz
Jim Kwasny
Anthony Lafferty
Bill Lafferty
Paul Lafferty
Jennie Lambert
Sidney Lane
Karen Langley
Terry Latham
Henry Latimer
Mike Laue
Will Lawler
Ronnie Lawrence
Gina Lawson
Joshua Lawson
Robin Layne
Jeremy Lee
Larry Lee
Keith Lehman
Brad Lemon
James Lenhart
Shannon Lenhart
Marty Lesley
John Paul Leslie
Dustin Lewis
Al Leyva

Jason Lierle
Wayne Light Jr.
Dan J. Lopata
Becky Lorton
Michael Lovelace
Michael Lovero
Alison Lowe
Dwayne Lowe
Jason Lundy
Paul Lupardus
Shauna Lyon
Sean Macias
Angie Mackey
Craig Manaugh
Amy Marburger
Robert Marsh III
Jace Marshall
Billy Martin
Danny Martin
Deb Martin
James Martin
Randy Martin
Robert Martin
Thomas A. Martin
Chema Martinez
Homer Martinez
Emily Massey
Bill Mathews
Thomson Mathews
Mack Matthews
Bruce Mattney
Jeff Maxwell
Mike May
James Maynard
Andrea Mays
Vicki McCabe
Katrina McCaslin
Dax McCauley
Chris McClaine
Mike McClellan
Jackie McComas
Thomas McComas
Meri McCorkle
Johnny McCoy Jr.
Rocky McCoy
Casey McDonough
Vanessa McDougal
William McFadden
Terry McGrady
Jeff McGuire
Donny McHenry
Amy McIlhenny
Stacy McKay
Arlie McKee
Keith McKee
Nick McKenzie
Bill McKinney
Doug McPherson
Dirk McReynolds
Donnie Meade
Melissa Meeker
Dan Melcher
Bruce Melton
Oscar Mendoza
Saxon Mesa
Paul Messer
Casey Miller
Cathy Miller
Daryl Miller
Jeff Miller
Kelli Miller
Mark Miller
Eligah Mills
Tom Mills
Maya Mims
Kyle Minyard
Greg Mitchum
Jeff Mobley
Cheryn Mok
Stephen Mollett
Jim Moore
Michael L. Moore
Sherrie Moore
Teresa Moore
Dave Morehouse
Jose Moreno III
Phil Moser
Jim Motteshead
Doug Mullins
Jaime Munoz
Dan Muret
Sean Murphy
Justin Murray
Bhavin Naik
Tim Nance
Tim Napier
Rusty Nash
James Neal Jr.
Scott Nease
Tommy Neathery
Donna Neel
Jarrod Newberry
Kena Newman
Roger Newsome Jr.
Robert Niavez
Sid Niles
Justin Nimrod
Kelly Nix
Curtis Nixon Jr.
Kenneth Nolan
Greg Northern
Rodney O'Brien
Adam Olivares Jr.
Michele Oliver
John O'Neal
Dara Oney
Charles Osborn
Billy Osendott
Bryan Ott
Kary Ott
Katie Overton
Tony Padgett
Joe Paetzold
Wray Paine
Bill G. Parker
Matthew Parker
Michael Parker
Toni Parks-Payne
Amanda Parsons
Trisha Pate
Hoot Patterson
Kevin Patterson
Kenneth Payne
Deborah Payne-Sherwood
Tom Pepper
Brooks Perry
Gena Perry
Jody Perry
Mike Perry
Denvard Peters
Joe Peterson
Donald Petzold Jr.
Teresa Pexa
Kevin Pfister
Greg Pichler
Michael Pickens
Susan Pickens
Joe Pierce
Billy Pillars
Josh Pitts
Steve Poe Jr.
Harold Porter
Johnny Porter
LaTonya Porter
Leon Potter
Jared Pounds
Cara Pourtorkan
Larry Prater
Reco Preece
Bob Price
John Prichard Jr.
Jennifer Prince
Martin Province
Bobby Putman
Jeff Raines
Weldon Rainey
Larry Raleigh
Kyle Range
Keith Rasmussen
Billy Ratliff
Jennifer Ratliff
Peter Rauscher
Donna Ray
Lonnie Ray
Vickie Ray
Gavin Reed
Kenneth Reed
Melissa Reed
Nathan Reed
Stevie Reed
Brian Reeder
Lorrie Renfro
Philip Renner
R.J. Retzer
Jeffery Rhoades
Stewart Rhoades
Jerad Rhodes
Mike Rice
Ray Rice
Bill Richardson
Chad Richardson
Joni Richardson
Ralph Riffle Jr.
Johndetta Riley
Johney Riley
Steven Riley
Brandon Ripley
AJ Risner
Nakita Rizzo
Ben Robinson
Carole Robinson
John Robinson
Rusty Robinson
Pedro Rodriguez
Brad Rogers
Cliff Rogers
Dionne Rogers
John F. Rogers
Chuck Rose
Dayton Rose
Kristin Rose
Hargis Ross
Lloyd Rubottom
Gary Russell
George Russell
Jim Russell
John Ryza
Scott Sachs
Clinton Salyers
Gary Sanders
Jason Sarakatsannis
Carl Sargent
Jay Savill
Brandon Scheffler
Rob Schindler
Doug Schmidt
Randall Schultz
Greg Schwerdtfeger
Kathy Scott
Bart Seaman
Jennifer Sebo
Larry Segar
Steve Seliquini
Ivan Semien
Perry Settles
Gail Shackelford
Tommy Shaffer
Arco Sharp Jr.
Jackie Shaver
Stan Shaw
Donald Shelley
Marvin Shepherd
John Shifflett
Greg Shingleton
Tammy Shingleton
Mike Short
John Shreve II
Odie Shreve
Lee Shreves
Derrick Sier
Bob Simmons II
Brian Simmons
Justin Simonton
Billy Sims Jr.
Cami Sims
Leo Sinnott Jr.
Brian Skidmore
Ralph Skinner Jr.
Charles Sloan
Malcom Slone
Miranda Small
Eric Smith
John Smith
Jonathan Smith
Lindsey Smith
Roy Smith
Scott Smith
Stephen Smith
Ronald Snyder Jr.
Manuel Soriano Jr.
Myron Sowards
Shellee Spencer
James Spiller
Keith Spitzenberger
Larry Stacy
Briana Steelman
Tarza Steiner
Robert Stickler
Robert Stickler II
Jason Stidham
Justin Stinson
Jayson Stock
Jack Stockton
Brandon Strack
Lola Strickland
Callie Stuckey
Dave Stumbo
Scott Sullivan
Travis Sullivan
Todd Swartzbaugh
Anthony Sweeney
Charles Switzer Jr.
Amanda Talmich
Jim Tampke
Philip Tanner
Mike Tarpley
Brian Tatro
Gearold Taylor
Jody Taylor
Stephen Taylor
Eric Tennant
Steve Tharp
Joe Thomas
Lawrence Thomas
Val Thomas
Willie Thompson Jr.
Mike Tigner
Jackie Tillery
Billy Timmons
Kelly Torri
Cheryl Tramell
Huy Tran
Matej Triska
Scott Truesdale
Vernetta Tubbs
Kristi Turner
Matt Turner
Susan Tuter
Kenna Ulderich
Sharon Ulmer
Jason Updegraff
Dana Vaden
Joseph Valerio II
Banner Vanderpool
Jakie Vaughan
Ryan Veirs
Suzanne Victoria
Lupe Villarreal Jr.
Tammie Voelker
Lindsey Von Tungeln
Carol Wagner
Kenneth Wagoner
Jay Walker
Benny Wallace
Charles Wallen
Richard Walls
Leonard Walters
Justin Wardrop
Brian Wasinger
Karen Watson
John Weaver
Ginny Webb
Thomas Webb
Lisa Webb Johnson
Shae Weddle
Jeff Weides
Keith Wells
Lee Wescott
Kyle White
Larry White
Mallorie White
Dan Whitmarsh
Valerie Wible
Charles Wilburn
Dale Wildman
Brooke Wiley
Mark Wiley II
Lisa Wilkinson
Dallas Williams
David S. Williams
Nancy Williams
Terry Williams
B.J. Williamson Jr.
Jason Williamson
Hack Willis
Ronnie Willis
Kent Willoughby
Brian Wines
Kelli Witte
Brad Wittrock
Justin Wollenberg
Julie Woodard
Donald Woody
Ricky Workman
Leann Wright
Yandy Yarbrough
Doug Yeager
Danna Yeargin
Bo Youngblood III
Justin Zerkle

2006 (1254)

Gary Abbott
Russell Ables
Jessica Acker
Claude Adams
James Adams
Kelli Adams
William Adkison
Ethan Adler
Rohit Aggarwal
Doyal Akers
Kris Aldridge
Daniel Alford
Kenny Alford
James Allen
Jamie Allen
Jason Allen
Joshua Allen
Jimmy Allred
Richard Allums
Billy Alven
Joe Aly
James Amelung
Bob Amyx
Carol Anderson
Gary Anderson
Otis Anderson
Randy Anderson
Shelby Andrew
Melanie Andrews
Howard Arnold
Zachary Arnold
David Arrington
Liz Arthur
Thad Ashcraft
Kevin Ashley
Amy Askew
Micah Assulin
Roger Averitt
David Avery
Ed Back
Misty Baeza
Tim Bagby
Allen Bagley
Michael Bahrenburg
Allison Bailey
Ronald Bailey
Butch Baird
Charles Baker
Dennis R. Baker
Sitaraman Balakrishnan
Boomi Balasubramaniyan
Leonardo Baldonado Jr.
Christa Ball
Michael T. Ball
Lisa Ballard
Janice Balliet
Michael Bane
William Barker
Dean Barnes
Keith Barrett
Cecelia Barrington
Joshua Barton
Lorie Barton
Brandon Bashaw
Adam Basquez
Warren Bass
Douglas Baughman
Tammy Baxter
Larry Beard
Tim Beard
Johnny Beasley
Jesse Beason
Tiffany Beaver
Terri Becker
Steven Beckett
Jim Bedford
Clint Beeby
Steve Beeson
Danny Beets
Bo Bekendam



FATHER/DAUGHTER DANCE Oklahoma Ken Thompson, Manager – Barnett Shale field, and his daughters enjoy an evening of dinner, dancing and horse carriage rides around campus at this very special annual event.

Robyn Belew
Paige Benedict
Cheryl Bennett
Garrett Benton
John Bergman
Sharon Berkley
Eric Bess
Robert Bevel
Amar Bhakta
Randy Bickel Jr.
Liz Bicoy
Jacob Biernacki
Pam Billingsley
Matthew Birch
Jeremy Black
David Black Jr.
Willis Blaker III
Phillip Blankenship
Emily Blaschke
Tony Blasier
Jimmy Blevins
Doug Bohlen
Richard Bolding
Marvin Bond
Brandi Bonner
Daniel Borowski
John Bottrell II
Brian Bounds
Barbara Bowersox
Deven Bowles
Donald Bowman
Drew Boyer
Ernest Bozarth
Phillip Bradford III
John Bradshaw
Mark Brannon
Matthew Branson
James Branton
Krystal Brauchi
Zora Braun
James Bray
Michael Brenizer
Bradie Brewton
H. Briant
Melvin Bright Jr.
Wesley Brogdin
Billy Bromlow
David Brooks
Vernon Broomfield
Rob Brott
Jay Brown
JP Brown
Natascha Brown
Rodney Brown Sr.
T. Brown
Tyanne Bruce
Timothy Brummage
Greg Bruton
Cheryl Bryan
J.D. Bryant
Marria Brydon
Kala Buerger
Joshua Buie
Todd Bules
Clifton Bullard
Blair Bunch
Niki Burch
Roger Burford
Darrel Burghardt
John Burkhouse Jr.
Jake Burnett
Jim Burnett
Aaron Burns
Burton Burns
Charles Burnsworth
Richard Burrhus
Phil Burrow
Joseph Burton
Dustin Bushnell
Eric Bynum
Tom A. Bynum
Tom W. Bynum
Korey Byrd
Scott Byrum
Stephanie Cahill
Jerry Caldwell
Rickie Callender III
Jorge Camacho
Jason Cameron
Johnnie Campbell
Karen Campbell
Kenneth Campbell
Shanna Campbell
John Canary
Steven Carder
Bryan Carey
Colt Carpenter
Connie Carpenter
Octavio Carpio

Deborah Carroll
James Carroll
Stephan Carroll
James Carter
Alex Casias
Bernardino Castaneda Jr.
Charles Castelli
Jose Castelo
Jose Castillo
Aaron Casto
Brandon Cates
Scott Cavner
Gregory Cavness
Cassie Cawyer
Rosa Chacon
Tim Chaloupek
Harvey Chambliss
Paul Charles
David Chavarria
Oscar Chavez
Kathy Cheesman
James Cheshire
Henry Childress
Richard Childress
Stephanie Choate

Dee Combs
Jason Conaway
Greg Condray
Jeffery Conley
Andy Conyers
Blayne Cook
Jim Cook
Jacob Cooper
Linda Cooper
Scott Copeland
Jeff Cornelius
Justin Cornell
Steve Cornett
Preston Corp
Diego Cortez
Mario Cortez
Janice Cory
Bob Costello
Bobby Costello
Cody Costello
Larry Costello
Stoney Costello
William Coston
Crystal Cottrell
Jereme Cowan

H.E.L.P. INITIATIVE Oklahoma
Mark Lester, Executive Vice President – Exploration, gives a pat on the back to Mark Orgren, the company's first H.E.L.P. Champion, for exemplifying Chesapeake's commitment as a good neighbor. Orgren organized volunteers to renovate the auditorium of Harding Charter Preparatory High School in Oklahoma City.

Rodney Christian
Twila Christy
Kerry Clapp
Suzanne Clapper
Brandon Clark
David Clark
Dustin Clark
James W. Clark
Leon Clark
Stacey Clark
Steve Clark
Jason Claunch
Brad Claypool
Erin Clayton
Jesse Clayton
Cathi Clements
Eric Clements
Jeff Clemons
Michael Clevenger
Ronald Clift
Lindy Cochran
Robert Cochran
Timothy Cockerham II
Brent Cockrell
Lauren Coco
Virgil Coleman
Davy Collins
Katie Collins

Jeffory Cowger
Chris Cox
Jeremy Cox
Steven Cox
Donnie Craft
Tina Craft Grant
Travis Craig
Denise Cramer
Bud Cravey
Joe Creech
Ricky Crider
Scott Crim
Jimmy Crone
John D. Crooks
Murphy Crosby
Paul Crow
Casey Culpepper
Melissa A. Cummens
Ray Cunningham II
Douglas Czako
Aaron Daharsh
Laurie Damron
Michael Damron
David Dani
Alvin Danley Jr.
David Danley
Joseph Darr
Beverly Dart

Jeffrie Davidson
Betsy Davis
Chad Davis
Garry Davis
Kathy Davis
Megan Davis
Rodger Davis
Ron Davis
Kenny Dawson
Robert Day
Greg Dean
Landon Dean
Stanley Dean
Kevin Deeds
Matthew Deel
Tim Deffenbaugh
Donald DeForest Jr.
Gary Dennis
Mark DeShazo
Karl Dexter
Gianny Diaz
Andrew Dickins
Ed Dillard
David Dison
Robert Dison
Linda Dixon
Michelle Dodd
Nicolas Dominguez
Gary Donley
Donald Dotson
Stephanie Doty
Dawn Douglas
Greg Douglas
Lorie Douglas
Johnny Dowdy
John Downing
Tammy Dresser
Alfonso Duenez
Dustin Dunlap
Regina Dunlap
Curtis Dunn Jr.
Larry Durant
Paul Duren
Jim Durst
Dustin Dye
Tammy Eaton
Robin Ebarb
Michael Eddins
Johnny Egnor Sr.
Craig Elder
Jammie Elder
Jeff Elder
Ebbin Elliott Jr.
Jordan Elliott
Melanie Ellis
Darrell Enderlin
Jon English
Richard Enoff
Steven Epps
Jarrod Esparza
Jonathan Eubank
Dee Eubank-Swiger
David B. Evans
Gary Evans
Jody Evans
Ricky Evans
Ronald Evans
Leann Evers
Ronnie Ezernack
Ricky Farnsworth
Andrew Farris
Marcie Farris
Shyla Fast
Bryan Ferguson
Keith Ferguson
Tessie Ferguson
Perry Fields III
Tommy Fillman
Thomas Finch
Brent Finley
Steven Fisbeck
David Fisher
Jerry Fisher
John Fisher
Michael Fite
Chris Flanagan
Michael Flanery
Matt Fleischer
Brenda Flesher

Jose Flores Jr.
Garrett Flowers
Terry Floyd Jr.
Thomas Flynn Jr.
Danny Ford
Martha Ford
Jimmy Forsyth
Anthony Foster
Clarence Foster
Robert Foster
Clayton Foutch
Julie Fox
Jason Franze
Annie Fredrickson
Travis Frels
Nicole Fritz
Larry Frost
Sam Frydenlund
James Fryman
Evan Fuqua Jr.
Christy Furbee
Carol Gaddis
Frank Gagliardi
Sarah Gainer
Junior Garcia Jr.
Martin Garcia Sr.
April Gardner
Chris Gardner
George Garfield
Lisa Garrett
Mark Garrett
Javier Garza
Javier Garza Jr.
Joel Garza
Raul Garzes
John Gasaway
Douglas Gaston
Scott Gaston
Brian Gauntt
Kennie Gay
Anne George
Rachel Gerlach
Jim Gerstner
Bobby Gibson
Steven Giddings
Timothy Giddings
Jon Giffin
Anthony Gilliam
Mandie Gilliam
Cameron Gilmer
Jim Gipson Jr.
Ryan Glenn
Jesse Gomez
Lindi Gomez
Zac Gonsior
Eric Gonzales
Alberto Gonzalez
April Gonzalez
Edgar Gonzalez
Julio Gonzalez
Billy Goodnight
Justin Goodson
Lacey Goodwin
Elijah Gordon
Donn Goss
Lindsay Gowan
Mitch Grant
Kenneth W. Graves
Billy Gravitt
Ron Gray
Gabe Green
Dylan Grey
Camm Grim
Lane Grimes III
Bradley Grimm
Rafael Guerra
Donald Gunnoe
Henry Gutierrez Jr.
Ricardo Guzman
Darryl Haas
Scott Hackworth
Lance Haffner
Larry Hagelberg
Robert Hagerdon
Wayne Haire
Freddy Hale
Kim Haley
Billy Hallman
John Hamilton

Joy Hamilton
Nathan Hamilton
Nathan Hanks
Joe Hanna
Robert Hanna
Tony Hansen
Randy Hansford
Dustin Hanson
Josh Hardie
Dean Harding
Fawn Hardman
James Hardway
Ryan Harkins
James Harman
Cody Harrel
John Harrington Jr.
Bryan Harris
Mike Harris
Robert Harris
Terry Harris
Samuel Harroff
Darrel Hart
Donald Hart
Kevin Hartl
Roger Hartley
Bobby Harvey
Steven R. Harvey
Don Harville
Timmy Hass
Darcy Hawkins
Carroll Hayes
Eric Hayes
Christopher Hayward
Robert Hayward
Teresa Hearn
Brad Heath
Virginia Hebert
Sabrina Hedrick
Daniel Henderson
George Henderson
Nicholas Henderson
Mary Henning
Mark Henry
Dan Hensley
Armando Hernandez
Rafael Hernandez
Matthew Herrin
Jamie Hibbs
Joe Hicks
Sid Hicks
Terry Hicks
Jennifer Higgins
Michelle Hileman
Chad Hill
James Hill
Clyde Hinson
Mark Hlatky
Chad Hledik
Justin Hobbs
Jimmy Hodges
Joseph Hodges
Justin Hodges
Patty Hoecker
Eric Hoehne
Chad Hoffman
Henry Hoffman
Lisa Hoffman
Bradley Holland
Tom Holland
Michelle Hollis
Mike Hollis
Bradley Holman
William Holman Jr.
Bryce Holmes
Timothy Holmes
Michael Holson
Larry Holt
Dustin Homesley
Michael Hommertzheim
Bill Hooper
Kevin Hooper
David Hoover
Melissa Hoppe
Ronnie Hoskins
Ronnie House
Debbie Houston
Seth Houston
Matt Howard
Scott Howard

Seth Howard
Jason Howe
Kenneth Hubbard
Rachel Hubbard
Cheryl Hudak
Chase Huddleston
Jarel Hughes
Justin Hughes
Mark Hughes
Marshall Hughes
Kirk Hungerford
Frankie Hunt
Bret Hunter
Tami Hunter
Elbert Idlett
Justin Idlett
Loyd Idlett
Pete Irby
Jeff Iven
Sherry Izell
Christopher Jacks
Joe Jackson
Lindsay Jackson
Marianne Jackson
Pamela Jackson
Troy Jacobs
Javey Jamison
Lance Jamison
Todd Jamison
Christopher Janzen
Anthony Jeansonne
Travis Jenkins
Eric Jenkinson
Jessica Jennings
Jon Jernigan
David Jirousek
Alex Johnson
Donald Johnson
Jeannie Johnson
Randy Johnson
Steve G. Johnson
William Johnson
Jeri Johnston
Joy Johnston
Cindy Jones
Gary Jones
Kyle Jones
Travis Jones
Bev Jordan
Doug Jordan
Lauren Jordan
Jeffery Judd
Nicholas Judd
Hunter Kam
Paul Karstens
Hemant Kataria
Troy Keel
Marvin Keeling Jr.
Kenneth Keeton
Belo Kellam III
Larry Keller
Diana Kelley
Tommy Kelley
Tracy Kelting
Sammy Kendall
Kris Kendrick
Josh Kennedy
Joe Ketzner
Gil Kiaha
Russell Kidd
John Kieschnick
Jeff Kiker
Wayne Kimberling
John Kimbleton
Fay Kincher
Jessica King
Richard King
Nathan Kirtley
Jeffrey Klingel
Aaron Knapp
Buzz Knapp
Allen Knippers
Jeff Knoblock
Charles Knotts
Steve Knowles
Laurie Knox
Sanjay Kodam
Denise Koger
Blake Koonce

Nathan Kress
Muhamed Kuburic
Sunita Kuburic
Cameron Kuykendall
Hoang Lam
Jane Lam
Tony Lamas
Dennis Lambert Jr.
Jerry Lambert Jr.
Corbin Land
Sandra Landgraf
Bob Langdon
B.J. Larman
Chris Lauhon
John Lawman Jr.
Johnny Lawrence
Kelly Lawson
Tom Layman
James LeBouef
Ryan Lee
Samuel Lee
Stanley Lee
Dave Leopold
Justin Lewellen
Cindy Lewis
Fred Lewis
Peter Lewis
Karen Liles
Jim Lindley
Jill Linkenauger
Trey Littau
Charles Livingston
Ronald Loeffler
Clayton Long
Ellen Long
Teresa Long
James Looney
David Lopez
Jaime Lopez
Niles Loudenslager
Candice Love
Morgan Love
Dustin Lovell
Jennifer Lowther
Silvano Lozada-Luna
Allen Luder
David Luke
Charlie Lumpkin III
Brent Lurry
Josh Lyons
Emily Lytle
Jeffrey MacKay
Kevin Mackey
Jamie Maddy
Glenda Mahoney
Jorge Maldonado
Juan Maldonado
Ramon Maldonado
Monica Malkey
James Manning
Juan Manriquez
Jimmy Manry
Kerry Manuel
Laura Marcellus
Markus Marr
Patty Martin
Braulio Martinez
Mark Martinez
Valente Martinez
Missy Martini
Michael Marunowski
Bobby Matthews
Nicholas Matthews
Maya Maximova
Delores Maxwell
Greg May
Michael Mayfield
Monty Mayfield
Angela McAlister
Derald McAlister
Julie McCann
Rich McClanahan
Katie McCord
Chris McCormack
Lacy McCornack
Garrett McCullough
Shaun McDaniel
Stephen McDonald
David McDougal

Jenni McEachern
Kelle McEwen
Ray McFarland
Harry McGarr
Meghan McGhee
Todd McGinley
Christopher L. McGinnis
John McGowen
Richard L. McGuire
Curtis McIntyre
Irma McIntyre
Chad McKamie
Dennis McKamie
John McKay
Patrick McKim
Heather McLain
Jessica McLain
Amy McLanahan
Walter McLaughlin
Aaron McLean
Caleb McLoud
Matthew McMahon
Steve McMillen
Beau McMillin
Matt McMurry
Heather McNeil
Robert McNutt
Danny McRae
James McWhirter
Donnie McWhorter
Ed Meade
Tom Meadows
Fernando Medina
Dennis Meigs
Junior Melendez
Douglas Melton
Wes Merchant
Curtis Merilatt
William Merkel
Jarod Merle
Justin Metz
Steven Meyer
Barry Michels
Allen Middleman
Allen Miller II
Greg Miller
Gregory Miller
Matthew Miller
Ronald Miller
Toni Millican
Audrey Mimbs
Benjamin Miner
Jerame Mink
Dustin Minton
Santiago Miranda
George Moats Jr.
Chris Mobley
Janice Modisette
Keith Moffatt
Mohammad Moinuddin
John Moles
Angela Moniger
Andrew Montgomery
Tom Mooney
Deanne Moore
Larry Moore
Michael S. Moore
Walter G. Moore
Arturo Morales
Guillermo Morales
Hector Morales
Guillermo Morales-Mata
Charles Morckel
Carroll Morgan
Jay Morgan
Roger Morgan
Nick Morland
Tim Morphis
James Morris
Mike Morris
Nicholas Morris
Ralph Morris
Billy Morsko
Jeffery Mortashed
Joseph Mortashed
Jason Moxley
Johnathan Mueller
Gregory Mumme II
Lewis Munn
Danny Murray
Matt Murry
Antoinette Nell
Bree Nelson
JW Nelson
Laverne Nelson
Rodney Nelson
Lacey Neuman
Kyle Nevels
Jere Newberry
Travis Newberry
Eric Newman Jr.
Shane Newman
Holly Newsom
Lori Nguyen
Thomas Nguyen
Nick Niemann
Drew Nugent
David O'Brien
Marvin Odermatt
Jason Offerman
Michael Ogletree
Dennis O'Handley
Anthony Olivas
Michael J. Oliver
Mark Orgren
Christy Orosco
Randy Orsburn
Don Osborn
Darrel Overgaard
Casey Overhultz
De Overstreet
Tammie Owens
Chris Pace
Thomas Pace
Lindsay Palazzolo
Janie Palma
Kurt Palmer
Robert Palmer Jr.
Betty Paolini
Candy Parker
Edwin Parker
Julie Parker
Carla Parrish
Umesh Patel
Monte Patterson
John Paul
Michael Payne
Rickey Payton
Daniel Pearce
Blain Pearson
Chester Pearson
Kim Pearson
Ariel Pena
Danielle Penland
Terry Perdue
Joe Perez
Addie Pesche
Paul Phillips
Alan Pierce
Jennifer Pierce
Marty Pierce
James Pine
Matt Pinion
Jeff Pinter
Roger Pippins Jr.
Lara Pitchford
Brooke Pittard
Michael Pittser
Filemon Plascencia-Aceves
Lori Plumley
Richard Pogue
David Poindexter
Randy Poindexter
Richard Poindexter
David Polve
Matthew Pompa
David Ponce
Taos Pool
Timothy Poole
Raymond Posey
Nick Pottmeyer
Jordan Powell
Kelli Pratt
Sindy Prescott
Joseph Presock
Marsha Presock
Ricky Pryor
Ronald Putman
Matt Queen
Maria Quezada
Mary Quinn
Barbie Quinn Davis
Tyson Raasch
Daren Rader
Mark Raidt
Johnny Rains
Hermenegildo Ramirez
Peter Ramirez Jr.
Raul Ramirez
Bonnie Ramon
Arturo Ramos
Jessie Ramos
Cody Ramsey
Gary Ramsey
Greg Ramsey
Roy Rash
Aaron Ream
Roger Redmond
Galen Reed
Raymond Reese
Jacob Reeves
Christopher Register Sr.
Keith Reightler
John Reinhart
Brad Rekieta
Allen Remmers
Santhanaraj Rengaian
Matt Reser
Aaron Reyburn
Jorge Reyes
Roger Reyes
Justin Reynolds
Chris Rice
Beth Richards
Henry Riffe
Sandi Riley
Larry Ritter
Gregory Rivera
Courtney Roberts
Josh Roberts
Matthew Roberts
Raymond Roberts
Stacy Roberts
Vincent Roberts
Daniel Robertson
Michael Robertson
Scott Robertson
Scott Robinson
Paul Rodesney
Andrew Rodriguez III
Joel Rodriguez
Maria Rodriguez
Robert Rodriguez
Ruben Rodriguez
Sarah Rodriguez
Juan Rodriguez-Huerta
Jon Rogers
Bailey Rollins
Danielle Roper
Leonard Roper
Vinson Roper
Glenn Rose
Richard Ross
Robert Ross
Tommy Ross
Greg Rossman
Scott Rotruck
Loni Rowan
David Rowland
Jackie Roy
Daniel Rucker
Eric Rucker
Michael Rushing
Dena Russell
Don Russell
Jackie Russell
Dusty Rust
Tracy Rust
Jason Ruth
Matthew Rutledge
Gurpreet Saluja
Kelly Sanders
Matthew B. Sanders
Dale Sanderson
John Satterfield II
Terry Saurborn
Phillip Saxon
Perry Scales
David Schmidt Jr.
Shawn Schmidt
Karen Schmuhl
Ernest Schroeder
Michael Schulz
Earnest Sconyers
Bannon Scott
Joseph Scott
Krystle Scott
Larry Scott
Kevin Scoville
Stoney Scrivner
David Searls
Scott Secrest
Dusty Seiger
Debbie Seiverling
Dale Self
Kenneth Sell
Jobey Sellers
Jon Selzer
Louis Senkyrik
Clint Sepulvado
Amanda Serna
J.C. Settles
Brooke Shannon
Douglas Shannon Jr.
Jimmy Sharp Jr.
Wendie Sharp
Farley Shaw
Frederick Shaw Jr.
Carroll Shearer
David Shellstrom
Michael Sherman
Michael Shiers
Kurt Shipley
Steve Shire
Carl Shorter
Allen Shuemaker
Gregorio Silva
Terry Simmons
C.J. Sims
Christopher Sims
Mary Sims
Randy B. Sims
Randy S. Sims
Rickie Sims
Rudy Sims Jr.
Ward Sims Jr.
Trevor Sinclair
James Singhisen
Ricky Singletary
Danny Singleton
Amanda Sisk
William Sisson
Charles Sitton
Michael Slamick
Bryan Sloan
Nathan Smarr
Eric Smeltzer
Brian E. Smith
Deane Smith
Denise Smith
Emily Smith
Ernest Smith
Jason Smith
Justin E. Smith
Kade Smith
Michael C. Smith
Michael E. Smith
Mitzi Smith
Monte K. Smith
Rusty Smith
Tommy Smith
Troy Smith
Waylon Smith
Brian Snider
Chad Snow
Rich Snyder Jr.
Pam Soltani
Becky Southerland
Pete Spadafora II
Rodney Spencer
Lou Spitznogle
Derek Spreier
Rene St. Pierre
Steve Stafford
Craig Staley
Jason Staley
Don Stanley Jr.
Ronnie Statton
John Stephens
Peter Stephens
Robby Stevens
Roger Stevens
Lyvonne Stewart
Jason Stollings
Michael Stone
Richard Stotler Jr.
Andy Strealy
Russell Streeter
John Strickland
Ronnie Stroh
Perry Studebaker
Teresa Sullivan
Heidi Suri
John Suter
Roger Sutterfield
Anastasia Svec
Rick Svor
Jayce Swartz
Joshua Swartz
Kevin Swiger
Colby Tackett
Kevin Tanner
Ronnie Tarver
Donny Taulbee Jr.
Alan Taylor
David Taylor
Jack Taylor
Matthew Taylor
Mike Taylor
Rick Taylor
Sarah Taylor
Andrew Tencer
Nicholas Terech
Daniel Terry
Ross Terry
Samson Tesfaselassie
Gwen Thomas
Jason D. Thomas
Lacey Thomas
Paul Thomas
Richard Thompson
Travis Thompson
Elmo Tillis
Andrew Tipton
Mikki Tomlinson
Scott Tomlinson
Jerry Toney
John Toney
Brandon Tree
Ignacio Trevino Jr.
Juan Trevino
Dominic Trivitt
Matthew Troup
Danny Trowbridge
Daniel Truong
Irina Tucker
Steve Turk
Chris Turner Jr.
Corey Turner
Jaffe Turner
Donald Tussey
Joshua Tycer
James Van Alstine
Jeffrey Van Grevenhof
Clyde Vance
Shawna Vance
Martha Vasek
Dakota Vaught
Brandt Vawter
Gerardo Velez
Randy Villaire
Dustin Vinson
Brenda Vitatoe
Jonathan Vogel
Curtis Voyles
Robert Wagoner
Huey Wagstaff
Willie Wainman
Erin L. Walker
Noah Walker
Christopher Wallace
Donnie Wallis
Matthew Walters
Elmer Warnick
Matt Warren
Wil Warren
Keith Washington
Matt Watkins
Dusty Watson
James Watson
Luke Watson
Matthew B. Watson
Rod Weatherby
Lauren Webb
John Weber
John Webster
Brad Wechsler
Donald Weed
Jody Weidner
Thomas Weidner
Matt Weinreich
John Weir Jr.
Michael Welch
Toyia Wells
Ann Wendorff
Leonard Wesley
Luke Westfahl
Sam Whitaker
Robert Whitbeck
Billy White
James B. White
James K. White
Jerry D. White
Jerry D. White Jr.
Christy Whited
Bernice Whiteshirt
Joe Whiteside
James Wilhite
Kent Wilkinson
Cynthia Williams
Eric Williams
Jim Williams
Joshua Williams
Justin Williams
Marlene Williams
Rashaw Williams
Thad Williams
Zachary Williams
Calvin Williamson Jr.
Jeff Willis
Tyler Willyard
Andrew Wilson
Brent Wilson
Chad Wilson
Julie Wilson
Steve Wilson
Trista Wilson
Warren Wilson
Jim Wimmler
Franklin Windham
Amos Wise
Craig Wittenhagen
Ivan Wolanski
Mike Wood
Taunya Wood
Henry Woodruff
Tara Woods
Megan Woodworth
Dan Woodzell
Shawn Wreath
Bradley Wright
Erran Wright
Mary Wright
Michael Wright
Greg Wyatt
Keith Yankowsky
Kevin Yarbrough
Scott A. Young
Mina Zaheri
Brigido Zaldivar
Simon Zavala
Jason Zielke
Jeff Ziga
Jody Zigler

2007 (1362)

Kenneth Aaron II
Robert Abbott
Michael Abila
Clifton Ables
Rodney Acosta
Chris Adair
Christopher Adair
David M. Adams
Jeremy Adams
Victoria Adams
Jamie Adamson
Kevin Agee
Roberto Aguilar-Garza
Yemi Ajijolaiya
Clint Ake
Raymond Akins
Adrian Alaniz
Israel Alaniz Jr.
Leonardo Alcantar-Lopez
John Alcorta
Debbie Allen
Ronnie Allen
Tucker Allen
Ryan Allison
Jacob Allyn
Ardy Amin
Jeff Amos

FORTUNE PARTY Oklahoma
Employees enjoy a party with a live band and dinner to celebrate Chesapeake's third consecutive inclusion in the FORTUNE 100 Best Companies to Work For® list.

Boz Anderson
Cody Anderson
Dusty Anderson
Maribeth Anderson
Rick Anderson
Wayne Anderson
Glenda Andrews
Moises Anguiano
Greg Archer
Steve Archer
Kolby Arnold
Roger Arnold Jr.

Tyrerei Ashcraft
Jerry Ashley
Robert Atchison
Joseph Atkins
Rickey Avery
Noa Avila
William Aycock
William Bagley Jr.
Chris Bailey
Kevin Bailey
Chris Baker
David L. Baker
David M. Baker
Garrett Baker
Jeremy Baker
Joe Baker
Leslie Baker
Teddy Baker
Chad Bakke
Rick Ball
Robert Ball
Cindy Balsly
Jeremy Banes
Amy Banu
Freddie Barela
Judson Barker
Beata Barna
Craig Barnard
Sharon Barnett
Jorge Barron
Julie Barron
Redmond Barry III
Wayne Bartlett
Travis Basinger
Adam P. Basquez Jr.
Stacey Baty
Laura Bauer
Benjamin Bax
Kimberly Beal
David Beard
Becky Bearman
Justin Beatty
Cory Beck
Larry Beckwith
Arianna Bedell
Jason Bedow
Sam Bedri
Rodney Belcher
Ben Bell
Christy Bell
Scott Bender
Andrew Bennett
Brooks Bennett
Laura Bennett
Nathan Berg
Barry Bergstrom
Ty Bermea
Pam Bert
Jon Biegel
Marvin Biggar
Bryce Biggs
Randy B. Billings
Randy T. Billings
Ryan Billings
Ed Birdshead
Jeremy Birkes
Wes Bishop
Robert Bitner
Quinton Black
Shawn Black
Craig Blackburn
Timothy Blackmon
Jerry Blair
John Blake Jr.
Jared Blakley
Brandon L. Blevins
Sammie Blevins
Blake Boecking
Debbie Boggs
Josh Bogle
Mercedes Bolen
Richard Bolt
Greg Bommer
Justin Bond
Dustin Boone
Jared Boren
Ryan Bose
Jimmy Bourlon
Alana Bouse
Ronald Bowden
Clayton Bowerman
Lesley Bowman
Mike Bownds
Chris Boyd
Diana Boyd
Eddie Boydston
Gene Boyer
Kyle Bradford
Casey Brady
Danny Branch
Jordan Brandenburg
Eugene Branham
Joe Branham
Danny Bratcher II
Erika Braver
Dennis Breakfield
Darryl Breland
Lance Breland
Jeff Bridgwater
Eric Britton
Keri Brock
Tanner Broomfield
Deanna Brouillette
Aaron Brown
David G. Brown
Eddie Brown
Jason Brown
Kenneth Brown Jr.
Scott Brown
Jeff Browning
James Brumley
Kasey Bryan
Joshua Bryant
Rusty Bryce
Jonathan Bryson
Tanna Buie
Kenton Bulson
Shannon Bunner
Philip Bunting
Stephen Burgin
John Burks
Tracy Burleson
Tom Burnett
Jerry Burnham
Jerry Burns
Sundee Busby
Louis Bushiey
Rocky Butler
Kurt Bynum
David Byrne
Matt Cagigal
Raymond Cagle
Jonathan Caldwell
Nathan Caldwell
Alan Callahan
Matthew Callahan
James Calloway
Andria Campbell
Ian Campbell
Jeffrey Campbell
Richard Campbell
Adrianne Cannon
Juan Cano
Jon Cantu
Chris Carender
Alicia Carey
Terry Cariker
Grant Carlisle
John Carney
Mark Carpenter
Earl Carr
Craig Carte
Darry Carter Sr.
Holly Cary
Ben Case
Alex Castaneda
Jose Castellano
Ricardo Castillo
John Casto
Jeremy Caywood
Curtis Celestine Jr.
Crystal Celsur
William Chambers
Kathy Chandler
Gordon Channel
Philip Chapman
Ryan Chappell
Ward Chase Jr.
Jamie Chastain
Lisa Chastain
Armando Chavez Jr.
Steve Chipera
Phillip Chism
Shandie Choate
Morgan Chrisman
Ronnie Christopher
Richard Chumley
John Churchwell
Rosa Cisneros
Beth Clanton
Darin Clanton
Matt Clark
Sheridan Clark
Dusty Clayton
Charles Clevenger
Colt Clinesmith
Thomas Clouette II
Wayne Cloutet
Andrew Cludius
Ryan Coalmer
Tobie Coffey
Don Cogar
Stephanie Coil
Kyle Coldiron
Adam Cole
Ashley Cole
Dustin Cole
Bob J. Coleman
Robert T. Coleman
Mark Collier
Dustin Collins
Joshua Collins
Stephen Collins
Brad Collison
Denise Condos
Dustin Conley
Steven Conn
Bill Connor
Damon Connor
Dustin Connor
Brandon Cook
Nathan Cook
Douglas Cooper
Misty Cooper
Catie Coppage
Ismael Correa
Anthony Corso II
Chad Corwin
Dennis Cottrill Jr.
William Coudding
Michael Counts Jr.
Todd Courson
Carl Covey
Brian K. Cox
Jennifer Cox
Stephen Crabb
Robert Crank
Rex Cravens
Melanie Crawford
Tracy Crawford
Brently Creel
Gary Crenshaw
Daniel Crihfield
Jeffrey Crihfield
Timothy Criner
Heath Criss
Steve Crocker
Jade Crockett
Zachary Cromer
K.W. Cryer
Julia Cuiksa
Robert Cumberland Jr.
Terry Cumberledge
Jered Cunningham
Timothy Curnutte
Tasie Dahl
Monte Dain
Steve Daniel
John Daniels
Haley Dark
Josh Darr
David Davis
Davy Davis
Donald Davis
Gayl Davis
Kevin Davis
Lynsey Davis
Nathan Davis
Nicole Davis
Butch Day II
Roque De La Torre
Kristine Dearmon
Duane Decker
Nick Delaloye
Jeff Delancy
Eric Denneny
William Denny
Holly DeRousse
Jerry Derr
Lisa DeSpain
Tracey Devera
Dewey Deville
Adam DeVries
Trey Dewald
Bryan Dilger
Kaye Dillingham
Donald Dobbs
Kristopher Dobbs
Martin Dobson
Jensen Doby
Dustin Doerr
Chelly Dolinar
Chad Dome
William Donahoe III
Kevin Donaldson
Michael Donisch
Adam Doty
Gary Driskell
J.P. Dube
Jed Dudley
Tim Dugan
Shannon Dulin
Buck Duncan
Jacob Dupuy
Bunky Dussetschleger Jr.
Brian Duvall
Laren Easley
Randall Easley
Justin Eason
Russ Eason
Dan Eaton
Joseph Eddy Jr.
Glenn Edwards
Jason Elder
James Ellard Jr.
Ricky Ellington
Steven Ellington
Billy Elliott
Catey Elliott
John Elliott
Lauren Elliott
Murphy Elliott
Paige Elliott
Adam Ellis
Laci Elmore
Keith Elroy
Bryan Ely
Amber Embrey
Alex Emerson
Jeremy Engles
Sef Escajeda
Tom Esparza
Joseph Etheredge
Bobby Etheridge
David Evans
Megan Evans
Michelle Evans
Daphne Everett
John Everett
David Fancher
Rosa Farias
Keith Faris
Gary Farnum
Tim Farrington
James Faulkner
Steven Feisal
Susan Fell
Amy Ferguson
Christina Ferguson
David Ferguson
Joe Ferguson
William Ferrebee
Faith Fields
Wayne Files
Jill Fisher
Ranson Fisher
Suzanne Fitzpatrick
Sam Flaming
Kenny Flanagan
Stephanie Fleet
Matt Fletcher
Armando Flores
Otoniel Flores
James Forcucci
Hoyt Ford
Rob Ford
Christopher Fore
Kodi Foreman
Jim Forney
Jake Forrest
Douglas Fortney II
Russell Fory
Danny Foster
Jerry Foster Jr.
Daniel Foulke
Jake Fowler
Sonia Fowler
Tamara Fox
Patrick Franklin
Daron Fredrickson
Teri Freeland
Holly Freeman
Phillip Freeman
Amanda Friese
Joel Fulenwider
Mark Fulkerson
Kimberly Fuller
William Fuller
David Gaddy
Randy Gafford
Benjamen Gaines
Juan Gallegos Jr.
Danny Games
Felipe Garcia
Melissa Gardner
Billy Gary
Don Gatewood
Todd Gatewood
Bill Gee
James Geiser
Matthew Gelnar
Joseph Genovese Jr.
Charles Gerlich
Marissa Gibbs
Christi Gibson
Jonathan Gill
Eric Gillespie
Brian Gilliam
Daniel Gilmore
David Gilmore
Shane Glassey
Barry Gober
Neva Godwin
Amy Gonzales
Alfonso Gonzalez Jr.
Francisco Gonzalez
Hector Gonzalez Jr.
Robert Gooch Jr.
Bill Goode
Carl Goodnight
David Gordon
Ashlynn Gosnell
Cody Goss
Preston Gotes
Jacob Grafa
Zach Gragg
David Graham
Jamie Graham
Jane Graham
Tim Graham
Lee Grampp
Amanda Graves
Kenneth C. Graves
Kevin Graves
D'Angelo Gray
Jimmy Gray
Kevin Gray
Tyler Gray
Marcus A. Green
Randy Green
Richard W. Green
Justin Greenfield
Bruce Griffin
Devyn Griffin
Tony Grigsby Jr.
Justin Grove
Dave Grumieaux
Roy Guerra
Brianne Gungoll
Donald Gunnoe II
Gilbert Gutierrez Jr.
Jose Gutierrez
Derrick Guzman
Summer Gwinn
Timothy Haack
Greg Haddock
Clarence Hadley
Josh Halbert
Lindsay Hale
Trey Hale III
Cary Hall
Rob Hall
Robert Ham
Zaid Hamdokh
Jeremy Hamill
Heather Hamilton
Weston Hamilton
Carolyn Hancock
Sheila Harder
Melanie Harless
Michael Harman
Charlie Harrington
Aaron Harris
Amy Harris
Dustin Harris
Jeff A. Harris
John Harris
Michael Harris
Mark Harrison
Daniel Hart
David Hart
David Hatton
Jerry Hausman
Shane Hayden
Amanda Hayes
Charles Hayes
Kelly Hayes
Patrick Hayes
Stephanie Hayes
Doug Haymaker
Mike Haynes
Dustin Hays
Thomas Hays
Tyler Hays
Kenneth Hazelwood
James Head
Anne Heatly
Gary Heinen
Lindsey Heintz
Christopher Heiskill
Kelly Helm
Kim Helvey
Rob Hembree
Kim Henderson
Kristi Henderson
Ron Henderson
TJ Henderson II
Greg Henry
William Henry
Dave Henson
Alvaro Hernandez
Francisco Hernandez
Mario Hernandez
Marisol Hernandez
Romualdo Hernandez Jr.
Jude Herring
Richard Hess
Claudus Hester Jr.
Anna Hibbard
Douglas Hicks
Josh Hicks
William Higginbotham
Hillary Higgins
Shawn Hignite

SCREEN ON THE GREEN Oklahoma Employees and their families roll out the picnic blankets and unfold the lawn chairs to enjoy an outdoor movie, carnival and dinner on the company's athletic field at its headquarters in Oklahoma City.

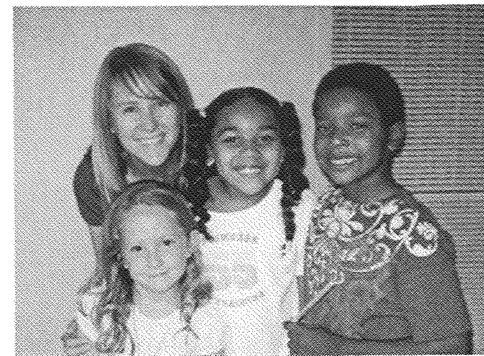
Shane Hilliard
Angelo Hilton
Weston Hinton
Keasha Hobbs
Charles Hodges
Missy Hoehn
Joe Hofer
Duston Hoffman
Eli Hohn
Eric Holcomb
Dan Holden
Adam Holland
Colby Holland
Janice Holloway
Adrianne Holmes
Dennis Holmes
Don Holt
Kyle Holt
Sheldon Holt
Tiffany Hopkins
Greg Hopper
Ryan Horn
Tim Horne
Matthew Horton
Bud Hoselton
Erin Howard
Nicole Howard
Joe Howell
John Howell
Ronnie Hubbard
Melissa Huddleston
Tara Hudson
Mont Huff Jr.
Barry Huggins
Keystone Hughes
Omar Huizar
Tracy Hulsey
Matthew Humphrey
Joe Hunley
Danny Hunt
Steven Hutchens Jr.
Daniel Hyatt
Steven Hyatt
Angela Ibara
Katy Igarta
Gerald Irwin III
Ernie Isenhart
Kate Ivey
Monsuru Iyanda
Lucio Izguerra
Alan Jackson
Angela Jackson
Beverly Jackson
Cara Jackson
Roger Jackson
Larry Jacobs
Cody Jacoway
Jose Jacquez
Jeremy James
Ken James
Tommy Jamison
Victor Jaramillo
Stephanie Jaronek
Billy Jeffers
Clint Jennings
Blu Jernigan
Li Jett
Pablo Jimenez
Billy T. Johnson
Brenda Johnson
Dannie Johnson
Jason Johnson
Kyle Johnson
Kyle R. Johnson
Randell Johnson
Stephen Johnson
Tyler Johnson
Perry Johnston
Aaron Jones
Anne Jones
J. Scott Jones
Jeff L. Jones
Marvin Jones Jr.
Chad Jongeling
Chris Jordan
Rigo Juarez
Andy Kapchinske
Andrew Karber
Tiffanie Karber

James Karraker
Doug Kathol
Rita Keary
Chip Keating III
Bradley Keech
Clayton Keenan
Bill Keller
Karin Keller
Kim Keller
Amber Kelley
Jason Kelley
John Kerns
Pamela Kerr
Mark Kincaid
Freddie King Jr.
Lanney King
Nelson King
Ryan Kintner
Dayna Kirk
Timothy Kirkwood
Dale Kisner
Robert Kitchens
Kasey Kliewer
Robert Kline
Megan Klusmeyer
Anthony Knuppel
Michael Koss
Allison Krittenbrink
Ryan Krittenbrink
Alischa Krystyniak
Dan Kucab
Miranda Lacey
Steve Ladner
Miranda Lair
Todd Lamb
Kelly Lamoreaux
Mindy Lamprich
Clay Lancon
Jason Landis
Nikki Landsberger
Dustin Langley
Abel Lara
Lindel Larison Jr.
Toby Lattea
Aaron Laubhan
Eugene Lauricella
Andy Lawrence
Wallace Lawrence
Cheryl Lawson
Toni Lawson
Luke Lawver
Reagan Lea
Greg Ledbetter
J. Lee
Melissa Lee
Tony Lee
Warren Lee
Jeremy Leger
Brandon Lehoski
Tim Leierer
Dan Leiphart
Logan Lemley
Luis Lerma
Christa Levescy
Joshua Lewellen
Chelsea Lewis
Greg Lewis
Stacey Lewis
John Libhart
Chuck Lilly
Jennifer Lindsey
Laura Linn
Cory Listen
Jeremy Litton
Brian Lockart
Nicole Logsdon
Angie Lohner
Ethel Long
James Long
Alfred Loper
Javier Lopez
Eric Loudenslager
T.D. Louis
Karson Love
Michael Love
Shirley Lovelady
Brandon Lovell
Michael Lovell
Lu Lovett-Voss

Benjamin Lucas Jr.
Dustin Lucas
Elyse Lucchese
Shane Luckett
Gerardo Lugo
Matthew Luna
Richard Luss
David Lynch
Penny Macias
Coleen Magness
Rhonda Maguire
Charlie Malcolm
John Manes
Karissa Mann
Terry Mann
Mark Manos
Chris Marble
Shawn Maricelli
Keith Marin
Travis Marker
Nathan Marks
LeeAnn Marley
Steve Marple
Adrian Marquez
Jamie Marriott
Rebecca Marshall
Paul Marti Jr.
Dustin Martin
Hugh Martin Jr.
Thomas E. Martin
Abel Martinez IV
Joe M. Martinez
Armando Martinez-Barrera
Oscar Martinez-Barrera
Laura Martini
David Masiker
James Mason
Ryan Mason
Steve Mason
John Masterson
Matt Matos
Darrick Matthews
Bobby Mattice
Jared Maus
Peggy Maxell
Joseph May
Benjamin Mayer
Anthony Maze
Christopher McAlvain
Harold McArthur
Jim McCall Jr.
Michael McCann
Michael McClanahan
Josh McClary
Josh McCollom
Randy McCollum
Elizabeth McCormick
James McCormick Jr.
Jay McCormick Jr.
Wayne McCormick
Jeffrey McCoy
Larry McCoy
Fadoua McCray
Joshua McCray
Robert McCue
John McCullough
Michael McDaniel
Miles McDaniel
Robert McDaniel
Dustin McDaugale
Debby McElreath
Jon McEntire
Juan McFadden
Charles McFarland
Julie McGill
JP McGinley
Billy McKamie
Jake McKeever
Mark McKelvey
Christopher McKown
Stuart McLain
Jim McLaughlin
Randy McLaughlin Jr.
Jonathan McLendon
John McLeod
Don McMahon
Terry McMinn
Tyrel McNatt
Nathan McRae

Joe McShane
Josh McWhirter
Kacee Meadows
Robert Mecom
David Medcalf
Michael Medcalf
Salvador Medina
Jessica Meek
Lindsey Melott
Joe Melton
Guadalupe Mendez
Renea Merchant
James Merrell
David Messer
Jennifer Messer
Renee Metcalf
Megan Meyer
Jonice Meziere
Tiffany Mikel
Jody Mikles
Lynn Miler
Anna Milledge
Drew Miller
John Miller
Julie Miller
Marc Miller
Maurey Miller
Rodney Miller
James Mills Jr.
Brad Minick
Gregg Miranda
Mike Miranda
Dexter Mitchell
Christopher Moon
Kenneth Mooney
Adam Moore
Andrew Moore
Ron Moore
Scotty Moore
Carl Mootz
Billy Moran
Coby Moran
Roger Moreau
Dwight Morey
Michael Morey
Danney Morgan
Grant Morgan
Heather Morgan
John Morozuk
Chad Morris
Jared Morris
Marc Morris
Melinda Morris
Steve Morris
Roxanna Morrow
Jean Mort
Don Mosher
Steve Mossor
Richard Mullican
Daniel Muncy
Ron Munyon
Matt Murphy II
Angie Murray
Carl Murray
Chris Murray
Jason Murray
Laura Murray
Ryan Murray
Lee Mustard
Danny Myers
Patrick Myers
Chris Nartey
Alvaro Natividad
David Nelson
Roger Nelson
Cathy Nester
Bob Newport
Cary Newton
Sean Nguyen
Joshua Nichols
Thomas Nicholson
Todd Nickels
Jason Nielsen
Timothy Noland
Derec Norman
Tommy Norman
Scott Norris
Alvonne Nuall
Kristin Nugent

Jennifer Nunn
Denny Nurkiewicz Jr.
Chima Nzewunwah
Steven Oakes
Chad O'Brien
James Ocholik
Jessica O'Daniel
Andrew Odell
James Olson
Mike Olson
Clint Oltmann
Christina Ontiveros
David Ortega
Michael Ortego
David Orth
Ismael Ortiz
Vicki Otey
Craig Overcash
Aaron Overturf
Jeff Owens
Michael Painter
Victor Palacios
Patrick Parish
Grant Parker
Shaphan Parker
Robert Parrie
Benjie Parsons
Jeffrey Parsons
Jonn Parsons
Matthew Parsons
Chip Patton III
Laura Patton
Mark Patton
Carissa Patzkowsky
Ally Payne
James Peace
Danny Peach
Seth Pearrow
Tom Pearson
Ty Peck
John Peek Sr.
Brandon Peffer
Scott Pegg
Michael Penner
Nick Penner
Kellie Pennington
Nathan Peppers
Fernando Perez
Hugo Perez Najera
Richard Perkins
Gene Perry
Melissa Petty
Philip Pfister
Lisa Phelps
James Phillips
Joseph Pilcher
Jonathan Piper
Brad Pipins
Clay Pitts
Brian Plum
Carl Poe Jr.
Neal Poindexter
Randy Pons
Dennis Pool
Eddie Posey
J.P. Potter
Fred Powell
Jerry Powell Jr.
Troy Powell
Kenneth Prangler Jr.
Judy Pratt
Mitra Pratt
David Prenatt
Elizabeth Price
Kristopher Price
Amanda Priest
Jerry Pritchard Jr.
Amanda Proctor
Adrian Proudfoot
Clint Province
Kristin Prudhom
Gary Pruett
Barkley Pruitt
Elizabeth Prykryl
John Pugh III
Brett Purvine
Bill Queen
Sylvia Quintana
James Rachal



H.E.L.P. INITIATIVE Texas
Kristin Ballard, Office Services Representative, makes new friends while volunteering at Broadway Baptist Church in Fort Worth.

Adam Rackis
Jon Radka
Mark Raines
Heather Ramsey
Robert Randolph
Brandy Ratcliff
Glenda Ratcliffe
Clint Ratke
Anne Rawlins
Eric Ray
Ismael Real
Ken Reardon
William Reather Jr.
Mike L. Reddick Jr.
Robert Redhat
Brittany Redmond
Jerriann Reeder
Robin Reese
Nathan Remedies
Jaime Resendiz
Gregorio Reyes
Alyse Reynolds
Joy Reynolds
Craig Rhodes
James Richards
Stan Richards
Drew Richardson
Zachary Richardson
Vernon Ricketts
Christopher Ricks
Brent Riggs
Randy Riley
Jesus Rivas
Joseph Rivers Jr.
Jerri Robbins
Katy Robbins
Jesse Roberts
Justin Roberts
Luke Roberts
Royce Roberts
Dean Robertson Jr.
Amber Robinson
Heath Robinson
Armando Rocha
David Rodgers
Amanda Rodriguez
Art Rodriguez
Juan Rodriguez
Johnny Rodriguez
Melanie Roe
Michael Rogers
Richard Rogers
Tommy Rogers
Alan Rogstad
Grant Rohlmeier
Clint Roland
Carlos Romo
Jeffrey Ronck
Justin Roper
James Roshto
Achley Ross
Dan Ross III
Michael Ross
Michelle Ross
Amber Rosser
Yury Rouba
Greg Rowland
Jimmie Rowland

Matt Rucker
Raul Ruiz
Clarence Russell II
Tim Rutherford
Brian Ryel
Steve Salter II
Matthew Sanders
Ryan Sanders
William Sanders
Kevin Sanderson
Ramon Sandoval
Chad Satterfield
Scott Sayre
Bryce Scalf
Cody Schaedig
Robert Scheetz
John Schieber
Chris Schmitz
John Schneider
Charles Scholz Jr.
Klint Schroeder
Jeff Scoggins
Jon Scolamiero
Amanda Scott
David Scott
Gina Scott
Jon Scott
Justin Scott
Mason Scott
Nathanial Scott II
Hilary Seagraves
Steven Sears
Nick Sentell
Keith Senti
Rodger Settle
David Seyler
Howard Shamblin
Charles Shannon
John F. Sharp
Sharon Sharp
Jim Shaw
Brian Shelton
Jerry Shelton
Kerri Shelton
Paul Shelton
Matt Sheppard
Jerry Shifflett
David Shinn Jr.
Taylor Shinn
David Shirley Jr.
Josh Shirley
Amber Shockley
Rachel Shortt
Larone Siemsen
Corey Simmons
Cynthia Simms
Chris Singleton
Clay Skoch
Kamberly Skoch
James Slaten
Fred Slaughter
Larry Smallwood
Pat Smelley
Amy Smith
Bonnie Smith
Bradley Smith
Brooke Smith
Bryan Smith

Clovis Smith
Darrell Smith
Jonathan L. Smith
Kirk Smith
Michael W. Smith
Monte W. Smith
Shane Smith
Sharla Smith
Boyce Smithson
Anna Snedeker
Randy Snow
Jason Solley
Jane Southard
Douglas Sparks
Victor Spikes
Paul Spoon
Christopher Spratt
Chris Sprute
Colby Staats
Gary Stacy
Joshua Standifer
Carl Standley
Johnny Stanford

RIG TOUR Oklahoma
Office employees learn from field employees how the company explores for and produces natural gas through drilling location tours.

Travis Stankorb
Todd Starkey
Charles Steaveson
Greg Steele
Michael Steinhour
Berk Stephens
Darrell Stephens
James Stephens
Rodney Stephenson
Carly Stevens
Sara Stevens
Scott Stevenson
Brian Stewart
Rebecca Stewart
Ryan Stewart
Steve Still
Jason Stinson
Ken Stinson
Joe Stockton
Natalie Stockton
William Stokes
Michael Storey
Mark Strack
Jason Strawser
Kevin Strawser
Ordare Stribling
Jessica Stricklin
Ryan Stricklin
Sarah Struck
Terry Stuck
Isaac Stump Jr.
Damon Suderman
Casey Sullivan
Teri Swarengin
Jonathan Swarthout
Michael Swonger
Auna Tackett
Paul Tackett
Kiel Talbert
Jason Tannehill
Ryan Tanner
Christie Taylor
Robert Taylor
Roberta Taylor
S. Kyle Taylor
Theressa Taylor
Tom D. Taylor III
Tom W. Taylor
Anthony Thomas
Danny Thomas
Dennis Thomas
LaDonna Thomas
Mark Thomas
Thaddius Thomas
Trista Thomas
Khristen Thomason
Cameron Thompson
Charlie Thompson
Harold Thompson
Ken Thompson
Matt B. Thompson
Raymond Thompson
Laura Tiffany
Brandon Tindle
Michael Tingle
Ronny Tinker
Adam Tinney
David Tollan
Thomas Tollett
David Tollison
Matt Toppins
Katie Torres
Mary Anne Townson
Keith Tran
Van Tran
Guy Trent
Tyler Trent
Lauren Trull
Adam Tucker
William Tuinstra
Jon Tuller
Ottie Turner Jr.
Lane Umsted
Chris Unwin
Rick Urash
Kristin Vafadar
Miguel Valero-Esparza
John Vankirk Jr.
Shawn Vasseur
Merrilee Veres
Ronald Vesely
Kristen Vickrey
Nathan Viggers
Tara Voth
Alexa Wade
Josh Walker
Kristen Walker
Johnny Wall
Brandon Wallace
Laura Wallace
Catalina Wallo
Monica Walls
Adam Walsh
Chelsey Walstad
Lori Walters
Michael Walters
Kyle Waltisperger
Danny Ward
Robert Warren III
Nick Watkins
Matthew L. Watson
Jason Waybourn
Kelly Weaver
Jeremy Weeks
Linda Weeks
Logan Wehling
Cody Weir
Jody Weir
Alison Weis
Melissa Wells
Gary Wenci
Brandi Wessel
Yukino West
Laura Whaley
Buck Wheat
David Wheeler
Rebekah Wheeler
Lauren Whitaker
Gary White
Jennifer White
Lain White
Mike White
Randall White
Robert White
Roger White
Sara White
Todd White
Jim Whitefield Jr.
Wendy Whitfill-Embry
Joni Whitney
Kiley Wiewel
Allen Wiley
Wayne Wiley
Colton Wilkinson
Allison Williams
Amy M. Williams
Christopher Williams
David C. Williams
Derek Williams
Jason Williams
Jerry Williams
Joe A. Williams
Joe L. Williams
Sherwin Williams
Shelli Williamson
David Willis II
Paul Willis
Bruce Willmott
Craig Wilson
Lacie Wilson
Matt Wilson
Robert Wilson
Sabreena Wilson
Chasta Wimmer
Kyle Winkler
Laura Winkler
Rory Winter
Lane Witt
Dallas Wood
Dan Wood
David Wood
Rick Wood
Tara Wood
Eric Woodard
Cameron Woods
Tyler Woods
Sean Woolverton
Tammy Worrell
Darren Wraspir
Lacey Wright
Magan Wright
Shalen Wyatt
Mark Wyckoff
Mike Yarbrough
Shaun Yates
Nathan Yeats
David Yelle
Preston Young
Jesse Yule
Ervin Zacharias
Jacob Zacharias
Travis Zamora
Jenny Zhang
Lester Zitkus
Kathryn Zynda

2008 (1883)

Ricky Aaron
Jerad Abbott
Richard Abel
Kacy Abney
Jose Adame
Juan Adame
Darla Adams
David Adams
Jeremiah Adams
John Adcock
Matt Aderhold
Doug Adkins
Douglas Adkins
Adam Aguirre
Jeffery Ainsworth
Amber Alcorn
Dennis Alder
Julie Alder
Christa Alderman
Greg Alexander
Karen Alexander
Christopher Allen
Sondra Allen
Justin Allert
Beth Allgood
David Allien
Kevin Allison
Reno Alton
Jerame Aly
Manuel Amaya
Derek Amyx
Heather M. Anderson
Matt D. Anderson
Matt S. Anderson
Milton Anderson Jr.
Shannon Anderson
Steven Anderson
Mara Andrews
Shari Annuschat
Brian Archer
Lucy Arebalo
Dann Armour
Dawn Arnhart
Chris Arnold
Jason Arnold
Matt Arnold
Tim Arnold
Billy Arnolds Jr.
Bryan Arrant
Amber Arterberry
Lauren Ary
Jason Ashley
Johnny Ashton
Erin Austin
Jesus Avila Torres
Crystal Bacon
Richard Baden
Jesse Bailey
Joshua Bailey
Patrick Bailey
Tommy Bailey
Jimmy Bailey II
Blake Baker
Charles Baker Jr.
Dashawn Baker
Donnie Baker
Krista Baker
Larry Baker
Ronald Baker
Dennis Balentine
Allison Bales
Kristen Balla
Kristin Ballard
Levi Ballard
Melissa Bane
Ron Baranski Jr.
Garry Barbee
Joshua Barker
Ashley Barlow
Adam Barnes
Ryan Barnes
Dan Barnett
Joshua Barron
Jeff Barry
Jenni Bartel
Steve Barwick
T.D. Baskin
Chris Basler
Susannah Batchelor
Ston Battisto
Brooke Battle
Gil Bayer
Luke Baze
Timothy Beach
Jason Beagle
David Bean
Rinda Beard
Matthew Beason
Ben Beaver
Zac Beavers
Carla Beaves
Kate Beavin
Robert Beckwith
John Bedgood
Jordan Bedwell
Ryan Bellew
Alifonso Beltran
Edmund Beltran
Troy Bending
Cynthia Benford
Leticia Benitez
Bob Bennett
Brandon Bennett
Dustin Bennett
Johnny Bennett
Cody Benson
Brett Bentley
Jerry Bentley
Jim Benton
Kevin Bernis
Steve Berry
Dave Bert
Todd Bevins
Tony Biasatti
Eugene Bickel
Bob Bickham
Joseph Billings
Donnie Bishop
Tim Bishop
Galyn Black
Jeremy T. Black
Bradford Blackcrow
Joshua Blackwell
James Blankenship
Kevin Blankenship
Timmy Blankenship
Damon Blasingame
Kenny Blaylock
Brandon M. Blevins
Shane Blevins
Chris Blockcolski
David Blythe
Emily Boecking
Dustin Boeckman
Kenton Boevers
Emiko Bogard
Michael Boiles
Casey Boland
Misty Bolanos
Kelly Bond
Michael Bone
Mitchell Boone
Ernesto Bordayo Jr.
Dan Borum
John Bostwick
Bruce Boudman
Christopher Boulet
Ginny Bourke
Steve Bourke
Cooper Bourne
Veronica Bowie
Johnny Bowman
Ken Bowman
Brandon Boyd
Donald Boyd
Tony Boyd
Amanda Boyle
Chris Brady
Matt Brady
James Brakefield
Jason Bramlette
Michael Brannum
Rodger Bratton
Brett Brayton
Neal Breazeale
Aimee Breeze
Robert Brevelle
Heath Brewer
Grady Briley
Katie Brinlee
Rock Briscoe
Sammy Briscoe
Bull Brister
Pam Brocato
Stacey Brodak
Candace Brooks
Johnny Brooks
Timothy Brooks
Tom Brooks
Dallion Broomfield
Brenda Brotherton
Hugh Brower
Blaire Brown
Brandon Brown
Donald Brown III
Donita Brown
Hunter Brown
Janet Brown
Laura Brown
Steven Brown
Justin Browning
Jerry Brumfield
Elaine Brummett
Daniel Brunsman
Cody Bruton
Steve Bruton
Jeremy Bryan
Frankie Buckner
David Buffington
Charli Bullard
Russel Bumgardner II
Rose Bunkley
Grant Bural
Amy Burch
Catherine Burdg
Emily Burgess
Eddie Burk
Kristen Burke
Laura Burke
Dianna Burks
Amber Burlison
Jason Burnett
Tyler Burris
Josh Burroughs
DaShawn Burse
Kelley Busby
Ryan Bushman
Adam Butkus
Ricky Butler
Joseph Button
Michael Button
Timothy Button
William Buzan
Steven Byers Sr.
Alan Byrnes
Francis Caffey
Lacy Cagle
Sharon Cahill
James Cain
Jamie Caldwell
Jesse Caldwell
Brandon Calhoun
Crystal Callahan
Chad Callender
Andrea Calvanese
Joe Camacho Jr.
Rafael Cambron
Kody Cammack
Grover Campbell
Brandon Cantrell
Alexander Cardenas
Billie Carender
Mike Carlson
Jeffrey Carpenter
Sandy Carpenter
Harold Carr
William Carrell
Andre Carrethers
Jose Carrizales
Jason Carroll
Tommy Carroll
Trent Carroll
Edward Carson
Kathy Carson
Tami Carson
Cam Carter
Eric Carter
Kevin Carter
Rainey Carter
William Carter
LaQuitta Carter-Pearson
Terry Casbeer
Toby Casey
Keith Caslin
Baige Casto
Bobby Caswell
David Cates
Jarrod Causey
David Cerezo
Vinicio Cerezo
Alejandro Chacon
Elliot Chambers
Tory Chambliss
Jay Chancey Jr.
Joe Chandler
Jerri Chapin-Terrazas
Brian Chapman
Caleb Chapman
Justin Chapman
Reaford Charlson
Alfred Chavez
Mayra Chavez
Raven Chavez
Bradley Chervenka
Courtney Childress
Lisa Christmas-Pretlow
Robert Cisneros
Britnee Clapp
Andrew Clark
Cassie Clark
James M. Clark
Reino Clark
Thadeus Clark
Thomas Clark
William C. Clark
Steven Clarke
Shelia Clayton
James Clem
Allen Clift
Kelsey Clinesmith
Terry Clinton
Diane Cloud
Wesley Coats
Eric Cobb
Wesley Cofer
John Cogar
Rick Cogar
Brandon Colbert
Adam A. Cole
Mike Cole
Chris Coleman
Matt Collingsworth
Tyler Collins
Melinda Colquitt
Keith Colwell
Antonio Compean
Daniel Conard
Richard Conley
Bennie Connolly
Leslie Connor
Jason Conway
Toney Conway Jr.
Christopher Cook
Dianna Cook
Landon Cook
Nate Cook
Sean Cook
Sherri Cook
Jim Cooper
Larry D. Cooper
Will Cooper
James Cope
Steffany Copeland
Paul Cornelius IV
Josh Cornell
Jessica Cornett
Daryl Correll

Terry Cortez
Jim Costin
Jeffery Cotherman
Cole Coulter
Randy Counts
Mario Coutino-Silva
Zach Cowden
Aaron Cox
Billy Cox
Christopher W. Cox
John Cox
Micah Cox
Orrin Cox
Jimmie Craig
Kurt Craig
Casey Crawford
Jerry Crawford Jr.
Kasi Crawford
Paul Crawford
Thomas Creecy
Rosalinda Crespo
Dale Crites
Thomas Crites
Nicky Crocker
David Crooks
Kathleen Crooks
Christi Crotsley
Jennifer Crouch
Nick Crouch
David Crouser
Eusebio Cruz
Rudy Cruz
Daniel Cruz-Mora
Dodie Cullen
Jane Cunningham
Kent Curran
Raymond Dabney
Bruce Dake
Cody D'Alessandro
Colleen Dame
Kiran Darapureddy
Raymond Daugherty
Tyler David
Chet Davies
Brandon Davis
Cayla Davis
Charles Davis III
David L. Davis
Francis Davis
Greg Davis
Joshua Davis
Mark Davis
Franklin Daws
Jason Day
Jill Day
Tim Deal
Ashley Dean
Robert Dean
Phillip Deaton
Belinda Debter
Sam DeFoor
Tim Dehan II
Nick Dell'Osso Jr.
Pam DeLong
Drew DeLozier
Jennifer Demel
Kenneth DeMoney
Toney Dempsey
Jaci Deterding
Benjamin Deville
Kolby DeVille
Michael Dew
Curt Dewbre
David DeWitt
Donald Diamond
Melissa Dickey
Michael Dickinson
Robert Dickson
Wade Dietzman
Chad Diffey
Tiffany Diggins
Kevin Digney
Scottie Dill
R.B. Dillard Jr.
Bryan Disher
Tom Divine
Shane Dixon
Allen Doan
Joshua Doane

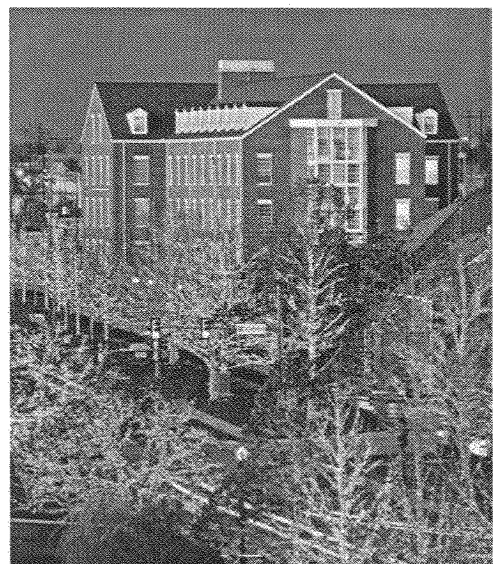
Dwayne Dockens
Ken Dodson
Jimmy Doolittle Jr.
James Dorsey
Zach Dorsey
Jerry Dotson Jr.
Rod Dotson
Billy Dougherty
Paige Dougherty
Josette Doughty
Eric Douglas
Jerrod Dovell
James Dowdell
Bobby Downs
Brett Dreyer
Reginald Drummer
Oscar Duarte
Danny Dudley
Matthew Dudley
Michelle Dugan
Amy Duke
Dana Duke
Richard Dunagan
Vallie Dunklin
Jason Dunlap
Chris Dunn
Jean Ann Dunn
Lesley Dunnagan
Tadd Dunnahoe
Ericka Durham
Chris Dybvig
Alicia Dye
Benjamin Dyne
Ron Dysart
Erick Eads
Jonathan Easter
Monte Eastman
Sean Easton
Bryan Eddington
Travis Edds
Jacob Edster
Chris Edwards
James Edwards II
Kyle Edwards
Paul Edwards
Will Edwards
Tyler Eilers
Janna Ellenburg
Brad Ellett
Shane Elli
Jake Elliott
Stephen Elliott
Troy Elliott
Erin Ellis
Shawn Ellis
Bo Embrey
Myron Emmons Jr.
Matthew Enkoff
Timothy Ennis
Emil Enoff Jr.
Tonya Enriquez
Kitty Ensminger
Clinton Erwin
Williams Espino
Christian Estep
Jeremy Estep
Crystal Evans
Jay Evans
Alisha Fagala
Travis Farmer
Fred Farndon
Donovan Farrow
Jonathan Faughtenberry
Mark Faulkner
Gary Favor
Erin Fay
Rob Fell
Carl Fenderson
Edgar Fernandez
Gabe Ferrell
Paul Fesler
Reginald Fielding
Keri Fieno
Matt Finney
Neil Fisher
Chad Fitzgerald
Derek Flesner
Joel Flores
Kevin Flores

Pete Flores
Lora Florez
David Floyd
Christopher Forcucci
Leonard Foreman
Patrick Foreman
Debbie Forester
David Foshee
Jonathan Fouse
Cassidy Fouts
Bill Fowler
Brandon Fox
Phil Fox
Mike Franklin
Belinda Franko
Gordon Frayne Jr.
Gregory Frazier
Allen Frederick
Joseph Free
Armando Frias
Norris Friend
Philip Friesen
Paula Friess
Steve Frost
Gilberto Fuentes-Perez
Bobby Furr
Joe Gabriel
William Gage
Blaine Galbreath
Kasha Galla
Cole Gallaway
Nicole Ganaway
Kevin Gant
Francisco Gaona
Eliseo Garcia
Leonel Garcia
Dan Gardner
Tim Garey
Matt Garlington
Jennifer Garner
Junior Garnes
Rick Garnett III
Johnny Garrard Jr.
Bryant Garrett
Donny Garrett
Asael Garza
Herman Garza
Austin Gaspard
Sarah Gately
Cody Gates
Yelena Gatewood
Eshetu Gebretsadik
Katie Genovese
Mel George
Mike Gialousis
Mike Gibson
Jeffery Gilder
Mike Gile
Chad Gill
David Gilley
Tom Gilmore
Trasey Gipson
Tyler Gizzi
Blake Gladhill
Brent Glasgow
Jeff Glenn
Larry Glime
Brian Glover
Chad Glover
Robert Gober Jr.
Robert Goff Jr.
Tami Goike
Sandy Goins
Wayne Goldman
Ryan Goltz
Justin Gomes
Jose Gomez
Juan Gomez
Nate Gomez
Eleuterio Gomez-Martinez
Rachel Gonser
Hector M. Gonzalez
Pete Gonzalez
Christopher Goodin
Cindy Goodwin
Daniel Goodwin
Kat Goodwin
Carol Gordon
Tony Gore

Gary Gould
Tommy Grace
Corey Graham
Julie Graham
Lindsey Graham
Neil Granberry
Robert Grant Jr.
Chris Gray
Shane Gray
Michael Gredler
Billy Green Jr.
David Green
Jerod Green
Kenny Green Jr.
Mark Green
Mattie Green
Teddy Green Jr.
Chris Greene
Edgar Gregory
Kevin Gregory
Larry Gregory II
Michael Gregory
Sarah Griffis
Owen Grimes
Kenneth Grimsley
Dakota Gring
Larry Grissom
Mike Grooms
Kenneth Grothe
Tyler Groves
Ramana Gudapati
Eduardo Guerra
Miguel Guillen
John Guillory
Greg Guinn
Jacob Guinn
Johnathan Guth
Manuel Gutierrez
Charley Gwin
DJ Hackney
Richard Haertlein
Brooke Hagedorn
Tim Haladay
Michelle Hale
Rick Hale
Rusty Hale
Julie Haley
Brad Hall II
David Hall
Jeff Hall
Lindsey Hall
Randall Hall
Richard Hall
Ron Hall
Dale Hallet
Tyler Ham
Joe Hamby
Lauren Hamm
Jimmie Hammontree Jr.
Melvin Hampton
Debra Haney
Heather Hanmer
Lee Hanna Jr.
Mike Hanson
Mark Harding
Nicholas Hardwick
Clarence Hardy
Cleophus Hardy
Dale Hardy
James Hardy II
Brett Hargrove
Jimmie Hargrove
Loretta Harkins
Christopher Harman
Jordan Harmor
Jennifer Harms
Casey Harrell
Ben Harris
Jeannie Harris
Lee Harris
Mark A. Harris
Mark L. Harris
Timothy Harrison
Drew Harrold
Kenneth Harsh
Curtis Hartley
Rowdy Hartley
Steven C. Harvey
Jeremy Harvill

Eric Haskins
Rex Hass
Floyd Hathaway Jr.
Kevin Hathaway
Chalis Hatton
Nathan Hatton
Ashley Hausman
Ron Hawkins
Ronald Hawkins
James Hay
James Hayes
Wesley Hayes
Ray Hayford
Kevin Haygood
Terry Haynes
Donnie Hays
Terry Heard
Timothy Hearnsberger
Kevin Heflin
Lesa Heilhecker
Tony Hellar
Norman Helmick
Jeffrey Helwick
John Hemmings
Megan Hendricks
Cory Hendrickson
Eric Hendrix
Johnie Henessee
Jimmy Henington
Curtis Henry
Hayden D. Henry
Hayden F. Henry
Keith Henry
Patrick Heringer
Alex Hernandez
Andres Hernandez
Leslie Hernandez
Norman Herrera
Shawn Herring
Joan Hess
Steven Hey
Thea Hibbard Jr.
Charles Hicks
Clint Hicks
Freddy Hicks Jr.
Mike Hicks
Nicolai Hicks
Nigel Hicks
Raquel Hicks
Ryan Hicks
Adam Hill
Amy Hill
Jennifer Hill
Lisa Hill
Megan Hill
Zach Hill
Gwen Hillhouse
Justen Hinkle
Glenn Hively
Robert Hixon
Terry Hobock
Sally Hoch
Edward Hodges
Joannie Hodges
Danielle Hoeltzel
Eli Hofeldt
Stephen Hoff
Craig Hoffman
Ira Hoffman
Austin Holland
Jim Holland
Molly Holley
Jeffrey Holliday
Crystal Holsinger
John Holt
Megan Honeycutt
William Hood Jr.
Wesley Hooper
Deidre Hopkins
Johnny Horn
Cliff Hornsby
Ben Horton
Chad Horton
Janna Hoskins
Trevor Houston
Veda Howell
Jared Howerton
Chloe Howlett
Clay Hubbard

Mark Huckaby
Levon Hudman
Lyle Hudnall
Chris Huey
Brian Huff
John Huff
Bryan Huffaker
Daniel Hughes
Derrek Hughes
Kennith Hughes
Walter Hughes
Daniel Humphries
Kasey Hundt
Nick Hunley
Holly Hunter
Michael Hunter
Jared Hurst
Patrick Hurst
Robert Hurt
Chad Hutches
Jessica Hutson
Brian Hyden
Jesse Hylton
Jose Ibarra



HOLIDAY LIGHTS Oklahoma
Beautifully lit trees on and around the Chesapeake campus create a holiday landmark each year in Oklahoma City.

Braxton Imke
Brian Ingalls
Marcus Ingram
Neil Ingram
Steven Ireland
Liesl Irwin
Ryan Irwin
Misty Isaacs
Koby Ivey
Paul Ivey
David Ivy
Adam Jackson
Darrell Jackson
Dwight Jackson
Randall Jackson
Isaac Jacobson
Travis Jacobson
Skip Jacot
Clifford James
Kyle James
Scott James
Renner Jantz
Timothy Janzen
Carly Jaro
Holly Jarolim
Scott Jeffrey

Brent Jenkins
Matthew Jenkins
Joseph Jennings
Brandi Johnson
Dawn Johnson
Jake Johnson
Jeremy Johnson
Jeremy S. Johnson
Joseph Johnson
Lindsey Johnson
Manny Johnson
Michael C. Johnson
Rickey Johnson
Michael A. Johnston
Michael Johnston II
Carrie Jones
Cindy M. Jones
Cody Jones
Denton Jones
Dustin Jones
Grant Jones
Jenny Jones
Jody Jones
Johnny Jones
RJ Jones
Stacey Jones
Tim Jones
Joshua Jordan
Steve Jordan
Sarie Joubert
Kevin Judd
Logan Judd
Michael Justice
Jeanne Kaminski
Sylvie Kao
Matt Karl
John Kastelic
Lauren Kastner
Richard Kastner
Russell Katigan
Christopher Keith
Angi Kelley
Kim Kelley
Steven Kelley
Pam Kelly
Josh Kemp
James Kennedy
Walter Kennedy
Clint Kenner
Shane Kennon

Sonia Kepler
Bruce Kessler
Chuck Ketterman
Branden Killingsworth
Kristopher Killman
Isaac Kimbrough
Aaron King Jr.
Justin King
Leah King
Rachelle King
Jade Kingcade
Kyle Kinney
James Kirby
Bruce Kirkland
Timothy Kirl
Don Kirschener
Steve Klassen
Stephen Klein
Jake Klingenberg
Gordon Klundt
Bobby Knapp
Shayne Knapp
Blake Knight
Tamara Knight
Tripp Knight
Douglas Knighten
Henry Konan
Glennette Koon
Justin Koonce
Ryan Koontz
Randy Kopisch Jr.
Chuck Kordis Jr.
Steven Kosciuk
Sue Koskela
Scott Kueck
Rick Kuper
Dustin Kurtz
Kade Kusik
Jeff Lagaly
Melissa Lambert
Nelson Lane
Michael Langford
Sam Langley
Nicole Lanphear
Lawrence LaPlante
Andy Large
Bobby Laster
Ryan Laster
Chris Laughlin
Matthew Lawrence
Michael Lawrence
Jeffery Lawson
Kenneth Lawson Jr.
Dustin Leavins
Nick Leber

BIKING FOR A CAUSE
Oklahoma Martha Burger, Senior Vice President – Human and Corporate Resources, cheers for Bobby Bolton, Chesapeake Land Manager – Anadarko District, who rode more than 130 miles to help buy new uniforms and equipment for the Erick–Sweetwater Public Schools.

Blake LeBlanc
Andrew Lee
Jesse Lee
Joshua Lee
Kent Lee
King Lee
Homer Leger Sr.
Tiesa Leggett
Frederick Lembach III
Gregory Lemley
Pamela Lemley
Robert Lemons
John Lennon
Carmen Lentz
Tiffany Leschber
Jacob Lester
Donald Leverich
Christopher Lewis
Jerry Lewis II
Kent Lewis
Micah Lewis
Nathan Lewis
Cody Light
Wes Liles
Kelli Lindsey
Brian Linger
John Lingle
Sandy Lister
Travis Little
Rick Little Axe
Mark Locklear
Angela Loest
Phil Logsdon
Bryan Lohoff
Joshua Long
Richard Long Jr.
Blake Looney
Kristi Looper
Andy Lopez
Luis Lopez
Paul Lopez
Robert Lopez
Susan Lorenzen
David Lowe
Cody Lucas
Mikel Lucas
Hector Lujan-Jurado
Robert Lumley
Cecil Luttrull
Donald Lynch
Terra MacAloney
Grant Macdonald
Glen Mackie
Greg Macksood
Michael Madar

Rafael Madrid
Richard Mahlock
Troy Mahurin
Michael Major
George Malone
Tim Mangham
Rico Manjarrez
Jonathan Manning
Mike Mannschreck
Joe Mansnack
Matt Mantell
Tyler Manwell
Alberto Manzano
Michael Mapp
Britt Marchbanks
Ronald Marchbanks
Paul Mares Jr.
Dennis Marsh
Gary Marsh
Clint Martin
Jimmie Martin
Mary Martin
Michael A. Martin
Michael Martin
Stacy Martin
Timothy Martin
Fabio Martinez
L. Joe Martinez
Leo Martinez
Luis Martinez
Rodolfo Martinez
Tony Martinez
Corina Martinez-Malone
Pam Massey
Jenn Masters
Lauren Masters
Mike Mathis
Timothy Mathis
Bryan Matthews
Matt Matthews
William Matthews Jr.
Brian Matula
Brett Maughan
Angel Maxwell
David May
Johnny May
Dennis Mayo
Melissa Mays
Joseph Mcalister
Kim McAuliffe
Garret McBrain
Allison McBride
Ray McCallister
Gary McCartney
Dakota McCarty
Randy McCarty
Roy McCasland
Branden McClain
Alan McClure
Scott McCollum
Kevin McCotter
Dennis McCoy
Don McCoy
Lance McCoy
Tommy McCoy
Jamie McCracken
Jeffrey McCroskey
Rick McCurdy
Brandy McDaniel
Justin McDaniel
Alvin McDonald
Emily McDonald
Matt McDonald
Shannon McDonald
Danny McDowell
Tony McEntyre
Julie McFarland
Becky McGee
Jamie McGee
Roderick McGee
Lonell McGhan
Kiley McGlothlin
Keri McGuire
Jason McIntosh
Charles McIntyre
Taylor McIntyre
Marshal McKee
Randy McKee
Thomas McKee

Leslie McKeever
Russell McKibben
Brandon McKinley
Willie McKinley
Alicia McLaughlin
Cody McLaughlin
Kippy McLelland
Michele McLemore
Aron McPike
Edward McQuaide
Cami McQuerry
Chad Meadows
Andrew Meadville
John Mease
James Meek
Ronnie Meeks
Derrick Megli
Ryan Mehan
Cody Meier
Araceli Mejia
Andy Melton
Zeke Melton
John Melville III
Taron Mendez
Kevin Mendoza
Tatiana Mercer
Carter Messer
Stanley Messer
Kenneth Metheny
Alan Metz
Josh Mey
Adam Meyer
Troy Meyers
Gordan Michaelis
Kevin Mick
Michael Mikulenka Jr.
Alex Miller
Drew Miller
Emily Miller
Jeanna Miller
Josh Miller
Rickey Miller
Steve A. Miller
Dan Mills
Scott Mills
Nichole Minnick
Tabb Minor
Kathy Mires
D'Antae Mitchell
Juliet Mitchell
Jeremy Mixon
T-Roy Mize
Brennan Moates
Jeffrey Mohs
Gilbert Moncivais
Mark Mongold
John Montgomery
Myron Montoya Jr.
Christie Moody
Amanda Moore
Leland Moore II
Michael L. Moore
Rex Moore
Roy Moore
Timothy Moore
Walter C. Moore
Matthew Moran
Mandy Moreno
Renita Moreno
Brandon Morgan
Charles Morgan
Eufaula Morgan
Shanon Morris
Hillary Moseley
Terri Mosher
Tyson Moulder
Michael Mowrer
Kevin Moxley
Pat Mullen
Lester Mullins
Clint Mullis
Adam Muncy
Ricky Muncy
Bond Munson
Rafael Murillo Del Angel
Elise Murlin
Bridget Murphy
Chasidy Murray
Jerome Murray

Kevin Murray
Steve Murray
Katrina Myers
Heather Myres
Shane Nafe
Gavin Nailon
Trebor Nall
Bobby Nance III
Crystal Nance
James Neely
Kyle Neuenschwander
Mike Newkirk
Casey Newman
Dana Newman
Joshua Newport
Steven Newton Jr.
Chi Nguyen
Derek Nicholas
Derek Nichols
Rome Nichols
Susan Nichols
Brandon Nicholson
Diane Nickel
Mark Nipper
Gary Nix
Henry Nixon
Chad Noland
Joseph Norman
Chase Norris
Tony Norris
John Nuckols
Aimee Null
Thomas Nunley
Fred Nunn
Cassi Nunnery
Jane Nye
Jason Oblander
Jessica Ockershauser
Ray Ofosu
Dane O'Glee
Kyle O'Kelley
Leah O'Kelley
Jill Olney
Brett Olson
Nate Olson
Chad O'Neal
Andy Opella
Dillon Orr
Fausto Ortiz
Pedro Ortiz
James Osborn
Gregory Osbourne
Lindsey Oswalt
Jeremy Otahal
Patricia Otero
Ray Oujesky
Aimee Owen
Courtney Owens
Savanna Owens Sr.
Jon Pace
Lupe Pacheco
Andrea Painter
Kim Painter
Brenda Palacios
Tyler Palesano
Emerson Palmer
James Palmer II
Matt Palmer
Jay Parham
Chase Paris
Brad Parker
Drew Parker
Joshua Parker
Taylor Parker
Tommy Parker
Whaquine Parker
Jordan Parmer
Robley Parmer
Ercil Parsons
Jason Parsons
Stuart Parsons
Ranita Patel
Alex Patton
Travis Patty
Jason Payne
Henry Payton
Matt Payton
Matthew Peach
Jim Pearman

Josh Pearman
Darby Pearrow
Jarrod Pearrow
Joe Peck
Kip Peck
Tonia Peck
Christopher Pena
Christina Pendarvis
Eric Pendleton
Tim Pendleton
Aaron Penix
Keith Peppers
Angela Perez
Charles Perez
Francisco Perez
Juan Perez
Jesus Perez-Garcia
Richard Periman
Jerry Perkins
Keera Perkins
Jamie Perot
Melvin Perrin
Charlie Perry Jr.
Farron Perry
Micah Perry
Nicole Peters
Gina Peterson
Marie Peterson
Jarred Pettijohn
Thao Phan
Steven Phathong
Ricky Phillips
Vernon Phillips Jr.
Charles Philyaw
Sam Pickett
Christopher Pilgreen
Kevin Pinkston
Lindsey Pitt
Cindy Pittman
Aaron Place
Norval Place Jr.
Jeff Plangman
William Plant
Arturo Plascencia
Charles Platt
Adam Pleasant
Ryan Plummer
Paul Plunkett
Adam Podschun
Erryn Pollock
Everett Poole
Jordan Pope
Kevin Postalwait
Maria Postman
Brian Potocki
Stacy Potter
Micheal Potts
Jackie Potvin
Randell Powell Jr.
Rowland Powell
Tiburcio Prado
Josh Prater
Roger Prater II
Paul Pratt
Frankie Preston
Mike Priest
Lisa Pritchard
Sade Proby
Aaron Procell
Christen Proctor
Barry Pruitt Jr.
Duane Puffer
Cody Puffinbarger
Nathan Pumphrey
Jody Purcell
Brian Putnam
Roger Putnam
Randy Pyle
T.J. Pyle
Amber Qerama
Matt Quade
Jacque Qualls
Randall Radcliff
Joseph Ragsdale
TJ Ragsdale
Frank Rainbow
Ryan Rainer
William Rainey
Hector Ramirez

Jose Ramos
Nelson Ramos
David Ramsey
Derrek Ramsey
Dina Ramsey
Paul Ramsperger
Roy Randolph III
Jared Ranum
Jenn Rauber
Shawn Rawls
Leif Rayburn
Amy Reames
Scott Reddick
Austin Reed
Jamie Reed
Jim Reed
Jerry Reeves
Kent Regens
Andy Rehm
Jason Reid
Mark Reinhardt
Danny Reno
James Retherford
Alisha Reynolds
Jackie Reynolds
Chris Rial
Amanda Rice
Don Richard
Mark Richards
Pat Richards
Richard Richards
Heath Richmond
Dale Riddle
Shane Ridenour
Jill Ridley
William Rieg Jr.
Bob Rieser
Julie Rigsby
Chad Riley
Claude Riley Jr.
Matthew Riley
Allen Roach
Bill Roach
Adam Roberts
Eric Roberts
Larry Roberts Jr.
Megan Roberts
Rhett Roberts
Ronnie Roberts II
Bill Robinson
Charles Robinson
Clarence Robinson
Dustin Robinson
Jonathan Robinson
Meg Robinson
Rob Robinson
Robbie Robinson
Tim Robinson
Clayton Robison
Justin Roby
Bertha Rodarte
Paul Rodgers Jr.
Eric Rodriguez
Esdras Rodriguez
Eustaquio Rodriguez
Raul Rodriguez
Eddy Rodriguez
Roberto Rodriguez Jr.
James Rogers
Michael B. Rogers
Nathan Rogers
Timothy Rogers Sr.
Kiley Rollins
John Roney
Rebecca Roper
Trey Roper III
Manuel Rosas
Teresa Rose
Jack Rosenberg
Dee Ross
Chris Rosson
Harvey Rotramel Jr.
Rusty Roush
Staci Rowell
Jason Rowland
Jenny Rowland
Mark Rowold
David Roy
Rebecca Roy

Jeremy Rubio
Brad Ruhman
Guadalupe Ruiz
Mike Ruiz II
Ben Russ
James Russell
Jamie Russell
Randy Russell
Tommy Russell Jr.
Bryan Ryan
John Rychtarik
Daniel Ryerson
James Safley
Baldemar Salazar
Baldemar Salazar Jr.
Ricardo Salazar
Federico Samora
McKenzie Sampson
Christy Samuels
Michele Samuels
Ema Sanchez
Steven C. Sanders
Woody Sandlin
Pedro Santana Jr.
Daniel Satterwhite
Cathy Saunders
Donnie Savage
Steve Savell
Jessica Savic
Wayne Savory
Brynn Scalf
Kevin Scarem
Susie Scasta
Jason Schafer
John Schafer
Deborah Schaffner
Travis Schenkers
Heather Schevetto
Boyd Schneider
Jake Schoeffler
David Scholl
Regan Schrader
Rebekah Schultz
Clint Schwarz
Jay Scogin Jr.
Dustin Sconyers
Gerald Scott
Mary Scott
Steve Scott
Clifford Scroggins
Mike Scroggins
Roby Scruggs
Brooke Secor
Erin Sedbrook
Brad Seelback
Steven Segrest
Terry Sells
Chellee Semon
Hayet Serradji
Charlie Sewell Jr.
Susan Seymore
Mitcheal Shackelford
Brian Shadwick
Charles Shadwick
Bindu Shah
Jerry Shamblin
Todd Shamblin
Michael Shanbour
Aaron Shannon
Neil Shannon
Jacob Sharp
Kevin Shaw
Lisa Shelden
Jennifer Sheline
Cheri Shepard
Eb Shepherd
Jesse Sheppard
Keith Shields Jr.
Brock Shindler
Ashley Shirley
Thomas Shock
Joseph Shofner
Jason Shook
Ashis Shrestha
J.R. Shull
Amanda Siebert
Vince Sifuentes
Cheryl Siler
Jose Silva
Gary Simer
David Similly
Patrick Simmons
Eula Simms
J.J. Simonsen Jr.
Alan Simpson
Rick Simpson Jr.
Brad Sinor
Steve Sistrunk
Jerimy Sites
Jon Sivertson
Tyler Skelton
Justin Sloan
Ryan Slosson
Joel Smallwood
Drew Smart
Jake Smedley
Heather Smiley
Aaron Smith
Adam Smith
Beth Smith
Dale Smith III
Dawn Smith
Greg Smith
Gwyn Smith
Jeffery Smith
Jerry S. Smith
Jimmee Smith
Joseph Smith
Julie Smith
Justin T. Smith
Milton Smith
Randy Smith
Stephanie Smith
Steve Smith
Vincent Smith
Zac Smith
Jeffrey Snell
David Snethen
Jason Snyder
Clarky Socia
Matt Solomon
Jaclyn Sommavilla
Gary Sons
Joshua Southerland
Pavlina Sovak
Brian Spaeth
Jeremy Spalvieri
Lindsay Sparks
Shawn Spencer
Jason Sprayberry
Jefferson Springer
Andrew Sprouse
Heather Spurlock
Gentry Squires
Francis Staat
Robin Stafford
Paul Stager
Michael Stair
David Stamper
Tim Stansel
Laura Steen
Nathan Steffee
Bumper Stegall
Gay Stephens
Jamie Stephens
Joshua Stephens
Laura Stephens
Cody Stephenson
Glenn Stetson
Joseph Stevens Jr.
Patrick Stevens
Richard Stevens Jr.
Chad Stewart
Darren Stewart
Haleigh Stewart
James Stewart
Mike Stice
Autumn Still
Corey Still
Corey Stockert
Harvey Stockman
Michael Stoll
Janeen Stonebraker
Brian Stoops
Bob Stowe
Ashleigh Strahler
Allie Street IV
Sam Stroder
Monica Stroman
Holli Strong
Robert Stroud
Nick Strunk
Jason Stryker
Edwin Stubbert
Donna Stubbs
Daniel Stumbo
Doug Sublette
Jordan Sudhoff
Brandy Sullens
Stephanie Sullivan
Christopher Summerfield
Jody Summers
John Swanson
Jason Tackett
Rocky Taliaferro
Jason Talkington
Caleb Tallent
Joshua Tanner
Kristin Tarbush
Julie Tarp
Justin Tarver
Aaron Tasier
Brian Tate
Tate Tatem
Casey Taylor
Christy Taylor
Monty Taylor
Tim A. Taylor
Josh Tedder
Jason Tell
Shawn Tenney
Bridget Thedorff
Matt Theriot
Cody Thiessen
Abbie Thomas
Brad Thomas
Denver Thomas
Britton Thomason
Joseph Thomason
Adam Thompson
Diane Thompson
Frank Thompson
Jon Thompson
Matt R. Thompson
Mitcheal Thompson
Sharon Thompson
William Thompson
Stephanie Thorn
Ashley Thornton
Scott Thornton
Preston Thurman
Todd Tigert
Isidro Tijerina
W. E. Tinkler
Cody Tipton
Tanner Tipton
Jim Todd
Kyle Toler
Richard Tollison
Suzette Tomlin
Greg Tompkins Sr.
Frankie Tovar III
Steve Trammell
Rick Treeman
Sarah Tribout
Nick Tricinella
Joseph Triplett
Chuck Tripp
Steve Trotter
Wesley Troub
Daniel Truman
Mike Trussell
Chance Turner
Kevin Twyman
Mark Tyler
Perry Ulicnik
Berto Ulloa
Kathleen Underwood
Tanner Upchurch
Jose Urbina
Justin Urena
Ken Utton
Bobby Vallery
Steve Van Strien
Donnette Vandersypen
Deloris VanLandingham
James Varner
Crystal Vasquez
Jeff Vasquez
Silver Vasquez III
Darren Vaughn
James Vaughn
Matt Vaughn
Nick Vaughn
Randy Vaughn
Rusty Vaughn
Maria Velez
Miguel Vences
Jose Vergara
Javier Villa
Juan Villarreal
Donna Villers
Link Vodron
Terri Vogt
Jennifer Voisin
Terry Von Allman
Ike Vorheis
Haley Voyles
Todd Waddle
Justin Wade
Donald Waggoner III
Fred Wagner Jr.
Steven Wagner
Willie Walden
Ken Waldroop
Chase Waldrop
Chris Walker
Danny Walker
Erin Lee Walker
Matthew Walker
Tiffany Walker
Tyler Walker
Ava Wallace
Brandi Wallis
Jimmie Walters Jr.
Michael Wanzer
Kevin Ward
Tara Ward
Rich Ware
Kent Warfield
Doug Warminski
Dennis Warner
BJ Warren
Brian Warren
Christian Warren
John Warren
Ray Warren
Britni Watson
Cody Watson
John Watson
Mike Watson
Gary Watts
Kelli Waxman
Guy Weatherman
Jeff Weaver
Michael Webb
Nathan Weber
Ryan Weber
Cody Weiss
George Weissman
Bill Welch
Brandon Welch
Brent Welch
Kip Welch
Melanie Welch
Brenna Wells
Geff Welsh
Tommy Wesson
Drew West
Kris West
Nathan West
Scott West
Colt Westbrook
Buck Wheaton
Jeric Wheeler
Todd Whisennand
Shawn Whitaker
Dennis White
Lisa White
Suzy White
Todd C. White
Danny Whitehead
Darien Whitehurst
Gary Whitley
Kody Whitley
Kyra Whitt
Darrell Whittemore
Bobby Whittington II
Sam Whitworth
Rachael Wickery
LeeAnn Widner
David Wiist Jr.
Terrence Wilhoit
Brent M. Williams
Brian Williams
Cody Williams
David L. Williams
Frankie Williams Jr.
Mike Williams
Sheila Williams
Whitney Williams
Forest Willis IV
Adam Wilson
B.C. Wilson
Darrel Wilson
Don Wilson
Erica Wilson
Jerry W. Wilson
Jonathan Wilson
Kayla Wilson
Kendal Wilson
Kevin Wilson
Lance Wilson
Sugar Ray Wilson
Terry M. Wilson
Terry T. Wilson
Todd Wilson
Clayton Winkler
Gary Winn
Keith Winsauer
Rhett Winter
Crystal Witcher
Nikki Witcher
David Witte
Kenneth Woechan
Ken Wolf
Ray Wolf
Glen Wolford
Luke Wood
Kim Woodall
Travis Woodard
Richard Woodbeck
Mike Woodfin
Kevin Woods
Kyle Woods
Monty Woods
David Wools
Becky Wooten
Billy Wooten
Jamie Word
Daniel Wortham
Lindsey Wortham
Emily Worthen
Darren K. Wraspir
Brandon J. Wright
Dan Wright
Kandice Wright
Mike R. Wright
Ryan Wright
Tom Wright
Chad Wyatt
Carolynn Wylder
Jennifer Yeahquo
Tonya York
Andrew Yost
Kevin Yost
Scot Young
Terri Young
Tammi Yount
Juan Zapata Jr.
Robert Zeiler
Debra Zimmerman
Linda Zimmerman
Melvin Zinke
Gerry Ziriaxe
Rigoberto Zubia

2009 (1778)

Timothy Abshire
Timothy O. Abshire
Ethan Acevedo
Daman Ackerman
Joshua Ackley
Jeremy Adam
Christopher Adams
DeAnn Adams
Doyle Adams
Heath Adams
Kyle Adams
Peter Adams
Mark Adkins
Michael Adkinson
David Adkison
Aaron Aguilar
David Ainsworth
Edward Ainsworth
Tasha Akers
Gavin Albright
Marco Aleman
Curtis Alexander
Stephen Alexander
Bart Alford
Albert Allen III
Michael Atkinson
Kelly Babb
Alberto Baeza
Rodney Baggett Jr.
Joey Bagnaro
Bill Bailey
Gordon Bailey
Jamie Bailey
Justin Bailey
Kenneth Bailey
T.J. Bailey
Brett Baker
Bryan Baker
Heath Baldwin
Michael D. Ball
Mike Ball
Jonathan Ballard
Lilli Ballinger

20TH ANNIVERSARY PARTY Louisiana Across all its operating areas, Chesapeake employees celebrated the company's 20th anniversary this year.

Cathy Allen
David Allen
James M. Allen
Jared Allen
Kane Allen
Mike Allen
Paul Allen
Tommy Allen
Sondra Allison
Maria Almanza De Garcia
Reginald Alston
Jacob Alvarez
James Alvis
Joe Aly
Brandon Amato
Matt Andersen
Andrew Anderson
Jeremy Anderson
Rondal Anderson Jr.
Tyler Anderson
Victor Anderson
Austin Andrews
Dustin Andrews
Jame Andrews Jr.
Bradly Andrus
Tony Angelo
Christopher Anglin
Gary Ansley
Rob Anthony
David Applegarth Jr.
Sam Arambula Jr.
Tony Aranda
Steven Armentrout
Gregory Armstead
Joshua Armstead
Brian Armstrong
Bubba Armstrong
David Armstrong
Priscella Arnett
Kyle Arnold
Daniel Ary
Samantha Ash
Mike Atchie
Billy Atkinson
Diana Bane
Kim Barbay
Linda Barber
Seth Barkocy
Dylan Barnes
Marcus Barnes
Ryan Barnhart
Ben Barresi
Shane Barrett
Joshua Bartholomew
Johnny Barton
Whitney Bash
George Bass
Justin Bass
Melissa Bassett
Brian Bastedo
Barry Bateman
Allen Bates
Christopher Bates
Everett Bates
Hope Baumgarner
James Baumgarner
Matt Bayne
Kara Beal
Coby Beals
Jonathan Beam
Bucky Beaver
Russell Beavers III
Adam Beck
Melissa Bednarcyk
Brandon Beechly
Jed Beegle Jr.
A.J. Beets
Jeremy Begeman
Kyle Behnke
Christopher Bell
Dustin Bell
Jason Belless
Dana Bennett
Ryan Bennett
Todd Bennett
Tyron Bennett
Allison Bentley
Daniel Bentley

Merideth Bentley
Matthew Bereuter
Jonas Bergman
Sherry Bernstein
Jacob Berry
Kevyn Berry
Steven Berry
Michael Berryman
Chris Beuchaw
Jared Beutler
Carl Bevor
Amber Bezdek
Cole Bieber
Dannye Billie
James Billings

HALLOWEEN UNITED WAY FUNDRAISER Oklahoma
Bringing out the fun-loving aspect of our people, a costume party drew more than 3,000 Chesapeake Oklahoma City corporate staff employees with lunch and prizes for costumes and skits — while raising funds for United Way.

Justin Billings
Brian Bilyk
Chris Bird
Andrew Bischoff
Carmen Bishop
James Bishop
Ryan Bishop
Kevin Black
Shyla Blackketter Dwyer
Johnathan Blacksten
Kent Blackwelder
Darrell Blagg
Raymond Blankenship
Tobey Blaylock
Joshua Blewer
Scott Blomgren
Jason Blose
Margaret Blount
Benjamin Blue
Dan Blythe
Victor Boatwright
Dennis Bode
Jonathan Bodine
Travis Bohannon
Ryan Bohnet
Jeremy Boitnott
Jen Bookwalter
Christopher Boomgarden
Curtis Boone
Justin Boop
Mike Bordes
Richard Bostick
Nathan Botti
Kent Bowman Jr.
Sonny Bowman II
Christopher Boyles
Shad Brackin
Arla Bradford
Blair Bradley
Colt Bradley
Dennis Bradley
Matt Bradley
Leon Bradshaw II
Ben Brallier Jr.
Justin Bray
Rick Bray
Christopher Breland
Rawlins Breland
Randall Brewer
Dawn Brick
Jason Bridges
Scott Bridges
Lindsay Bridgwater
Keith Briggs
Kenny Briley
Brian Bristol
Bryan Britt
James Britt
Becky Brittain
Clint Brooks
Gerald Brooks
Joe Brooks
Landon Brooks
Martin Brooks
Shannon Brooks
Jonathan Broome
Leslie Bross
Sarah Brothers
Charles Brown II
David B. Brown
Matthew Brown
Mike Brown
Robert Brown
Timothy Brown
Robert Browning
Mary Bruce
Benjamin Brulet
Heather Brulet
Jennifer Brumage
Chris Brummett
Jeremy M. Bryan
Scottie Bryan
Jeffrey Bryant
Nathan Bryant
Ron Bryant
Megan Bryce
David Bryson
Jared Buchan
Jamie Buchanan
John Bunner
Steve Burnley
Jeffery Burns
Lonnie Burns
Christopher Burris
Amy Burrous-Medina
Sylvia Bustamante
Jeff Butler
Byron Button Jr.
John Byler
Steve Byrd
Bradley Cagle
Christopher Cain
Mike Caldwell
Stephen Callahan
Craig Callas
James Callender
Juan Camacho
Martin Camacho
Jeremy Camburn
David Camero
Kim Cameron
Stephen Cammann Jr.
Jimmy Camp
Derek Campbell
JC Campbell
Scott Campbell
Steven Canada
Luis Canales
Michael Caneen
Steve Canfield
Irene Cantu
James Carbary
Casey Cardin
Cody Carlisle
Nathan Carlson
Lonnie Carpenter
Luke Carpenter
Jeremy Carraway
Bobby Carter
Charles Carter III
Jeremy Carter
Toby Cashion
Ken Cason
Jefferson Castie
Chris Castleberry
Jimmie Casto
Melissa Cates
Thomas Caton Jr.
Ken Cavner
Scott Cazabat
Brad Chambers
Erin Chancellor
Rocky Chapman
Chris Chappell
Chuck Charleston
Dedra Chavez
Lonnie Chevallier
Eugene Childers
Lindsay Choate
Amanda Clark
Christopher Clark
William G. Clark
Tom Clarke
Jane Clements
Christopher Clevenger
Chad Clifford
Megan Clinkenbeard
Michael T. Clinton
Jason Coates
Anthony Cochran
Randall Cochran
Lloyd Cockrell
Mike Cody
Merrick Coe
Merle Coffman Jr.
Christopher Cogswell
Dustin Cogswell
Joe Coladipietro
Glenn Colbert
Karen Colbert
John Cole
Justin Colegrove
Bob V. Coleman
Juri Coleman
Justin Collier
Nathan Collins
Rick Collins
Tom Comer
Ron Comes
Amanda Consbruck
Paul Conti
Dave Cook
Jud Cook
Rickey Cook
Dustin Cooper
Chad Corcoran
Jon Corley
Adam Cornell
Jose Corralejo
Benjamin Corso
Agustin Cortes
Marcus Corvino
Keith Cowell
David Cox
Stephen Cox
Josh Craig
Julie Craig
Brandon Cramer
Andrea Crawford
Cory Crawford
Jonathan Creagan
Robbie Crosier
Derik Cross
Michael Cross
Johnathon Crossen
Willard Crossen
Corinne Croucher
Pam Crum
Erasmo Cuellar
Jeremy Cummings
David Cunningham
Dwight Cunningham
Natalie Cunningham
Bryan Curtis
Jimmy Cyrus II
Tiffany Dailey
Durwood Dalton
Jeffery Daniel
Becky Danker
Joe Darnell
Adam Daugherty
Brian Daugherty
Joe Daugherty
Rick Daugherty
Pat Davenport
Orin David
Ben Davidson
Robert Davidson
Andrew Davis
Darryl Davis
Daryl Davis
Dustin Davis
Gary Davis
Joel Davis
John W. Davis
Kerri Davis
Landon Davis
Steven Davis
Tim Davis
William Davis
David Dawson
Brian Dean
Ryan V. Dean
Shane Dean
Eric Decker
Eric Deeter
William DeFoor III
David Dehn Jr.
Bradley Deines
Billie Demott
Gregory Desper
Brian Devaney
Danny Deville
Fnu Dezvita
Valente Diaz
Chase Dickens
Bentley Dill
Jerry Dilley II
Jerry Dilley Sr.
Nicholas Dimauro
Drew Dixon
Lee Dixon
Jeb Dobbs
Amy Dobkin
Brandon Dodgen
Renee Dollar
Chuy Dominguez
Crystal Doty
Marshall Dougherty
Karl Doughty Jr.
Terry Doughty
Irene Dougrey
Anna Dovedan
Dewey Dowdy
Cheryl Dowis
John Dozer Jr.
Michael Drake
William Draper
Greg Duffy
Will Duffy
Bryan Duke
Connie Duke
Robert Duke
Justin Dulaney
Chad Duncan
Cody Duncan
Jim Dunham
Chris Dunton
Jeffery Durham
Cory Durig
Chris Duroy
Chase Dwiggins
Greg Dykes Sr.
Joe Eades
Allison Earl
Shannon Earley
Jacob Eastham
Jeremy Easton
Billy Eastwood
Janelle Eaton
Tammie Ebert
Layna Edd
Joseph Eddy III
Jarrod Edens
Christopher Edge
Michael Edie
Jeremy Edmister
Kelly Edson
Raymond Edwards
Daniel Eidt
Luis Elizondo
John Elkins
John Ellard
Benjamin Elliott
Chad Elliott
Don Elliott
Codey Ellis
Gilbert Ellis
Jim Ellis
James Ellsbury
Brandon Embery
Amanda Embry
Joseph Emerson
Gary Emmert
Tyler Emrich
Colton Ensminger
Thomas Erp
Zacarias Escalante
Christopher Escher
Jevon Escobar
Craig Estes
Keith Eubanks
Don Evans
James Evans
Jason Evener
Guy Ewart
Lyric Ewing
Richard Faries
Ryan Farley
Christopher Farrar
Kameron Farris
Chris Feazell
Zachary Fegley
Jon Fennel
Amy N. Ferguson
Ronnie Ferguson
Tyler Ferguson
Maria Fernandez
Michael Fesmire
Linette Fibiger
Brandin Fields
Casey Fields
Jamie Fields
Kevin Fields
Peggy Fields
Jeremy Findley
Brett Finley
Amanda Finney
Jesse Fisher
John E. Fisher
Mike Fisher
Pete Fisher
Timothy Fisher
Randy Fite
Billy Fitt
William Fitzgerald
Jared Flesher
Ronald Fletcher
Vernon Fletcher Jr.
David Montes Flores
Donald Flores
Michael Flores
Toni Flowers
Kevin Floyd
Dave Fogelman
Robert Foland
William Ford
Tim Fordenbacher
Rhonda Fortuin
Blake Foster
Justin Foster
Chris Fournier
Bobby Fowler
Buddy Fox
John Fox
Sandra Fraley
Joshua Franks
Chris Frazier
LeeAnn Frazier
Billy Freeland
Lynn French
Greg Fritze
Tina Fruge
Tyler Gage
Darren Gagliardi
Wayne Galliher II
Cecil Gamble
Matthew Gammon
Jim Gann
Alfonso Garcia
James Garcia
Joshua Garcie
Kenneth Garland
Greg Garrison
Dan Garwood
Alan Gary
Naomi Garza
Freddie Gates
Lynda Gearheart
Warren Geionety
Nicole Geisinger
Ryan George
Todd George
Mark Geurkink
Bert Gibson
Fred Gibson
Josh D. Gibson
Robert Gifford
Michael Gilbert
Robert Gill
Jennifer Gilliam
Ellen Gilliland
Florence Gills Jr.
James Gilpin
Tim Gilpin
Ned Gipson
Shannon Glancy
Travis Glauser
Michael Gleason
Bradley Glosup
Mitchell Godbey
Karl Goebel
Darrell Goeringer
Devin Golden
Jessie Gonzales
Jose Gonzales
Cirilo Gonzalez
Ernest Gooden
Mark Goodin
Richard Goodrich
Daniel Gorham
Julian Gorman
Ryan Gorman
Shawn Goss
Adam Gossen
Joseph Gottschall
Mike Grady
Ike Graham
Inna Graham
Jamie Granger
Caleb Grantges
Matt Grassmyer
Kristel Graves
Mike Graves
James Gray Jr.
Stanford Gray
Trey Graybill III
Lance Green
Mike Green
Sheri Green
Whit Green
Allan Greenawalt
Dustin Greenway
James Greenwood
Josh Greiner
Jason Griffis
Lambert Grim
Brian Grogg
Brian Grove
Christopher Guajardo
Rich Guenther
Glenda Guerra
Rene Guerra
Angel Guerrero
Isela Guerrero
Brian Gunsaulis
BoJames Gunter
Christopher Gustavus
Paul Gutta
Sarah Hacker
August Hadwiger
Ryan Haffner
David Hagadorn
Paul Hagerty
Keith Haggard
Stephen Haggerty
Greg Hakman
Brian Hale
Brandon Hall
Dustin Hall
Jessie Hall
Renee Hall
Rick Hall
Zach Hall
Clint Hamilton
James Hamilton
William Han
Nick Hancock
Kristi Hanna
Sean Hansen
David Harbin
Daniel Hardy II
Stephen Hardy
Eddie Hare
Justin Hargett
Tubby Hargrove Sr.
Alysia Hargus
Aaron Harper
Adam Harper
Christopher Harper
Gregory Harper
Charles Harris
Jackie Harris
Jerry Harris
Berlin Harrison
Mark R. Harrison
Charles Hart
Kevin Hart
Randal Hart
Larry Hartgrave
Kenneth Harvey
Michael Harvey
Matthew Harville
Leonard Harzinski Jr.
Jon Haskins
Heath Hatcher
Marshall Hatcher
Erin Hathaway
John Hatton
Thomas Haun
Michael Hausvater
Robert Havens Jr.
William Hawkins Jr.
Rick Hawthorne
D.J. Haydon Jr.
Adam Haynes
Kenneth Hays
Allen Head
Garry Headrick
Jennie Heard

Jonathan Hearitige
Greg Heater
Kellie Hefner
Anthony Heggenstaller
Cory Heid
Jeremiah Heidreth
James Henderson
Rob Hendle Jr.
Cory Hendrix
Sandra Hendrix
David Hennessy
David Henry
Earl Henry Jr.
Marcus Henry
Matthew Henry
Phil Hensley
James Henson
Parish Henson
Brandi Hernandez
Jose Hernandez
Raymond Herndon III
Mike Hershberger
Kurt Hibbard
Sean Hibbard
Alyssa Hickey
Sonny Hickman
Carlos Hicks
Danny Hicks
Gary Hicks
Jacala Hicks
Jason Hicks
Michael Hicks
Dean Higganbotham
Duke Hightower
Christopher Hill
William Hillier
James Hilt
Alina Hines
Ashley Hines
Chase Hines
Edgar Hinojos
Kerry Hinsley
Cory Hixson
Mark Hlatky Jr.
Angi Hodge
Steven Hodges
Russell Hogue
Dustin Holben
Brandon Holley
John Hollister
Jolene Holloman
Laura Holmes
Clay Holt
Gene Holt
Kevin Holt
PT Honeycutt
Thomas Hood
Matt Hoops
Wes Hope
Amy Hopmann
Denver Horn II
Jason Horn
Jennifer Horrigan
Sherry Hosey
Lanny Hotaling
Nicolas Hough
Sara Howard
Sherry Howell
Eddie Howen
Matthew Hudman
Morgan Hudson
Stacy Hudson
Daniel Hudspeth
Nathaniel Huggans
Braxton Hughes
Lori Hughes
Hayley Humpert
Jeremy Hunter
Alberto Huron Jr.
Eddie Hurst
Edward Hurst
Kollin Hurt
Kyle Hurt
Lisa Hutcherson
Allen Hutchins
Kevin Hutchins
Jon Hyde
Wesley Hyde
Derek Hyre

Dennis Idlett
Neal Impson
Donnie Ingram
Patrick Innes
Eric Inskeep
Orlando Isaias
Laramie Isley
Steve Iwersen
Robert Izell
Blake Jackson
Brian Jackson
Cody Jackson
Mark Jackson
Shawn Jackson
Stephen Jackson
Hillary Jacobson
Don James
Kenneth James II
Larry James
Lamont Janz
Ryan Jarratt
Calvin Jarrell
Jonathan Jarvis
Robert Jarvis
Victor Jarvis Jr.
Chance Jenkins
David Jennings
Erinn Jennings
Bob Joest
Bradford Johnson
Braydn Johnson
Brian Johnson
Elmer Johnson
Franklin Johnson
Gary W. Johnson
Jimmy Johnson
Kevin Johnson
Larry Johnson
Matt Johnson
Michael M. Johnson
Mykal Johnson
Rich Johnson II
Scott Johnson
Steve M. Johnson
Amy Jones
Bobby Jones
Brady Jones
Cyndi Jones
Dan Jones
Daniel Jones
Emily Jones
Hunter Jones
Jennifer Jones
Jeremy Jones
Joshua Jones
Julie Jones
W. Scott Jones
Whitney Jones
Xavier Jones
John Jordan
Will Jordan
Ed Jozwick
Ron Juratovac
Ronald Justice
Jared Kaley
Alex Karim
Justin Kay
Clint Keating
Cale Keim
Mark Keitz
Lynne M. Keller
Shawn Keller
Chad Kelley
Jordan Kelley
Matthew Kellum
Steven Kelly
Matt Kemper
Josh Kendrick
Greg Kennedy
Matthew Kent
Cheryl Kerr
Jeffery Kesner
John Kiehlmeier
John Kilgallon
Christopher Kimble
Colby King
Gary R. King
Jeremy King
Parker King

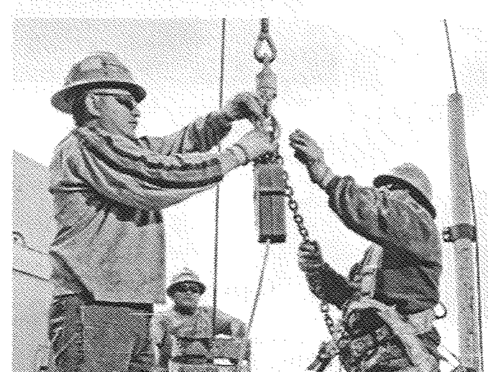
Melissa Kingry
Will Kington
Woody Kinney
Michael Kinsey
Kenny Kipper
Carey Kirby
Beth Kirchner
Wayne Kirk Jr.
Whitney Kirk
Kerry Kirksmith
Heidi Kirsch
John Kitchen
Shayna Kjellsen
Josh Kling
Zackery Knell
Aaron Knight
Chuck Knight
James Knight
John G. Knox
John M. Knox
Todd Kreamer
Travis Kunkle
Isaac Kurtz
John Kurtz
Julia LaBella
Ben Lacy
JV Laffitte
John Lair
Daniel Lamar
Daniel Lancaster
Bobby Landrum Jr.
Mark Landrum II
Kim Landry
David Lane
Richard Lane
Clay Langley
Mike Langley
Jimmie Laningham
Craig Lankford
Claudia LaPlante
Daniel Lara
Corey Lasley
Joe Latham
Brian Layman
Ted Layton
Lucy Lazos
Courtney Leach
Eric Leatherwood
Celeste LeBlanc
Scott Ledbetter
Aaron Lee
Alexa Lee
Christopher Lee
Clayton Lee
Dale Lee
Tot Lee III
Will Lee Jr.
Micah LeGall
Bryan Legg
Marie Leifheit
Wesley Lemens
Cruz Lemus
Jared Leseman
Andy Levine
Mark Levingston
Chad Lewis
Tim Lewis
Sam Liebhart
Frederick Ligons
Eric Lindberg
Jeffrey Lindsey
Lindsay Line
Larry Lines
Andrew Linquist
Rosie Linton
John Little
Michael Little
Robby Little
Michael Livingston
Neil Lloyd
Logan Lobue
Scott Locklear
Casey Logan
Tony Logue
Lyndel Loman
Angie Long
Carson Long
David Long
Diana Long

Eddy Long
Orval Long
Dan C. Lopata
Colby Loper
Andres Lopez
John Lorentz
James Louiso
Owen Love
Joseph Lowery
Steve Lowther
Francisco Lozano
Omar Lozano
Petra Lozano De
Thompson
Bonnie Lucas
Cody J. Lucas
Harvey Lucas Jr.
Derek Lueallen
Tyler Lumpkin
Donald Lundy
Bill Lusk
David Luttrell
Dustin Lynn
Cain Mackenzie
Gerald Mackenzie Jr.
Mathew Mackey
Shad MacNaughton
Ashley Madison
Anthony Maes
Daniel Maffei
Marissa Mahan
Nicolas Mahan
Damon Maikell
Timothy Major
Bob Malecki
Jim Malone Jr.
Dale Manahan
Nathan Manhart
Michael Mann
Sid Manning
Joe Marecic
Adolfo Marin
Rodrigo Marin Ruiz
Rickie Marks Jr.
Aaron Marlow
Stanley Marlow
Pedro Marquez
Michael Mars II
Dusty Marsh
Lester Marsh
Evan Marshall
Tammy Marston
Dan Martin
John Martin Jr.
Michael L. Martin
Rick Martin
Ricky Martin
Shane Martin
Stephen Martin
Joe M. Martinez
Joel Martinez Jr.
Justin Martinez
Rick Martinez
Paul Marton
Graycen Mashburn
Jerry Massey Jr.
Shain Masterson
Efraim Mata
Christopher Matthews
Brandon Mattison
Roger Mattox Jr.
Tamara Mauk
Jess Maulsby
Matt Mayhew
Kevin McBee
Gary McBride
Jesse McCabe
Thomas McCambridge
Stu McCarthy
Brad McCarty
Michael McCarty
Jeff McCathern
Michael McClintic
OG McClinton Jr.
Bill McClure
Glen McConnell
William McConnell
Chad McCool
Brian McCoy

Gregory McCoy
Tierra McCrary
Katie McCullin
Jeremy McCumbers
Crystal McCusker
Calvin McDaniel
Kelly McDaniel
Dave McDiffitt
Bryan McDonald
Mickey McDonald Jr.
Eric McEntyre
David McFall
Christopher W. McGinnis
Mike McGlothlin II
Travis McGloughlin
Gerald McGuire
Richard W. McGuire
Jasen McKay
James McKee
Mike McKee
Nathan McKeehan
Stephanie McLaughlin
Steve McLaughlin
Keegan McManus
Matt McMillan
Nathan McMullen
Janie McNabb
Kyle McNayr
Dan McNickol
Brandon McReynolds
Thomas Measel
Kayla Medina
Robby Mehdi
Fidel Mendoza
Tay Mendoza
Travis Menear
Leah Merciez
Damon Merritt
Matt Meyer
Ryan Meyer
Randal Mick
Travis Miles
Chris Miller
Justin Miller
Ken Miller
Kenneth Miller
Kirby Miller
Marianne Miller
Michael Miller
Mike Miller Sr.
Roger Miller
Sedrick Miller
Tim Miller
Vernon Miller
William Miller
Charles Mills III
Danya Mills
Karen Mills
Jarrod Mink
Richard Minshew
Danelle Minton
Tommy Mitch
Chris Mitchel
Randall Mitchell
Ryan Mixon
James Mode
Darin Molone
Cirilo Mondragon
Corey Montgomery
Robert Montgomery
Glen Moody
Charlene Moore
Cliff Moore
Dakota Moore
Daylan Moore
Delbert Moore Jr.
Densel Moore Jr.
Densel Moore Sr.
Joel Moore
John Moore
Margaret Moore
Philip Moore
Erik Moorman
Jerry Morales
Abel Morales-Macias
Kevin Morehead
Duane Moreland
Armando Moreno
Christopher Morgan

James Morgan
Justin Morgan
Nathan Morgan
Sloane Morgan
Willie Morgan
David Morris
David Morris Jr.
Joseph Morris
Lonza Morris
Sydney Morris
Joshua Morrison
Shannon Mosby
Jason Mosley
James Mossor
Kelley Mowdy
Justin Moxley
Mark Muegge Jr.
Jared Mueller
Stacey Mullenax
Levi Mullins
Lawrence Munsey
Brian Murnahan
Lauren Murphy
Robert Murphy Jr.
Steven Murphy
Christopher Musgrave
Donald Muth
Kathy Myers
Louis Nagel
Mike Narcavage III
Robbi Nartey
Tyrel Naugle
Amy Neal
Gary Neal
Michael Neal
Freddy Neighbors
Rick Neiswonger

Justin Norman
Justin Norris
Adam Norwood
James Novak
Connie Nowell
Selena Nunez
Joseph Nunn
Jared Nutter
Mark OByrne
Daniel Odell
Peter Odima
Dean Ogden
Charles Ohlson
Victor Okeh
John Olesh
James Olive
Michael S. Oliver
Doug Olivier
James Olson Jr.
Blake O'Neill
Brent Opfer
Amanda O'Quinn
Pam Orth
Jason Orwan
Robert Ostrander Jr.
Gregg Oudit
Ashley Overstreet II
Ryan Overton
Stacey Owen
Jesse Owens
Kevin Pack
Meosha Paige
Allen Pair
Cristian Parau
Bill F. Parker
Nicholas Parker
Laura Parrish



SAFETY IN THE FIELD
Pennsylvania Nomac rig 7 employees rig up their safety gear as they do their part to maintain a safe work environment.

Terry Neitzler
Johnathon Nelson
Lisa Nelson
Sky Nelson
Luke Nettrouer
Matthew Neubert
Benjamin Nevill
Colin Newhouse
Marcus Newman
Cheyenne Newsome
O'Ryan Newton
Jessica Nguyen
Chris Nichols
Jonathan Nichols
Luke Nichols
Sean Nichols
Barry Nicholson
Kenneth Nickeson
Cassie Niemann
Jason Nieuwenhuis
Ryan Nix
Winston Noel

Eddie Parsons
Kevin Parsons
Reema Patel
David Patterson II
Kathleen Patton
Ben Paugh
Joseph Paup
Brian Peery
Kathleen Penn
Siva Pennabadi
Bradley Pentecost
James Penzo
Clifford Pepper
James Perkins
Joshua Perkins
Chris Persellin
Catherine Peterson
Renee Peterson
Jay Petree
J R Pettijohn Jr.
Tu Phan
Heather Phelps

A REVVING GOOD PARTNERSHIP Oklahoma

The drilling crew of Nomac rig 42 poses with Paul Teutul, Sr., founder of Orange County Choppers and star of the television series "American Chopper," with whom Chesapeake collaborated to develop the world's first natural gas-powered chopper.

Knut Philippi
Daniel Phillips
Dustin Phillips
Lyn Phillips
Richard Phillips
Alex Pierce
Jayson Pihajlic
Timothy Place
Monte Plummer
John Poarch
Levi Poe
Chris Poirot
Venkat Pokkuluri
Angie Pool
Charles Poole
Dustin Poole
Kerry Poole
Ty Porche
Kenneth Porter
Adia Powell
Dale Powell
Nathan Powell
Natalie Pralle
Erin Pratt
Chad Preston
Jerren Preston
Kyle Preston
James Price
Jeffrey Price
David Pritchard
James Pritchard
Chase Pritchett
Justin Pritchett
Alan Procell
Michael Proctor
Estevan Puente
Kyle Puffinbarger
Michael Pugh
Bob Purgason
Mickle Putnam
Stony Queen
Venicia Queen
Stephanie Quinn
Robert Quintero
Aaron Rachall
Jeff Ragan
Anthony Rahm
Keith Rahm
Michael Raisig
Juan Ramirez Jr.
Tim Ramirez
Timothy Ramsey
Cathy Raney
Jeffrey Rankin
Boyd Ransom
Will Ratcliffe
Gerald Ratliff
Jason Ratliff
Charles Ratts
David Rauh
Christopher Ray
David Ray
Joseph Raybon
Reid Reagan
Burt Reed
Jerry Reel
Roy Reel
Flint Reeve
Damon Reeves
David Reeves
Reagan Register
Andy Reinert
John Repp
Robert Revilla
Brandon Reyes
Leonard Reyez
Udel Reyna
Jimmy Rhodes
John Rhodes
Rory Rice
Patrice Rich
Bobby Richards Jr.
Rene Richards
James Richardson
Joseph Richardson
Luke Richardson
Jackie Riddle Jr.
Dustin Rider
James Riffle III
Rodney Riffle
Richard Riggins
Jonathan Riggle
John Riggs
James Riley
Levi Riojas
Amanda Rios
Freddy Rios
Oscar Riveracano
Cassie Rivers
Sandon Roath
Candace Robert
Michael Robert
Joseph Roberts
Ronald Roberts
Diana Robertson
Randall Robertson
Brian Robinson
Chad Robinson IV
Shae Robinson
Sarah Robinson-Garcia
Kaylan Roby
Woodrow Rodgers Jr.
Michael Rodrigues
Chance Rodriguez
Gustavo Rodriguez
John Rodriguez
Dawayne Roehrick
John Rogers
Kathy Rogers
Mike Rogers
Mark Rohrbough
Robert Rollins
Marc Rome
Domingo Romero-Luna
Jacque Ross
Jessica Ross
Rhonda Ross Sr.
Paige Rowe
Terry Rowe
Harold Rowell
Julie Roy
Chris Royse
Ricky Rucker
Austin Rupard
Rick Rupard
Michael Rupp
Jason Ruppert
Joanna Rus
Ron Rush Jr.
Jackie Rutherford Jr.
Jeffrey Rutherford
Stacy Rutledge
Peter Rutt Jr.
Danny Ryan Jr.
Thom Rychecky
Arnoldo Saenz
Jesus Salinas
Gary Saling
Francis Sallee
Gene Sampson
Zack Samuels
Lucio Sanchez
Chase Sanders
Daniela Sanders
David Sanders
Marc Sanders
Steven J. Sanders
Brad Sandifer
Vincent Sandoval
Kara Sardis
James Saultz
John Saxon Jr.
Harley Scanlon
Gabe Scheer
Matthew Schellhase
Jess Schenk
James Schlarb
Crystal Schmeckenbecher
Jason Schmitz
Eric Schneider
Ashton Schoaps
Robert Schoenfeldt Jr.
Greg Schoffner
Cassie Schoshke
Eli Schrock
Phillip Schroeder
Tony Schroeder
Chris Schuman
Michael Schweighart
Brandon Scoggins
Joshua Sconyers
Brian Scott
Jesse Scott
Kelby Scott
Candace Scudder
Tanner Seal
James Sears
Charles Sechler
Stephen Seibert
John Seifreid III
Josh Sentyz
Brandon Sepulvado
Raquel Shacklett
James Shamblin
Alton Sharp
Jeffery Sharp
Willie Sharp
Dan Sharpe
Shea Shelby
Jason Sheihamer
Tom Sheme Jr.
William Shepardson IV
Justin Shields
Justin Shirey
Sherri Shirley
Rob Shores
Jesse Short
Troy Short II
Tim Shue
James Shull
Lynette Shults
Clayton Shumway
Anthony Shuster
Darren Silcott
Andrew Silvestri
Jason Simpson
Nicholas Sims
Greg Singleton
Robert Sisca
Jonathan Sisk
Buddy Sissom Jr.
Pat Skinner
Randy Skinner
Kristy Skiro
Reggie Sloan
Timothy Slone
David Smarkusky
Anthony Smith
Brian Smith
Bryan L. Smith
Cody Smith
J.D. Smith
Jarrett Smith
Jeffrey Smith
Jerry W. Smith
John D. Smith
Josh Smith
Joshua Smith
Katherine Smith
Matthew Smith
Michael G. Smith
Michael W. Smith
Mike R. Smith
Mike Smith
Ricky J. Smith
Ricky L. Smith
Shawn Smith
Will Smith
Amy Snedeker
Casey Snow
Cory Snyder
Kendel Snyder
Richard Snyder
Stephen Socha
Jason Sonnema
Frank Sopher
Danielle Southall
Lawerance Southerland
Bobby Sparkman Jr.
Jack Sparks Jr.
Rick Sparks
Gary Spencer II
Levi Spencer
Rick Spicer
Dave Spigelmyer
Shelly Spitznogle
Shane Spradlin
Justin Spruell
Curtis Spruill
Loni Staats
Stan Stacy Jr.
Timothy Stamper
Ryan Stamps
Randall Stancil
Richard Standage
Amy Stanley
Harold Starr
Hancel Steen
Michael Stephens
Daniel Steppe
Teena Sterling
Billy Stevens Jr.
Jeremiah Stevens
Eric Stewart
Jeffrey Stewart
Joshua Stiles
Mike Stivers
Heath Stockton
Dillon Storer
Kim Stovall
Eugene Stradley
Sean Strange
Elizabeth Strawn
Tyler Sturm
Frank Sullivan
Jake Swanson
Sherrie Swift
Tamara Szczerbacki
Jimmie Tabor Jr.
Steven Talada
David Talley
Kevin Tapia
Steven Tatro
Jonathan Tatum
Ryan Tatum
Amanda Taylor
B. Kyle Taylor
Barbara Taylor
Brad Taylor
Chad Taylor
Chaya Taylor
Darrell Taylor
Dennis Taylor II
Dudley Taylor II
Jason Taylor
Jeremy Taylor
John Taylor
Simone Taylor
Jessica Tedder
Jeffrey Tedesco Jr.
Wossen Tefera
David Templet
Amy Tennison
Erin Tewell
Cody Theimer
Colby Therwhanger
Ashley Thomas
Dennis Thomas
Ray Thomas
Taylor Thomas
Tommy Thomas
Bruce Thompson
Cole Thompson
Jeff Thompson
Justin Thompson
Kristi Thompson
Schon Thorne
Cody Thornton
Rene' Thurman
James Tillman
Joseph Tingler
Matt Tinkle
Taylor Tisdal
Gregory Tomlinson
Philp Tomlinson
Justin Toney
Jeffrey Toot
Alfredo Torres
Donald Torres Jr.
Rogelio Torres
Richard Trachta
Virgil Trammel
Richard Trammell
Donie Treadaway
Joshua Tredway
Tyler Treece
Alejandro Trejo
Marsela Treska
Joshua Triplett
Addie Triska
Cody Trisler
Cole Troup
Scott Troutman
Michael Tucker
Randy Tullos
Bronson Turley
Michael Turner
Jesse Tuthill
Jackie Tuttle II
Nick Tyler
Jack Tyre
Don Tyson
Christopher Underwood
Russell Vadas
Kie Vander Sys
Keith Vanliew
Stephanie Vann
Mark Vannasdall
Phillip Vanover
Roger VanRyn III
Fabio Vargas
Joseph Vargas
Andrew Vargeson
Todd Varner II
Stephanie Vaughan
Peyton Vaughn
Chris Veazey
Marcelo Vera
Raymond Verhoeven
Kate Via
Rick Vickers
Danny Vickery
Derek Viljoen
Darren Vincent
Michael Vincent
Travis Vinsek
Billy Vo
Gregory Vogel
Ben Voigt
Matthew Volner
Casey Voss
JT Voth
Alyssa Vowell
Robert Waggoner
Walter Waite
Jason Waldenville
Connie Waldrop
Audie Walker
Christopher Walker
Doyle Walker
James Walker
Patrick Walker
Bill Walko
Billy Wallace
Brandon Wallace
Jason Wallace
Joshua Wallace
Kristin Wallace
Michael Wallace
Karen Walters
Scotty Walton
Tony Ward
Craig Warren
Joseph Warren
Larry Warren
Michael Warren
Tanya Wartchow
Earl Waterbury
Robert Wates
Jerry Watkins
Rocky Watkins Jr.
Brent Watson
Stephen Watts
Rusty Webb
Vance Webster II
Blake Wedel
Darren Weed
Charles Wegman
Cutter Weiand
Jared Weingartner
Jason Weingartner
Dennis Welch
Ralph Welch Jr.
EuJene Wellborn
Derek Wells
Sean Wells
Damon West
David West
Lee West
Tommy White
Zach White
Jimmy Whitehead
Daniel Whiteman
Gary Whitis
Taylor Whitis
Cole Whitman
Emily Whitney
Tyler Whitsett
Earston Whyel
Jeremy Wiedenmann
James Wiggins
Michael Wiggins
Opie Wigginton
Todd Wilfong
Jesse Wilkinson
Dustin Willbanks
Ralph Willett Jr.
Aaron Williams
Amy Williams
Clifford Williams II
Hoyt Williams
Jeff Williams
Jordan Williams
Joseph Williams
Kevin Williams
Larry Williams
Lisa Williams
Monte Williams Jr.
Stephanie Williams
Ty Williams
Josh Williamson
Doug Willits
Kendra Wilmeth
Alan Wilson
Colton Wilson
Jaime Wilson
Kory Wilson
Preston Wilson
Christopher Wilt
Byron Windham
Bernard Winn
William Winstead
Brandon Winters
Co Wisdom
Travis Wishon
Ari Wolever
Andrew Wolfe
Ronald Wolfe
Kenneth Wood
Jana Woodard
Luke Woodard
Robbie Woodard
Sterling Woodard
JR Woodfin
Joshua Woods
Katie Wooten
Larry Wooten
Andrew Work
Rick Worley
Brandon Wright
Brian Wright
John Wright
Mike W. Wright
Sammy Wyatt
Dwayne Wylie
Steve Wyman
Larry Yawn
Amanda Yeager
James Young
Jason Young
Randy Young
Brett Yourish
Art Ysaguirre Jr.
Sam Yule
Doug Yurek
Mark Zabala
Gregory Zacharias
Megan Zachary
Matthew Zeman
John Zimmerman Jr.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☒ **Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the Fiscal Year Ended December 31, 2009

☐ **Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period from _____ to _____

Commission File No. 1-13726

Chesapeake Energy Corporation
(Exact name of registrant as specified in its charter)

Oklahoma	**73-1395733**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
6100 North Western Avenue	
Oklahoma City, Oklahoma	**73118**
(Address of principal executive offices)	(Zip Code)

(405) 848-8000

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01	New York Stock Exchange
7.5% Senior Notes due 2013	New York Stock Exchange
7.625% Senior Notes due 2013	New York Stock Exchange
7.0% Senior Notes due 2014	New York Stock Exchange
7.5% Senior Notes due 2014	New York Stock Exchange
6.375% Senior Notes due 2015	New York Stock Exchange
9.5% Senior Notes due 2015	New York Stock Exchange
6.625% Senior Notes due 2016	New York Stock Exchange
6.875% Senior Notes due 2016	New York Stock Exchange
6.5% Senior Notes due 2017	New York Stock Exchange
6.25% Senior Notes due 2018	New York Stock Exchange
7.25% Senior Notes due 2018	New York Stock Exchange
6.875% Senior Notes due 2020	New York Stock Exchange
2.75% Contingent Convertible Senior Notes due 2035	New York Stock Exchange
2.5% Contingent Convertible Senior Notes due 2037	New York Stock Exchange
2.25% Contingent Convertible Senior Notes due 2038	New York Stock Exchange
4.5% Cumulative Convertible Preferred Stock	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ☒ NO ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. YES ☐ NO ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES ☒ NO ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES ☒ NO ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer ☒ Accelerated Filer ☐ Non-accelerated Filer ☐
Smaller Reporting Company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES ☐ NO ☒

The aggregate market value of our common stock held by non-affiliates on June 30, 2009 was approximately $12.5 billion. At February 24, 2010, there were 651,861,064 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2010 Annual Meeting of Shareholders are incorporated by reference in Part III.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
2009 ANNUAL REPORT ON FORM 10-K
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Part I

ITEM 1. *Business*

General

We are the second-largest producer of natural gas in the United States. We own interests in approximately 44,100 producing natural gas and oil wells that are currently producing approximately 2.4 billion cubic feet equivalent, or bcfe, per day, 93% of which is natural gas. Our strategy is focused on discovering, acquiring and developing conventional and unconventional natural gas reserves onshore in the U.S., primarily in our "Big 6" natural gas shale plays: the Barnett Shale in the Fort Worth Basin of north-central Texas, the Haynesville and Bossier Shales in the Ark-La-Tex area of northwestern Louisiana and East Texas, the Fayetteville Shale in the Arkoma Basin of central Arkansas, the Marcellus Shale in the northern Appalachian Basin of West Virginia, Pennsylvania and New York and the Eagle Ford Shale in South Texas. We also have substantial operations in the Granite Wash Plays of western Oklahoma and the Texas Panhandle regions as well as various other plays, both conventional and unconventional, in the Mid-Continent, Appalachian Basin, Permian Basin, Delaware Basin, South Texas, Texas Gulf Coast and Ark-La-Tex regions of the U.S.

We have been developing expertise in horizontal drilling technology since shortly after our inception in 1989 and have focused almost exclusively on developing natural gas properties in the U.S. since 2000. We were one of the first companies to recognize the potential of unconventional natural gas properties, especially shales, in the U.S. during the early part of the prior decade. During the past five years, we have grown from the eighth-largest natural gas producer in the U.S. to the second-largest natural gas producer, in large part as a result of our success in finding and developing unconventional natural gas assets. We have recently announced that we are extending our strategy to apply the horizontal drilling expertise we have gained in our natural gas shale plays to unconventional oil reservoirs. We expect to begin increasing our production of oil and natural gas liquids in 2010 in new developing unconventional oil plays, particularly in the Granite Wash and Eagle Ford.

During 2009, our estimated proved reserves grew from 12.051 trillion cubic feet equivalent, or tcfe, to 14.254 tcfe, of which 95% were natural gas, 58% were proved developed and 100% were onshore in the U.S. We replaced our 906 bcfe of production with an estimated 3.109 tcfe of new proved reserves for a reserve replacement rate of 343%. Reserve replacement through the drillbit was 3.296 tcfe, or 364% of production, including 445 bcfe of downward revisions resulting from changes to previous estimates and 952 bcfe of downward revisions resulting from lower natural gas prices using the average 12-month price in 2009 compared to the spot price as of December 31, 2008. During 2009, we acquired 33 bcfe of estimated proved reserves and divested 220 bcfe of estimated proved reserves.

Chesapeake continued the industry's most active drilling program in 2009 and drilled 1,212 gross operated wells (885 net) and participated in another 994 gross wells operated by other companies (118 net). The company's drilling success rate was 99% for company-operated wells and 98% for non-operated wells. Also during 2009, we invested $2.941 billion in operated wells (using an average of 104 operated rigs) and $439 million in non-operated wells (using an average of 60 non-operated rigs) for total drilling, completing and equipping costs of $3.380 billion.

During the second half of 2008 and in early 2010, we entered into joint venture arrangements that monetized a portion of our investment in five of our shale plays and provided drilling cost carries for our retained interest. The following table provides information about our joint ventures ($ in millions):

Shale Play	Joint Venture Partner[(a)]	Joint Venture Date	Proceeds Received at Closing	Total Drilling Carries	Drilling Carries Remaining
Haynesville and Bossier	PXP	July 2008	$ 1,650	$ 1,508[(b)]	$ —
Fayetteville	BP	September 2008	1,100	800	—
Marcellus	STO	November 2008	1,250	2,125	1,963[(c)]
Barnett	TOT	January 2010	800	1,450	1,450[(d)]
			$ 4,800	$ 5,883	$ 3,413

(a) Joint venture partners include Plains Exploration & Production Company (PXP), BP America (BP), Statoil (STO) and Total S.A. (TOT).

(b) In September of 2009, PXP accelerated the payment of its remaining joint venture carries in exchange for an approximate 12% reduction to the total amount of drilling carry obligations due to Chesapeake.

(c) As of December 31, 2009

(d) As of January 26, 2010

Collectively, in these four joint ventures, we received upfront cash payments of $4.8 billion and future drilling cost carries of up to $5.9 billion for total consideration of up to $10.7 billion against a cost basis of approximately $2.7 billion in the property interests we sold. Moreover, Chesapeake retained an 80% interest in the Haynesville and Bossier Shale properties, a 75% interest in the Fayetteville Shale properties, a 67.5% interest in the Marcellus Shale properties and a 75% interest in the Barnett Shale properties.

In September 2009, we formed a joint venture with Global Infrastructure Partners (GIP), a New York-based private equity fund, to own and operate natural gas midstream assets. As part of the transaction, we contributed substantially all of our midstream assets in the Barnett Shale and also the majority of our non-shale midstream assets in the Arkoma, Anadarko, Delaware and Permian Basins to a new entity, Chesapeake Midstream Partners, L.L.C. (CMP), and GIP purchased a 50% interest in CMP for $588 million in cash.

Our principal executive offices are located at 6100 North Western Avenue, Oklahoma City, Oklahoma 73118 and our main telephone number at that location is (405) 848-8000. We make available free of charge on our website at *www.chk.com* our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. From time to time, we also post announcements, updates and investor information on our website in addition to copies of all recent press releases. References to “us”, “we” and “our” in this report refer to Chesapeake Energy Corporation together with its subsidiaries.

Business Strategy

Since our inception in 1989, Chesapeake's goal has been to create value for investors by building one of the largest onshore natural gas resource bases in the United States. For the past twelve years, our strategy to accomplish this goal has been to focus on developing unconventional plays onshore in the U.S., where we believe we can generate the most attractive risk-adjusted returns. In building our industry-leading natural gas resource base during the period from 1998 to 2009, we integrated an aggressive and technologically-advanced drilling program with an active property consolidation program focused on small to medium-sized corporate and property acquisitions. During the past three years, we have shifted our strategy from drilling inventory capture to drilling inventory conversion and monetization. In doing so, we have de-emphasized acquisitions of proved properties, further emphasizing our industry-leading drilling program to convert our substantial backlog of drilling opportunities into proved developed producing reserves through the drillbit and also focused on capturing value by selling a portion of our leasehold and producing properties. Key elements of this business strategy are further explained below.

Grow Through the Drillbit. We believe that our most distinctive characteristic is our commitment and ability to grow production and reserves organically through the drillbit. We are currently utilizing 118 operated drilling rigs and 70 non-operated drilling rigs to conduct the most active drilling program in the U.S. We are active in most of the unconventional plays in the U.S., where we drill more horizontal wells than any other company in the industry. For several years, we have been actively investing in leasehold, 3-D seismic information and human capital to take full advantage of our capacity to grow through the drillbit. We are one of the few large-cap independent natural gas and oil companies that have been able to consistently increase production, which we have successfully achieved for the past 20 consecutive years. We believe the key elements of the success and scale of our drilling programs have been our recognition earlier than most of our competitors that new horizontal drilling and completion techniques would enable development of previously uneconomic natural gas and oil reservoirs and that, as a consequence, various shale formations could be recognized and developed as potentially prolific natural gas and oil reservoirs rather than just as source rocks for conventional reservoirs. In response to our early recognition of these trends, we have proactively hired thousands of new employees and have built the nation's largest onshore leasehold and 3-D seismic inventories. These stand as the building blocks of our successful large-scale drilling program and the foundation of value creation for our company.

Control Substantial Land and Drilling Location Inventories. After we identified the trends discussed above, we initiated a plan to build and maintain the largest inventory of onshore drilling opportunities in the U.S. Recognizing that better horizontal drilling and completion technologies when applied to various new shale plays would likely create a unique opportunity to capture decades worth of drilling opportunities, we embarked on a very aggressive lease acquisition program which we have referred to as the "land rush". We believed that the winner of the land rush would enjoy a distinctive competitive advantage for decades to come as other companies would be locked out of the best new shale plays in the U.S. We believe that we have executed our land acquisition strategy with particular distinction. At December 31, 2009, we owned approximately 13.2 million net acres of leasehold in the U.S. and have identified approximately 35,750 drilling opportunities on this leasehold. We believe this deep backlog of drilling, more than ten years worth at current drilling levels, provides unusual confidence and transparency into our future growth capabilities.

Develop Proprietary Technological Advantages. In addition to our industry-leading leasehold position, we have developed a number of proprietary technological advantages. First, we have acquired what we believe is the nation's largest inventory of three-dimensional (3-D) seismic information. Possessing this 3-D seismic data enables us to image reservoirs of natural gas that might otherwise remain undiscovered and to drill our horizontal wells more accurately inside the targeted shale formation and avoid various underground geohazards such as faults and karsts. In addition, we have developed an industry-leading information-gathering program that gives us insight into new plays and competitor activity. As a result of our initiatives, we now produce approximately 4% of the nation's natural gas, drill approximately 12% of its wells and participate in almost an equal number of wells drilled by others. By gathering this information on a real-time basis, then quickly assimilating and analyzing the information, we are able to react quickly to opportunities that are created through our drilling program and those of our competitors. Furthermore, we have established a unique state-of-the-art Reservoir Technology Center (RTC) in Oklahoma City. The RTC enables us to more quickly, accurately and confidentially analyze core data from shale wells on a proprietary basis and then identify new plays and leasing opportunities ahead of our competition to improve existing plays. It also allows us to design fracture stimulation procedures that might work most productively in the shale formations that we target. We believe the RTC provides a very substantial competitive advantage in developing new shale plays and improving existing shale plays.

Build Regional Scale. We believe one of the keys to success in the natural gas exploration industry is to build significant operating scale in a limited number of operating areas that share many similar geological and operational characteristics. Achieving such scale provides many benefits, including superior geoscientific and engineering information, higher per unit revenues, lower per unit operating costs, greater rates of drilling success, higher returns from more easily integrated acquisitions and higher returns on drilling investments. By focusing most of our future activities in the Big 6 shale plays and the Granite Wash plays, we will continue to achieve even greater regional scale in North Texas for the Barnett, northwestern Louisiana and East Texas for the Haynesville and the Bossier, central Arkansas for the Fayetteville, northeastern and southwestern Pennsylvania and northwestern West Virginia for the Marcellus, South Texas for the Eagle Ford and western Oklahoma and the Texas Panhandle for the Granite Wash.

Focus on Low Costs. By minimizing lease operating costs and general and administrative expenses through focused activities, vertical integration and increased scale, we have been able to deliver attractive profit margins and financial returns through all phases of the commodity price cycle. We believe our low cost structure is the result of management's effective cost-control programs, a high-quality asset base, extensive and competitive services and natural gas processing and transportation infrastructures that exist in our key operating areas. In addition, to control costs and service provider quality, we have made significant investments in our drilling rig and trucking service operations and in our midstream gathering and compression operations that create substantial benefits from vertical integration. As of December 31, 2009, we operated approximately 25,150 of our 44,100 wells, which delivered approximately 80% of our daily production volume. This large percentage of operated properties provides us with a high degree of operational flexibility and cost control.

Mitigate Natural Gas and Oil Price Risk. We have used and intend to continue using hedging programs to mitigate the risks inherent in developing and producing natural gas and oil reserves, commodities that are often characterized by significant price volatility. If this price volatility continues in the years ahead, we intend to use this volatility to our benefit by taking advantage of prices when they reach levels that management believes are either unsustainable for the long-term or provide unusually high rates of return on our invested capital. As of February 17, 2010, we have natural gas and oil swaps and collars in place covering approximately 60% of our expected production in 2010 at average prices of $8.16 per mcfe, thereby providing price certainty for a substantial portion of our future cash flow.

Form Unique Joint Venture Arrangements. In the second half of 2008 and early 2010, the company entered into four joint venture arrangements covering five of the company's Big 6 shale plays. In the joint ventures, the company has collaborated with other leading energy companies to accelerate the development of the company's properties in the Haynesville and Bossier Shales, the Fayetteville Shale, the Marcellus Shale and the Barnett Shale. To date, we have sold leasehold and producing property assets in which we had a cost basis of approximately $2.7 billion to these four joint venture partners for total cash consideration of $4.8 billion and up to $5.9 billion of future drilling cost carries while we retained a majority interest in each joint venture. The drilling cost carries of approximately $2.0 billion that remained unused as of December 31, 2009 and the additional $1.45 billion in the Barnett Shale will be extremely valuable in the years ahead by enabling the company to develop reserves in these joint venture shale plays at greatly reduced costs. We are also considering opportunities for other joint venture transactions to develop our properties. Our 50/50 joint venture with Global Infrastructure Partners in September 2009 is another example of us joining with a strong partner to develop key assets, in this case, our midstream assets in the Barnett Shale and other midstream assets in the Mid-Continent. Upon the closing of this transaction, we received proceeds of $588 million.

Maintain an Entrepreneurial Culture. Chesapeake was formed in 1989 with an initial capitalization of $50,000 and fewer than ten employees. We completed our initial public offering of common stock in early 1993 and subsequent to those early corporate milestones, our management team has guided the company through various operational and industry challenges and extremes of natural gas and oil prices to create the second-largest independent producer of natural gas in the U.S. with approximately 8,200 employees currently. The company takes pride in its innovative and aggressive implementation of its business strategy and strives to be as entrepreneurial today as it has been in its past. We have maintained an unusually flat organizational structure as we have grown to help ensure that important information travels rapidly through the company and decisions are made and implemented quickly.

Improve our Balance Sheet. Among our large-cap peers in the natural gas exploration and production industry, we are the only company without an investment grade credit rating. We believe this is a competitive disadvantage and we intend to address this issue in the years ahead by reducing our debt and by growing our asset base such that by year-end 2011, our long-term debt divided by our estimated proved reserves results in long-term debt per mcfe that is less than $0.60 per mcfe compared to $0.84 per mcfe at year-end 2009. We believe the reduction in our debt will lower our borrowing costs, reduce concerns about our ability to access capital markets if such access were needed, increase our financial flexibility, improve our hedging capabilities and increase our stock market valuation.

Outlook

We believe that demand for natural gas will increase in the U.S. and around the world because of its favorable environmental characteristics and its great abundance. This outlook is gathering more national attention when compared to oil, which is likely to return to being in increasingly short supply once the current worldwide economic slowdown is over, and to coal, which has many unfavorable environmental characteristics. Chesapeake's strategy for 2010 is to continue developing our natural gas assets, especially in our Big 6 Shale plays, in which we anticipate investing approximately 75% of our drilling capital in 2010, through exploratory and developmental drilling. In addition, we are taking steps to increase our production of oil and natural gas liquids in 2010 in new unconventional plays such as the Granite Wash and Eagle Ford. We project that our 2010 production will be between 975 bcfe and 995 bcfe, an 8% to 10% increase over 2009 production. We have budgeted $3.3 billion for drilling capital expenditures, net leasehold and producing property transactions, seismic and other property, plant and equipment capital expenditures, which we expect to fund with operating cash flow based on our current assumptions in our 2010 financial plan. Our budget is frequently adjusted based on changes in natural gas and oil prices, drilling results, drilling costs and other factors.

Operating Areas

Chesapeake focuses its natural gas exploration, development and acquisition efforts in the eight operating areas described below.

Barnett Shale. Chesapeake's Barnett Shale proved reserves represented 3.434 tcfe, or 24%, of our total proved reserves as of December 31, 2009. During 2009, the Barnett Shale assets produced 238 bcfe, or 26%, of our total production, and we invested approximately $1.197 billion to drill 417 (339 net) wells in the Barnett Shale. For 2010, we anticipate spending approximately $480 million, or 11% of our total budget, for exploration and development activities, net of carries, in the Barnett Shale. Total, our joint venture partner in the Barnett Shale, will pay 60% of our drilling, completion and equipping costs in the play over the next few years. Of the total $1.45 billion drilling cost carry, we expect approximately $500 million will be applied in 2010.

Fayetteville Shale. Chesapeake's Fayetteville Shale proved reserves represented 2.167 tcfe, or 15%, of our total proved reserves as of December 31, 2009. During 2009, the Fayetteville Shale assets produced 91 bcfe, or 10%, of our total production, and we invested approximately $179 million to drill 774 (209 net) wells in the Fayetteville Shale. BP, our joint venture partner in the Fayetteville Shale, paid $601 million in carries of our drilling, completion and equipping costs on these wells in 2009. For 2010, we anticipate spending approximately $450 million, or 11% of our total budget, for exploration and development activities in the Fayetteville Shale.

Haynesville Shale (including the Bossier Shale). Chesapeake's Haynesville Shale proved reserves represented 1.834 tcfe, or 13%, of our total proved reserves as of December 31, 2009. During 2009, the Haynesville Shale assets produced 85 bcfe, or 10%, of our total production, and we invested approximately $744 million to drill 337 (163 net) wells in the Haynesville Shale. Our joint venture partner in the Haynesville Shale, PXP, paid $390 million in carries of our drilling, completion and equipping costs on these wells in 2009 along with the $1.1 billion in September 2009 as a result of the amendment to the joint venture agreement. For 2010, we anticipate spending approximately $1.785 billion, or 42% of our total budget, for exploration and development activities in the Haynesville Shale.

Marcellus Shale. Chesapeake's Marcellus Shale proved reserves represented 259 bcfe, or 2%, of our total proved reserves as of December 31, 2009. During 2009, the Marcellus Shale assets produced 15 bcfe, or 2%, of our total production, and we invested approximately $145 million to drill 149 (74 net) wells in the Marcellus Shale. Our joint venture partner in the Marcellus Shale, Statoil, paid $162 million in carries of our drilling, completion and equipping costs on these wells in 2009. For 2010, we anticipate spending approximately $360 million, or 8% of our total budget, for exploration and development activities, net of carries, in the Marcellus Shale. Statoil will pay 75% of our drilling, completion and equipping costs in the play over the next few years. Of the total $1.963 billion drilling cost carry remaining at December 31, 2009, we expect approximately $600 million will be applied in 2010.

Mid-Continent. Chesapeake's Mid-Continent proved reserves of 4.098 tcfe represented 29% of our total proved reserves as of December 31, 2009. During 2009, this area produced 305 bcfe, or 34%, of our 2009 production, and we invested approximately $712 million to drill 386 (144 net) wells in the Mid-Continent. For 2010, we anticipate spending approximately $800 million, or 19% of our total budget, for exploration and development activities in the Mid-Continent region, with an increased focus on the Granite Wash and other horizontal oil and liquids-rich unconventional plays.

Permian and Delaware Basins. Chesapeake's Permian and Delaware Basin proved reserves represented 741 bcfe, or 5%, of our total proved reserves as of December 31, 2009. During 2009, the Permian assets produced 75 bcfe, or 8%, of our total production, and we invested approximately $322 million to drill 93 (42 net) wells in the Permian and Delaware Basins. For 2010, we anticipate spending approximately $175 million, or 4% of our total budget, for exploration and development activities in the Permian and Delaware Basins, with an increased focus on various horizontal oil and liquids-rich unconventional plays.

South Texas/Gulf Coast/Ark-La-Tex (including the Eagle Ford Shale). The proved reserves of our South Texas/Texas Gulf Coast/Ark-La-Tex regions represented 565 bcfe, or 4%, of our total proved reserves as of December 31, 2009. During 2009, these assets produced 67 bcfe, or 7%, of our total production, and we invested approximately $197 million to drill 41 (25 net) wells in the South Texas/ Texas Gulf Coast/Ark-La-Tex regions. For 2010, we anticipate spending approximately $200 million, or 5% of our total budget, for exploration and development activities in the South Texas/Texas Gulf Coast/Ark-La-Tex regions, especially in the Eagle Ford Shale of South Texas.

Appalachian Basin (excluding the Marcellus Shale). Chesapeake's Appalachian Basin proved reserves represented 1.156 tcfe, or 8%, of our total proved reserves as of December 31, 2009. During

2009, the Appalachian assets produced 30 bcfe, or 3%, of our total production, and we invested approximately $44 million to drill 9 (7 net) wells in the Appalachian Basin. For 2010, we do not anticipate spending capital for exploration and development activities in the Appalachian Basin, except for our Marcellus Shale activities.

Well Data

At December 31, 2009, we had interests in approximately 44,100 (22,900 net) productive wells, including properties in which we held an overriding royalty interest, of which 36,950 (20,700 net) were classified as primarily natural gas productive wells and 7,150 (2,200 net) were classified as primarily oil productive wells. Chesapeake operates approximately 25,150 of its 44,100 productive wells. During 2009, we drilled 1,212 (885 net) wells and participated in another 994 (118 net) wells operated by other companies. We operate approximately 80% of our current daily production volumes.

Drilling Activity

The following table sets forth the wells we drilled or participated in during the periods indicated. In the table, "gross" refers to the total wells in which we had a working interest and "net" refers to gross wells multiplied by our working interest.

	2009				2008				2007			
	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent
Development:												
Productive	1,971	98%	875	99%	3,479	99%	1,650	99%	3,439	98%	1,792	99%
Dry	33	2	8	1	40	1	13	1	53	2	10	1
Total	2,004	100%	883	100%	3,519	100%	1,663	100%	3,492	100%	1,802	100%
Exploratory:												
Productive	196	97%	115	96%	142	90%	63	90%	177	99%	116	99%
Dry	6	3	5	4	15	10	7	10	2	1	1	1
Total	202	100%	120	100%	157	100%	70	100%	179	100%	117	100%

The following table shows the wells we drilled or participated in by area:

	2009		2008		2007	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Big 6 Shales:						
Barnett Shale	417	339	776	600	512	410
Fayetteville Shale	774	209	814	220	464	131
Haynesville Shale	337	163	81	42	121	77
Marcellus Shale	149	74	32	23	—	—
Bossier Shale	—	—	—	—	—	—
Eagle Ford Shale	—	—	—	—	—	—
Other:						
Mid-Continent	386	144	1,515	542	1,662	654
Permian and Delaware Basins	93	42	165	95	253	107
South Texas/Gulf Coast/Ark-La-Tex	41	25	164	97	228	167
Appalachian Basin	9	7	129	114	431	373
Total	2,206	1,003	3,676	1,733	3,671	1,919

At December 31, 2009, we had 153 (63 net) wells in process.

Production, Sales, Prices and Expenses

The following table sets forth information regarding the production volumes, natural gas and oil sales, average sales prices received, other operating income and expenses for the periods indicated:

	Years Ended December 31,		
	2009	2008	2007
Net Production:			
Natural gas (bcf)	834.8	775.4	655.0
Oil (mmbbl)	11.8	11.2	9.9
Natural gas equivalent (bcfe)	905.5	842.7	714.3
Natural Gas and Oil Sales ($ in millions):			
Natural gas sales	$ 2,635	$ 6,003	$ 4,117
Natural gas derivatives – realized gains (losses)	2,313	267	1,214
Natural gas derivatives – unrealized gains (losses)	(492)	521	(139)
Total natural gas sales	4,456	6,791	5,192
Oil sales	656	1,066	678
Oil derivatives – realized gains (losses)	33	(275)	(11)
Oil derivatives – unrealized gains (losses)	(96)	276	(235)
Total oil sales	593	1,067	432
Total natural gas and oil sales	$ 5,049	$ 7,858	$ 5,624
Average Sales Price (excluding gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 3.16	$ 7.74	$ 6.29
Oil ($ per bbl)	$ 55.60	$ 95.04	$ 68.64
Natural gas equivalent ($ per mcfe)	$ 3.63	$ 8.39	$ 6.71
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 5.93	$ 8.09	$ 8.14
Oil ($ per bbl)	$ 58.38	$ 70.48	$ 67.50
Natural gas equivalent ($ per mcfe)	$ 6.22	$ 8.38	$ 8.40
Other Operating Income ($ per mcfe):			
Marketing, gathering and compression net margin	$ 0.16	$ 0.11	$ 0.10
Service operations net margin	$ 0.01	$ 0.04	$ 0.06
Expenses ($ per mcfe):			
Production expenses	$ 0.97	$ 1.05	$ 0.90
Production taxes	$ 0.12	$ 0.34	$ 0.30
General and administrative expenses	$ 0.38	$ 0.45	$ 0.34
Natural gas and oil depreciation, depletion and amortization	$ 1.51	$ 2.34	$ 2.57
Depreciation and amortization of other assets[b]	$ 0.27	$ 0.21	$ 0.21
Interest expense[a][b]	$ 0.22	$ 0.22	$ 0.50

(a) Includes the effects of realized (gains) or losses from interest rate derivatives, but excludes the effects of unrealized (gains) or losses and is net of amounts capitalized.

(b) Adjusted for the retrospective application of accounting guidance for debt with conversion and other options.

Natural Gas and Oil Reserves

The tables below set forth information as of December 31, 2009 with respect to our estimated proved reserves, the associated estimated future net revenue and present value (discounted at an annual rate of 10%), of estimated future net revenue before and after future income taxes (standardized measure) at such date. Neither the pre-tax present value of estimated future net revenue nor the after-tax standardized measure is intended to represent the current market value of the estimated natural gas and oil reserves we own. All of our estimated natural gas and oil reserves are located within the United States.

	December 31, 2009		
	Natural Gas (bcf)	Oil (mmbbl)	Total (bcfe)[(a)]
Proved developed	7,859	78.8	8,331
Proved undeveloped	5,651	45.2	5,923
Total proved	13,510	124.0	14,254

	Proved Developed	Proved Undeveloped	Total Proved
		($ in millions)	
Estimated future net revenue[(b)]	$ 16,537	$ 7,284	$ 23,821
Present value of estimated future net revenue[(b)]	$ 8,317	$ 1,132	$ 9,449
Standardized measure[(b)(c)]			$ 8,203

	Natural Gas (bcf)	Oil (mmbbl)	Natural Gas Equivalent (bcfe)[(a)]	Percent of Proved Reserves	Present Value ($ in millions)
Big 6 Shales:					
Barnett Shale	3,433	0.2	3,434	24%	$ 1,502
Fayetteville Shale	2,167	—	2,167	15	1,060
Haynesville Shale	1,834	—	1,834	13	703
Marcellus Shale	259	—	259	2	331
Bossier Shale	—	—	—	—	—
Eagle Ford Shale	—	—	—	—	—
Other:					
Mid-Continent	3,646	75.4	4,098	29	4,280
Permian and Delaware Basins	482	43.2	741	5	850
South Texas/Gulf Coast/Ark-La-Tex	540	4.1	565	4	431
Appalachian Basin	1,149	1.1	1,156	8	292
Total	13,510	124.0	14,254	100%	$ 9,449[(b)]

(a) Natural gas equivalent based on six mcf of natural gas to one barrel of oil.

(b) Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs under existing economic conditions at December 31, 2009. For the purpose of determining "prices", we used the unweighted arithmetical average of the prices on the first day of each month within the 12-month period ended December 31, 2009. The prices used in our external and internal reserve reports were $3.87 per mcf of natural gas and $61.14 per barrel of oil, before price differential adjustments. These prices should not be interpreted as a prediction of future prices, nor do they reflect the value of our commodity hedges in place at December 31, 2009. The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization. Estimated future net revenue and the present value thereof differ from future net cash flows and the standardized measure thereof only because the former do not include the effects of estimated future income tax expenses ($1.2 billion as of December 31, 2009).

Management uses future net revenue, which is calculated without deducting estimated future income tax expenses, and the present value thereof as one measure of the value of the company's current proved reserves and to compare relative values among peer companies without regard to income taxes. We also understand that securities analysts and rating agencies use this measure in similar ways. While future net revenue and present value are based on prices, costs and discount factors which are consistent from company to company, the standardized measure of discounted future net cash flows is dependent on the unique tax situation of each individual company.

(c) Additional information on the standardized measure is presented in Note 10 of the notes to our consolidated financial statements included in Item 8 of this report.

As of December 31, 2009, our reserve estimates included 5.923 tcfe of reserves classified as proved undeveloped (PUD), compared to 3.960 tcfe as of December 31, 2008. This increase is partially attributable to our ability to report additional proved reserves under new reserve recognition rules as of year-end 2009 adopted by the Securities and Exchange Commission (SEC). These increases were offset by the conversion of 432 bcfe of PUDs to proved developed reserves during 2009. Additionally, we deleted approximately 2,250 previously booked PUD locations, including 580 bcfe of natural gas and oil reserves associated with locations not expected to be developed within five years. As of December 31, 2009, there were no material PUDs that have remained undeveloped for five years or more.

We invested approximately $621 million in 2009 to convert 432 bcfe of PUDs to proved developed reserves. In 2010, we estimate that we will invest approximately $929 million for PUD conversion. Our annual decline rate on producing properties is projected to be 28% from 2010 to 2011, 18% from 2011 to 2012, 14% from 2012 to 2013, 11% from 2013 to 2014 and 9% from 2014 to 2015. Of our 8.3 tcfe of proved developed reserves as of December 31, 2009, 1.0 tcfe were non-producing. Such reserves were primarily "behind pipe" zones.

The future net revenue attributable to our estimated proved undeveloped reserves of $7.3 billion at December 31, 2009, and the $1.1 billion present value thereof, have been calculated assuming that we will expend approximately $8.0 billion to develop these reserves. Net of joint venture cost carries, we have projected to incur $929 million in 2010, $1.6 billion in 2011, $1.5 billion in 2012 and $4.0 billion in 2013 and beyond, although the amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs, product prices and the availability of capital. Chesapeake's developmental drilling schedules are subject to revision and reprioritization throughout the year resulting from unknowable factors such as the relative success in an individual developmental drilling prospect leading to an additional drilling opportunity, rig availability, title issues or delays, and the effect that acquisitions may have on prioritizing developmental drilling plans.

Chesapeake's ownership interest used in calculating proved reserves and the associated estimated future net revenue was determined after giving effect to the assumed maximum participation by other parties to our farmout and participation agreements. The prices used in calculating the estimated future net revenue attributable to proved reserves do not reflect market prices for natural gas and oil production sold subsequent to December 31, 2009. There can be no assurance that all of the estimated proved reserves will be produced and sold at the assumed prices.

The company's estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2009, 2008 and 2007, and the changes in quantities and standardized measure of such reserves for each of the three years then ended, are shown in Note 10 of the notes to the consolidated financial statements included in Item 8 of this report. No estimates of proved reserves comparable to those included herein have been included in reports to any federal agency other than the SEC.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond Chesapeake's control. The reserve data represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates made by different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimates, and such revisions may be material. Accordingly, reserve estimates are often different from the actual quantities of natural gas and oil that are ultimately recovered. Furthermore, the estimated future net revenue from proved reserves and the associated present value are based upon certain assumptions, including prices, future production levels and costs that may not prove correct. Future prices and costs may be materially higher or lower than the prices and costs as of the date of any estimate. A change in price of $0.10 per mcf for natural gas and $1.00 per barrel for oil would result in a change in the December 31, 2009 present value of estimated future net revenue of our proved reserves of approximately $500 million and $60 million, respectively. The estimated future net revenue used in this analysis does not include the effects of future income taxes or hedging. The foregoing uncertainties are particularly true as to proved undeveloped reserves, which are inherently less certain than proved developed reserves and which comprise a significant portion of our proved reserves.

Reserves Price Sensitivity

Chesapeake's management uses forward-looking market-based data in developing its drilling plans, assessing its capital expenditure needs and projecting future cash flows. We believe that using the 10-year average NYMEX strip prices yields a better indication of the likely economic producibility of proved reserves than the trailing average 12-month price required by the SEC's reserves rules or a period-end spot price, as used under the SEC rules before December 31, 2009. The table below compares our estimated proved reserves and associated present value (discounted at an annual rate of 10%) of estimated future revenue before income tax using the 2009 12-month average prices reflected in our reported reserve estimates and the 10-year average future NYMEX strip prices as of December 31, 2009, which were $6.94 per mcf and $92.24 per barrel, before price differential adjustments. There is no change to our cost or other assumptions between this higher price scenario and those used in the estimation of our reported reserves.

	December 31, 2009			
	Gas (bcf)	**Oil (mmbbl)**	**Total (bcfe)**	**Present Value ($ in millions)**
2009 12-month average prices (SEC)	13,510	124.0	14,254	$ 9,449
10-year average future NYMEX strip prices as of December 31, 2009	14,751	131.4	15,540	$28,713

Reserves Estimation

Chesapeake's Reservoir Engineering Department prepared approximately 17% of the proved reserves estimates (by volume) disclosed in this report based upon a review of production histories and other geologic, economic, ownership and engineering data we developed. The estimates were not based on any single significant assumption due to the diverse nature of the reserves and there is no significant concentration of proved reserve volume or value in any one well or field. The department currently has a total of 87 full-time employees, consisting of 54 degreed engineers (ten serving in management capacities), 31 engineering technicians with a minimum of a four-year degree in mathematics, economics, finance or other business/science field, and two administrative persons. Eleven of our engineers are registered professional engineers with various state board certifications. The department collectively has approximately 1,450 years of engineering industry experience.

Chesapeake maintains a continuous education program for engineers and technicians on new technologies and industry advancements and also offers refresher training on basic skill sets.

Chesapeake maintains internal controls such as the following to ensure the reliability of reserves estimations:

- No employee's compensation is tied to the amount of reserves booked.
- We follow comprehensive SEC-compliant internal policies to determine and report proved reserves. Reserves estimates are made by experienced reservoir engineers or under their direct supervision.
- The Reservoir Engineering Department reviews all the company's reported proved reserves at the close of each quarter.
- Each quarter, Reservoir Engineering Department managers, the Vice President of Reservoir Engineering, the Senior Vice President of Production and the Chief Operating Officer review all significant reserve changes and all new proved undeveloped reserves additions.
- The Reservoir Engineering Department reports independently of any of our operating divisions.

Chesapeake's Vice President of Reservoir Engineering is the technical person primarily responsible for overseeing the preparation of the company's reserve estimates. His qualifications include the following:

- 34 years of practical experience in petroleum engineering with 31 years of this experience being in the estimation and evaluation of reserves
- certified professional engineer in the state of Oklahoma
- Bachelor of Science degree in Petroleum Engineering
- member in good standing of the Society of Petroleum Engineers

We engaged four third-party engineering firms to prepare portions of our reserve estimates comprising approximately 83% of our estimated proved reserves (by volume) at year-end 2009. The portion of our estimated proved reserves prepared by each of our third-party engineering firms as of December 31, 2009 is presented below.

	% Prepared (by Volume)	**Principal Properties**
Netherland, Sewell & Associates, Inc.	59%	Barnett Shale Fayetteville Shale Haynesville Shale Mid-Continent (portions) Permian and Delaware Basins Ark-La-Tex (portions)
Lee Keeling and Associates, Inc.	10%	Mid-Continent South Texas/ Texas Gulf Coast (portions)
Data and Consulting Services, Division of Schlumberger Technology Corporation	7%	Marcellus Shale Appalachian Basin
Ryder Scott Company, L.P.	7%	Mid-Continent (portions) South Texas/ Texas Gulf Coast (portions)

Copies of the reports issued by the engineering firms are filed with this report as Exhibits 99.1 – 99.4. The qualifications of the technical person at each of these firms primarily responsible for overseeing his firm's preparation of the company's reserve estimates are set forth below.

Netherland, Sewell & Associates, Inc.:

- over 30 years of practical experience in petroleum engineering, with over 29 years of this experience being in the estimation and evaluation of reserves
- a registered professional engineer in the state of Texas
- Bachelor of Science Degree in Chemical Engineering

Lee Keeling and Associates, Inc.:

- over 45 years of practical experience in petroleum engineering and in the estimation and evaluation of reserves
- a certified professional engineer in the state of Oklahoma
- Bachelor of Science Degree in Petroleum Engineering

Data and Consulting Services, Division of Schlumberger Technology Corporation:

- over 20 years of practical experience in petroleum geology and in the estimation and evaluation of reserves
- registered professional geologist license in the commonwealth of Pennsylvania
- certified petroleum geologist of the American Association of Petroleum Geologists
- Bachelor of Science Degree in Geological Sciences
- member in good standing of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers

Ryder Scott Company, L.P.:

- over 30 years of practical experience in the estimation and evaluation of reserves
- registered professional engineer in the state of Texas
- Bachelor of Science Degree in Electrical Engineering
- member in good standing of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers

Exploration and Development, Acquisition and Divestiture Activities

The following table sets forth historical cost information regarding our exploration and development acquisition and divestiture activities during the periods indicated:

	December 31,		
	2009	2008	2007
	($ in millions)		
Development and exploration costs:			
Development drilling[a]	$ 2,729	$ 5,185	$ 4,402
Exploratory drilling	651	612	653
Geological and geophysical costs[b][c]	162	314	343
Asset retirement obligation and other	(2)	10	29
Total	3,540	6,121	5,427
Acquisition costs:			
Unproved properties[d]	2,793	8,250	2,507
Proved properties	61	355	671
Deferred income taxes	—	13	131
Total	2,854	8,618	3,309
Proceeds from divestitures:			
Unproved properties	(1,265)	(5,302)	—
Proved properties	(461)	(2,433)	(1,142)
Total	$ 4,668	$ 7,004	$ 7,594

(a) Includes capitalized internal costs of $332 million, $326 million and $243 million, respectively.

(b) Includes capitalized internal costs of $22 million, $26 million and $19 million, respectively.

(c) Includes $29 million, $25 million and $16 million of related capitalized interest, respectively.

(d) Includes $598 million, $561 million and $296 million of related capitalized interest, respectively.

Our development costs included $621 million, $1.5 billion and $1.5 billion in 2009, 2008 and 2007, respectively, related to properties carried as proved undeveloped locations in the prior year's reserve reports.

A summary of our exploration and development, acquisition and divestiture activities in 2009 by operating area is as follows:

	Gross Wells Drilled	Net Wells Drilled	Exploration and Development	Acquisition of Unproved Properties	Acquisition of Proved Properties	Sales of Unproved Properties[a]	Sales of Proved Properties[a]	Total
			($ in millions)					
Big 6 Shales:								
Barnett Shale	417	339	$ 1,197	$ 209	$ 1	$ —	$ —	$1,407
Fayetteville Shale	774	209	179	56	—	—	3	238
Haynesville Shale	337	163	744	1,270	42	(1,074)	—	982
Marcellus Shale	149	74	145	1,038	15	(176)	—	1,022
Bossier Shale	—	—	—	—	—	—	—	—
Eagle Ford Shale	—	—	—	—	—	—	—	—
Other:								
Mid-Continent	386	144	712	120	3	11	109	955
Permian and Delaware Basins	93	42	322	31	—	(3)	(2)	348
South Texas/ Gulf Coast/ Ark-La-Tex	41	25	197	69	—	(23)	(571)	(328)
Appalachian Basin	9	7	44	—	—	—	—	44
Total	2,206	1,003	$ 3,540	$ 2,793	$ 61	$ (1,265)	$ (461)	$4,668

(a) Balance includes payments and remaining accruals for post-closing adjustments due to title defects in connection with certain 2008 joint venture and divestiture transactions.

Acreage

The following table sets forth as of December 31, 2009 the gross and net acres of both developed and undeveloped natural gas and oil leases which we hold. "Gross" acres are the total number of acres in which we own a working interest. "Net" acres refer to gross acres multiplied by our fractional working interest. Acreage numbers do not include our options to acquire additional acreage which have not been exercised.

	Developed		Undeveloped		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Big 6 Shales:						
Barnett Shale	194,477	160,277	202,493	129,595	396,970	289,872
Fayetteville Shale	276,148	123,384	2,078,125	1,033,437	2,354,273	1,156,821
Haynesville Shale[a]	215,754	151,439	545,240	362,806	760,994	514,245
Marcellus Shale	426,101	215,958	2,802,937	1,407,147	3,229,038	1,623,105
Eagle Ford Shale	106	106	86,360	79,862	86,466	79,968
Other:						
Mid-Continent	4,396,456	2,206,548	2,873,781	1,614,026	7,270,237	3,820,574
Permian and Delaware Basins	469,067	267,195	3,046,170	1,884,421	3,515,237	2,151,616
South Texas/Gulf Coast/ Ark-La-Tex	527,081	311,430	509,894	295,441	1,036,975	606,871
Appalachian Basin	1,696,871	1,483,204	3,214,139	1,448,205	4,911,010	2,931,409
Total	8,202,061	4,919,541	15,359,139	8,254,940	23,561,200	13,174,481

(a) The Bossier Shale acreage overlaps the Haynesville Shale acreage and is included within the Haynesville Shale totals.

Marketing, Gathering and Compression

Marketing

Chesapeake Energy Marketing, Inc., one of our wholly-owned subsidiaries, provides natural gas and oil marketing services, including commodity price structuring, contract administration and nomination services for Chesapeake, its partners and other producers. We attempt to enhance the value of our natural gas production by aggregating natural gas to be sold to natural gas marketers and pipelines. This aggregation allows us to attract larger, more creditworthy customers that in turn assist in maximizing the prices received for our production.

Our oil production is generally sold under market sensitive or spot price contracts. The revenue we receive from the sale of natural gas liquids is included in oil sales.

Our natural gas production is sold to purchasers under percentage-of-proceeds contracts, percentage-of-index contracts or spot price contracts. By the terms of the percentage-of-proceeds contracts, we receive a percentage of the resale price received by the purchaser for sales of residue gas and natural gas liquids recovered after transportation and processing of our natural gas. These purchasers sell the residue gas and natural gas liquids based primarily on spot market prices. Under percentage-of-index contracts, the price per mmbtu we receive for our natural gas is tied to indexes published in *Inside FERC* or *Gas Daily*. Although exact percentages vary daily, as of February 2010, approximately 80% of our natural gas production was sold under short-term contracts at market-sensitive prices.

During 2009, sales to EDF Trading North America LLC (formerly Eagle Energy Partners, I, L.P.) of $571 million accounted for 10% of our total revenues (excluding gains (losses) on derivatives). In 2007, we sold our 33% limited partnership interest in Eagle Energy Partners I, L.P., which we first acquired in 2003, for proceeds of $124 million and a gain of $83 million. Management believes that the loss of this customer would not have a material adverse effect on our results of operations or our financial position. No other customer accounted for more than 10% of total revenues (excluding gains (losses) on derivatives) in 2009.

Our marketing activities constitute a reportable segment under accounting guidance for disclosure about segments of an enterprise and related information. See Note 17 of the notes to our consolidated financial statements in Item 8.

Midstream Gathering Operations

Chesapeake invests in gathering systems and processing facilities to complement our natural gas operations in regions where we have significant production and additional infrastructure is required. By doing so, we are better able to manage the value received for and the costs of, gathering, treating and processing natural gas. These systems are designed primarily to gather company production for delivery into major intrastate or interstate pipelines. In addition, our midstream business provides services to third-party customers. Chesapeake generates revenues from its gathering, treating and compression activities through fixed-rate fee structures. The company also processes a portion of its natural gas at various third-party plants.

Our midstream assets were held in various wholly-owned subsidiaries of Chesapeake until February 2008 when we transferred our non-Appalachian midstream assets to our wholly-owned subsidiary Chesapeake Midstream Development, L.P. (CMD) and its subsidiaries. In September 2009, we formed a joint venture with Global Infrastructure Partners (GIP) to own and operate natural gas midstream assets. As part of the transaction, we contributed certain natural gas gathering systems that had been held by CMD and its subsidiaries to a new entity, Chesapeake Midstream Partners, L.L.C. (CMP) and GIP purchased a 50% interest in CMP for $588 million in cash. The accounting for the joint venture is described in Note 11 of the consolidated financial statements included in this report. The assets we contributed to the joint venture were substantially all of our midstream assets in the Barnett Shale and also the majority of our non-shale midstream assets in the Arkoma, Anadarko, Delaware and Permian Basins. Together, these assets constituted approximately 57% of our total midstream assets as of September 30, 2009.

Subsidiaries of CMD continue to operate our midstream assets outside of the CMP joint venture. These include natural gas gathering assets in the Fayetteville Shale, Haynesville Shale, Marcellus Shale and other areas in Appalachia. Compared to the Barnett Shale and Mid-Continent areas where the CMP midstream assets are located, these are less developed areas and will require significant build-out capital expenditures. A source of liquidity for this business is the $250 million revolving credit facility described under *Liquidity and Capital Resources* in Item 7 below. The CMD systems, which are located in Oklahoma, Texas, Colorado, New Mexico, New York, Ohio, Maryland, Louisiana, Arkansas, Pennsylvania and West Virginia, consist of approximately 1,500 miles of gathering pipelines, servicing over 900 natural gas wells.

On February 16, 2010, Chesapeake Midstream Partners, L.P. (the Partnership) filed a registration statement on Form S-1 with the SEC relating to a proposed underwritten initial public offering of common units, representing limited partnership interests in the Partnership. The Partnership was formed by Chesapeake and GIP, equal indirect owners of the general partner of the Partnership, to own, operate, develop and acquire midstream assets. Upon the closing of the offering, Chesapeake and GIP will contribute CMP's interests to the Partnership and the Partnership will continue CMP's business. It is expected that the Partnership will succeed to CMP's $500 million revolving credit facility, with certain amendments, and a portion of the proceeds of the offering will be used to repay the outstanding borrowings under the midstream joint venture revolving credit facility described under *Liquidity and Capital Resources* in Item 7 below.

Compression

Since 2003, Chesapeake has expanded its compression business. Our wholly-owned subsidiary, MidCon Compression, L.L.C., operates wellhead and system compressors to facilitate the transportation of our natural gas production. In a series of transactions in 2007, 2008 and 2009, MidCon sold a significant portion of its compressor fleet, consisting of 1,685 compressors, for $370 million and entered into a master lease agreement. These transactions were recorded as sales and operating leasebacks. During 2010, we expect to take delivery of 324 new compressors that are on order for approximately $100 million, and we intend to simultaneously enter into sale/leaseback transactions with financial counterparties as the compressors are delivered, if acceptable leasing arrangements are available to us.

Service Operations

Drilling

Securing available rigs is an integral part of the exploration process and therefore owning our own drilling company is a strategic advantage for Chesapeake. In 2001, Chesapeake formed its wholly-owned drilling subsidiary, Nomac Drilling Corporation, with an investment of $26 million to build and refurbish five drilling rigs. As of December 31, 2009, Chesapeake had invested approximately $897 million to build or acquire 98 drilling rigs. In a series of transactions in 2006, 2007 and 2008, our drilling subsidiaries sold 83 rigs for $677 million and subsequently leased back the rigs through 2018. The drilling rigs have depth ratings between 3,000 and 25,000 feet and range in drilling horsepower from

525 to 2,000. These drilling rigs are currently operating in Oklahoma, Texas, Arkansas, Louisiana and Appalachia. Chesapeake is the fourth largest drilling rig contractor in the U.S.

Trucking

In 2006, Chesapeake expanded its service operations by acquiring two privately-owned oilfield trucking service companies. We now own one of the largest oilfield and heavy haul transportation companies in the industry. Our trucking business is utilized primarily to transport drilling rigs for both Chesapeake and third parties. Through this ownership, we are better able to manage the movement of our rigs. As of December 31, 2009, our fleet included 255 trucks and 19 cranes, which mainly service the Mid-Continent, Barnett Shale and Appalachian regions.

Seasonal Nature of Business

Generally, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers can lessen or intensify this fluctuation. In addition, pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can lessen seasonal demand fluctuations. World weather and resultant prices for LNG can also affect deliveries of competing LNG into this country from abroad, affecting the price of domestically produced natural gas.

Competition

We compete with both major integrated and other independent natural gas and oil companies in acquiring desirable leasehold acreage, producing properties and the equipment and expertise necessary to explore, develop and operate our properties and market our production. Some of our competitors may have larger financial and other resources than ours. The natural gas and oil industry also faces competition from alternative fuel sources, including other fossil fuels such as coal and imported LNG. Competitive conditions may be affected by future legislation and regulations as the U.S. develops new energy and climate-related policies. In addition, some of our larger competitors may have a competitive advantage when responding to factors that affect demand for natural gas and oil production, such as changing prices, domestic and foreign political conditions, weather conditions, the price and availability of alternative fuels, the proximity and capacity of gas pipelines and other transportation facilities, and overall economic conditions. We believe that our technological expertise, our exploration, land, drilling and production capabilities and the experience of our management generally enable us to compete effectively.

Hedging Activities

We utilize hedging strategies to hedge the price of a portion of our future natural gas and oil production and to manage interest rate exposure. See Item 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

Regulation

General. All of our operations are conducted onshore in the United States. The U.S. natural gas and oil industry is regulated at the federal, state and local levels, and some of the laws, rules and regulations that govern our operations carry substantial penalties for noncompliance. These regulatory burdens increase our cost of doing business and, consequently, affect our profitability.

Regulation of Natural Gas and Oil Operations. Our exploration and production operations are subject to various types of regulation at the U.S. federal, state and local levels. Such regulation includes requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling and well operations. Other activities subject to regulation include, but are not limited to:

- the location of wells;
- the method of drilling and completing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells;
- the disposal of fluids used or other wastes generated in connection with operations;
- the marketing, transportation and reporting of production; and
- the valuation and payment of royalties.

Our operations are also subject to various conservation regulations. These include the regulation of the size of drilling and spacing units (regarding the density of wells that may be drilled in a particular area) and the unitization or pooling of natural gas and oil properties. In this regard, some states, such as Oklahoma, allow the forced pooling or integration of tracts to facilitate exploration, while other states, such as Texas and New Mexico rely on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units and therefore, more difficult to fully develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws establish maximum rates of production from natural gas and oil wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these regulations is to limit the amount of natural gas and oil we can produce and to limit the number of wells and the locations at which we can drill.

Chesapeake operates a number of natural gas gathering systems. The U.S. Department of Transportation and certain state agencies regulate the safety and operating aspects of the transportation and storage activities of these facilities. There is currently no price regulation of the company's sales of oil, natural gas liquids and natural gas, although governmental agencies may elect in the future to regulate certain sales.

We do not anticipate that compliance with existing laws and regulations governing exploration, production and natural gas gathering will have a material adverse effect upon our capital expenditures, earnings or competitive position.

Environmental, Health and Safety Regulation. The business operations of the company and its ownership and operation of natural gas and oil interests are subject to various federal, state and local environmental, health and safety laws and regulations pertaining to the release, emission or discharge of materials into the environment, the generation, storage, transportation, handling and disposal of materials (including solid and hazardous wastes), the safety of employees, or otherwise relating to pollution, preservation, remediation or protection of human health and safety, natural resources, wildlife or the environment. We must take into account the cost of complying with environmental regulations in planning, designing, constructing, drilling, operating and abandoning wells and related surface facilities. In most instances, the regulatory frameworks relate to the handling of drilling and production materials, the disposal of drilling and production wastes, and the protection of water and air. In addition, our operations may require us to obtain permits for, among other things,

- air emissions;
- the construction and operation of underground injection wells to dispose of produced saltwater and other non-hazardous oilfield wastes; and
- the construction and operation of surface pits to contain drilling muds and other non-hazardous fluids associated with drilling operations.

Federal, state and local laws may require us to remove or remediate previously disposed wastes, including wastes disposed of or released by us or prior owners or operators in accordance with current laws or otherwise, to suspend or cease operations at contaminated areas, or to perform remedial well plugging operations or response actions to reduce the risk of future contamination. Federal laws, including the Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, and analogous state laws impose joint and several liability, without regard to fault or legality of the original conduct, on classes of persons who are considered responsible for releases of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and persons that disposed of or arranged for the disposal of hazardous substances at the site. CERCLA and analogous state laws also authorize the U.S. Environmental Protection Agency (EPA), state environmental agencies and, in some cases, third parties to take action to prevent or respond to threats to human health or the environment and to seek to recover from responsible classes of persons the costs of such actions.

Other federal and state laws, in particular the federal Resource Conservation and Recovery Act, regulate hazardous and non-hazardous wastes. Under a longstanding legal framework, certain wastes generated by our natural gas and oil operations are not subject to federal regulations governing hazardous wastes, though they may be regulated under other federal and state laws. These wastes may in the future be designated as hazardous wastes and may thus become subject to more rigorous and costly compliance and disposal requirements.

Vast quantities of natural gas deposits exist in deep shale and other formations. It is customary in our industry to recover natural gas from these deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in formations underground where water, sand and other additives are pumped under high pressure into a shale gas formation. These formations are generally geologically separated and isolated from fresh ground water supplies by protective rock layers. Our well construction practices include installation of multiple layers of protective steel casing surrounded by cement that are specifically designed and installed to protect freshwater aquifers by preventing the migration of fracturing fluids into aquifers. Legislative and regulatory efforts at the federal level and in some states have sought to render permitting and compliance requirements more stringent for hydraulic fracturing. If passed into law, such efforts could have an adverse effect on our operations.

Federal and state occupational safety and health laws require us to organize and maintain information about hazardous materials used, released or produced in our operations. Certain portions of this information must be provided to employees, state and local governmental authorities and local citizens. We are also subject to the requirements and reporting set forth in federal workplace standards.

We have made and will continue to make expenditures to comply with environmental, health and safety regulations and requirements. These are necessary business costs in the natural gas and oil industry. Although we are not fully insured against all environmental, health and safety risks, and our insurance does not cover any penalties or fines that may be issued by a governmental authority, we maintain insurance coverage which we believe is customary in the industry. Moreover, it is possible that other developments, such as stricter and more comprehensive environmental, health and safety laws and regulations, as well as claims for damages to property or persons, resulting from company operations, could result in substantial costs and liabilities, including civil and criminal penalties, to Chesapeake. We believe that we are in material compliance with existing environmental, health and safety regulations. We believe that the cost of maintaining compliance with these existing regulations will not have a material adverse effect on our business, financial position and results of operation, but new or more stringent regulations could increase the cost of doing business.

Climate Change. On December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. The EPA has proposed two sets of regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and these regulations, if finalized, could lead to the imposition of greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. The adoption and implementation of regulations governing or limiting emissions of greenhouse gases from our equipment and operations could require us to incur additional operating costs and could adversely affect demand for the natural gas and oil we sell.

The United States Congress has been considering various bills that would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. Such a program, if enacted, could require phased reductions in greenhouse gas emissions over several or many years and could authorize the issuance of a declining number of tradable allowances to sources of these emissions so that they may continue to emit greenhouse gases into the atmosphere. The creation of such a program remains uncertain, as do the timing and degree of reduction in emissions and the costs associated with any tradable emissions allowances. Although it is not possible at this time to predict the outcome of Congressional consideration of legislation concerning greenhouse gas emissions, any future federal laws or implementing regulations that may be enacted concerning greenhouse gas emissions could require us to incur increased operating costs and could adversely affect demand for the natural gas and oil we sell.

The potential increase in the costs of our operations resulting from any legislation or regulation to restrict emissions of greenhouse gases could include new or increased costs to operate and maintain our equipment and facilities, install new emission controls on our equipment and facilities, acquire allowances to authorize our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for natural gas and oil.

Title to Properties

Our title to properties is subject to royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the natural gas and oil industry, to liens for current taxes not yet due and to other encumbrances. As is customary in the industry in the case of undeveloped properties, only cursory investigation of record title is made at the time of acquisition. Drilling title opinions are usually prepared before commencement of drilling operations. We believe we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the natural gas and oil industry. Nevertheless, we are involved in title disputes from time to time which result in litigation.

Operating Hazards and Insurance

The natural gas and oil business involves a variety of operating risks, including the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards such as oil spills, natural gas leaks, ruptures or discharges of toxic gases. If any of these should occur, Chesapeake could suffer substantial losses due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, and suspension of operations. Our horizontal and deep drilling activities involve greater risk of mechanical problems than vertical and shallow drilling operations.

Chesapeake maintains a $50 million control of well policy that insures against certain sudden and accidental risks associated with drilling, completing and operating our wells. There is no assurance that this insurance will be adequate to cover all losses or exposure to liability. Chesapeake also carries a $350 million comprehensive general liability umbrella policy and a $100 million pollution liability policy. We provide workers' compensation insurance coverage to employees in all states in which we operate. While we believe these policies are customary in the industry, they do not provide complete coverage against all operating risks.

Facilities

Chesapeake owns an office complex in Oklahoma City and we continue to construct additional buildings in Oklahoma City and in our operating areas as needed to accommodate our ongoing growth. We also own or lease various field or administrative offices in the areas in which we conduct operations.

Employees

Chesapeake had approximately 8,200 employees as of December 31, 2009.

Glossary of Natural Gas and Oil Terms

The terms defined in this section are used throughout this Form 10-K.

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet of natural gas equivalent.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

Bbtu. One billion British thermal units.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Commercial Well; Commercially Productive Well. A natural gas and oil well which produces natural gas and oil in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Conventional Reserves. Natural gas and oil occurring as discrete accumulations in structural and stratigraphic traps.

Developed Acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development Well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Drilling Carry Obligation. An obligation of one party to pay certain well costs attributable to another party.

Dry Hole; Dry Well. A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as a natural gas or oil well.

Exploratory Well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir.

Farmout. An assignment of an interest in a drilling location and related acreage conditional upon the drilling of a well on that location.

Formation. A succession of sedimentary beds that were deposited under the same general geologic conditions.

Full-Cost Pool. The full-cost pool consists of all costs associated with property acquisition, exploration and development activities for a company using the full-cost method of accounting. Additionally, any internal costs that can be directly identified with acquisition, exploration and development activities are included. Any costs related to production, general corporate overhead or similar activities are not included.

Gross Acres or Gross Wells. The total acres or wells, as the case may be, in which a working interest is owned.

Horizontal Wells. Wells which are drilled at angles greater than 70 degrees from vertical.

Infill Drilling. Drilling wells between established producing wells on a lease; a drilling program to reduce the spacing between wells in order to increase production and/or recovery of in-place hydrocarbons from the lease.

Karst. An area of irregular limestone in which erosion has produced fissures, sinkholes, underground streams and caverns.

Mbbl. One thousand barrels of crude oil or other liquid hydrocarbons.

Mbtu. One thousand btus.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet of natural gas equivalent.

Mmbbl. One million barrels of crude oil or other liquid hydrocarbons.

Mmbtu. One million btus.

Mmcf. One million cubic feet.

Mmcfe. One million cubic feet of natural gas equivalent.

Net Acres or Net Wells. The sum of the fractional working interests owned in gross acres or gross wells.

NYMEX. New York Mercantile Exchange.

Play. A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential natural gas and oil reserves.

Present Value or PV-10. When used with respect to natural gas and oil reserves, present value, or PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices calculated as the average natural gas and oil price during the preceding 12-month period prior to the end of the current reporting period, (determined as the unweighted arithmetical average of prices on the first day of each month within the 12-month period) and costs in effect at the determination date, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

Price Differential. The difference in the price of natural gas or oil received at the sales point and the New York Mercantile Exchange (NYMEX).

Productive Well. A well that is not a dry well. Productive wells include producing wells and wells that are mechanically capable of production.

Proved Developed Reserves. Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

Proved Properties. Properties with proved reserves.

Proved Reserves. Proved natural gas and oil reserves are those quantities of natural gas and oil, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of a reservoir considered as proved includes (a) the area indentified by drilling and limited by fluid contacts, if any, and (b) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible natural gas or oil on the basis of available geoscience and engineering data. In the absence of information on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (a) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (b) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved Undeveloped Location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved Undeveloped Reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Reserve Replacement. Calculated by dividing the sum of reserve additions from all sources (revisions, extensions, discoveries and other additions and acquisitions) by the actual production for the corresponding period. The values for these reserve additions are derived directly from the proved reserves table located in Note 10 of the notes to our consolidated financial statements. In calculating reserve replacement, we do not use unproved reserve quantities or proved reserve additions attributable to less than wholly-owned consolidated entities or investments accounted for using the equity method. Management uses the reserve replacement ratio as an indicator of the company's ability to replenish annual production volumes and grow its reserves, thereby providing some information on the sources of future production. It should be noted that the reserve replacement ratio is a statistical indicator that has limitations. As an annual measure, the ratio is limited because it typically varies widely based on the extent and timing of new discoveries and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not imbed the cost or timing of future production of new reserves, it cannot be used as a measure of value creation.

Royalty Interest. An interest in a natural gas and oil property entitling the owner to a share of oil or natural gas production free of costs of production.

Seismic. An exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of subsurface rock formation (3-D seismic provides three-dimensional pictures).

Shale. Fine-grained sedimentary rock composed mostly of consolidated clay or mud. Shale is the most frequently occurring sedimentary rock.

Standardized Measure of Discounted Future Net Cash Flows. The discounted future net cash flows relating to proved reserves based on the prices used in estimating the proved reserves, year-end costs and statutory tax rates (adjusted for permanent differences) and a 10-percent annual discount rate.

Tcf. One trillion cubic feet.

Tcfe. One trillion cubic feet of natural gas equivalent.

Unconventional Reserves. Natural gas and oil occurring in regionally pervasive accumulations with low matrix permeability and close association with source rocks.

Undeveloped Acreage. Acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

Unproved Properties. Properties with no proved reserves.

VPP. As we use the term, a volumetric production payment represents a limited-term overriding royalty interest in natural gas and oil reserves that (i) entitles the purchaser to receive production volumes over a period of time from specific lease interests; (ii) is free and clear of all associated future production costs and capital expenditures; (iii) is nonrecourse to the seller (i.e., the purchaser's only recourse is to the reserves acquired); (iv) transfers title of the reserves to the purchaser; and (v) allows the seller to retain the remaining reserves after the production volumes have been delivered.

Working Interest. The operating interest which gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

ITEM 1A. ***Risk Factors***

Natural gas and oil prices fluctuate widely, and lower prices for an extended period of time are likely to have a material adverse effect on our business.

Our revenues, operating results, profitability and ability to grow depend primarily upon the prices we receive for the natural gas and oil we sell. We require substantial expenditures to replace reserves, sustain production and fund our business plans. Lower natural gas or oil prices can negatively affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves. In addition, lower prices may result in ceiling test write-downs of our natural gas and oil properties. We urge you to read the risk factors below for a more detailed description of each of these risks.

Historically, the markets for natural gas and oil have been volatile and they are likely to continue to be volatile. Wide fluctuations in natural gas and oil prices may result from relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and other factors that are beyond our control, including:

- domestic and worldwide supplies of natural gas, natural gas liquids and oil, including U.S. inventories of natural gas and oil reserves;
- weather conditions;
- changes in the level of consumer demand;
- the price and availability of alternative fuels;
- the availability, proximity and capacity of pipelines, other transportation facilities and processing facilities;
- the level and effect of trading in commodity futures markets, including by commodity price speculators and others;
- the price and level of foreign imports;
- the nature and extent of domestic and foreign governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil and gas producing regions; and
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future natural gas and oil price movements with any certainty. Further, natural gas and oil prices do not necessarily move in tandem. Because approximately 95% of our reserves at December 31, 2009 were natural gas reserves, we are more affected by movements in natural gas prices.

Our level of indebtedness may limit our financial flexibility.

As of December 31, 2009, we had long-term indebtedness of approximately $12.3 billion, and our net indebtedness represented 49% of our total book capitalization. We had $1.936 billion and $1.250 billion of outstanding borrowings drawn under our revolving bank credit facilities at December 31, 2009 and February 26, 2010, respectively.

Our level of indebtedness affects our operations in several ways, including the following:

- a portion of our cash flows from operating activities must be used to service our indebtedness and is not available for other purposes;
- we may be at a competitive disadvantage as compared to similar companies that have less debt;
- the covenants contained in the agreements governing our outstanding indebtedness and future indebtedness may limit our ability to borrow additional funds, pay dividends and make certain investments and may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- the revolving bank credit facilities of our midstream subsidiary and our midstream joint venture restrict the payment of dividends or distributions to Chesapeake;
- additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes may have higher costs and more restrictive covenants; and
- changes in the credit ratings of our debt may negatively affect the cost, terms, conditions and availability of future financing, and lower ratings will increase the interest rate and fees we pay on our revolving bank credit facilities.

The borrowing base of our corporate revolving bank credit facility is subject to periodic redetermination. A lowering of our borrowing base could require us to repay indebtedness in excess of the borrowing base, or we might need to further secure the lenders with additional collateral. We may incur additional debt, including secured indebtedness, in order to develop our properties and make future acquisitions. A higher level of indebtedness increases the risk that we may default on our obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, natural gas and oil prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital.

Low natural gas prices throughout 2009 resulted in a write-down of our asset carrying values, and further price declines could result in additional write-downs in the future.

We utilize the full-cost method of accounting for costs related to our natural gas and oil properties. Under this method, all such costs (for both productive and nonproductive properties) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the unit-of-production method. However, these capitalized costs are subject to a ceiling test which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved natural gas and oil reserves discounted at 10% plus the lower of cost or market value of unproved properties. The full-cost ceiling is evaluated at the end of each quarter using the unweighted arithmetical average of the prices on the first day of each month within the 12-month period ending in the quarter, adjusted for the impact of derivatives accounted for as cash flow hedges.

Natural gas prices were depressed throughout 2009, resulting in a write-down of our natural gas and oil property asset carrying value. Our financial statements for the year ended December 31, 2009 reflect an impairment of approximately $6.9 billion, net of income tax, of our natural gas and oil properties. We also had an after-tax non-cash impairment charge to certain investments and fixed assets of approximately $183 million in 2009 as a result of lower asset valuation estimates.

The risk that we will be required to further write-down the carrying value of our natural gas and oil properties increases when natural gas and oil prices are low or volatile. We may experience further ceiling test write-downs or other impairments in the future.

Significant capital expenditures are required to replace our reserves.

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations, our corporate revolving bank credit facility and debt and equity issuances. Beginning in late 2007, we have also had significant cash proceeds from a number of asset monetization transactions. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of natural gas and oil, our success in developing and producing new reserves, the orderly functioning of credit and capital markets and our ability to complete additional planned asset monetization transactions. If revenues were to decrease as a result of lower natural gas and oil prices or decreased production, and our access to capital were limited, we would have a reduced ability to replace our reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may not be able to access additional bank debt, debt or equity or other methods of financing on an economic basis to meet these requirements.

If we are not able to replace reserves, we may not be able to sustain production.

Our future success depends largely upon our ability to find, develop or acquire additional natural gas and oil reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, exploration or acquisition activities, our proved reserves and production will decline over time. In addition, approximately 42% of our total estimated proved reserves (by volume) at December 31, 2009 were undeveloped. By their nature, estimates of proved undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. Our reserve estimates reflect that our production rate on producing properties will decline approximately 28% from 2010 to 2011. Thus, our future natural gas and oil reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves.

The actual quantities and present value of our proved reserves may prove to be lower than we have estimated.

This report contains estimates of our proved reserves and the estimated future net revenues from our proved reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating natural gas and oil reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from these estimates. Such variations may be significant and could materially affect the estimated quantities and present value of our proved reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development drilling, prevailing natural gas and oil prices and other factors, many of which are beyond our control. Our properties may also be susceptible to hydrocarbon drainage from production by operators on adjacent properties.

At December 31, 2009, approximately 42% of our estimated proved reserves (by volume) were undeveloped. These reserve estimates reflect our plans to make significant capital expenditures to convert our proved undeveloped reserves into proved developed reserves, including approximately $929 million in 2010. You should be aware that the estimated development costs may not be accurate, development may not occur as scheduled and results may not be as estimated.

You should not assume that the present values referred to in this report represent the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, the estimates of our present values are based on prices and costs as of the date of the estimates. The price on the date of estimate is calculated as the average natural gas and oil price during the 12 months ending in the current reporting period, determined as the unweighted arithmetical average of prices on the first day of each month within the 12-month period. The December 31, 2009 present value is based on $3.87 per mcf of natural gas and $61.14 per barrel of oil before price differential adjustments. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of an estimate.

Any changes in consumption by natural gas and oil purchasers or in governmental regulations or taxation will also affect the actual future net cash flows from our production.

The timing of both the production and the expenses from the development and production of natural gas and oil properties will affect both the timing of actual future net cash flows from our proved reserves and their present value. In addition, the 10% discount factor which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes is not necessarily the most accurate discount factor. The effective interest rate at various times and the risks associated with our business or the natural gas and oil industry in general will affect the accuracy of the 10% discount factor.

Our 2009 year-end reserve estimates are not directly comparable to prior estimates because of new reporting rules, and our interpretations of the new rules may differ materially from future guidance or comments issued by the SEC.

The year-end 2009 proved reserves estimates presented in this report have been prepared using new SEC disclosure rules that differ in a number of respects from prior rules. As a result of changes in the reporting rules, our reserve estimates beginning with year-end 2009 will not be directly comparable to our previously-reported reserves.

The SEC has not reviewed our or any reporting company's reserve estimates under the new rules and has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules. Accordingly, while the estimates of our proved reserves at December 31, 2009 included in this report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the new SEC rules, those estimates could differ materially from any estimates we might prepare applying more specific SEC interpretive guidance.

Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

We acquire significant amounts of unproved property in order to further our development efforts. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our initial investments. Additionally, there can be no assurance that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Drilling for natural gas and oil may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient commercial quantities to cover the drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and many factors can adversely affect the economics of a well or property. Drilling operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, equipment failures or accidents, shortages of equipment or personnel, environmental issues and for other reasons. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and future market prices for natural gas and crude oil, costs associated with producing natural gas and oil and our ability to add reserves at an acceptable cost. We rely to a significant extent on seismic data and other advanced technologies in identifying unproved property prospects and in conducting our exploration activities. The seismic data and other technologies we use do not allow us to know conclusively, prior to acquisition of unproved property or drilling a well, whether natural gas or oil is present or may be produced economically. The use of seismic data and other technologies also requires greater pre-drilling expenditures than traditional drilling strategies. Drilling results in our newer shale plays may be more uncertain than in shale plays that are more developed and have longer established production histories, and we can provide no assurance that drilling and completion techniques that have proven to be successful in other shale formations to maximize recoveries will be ultimately successful when used in new shall formations.

Certain of our undeveloped leasehold assets are subject to leases that will expire over the next several years unless production is established on units containing the acreage.

As of December 31, 2009, we had leases on approximately 0.51 million and 1.62 million net acres, respectively, in the Haynesville and Marcellus Shale areas. A sizeable portion of this acreage is not currently held by production. Unless production in paying quantities is established on units containing these leases during their terms, the leases will expire. If our leases expire and we are unable to renew the leases, we will lose our right to develop the related properties. While the company intends to drill sufficient wells to hold the vast majority of its leasehold in all its major plays, our drilling plans for these areas are subject to change based upon various factors, including drilling results, natural gas and oil prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals.

Our hedging activities may reduce the realized prices received for our natural gas and oil sales, require us to provide collateral for hedging liabilities and involve risk that our counterparties may be unable to satisfy their obligations to us.

In order to manage our exposure to price volatility in marketing our natural gas and oil, we enter into natural gas and oil price risk management arrangements for a portion of our expected production. Commodity price hedging may limit the prices we actually realize and therefore reduce natural gas and oil revenues in the future. Our commodity hedging activities will impact our earnings in various ways, including recognition of certain mark-to-market gains and losses on derivative instruments. The fair value of our natural gas and oil derivative instruments can fluctuate significantly between periods. In addition, our commodity price risk management transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement; or
- the counterparties to our contracts fail to perform under the contracts.

Hedging transactions involve the risk that counterparties, which are generally financial institutions, may be unable to satisfy their obligations to us. Although our counterparties to our multi-counterparty secured hedge facility are required to secure their hedging obligations to us under certain scenarios, if any of our counterparties were to default on its obligations to us under the hedging contracts or seek bankruptcy protection, it could have an adverse effect on our ability to fund our planned activities and could result in a larger percentage of our future production being subject to commodity price changes. The risk of counterparty default is heightened in a poor economic environment.

A substantial portion of our natural gas and oil derivative contracts are with the 13 counterparties to our multi-counterparty hedging facility. Our obligations under the facility are secured by natural gas and oil proved reserves, the value of which must cover the fair value of the transactions outstanding under the facility by at least 1.65 times. If the collateral value falls below the coverage designated, we would be required to post cash or letters of credit with the counterparties if we did not have sufficient unencumbered natural gas and oil properties available to cover the shortfall. Future collateral requirements are dependent to a great extent on natural gas and oil prices.

Lower natural gas and oil prices could negatively impact our ability to borrow or raise additional capital.

Our corporate revolving bank credit facility limits our borrowings to the lesser of the borrowing base and the total commitments. Currently both are $3.5 billion, although one lender, Lehman Brothers Commercial Bank, has not funded its share (2.1%) of our borrowings under the facility beginning in the third quarter of 2008, and we do not expect that it would fund any future borrowings. The borrowing base is determined periodically at the discretion of the banks and is based in part on natural gas and oil prices. Additionally, some of our indentures contain covenants limiting our ability to incur indebtedness in addition to that incurred under our corporate revolving bank credit facility. These indentures limit our ability to incur additional indebtedness unless we meet one of two alternative tests. The first alternative is based on our adjusted consolidated net tangible assets (as defined in all of our indentures), which is determined using discounted future net revenues from proved natural gas and oil reserves as of the determination date. The second alternative is based on the ratio of our adjusted consolidated EBITDA (as defined in the relevant indentures) to our adjusted consolidated interest expense (as defined in the relevant indentures) over a trailing 12-month period. Currently, we are permitted to incur additional indebtedness under the second incurrence test but not the first test. Lower natural gas and oil prices in the future could reduce our adjusted consolidated EBITDA, as well as our adjusted consolidated net tangible assets, and thus could reduce our ability to incur additional indebtedness.

Natural gas and oil drilling and producing operations can be hazardous and may expose us to liabilities, including environmental liabilities.

Natural gas and oil operations are subject to many risks, including well blowouts, cratering and explosions, pipe failures, fires, formations with abnormal pressures, uncontrollable flows of natural gas, oil, brine or well fluids and other environmental hazards and risks. Our drilling operations involve risks from high pressures and from mechanical difficulties such as stuck pipes, collapsed casings and separated cables. If any of these risks occurs, we could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources or equipment;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigations and administrative, civil and criminal penalties; and
- injunctions resulting in limitation or suspension of operations.

There is inherent risk of incurring significant environmental costs and liabilities in our exploration and production operations due to our generation, handling and disposal of materials, including wastes and petroleum hydrocarbons. We may incur joint and several, strict liability under applicable U.S.

federal and state environmental laws in connection with releases of petroleum hydrocarbons and other hazardous substances at, on, under or from our leased or owned properties, some of which have been used for natural gas and oil exploration and production activities for a number of years, often by third parties not under our control. For our non-operated properties, we are dependent on the operator for operational and regulatory compliance. While we may maintain insurance against some, but not all, of the risks described above, our insurance may not be adequate to cover casualty losses or liabilities, and our insurance does not cover penalties or fines that may be assessed by a governmental authority. Also, in the future we may not be able to obtain insurance at premium levels that justify its purchase.

Potential legislative and regulatory actions could increase our costs, reduce our revenue and cash flow from natural gas and oil sales, reduce our liquidity or otherwise alter the way we conduct our business.

The activities of exploration and production companies operating in the United States are subject to extensive regulation at the federal, state and local levels. Changes to existing laws and regulations or new laws and regulations such as those described below could, if adopted, have an adverse effect on our business.

Federal Taxation of Independent Producers

Federal budget proposals would potentially increase and accelerate the payment of federal income taxes of independent producers of natural gas and oil. Proposals that would significantly affect us would repeal the expensing of intangible drilling costs, repeal the percentage depletion allowance and increase the amortization period of geological and geophysical expenses. These changes, if enacted, will make it more costly for us to explore for and develop our natural gas and oil resources.

Derivatives Trading

The U.S. Congress is considering measures aimed at increasing the transparency and stability of the over-the-counter (OTC) derivative markets and preventing excessive speculation. We maintain an active price and basis protection hedging program related to the natural gas and oil we produce to manage the risk of low commodity prices and to predict with greater certainty the cash flow from our hedged production. We have used the OTC market exclusively for our natural gas and oil derivative contracts. Some proposals being considered would impose clearing and standardization requirements for all OTC derivatives and restrict trading positions in the energy futures markets. Such changes would likely materially reduce our hedging opportunities and could negatively affect our revenues and cash flow during periods of low commodity prices.

Hydraulic Fracturing

It is customary in our industry that most natural gas and oil wells use the hydraulic fracturing process. Certain environmental and other groups have suggested that additional laws and regulations may be needed to more closely regulate the hydraulic fracturing process, and legislation has been proposed by some members of Congress to provide for such regulation. We cannot predict whether any such federal or state legislation or regulation will be enacted and if so, what its provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations, our business and operations could be subject to delays, increased operating and compliance costs and process prohibitions.

Climate Change

The U.S. government is considering enacting new legislation or promulgating new regulations governing or restricting the emission of greenhouse gases from stationary sources such as our equipment and operations. The EPA has already made findings and issued proposed regulations that could lead to the imposition of restrictions on greenhouse gas emissions from stationary sources such as ours. In addition, the U.S. Congress has been considering various bills that would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. Such a program, if enacted, could require phased reductions in greenhouse gas emissions over several or many years as could the issuance of a declining number of tradable allowances to sources of these emissions so that they may continue to emit greenhouse gases into the atmosphere. Legislative and regulatory proposals for restricting greenhouse gas emissions or otherwise addressing climate change could require us to incur additional operating costs and could aversely affect demand for the natural gas and oil that we sell. The potential increase in our operating costs could include new or increased costs to operate and maintain our equipment and facilities, install new emission controls on our equipment and facilities, acquire allowances to authorize our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for natural gas and oil.

The recent decline in general economic, business or industry conditions and the current economic uncertainty may have a material adverse effect on our results of operations, liquidity and financial condition.

Recently, concerns over inflation, energy costs, geopolitical issues, the availability and cost of credit, the U.S. mortgage market and a declining real estate market in the United States have contributed to increased economic uncertainty and diminished expectations for the global economy.

These factors, combined with volatile natural gas and oil prices, the recent decline in business and consumer confidence and increased unemployment, have precipitated an economic slowdown and a recession. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates further, demand for petroleum products could continue to diminish and prices for natural gas and oil could continue to decrease, which could adversely impact our results of operations, liquidity and financial condition.

Our cash flow from operations, our revolving bank credit facilities and cash on hand historically have not been sufficient to fund all of our expenditures, and we have relied on the capital markets and asset monetization transactions to provide us with additional capital. Poor economic conditions may negatively affect:

- our ability to access the capital markets at a time when we would like, or need, to raise capital;
- the number of participants in our proposed asset monetization transactions or the values we are able to realize in those transactions, making them uneconomic or harder or impossible to consummate;
- the collectability of our trade receivables could cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection; or
- the ability of our joint venture partners to meet their obligations to fund a portion of our drilling costs in the Marcellus or Barnett Shale plays as agreed under our joint venture arrangements.

Our ability to sell natural gas and/or receive market prices for our natural gas may be adversely affected by pipeline and gathering system capacity constraints and various transportation interruptions.

If drilling in the Haynesville and Marcellus Shales continues to be successful, the amount of natural gas being produced by us and others could exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available in these areas. If this occurs, it will be necessary for new pipelines and gathering systems to be built. Because of the current economic climate, certain pipeline projects that are planned for the Haynesville and Marcellus Shale areas may not occur for lack of financing. In addition, capital constraints could limit our ability to build intrastate gathering systems necessary to transport our gas to interstate pipelines. In such event, we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell natural gas production at significantly lower prices than those quoted on NYMEX or than we currently project, which would adversely affect our results of operations.

A portion of our natural gas and oil production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow.

ITEM 1B. *Unresolved Staff Comments*

None.

ITEM 2. *Properties*

Information regarding our properties is included in Item 1 and in Note 10 of the notes to our consolidated financial statements included in Item 8 of this report.

ITEM 3. *Legal Proceedings*

Litigation

On February 25, 2009, a putative class action was filed in the U.S. District Court for the Southern District of New York against the company and certain of its officers and directors along with certain underwriters of the company's July 2008 common stock offering. Following the appointment of a lead plaintiff and counsel, the plaintiff filed an amended complaint on September 11, 2009 alleging that the registration statement for the offering contained material misstatements and omissions and seeking damages under Sections 11, 12 and 15 of the Securities Act of 1933 of an unspecified amount and rescission. The action was transferred to the U.S. District Court for the Western District of Oklahoma on October 13, 2009. The company has filed a motion to dismiss which has not been fully briefed. A derivative action was also filed in the District Court of Oklahoma County, Oklahoma on March 10, 2009 against the company's directors and certain of its officers alleging breaches of fiduciary duties relating to the disclosure matters alleged in the securities case.

On March 26, 2009, a shareholder filed a petition in the District Court of Oklahoma County, Oklahoma seeking to compel inspection of company books and records relating to compensation of the company's CEO. On August 20, 2009, the court denied the inspection demand, dismissed the petition and entered judgment in favor of Chesapeake. The shareholder is appealing the court's ruling.

Three derivative actions were filed in the District Court of Oklahoma County, Oklahoma on April 28, May 7, and May 20, 2009 against the company's directors alleging breaches of fiduciary duties relating to compensation of the company's CEO and alleged insider trading, among other things, and seeking unspecified damages, equitable relief and disgorgement. These three derivative actions were consolidated and a Consolidated Derivative Shareholder Petition was filed on June 23, 2009. Chesapeake is named as a nominal defendant. Chesapeake has filed a motion to dismiss which was heard on February 1, 2010. On February 26, 2010, the court ordered that plaintiffs' claims be dismissed and granted plaintiffs leave to file an amended petition within 90 days.

It is inherently difficult to predict the outcome of litigation, and we are currently unable to estimate the amount of any potential liabilities associated with the foregoing cases, which are all in preliminary stages.

Chesapeake is also involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, claims for underpayment of royalties, property damage claims and contract actions. With regard to the latter, several mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their oil and natural gas interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The company has satisfactorily resolved several of the suits but some remain pending. The remaining leasehold acquisition cases are in various stages of discovery. The company believes that it has substantial defenses to the claims made in all these cases.

ITEM 4. Reserved.

Part II

ITEM 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Price Range of Common Stock

Our common stock trades on the New York Stock Exchange under the symbol "CHK". The following table sets forth, for the periods indicated, the high and low sales prices per share of our common stock as reported by the New York Stock Exchange:

	Common Stock	
	High	Low
Year ended December 31, 2009:		
Fourth Quarter	$30.00	$22.06
Third Quarter	$29.49	$16.92
Second Quarter	$24.66	$16.43
First Quarter	$20.13	$13.27
Year ended December 31, 2008:		
Fourth Quarter	$35.46	$ 9.84
Third Quarter	$74.00	$31.15
Second Quarter	$68.10	$45.25
First Quarter	$49.87	$34.42

At February 23, 2010, there were approximately 2,050 holders of record of our common stock and approximately 466,700 beneficial owners.

Dividends

The following table sets forth the amount of dividends per share declared on Chesapeake common stock during 2009 and 2008:

	2009	2008
Fourth Quarter	$0.075	$ 0.075
Third Quarter	$0.075	$ 0.075
Second Quarter	$0.075	$ 0.075
First Quarter	$0.075	$0.0675

While we expect to continue to pay dividends on our common stock, the payment of future cash dividends is subject to the discretion of our Board of Directors and will depend upon, among other things, our financial condition, our funds from operations, the level of our capital and development expenditures, our future business prospects, contractual restrictions and other factors considered relevant by the Board of Directors.

In addition, our corporate revolving bank credit facility and the indentures governing certain of our outstanding senior notes contain restrictions on our ability to declare and pay cash dividends. Under the corporate revolving bank credit facility and these indentures, we may not pay any cash dividends on our common or preferred stock if an event of default has occurred. These indentures further restrict cash dividends if we have not met one of the two debt incurrence tests set forth in the indentures, or if immediately after giving effect to the dividend payment, we have paid total dividends and made other restricted payments in excess of the permitted amounts. As of December 31, 2009, our coverage ratio for purposes of the debt incurrence test under the relevant indentures was 5.33 to 1, compared to a minimum of 2.25 to 1 required in such indentures. Our adjusted consolidated net tangible assets did not exceed 200% of our total indebtedness.

The certificates of designation for our preferred stock prohibit payment of cash dividends on our common stock unless we have declared and paid (or set apart for payment) full accumulated dividends on the preferred stock.

Purchases of Common Stock

The following table presents information about repurchases of our common stock during the three months ended December 31, 2009:

Period	Total Number of Shares Purchased[(a)]	Average Price Paid Per Share[(a)]	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs[(b)]
October 1, 2009 through October 31, 2009	56,574	$ 26.35	—	—
November 1, 2009 through November 30, 2009	19,013	$ 24.01	—	—
December 1, 2009 through December 31, 2009	18,114	$ 26.13	—	—
Total	93,701	$ 26.17	—	—

(a) Represents the surrender to the company of shares of common stock to pay withholding taxes in connection with the vesting of employee restricted stock.

(b) We make matching contributions to our 401(k) plan and deferred compensation plan using Chesapeake common stock which is held in treasury or is purchased by the respective plan trustees in the open market. The plans contain no limitation on the number of shares that may be purchased for the purposes of the company contributions. There are no other repurchase plans or programs currently authorized by the Board of Directors.

ITEM 6. *Selected Financial Data*

As further discussed in Note 3 of the notes to our consolidated financial statements, our consolidated financial statements for each period presented have been adjusted for the retrospective application of accounting guidance for debt with conversion and other options. The impact of the application of this standard is reflected in the table below.

The following table sets forth selected consolidated financial data of Chesapeake for the years ended December 31, 2009, 2008, 2007, 2006 and 2005. The data are derived from our audited consolidated financial statements revised to reflect the reclassification of certain items. Changes in annual average natural gas and oil prices and increased production from drilling and acquisition activity in recent years have impacted comparability between years. See Note 10 of the notes to our consolidated financial statements. The table should be read in conjunction with *Management's Discussion and Analysis of Financial Condition and Results of Operations* and our consolidated financial statements, including the notes, appearing in Items 7 and 8 of this report.

	Years Ended December 31,				
	2009	2008	2007	2006	2005
Statement of Operations Data:	($ in millions, except per share data)				
REVENUES:					
Natural gas and oil sales	$5,049	$ 7,858	$5,624	$5,619	$3,273
Marketing, gathering and compression sales	2,463	3,598	2,040	1,577	1,392
Service operations revenue	190	173	136	130	—
Total revenues	7,702	11,629	7,800	7,326	4,665

	Years Ended December 31,				
	2009	2008	2007	2006	2005
	($ in millions, except per share data)				
Statement of Operations Data – (Continued):					
OPERATING COSTS:					
Production expenses	876	889	640	490	317
Production taxes	107	284	216	176	208
General and administrative expenses	349	377	243	139	64
Marketing, gathering and compression expenses	2,316	3,505	1,969	1,522	1,358
Service operations expense	182	143	94	68	—
Natural gas and oil depreciation, depletion and amortization	1,371	1,970	1,835	1,359	894
Depreciation and amortization of other assets	244	174	153	103	51
Impairment of natural gas and oil properties and other assets	11,130	2,830	—	—	—
Loss on sale of other property and equipment	38	—	—	—	—
Restructuring costs	34	—	—	—	—
Employee retirement expense	—	—	—	55	—
Total Operating Costs	16,647	10,172	5,150	3,912	2,892
INCOME (LOSS) FROM OPERATIONS	(8,945)	1,457	2,650	3,414	1,773
OTHER INCOME (EXPENSE):					
Other income (expense)	(28)	(11)	15	26	10
Interest expense	(113)	(271)	(401)	(316)	(221)
Impairment of investments	(162)	(180)	—	—	—
Loss on exchanges or repurchases of Chesapeake debt	(40)	(4)	—	—	(70)
Gain on sale of investments	—	—	83	117	—
Total Other Income (Expense)	(343)	(466)	(303)	(173)	(281)
INCOME (LOSS) BEFORE INCOME TAXES	(9,288)	991	2,347	3,241	1,492
INCOME TAX EXPENSE (BENEFIT):					
Current income taxes	4	423	29	5	—
Deferred income taxes	(3,487)	(36)	863	1,242	545
Total Income Tax Expense (Benefit)	(3,483)	387	892	1,247	545
NET INCOME (LOSS)	(5,805)	604	1,455	1,994	947
Net (income) loss attributable to noncontrolling interest	(25)	—	—	—	—
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(5,830)	604	1,455	1,994	947
Preferred stock dividends	(23)	(33)	(94)	(89)	(42)
Loss on conversion/exchange of preferred stock	—	(67)	(128)	(10)	(26)
NET INCOME (LOSS) AVAILABLE TO CHESAPEAKE COMMON STOCKHOLDERS	$ (5,853)	$ 504	$ 1,233	$ 1,895	$ 879
EARNINGS (LOSS) PER COMMON SHARE:					
Basic	$ (9.57)	$ 0.94	$ 2.70	$ 4.76	$ 2.73
Assuming dilution	$ (9.57)	$ 0.93	$ 2.63	$ 4.33	$ 2.51
CASH DIVIDENDS DECLARED PER COMMON SHARE	$ 0.30	$0.2925	$0.2625	$ 0.23	$ 0.195
CASH FLOW DATA:					
Cash provided by operating activities	$ 4,356	$ 5,357	$ 4,974	$ 4,843	$ 2,407
Cash used in investing activities	5,462	9,965	7,964	8,942	6,921
Cash (used in) provided by financing activities	(336)	6,356	2,988	4,042	4,567
BALANCE SHEET DATA (AT END OF PERIOD):					
Total assets	$29,914	$38,593	$30,764	$24,413	$16,114
Long-term debt, net of current maturities	12,295	13,175	10,178	7,187	5,286
Total equity	12,341	17,017	12,624	11,366	6,299

ITEM 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

Financial Data

The following table sets forth certain information regarding the production volumes, natural gas and oil sales, average sales prices received, other operating income and expenses for the periods indicated:

	Years Ended December 31,		
	2009	2008	2007
Net Production:			
Natural gas (bcf)	834.8	775.4	655.0
Oil (mmbbl)	11.8	11.2	9.9
Natural gas equivalent (bcfe)	905.5	842.7	714.3
Natural Gas and Oil Sales ($ in millions):			
Natural gas sales	$ 2,635	$ 6,003	$ 4,117
Natural gas derivatives – realized gains (losses)	2,313	267	1,214
Natural gas derivatives – unrealized gains (losses)	(492)	521	(139)
Total natural gas sales	4,456	6,791	5,192
Oil sales	656	1,066	678
Oil derivatives – realized gains (losses)	33	(275)	(11)
Oil derivatives – unrealized gains (losses)	(96)	276	(235)
Total oil sales	593	1,067	432
Total natural gas and oil sales	$ 5,049	$ 7,858	$ 5,624
Average Sales Price (excluding gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 3.16	$ 7.74	$ 6.29
Oil ($ per bbl)	$ 55.60	$ 95.04	$ 68.64
Natural gas equivalent ($ per mcfe)	$ 3.63	$ 8.39	$ 6.71
Average Sales Price (excluding unrealized gains (losses on derivatives):			
Natural gas ($ per mcf)	$ 5.93	$ 8.09	$ 8.14
Oil ($ per bbl)	$ 58.38	$ 70.48	$ 67.50
Natural gas equivalent ($ per mcfe)	$ 6.22	$ 8.38	$ 8.40
Other Operating Income[(a)] ($ in millions):			
Marketing, gathering and compression net margin	$ 147	$ 93	$ 71
Service operations net margin	$ 8	$ 30	$ 42
Other Operating Income[(a)] ($ per mcfe):			
Marketing, gathering and compression net margin	$ 0.16	$ 0.11	$ 0.10
Service operations net margin	$ 0.01	$ 0.04	$ 0.06
Expenses ($ per mcfe):			
Production expenses	$ 0.97	$ 1.05	$ 0.90
Production taxes	$ 0.12	$ 0.34	$ 0.30
General and administrative expenses	$ 0.38	$ 0.45	$ 0.34
Natural gas and oil depreciation, depletion and amortization	$ 1.51	$ 2.34	$ 2.57
Depreciation and amortization of other assets	$ 0.27	$ 0.21	$ 0.21
Interest expense[(b)]	$ 0.22	$ 0.22	$ 0.50
Interest Expense ($ in millions):			
Interest expense	$ 227	$ 192	$ 360
Interest rate derivatives – realized (gains) losses	(23)	(6)	1
Interest rate derivatives – unrealized (gains) losses	(91)	85	40
Total interest expense	$ 113	$ 271	$ 401
Net Wells Drilled	1,003	1,733	1,919
Net Producing Wells as of the End of Period	22,919	22,813	21,404

(a) Includes revenue and operating costs and excludes depreciation and amortization of other assets.

(b) Includes the effects of realized (gains) losses from interest rate derivatives, but excludes the effects of unrealized (gains) losses and is net of amounts capitalized.

We manage our business as three separate operational segments: exploration and production; marketing, gathering and compression (midstream); and service operations, which is comprised of our wholly-owned drilling and trucking operations. We refer you to Note 17 of the notes to our consolidated financial statements appearing in Item 8 of this report, which summarizes by segment our net income and capital expenditures for 2009, 2008 and 2007 and our assets as of December 31, 2009, 2008 and 2007.

Executive Summary

We are the second-largest producer of natural gas in the United States. We own interests in approximately 44,100 producing oil and natural gas wells that are currently producing approximately 2.4 bcfe per day, 93% of which is natural gas. Our strategy is focused on discovering, acquiring and developing conventional and unconventional natural gas reserves onshore in the U.S., primarily in our "Big 6" natural gas shale plays: the Barnett Shale in the Fort Worth Basin of north-central Texas, the Haynesville and Bossier Shales in the Ark-La-Tex area of northwestern Louisiana and East Texas, the Fayetteville Shale in the Arkoma Basin of central Arkansas, the Marcellus Shale in the northern Appalachian Basin of West Virginia, Pennsylvania and New York and the Eagle Ford Shale in South Texas. We also have substantial operations in the Granite Wash Plays of western Oklahoma and the Texas Panhandle regions as well as various other plays, both conventional and unconventional, in the Mid-Continent, Appalachian Basin, Permian Basin, Delaware Basin, South Texas, Texas Gulf Coast and Ark-La-Tex regions of the U.S.

We have recently announced that we are extending our strategy to apply the horizontal drilling expertise we have gained in our natural gas shale plays to unconventional oil reservoirs. We expect to begin increasing our production of oil and natural gas liquids in 2010 in new developing unconventional oil plays, particularly in the Granite Wash and Eagle Ford.

Chesapeake began 2009 with estimated proved reserves of 12.051 tcfe and ended the year with 14.254 tcfe, an increase of 2.203 tcfe, or 18%. During 2009, we replaced 906 bcfe of production with an estimated 3.019 tcfe of new proved reserves, for a reserve replacement rate of 343%. Reserve replacement through the drillbit was 3.296 tcfe, or 364% of production, including 445 bcfe of downward revisions resulting from changes to previous estimates and 952 bcfe of downward revisions resulting from lower natural gas prices using the average 12-month price in 2009 compared to the spot price as of December 31, 2008. During 2009, we acquired 33 bcfe of estimate proved reserves and divested 220 bcfe of estimated proved reserves.

Chesapeake continued the industry's most active drilling program in 2009 and drilled 1,212 gross (885 net) operated wells and participated in another 994 gross (118 net) wells operated by other companies. The company's drilling success rate was 99% for company-operated wells and 98% for non-operated wells. Also during 2009, we invested $2.941 billion in operated wells (using an average of 104 operated rigs) and $439 million in non-operated wells (using an average of 60 non-operated rigs) for total drilling, completing and equipping costs of $3.380 billion.

Since 2000, Chesapeake has built the largest combined inventories of onshore leasehold (13.2 million net acres) and 3-D seismic (23.6 million acres) in the U.S. We are currently using 118 operated rigs and 70 non-operated rigs to further develop our inventory of approximately 35,750 net drillsites, which represents more than a 10-year inventory of drilling projects.

Business Strategy

Our exploration, acquisition and development activities require us to make substantial operating and capital expenditures. Our current budgeted drilling capital expenditures, net of drilling carries, are \$4.100 billion to \$4.400 billion in 2010 and \$4.300 billion to \$4.600 billion in 2011. We anticipate directing approximately 75% of the drilling capital expenditure (before drilling carries) during 2010 and 2011 to our Big 6 shale plays.

During 2009, our exploration and development costs were significantly lower than 2008 costs as a result of a significant decrease in drilling activity and the benefit of approximately \$1.2 billion of joint venture drilling carries in four of our Big 6 shale plays. We expect exploration and development costs to generally increase in 2010, partially offset by the use of a portion of our remaining \$3.4 billion of drilling carries associated with our joint ventures in the Barnett and Marcellus Shales. These drilling carries create a significant cost advantage for us that will allow us to continue to drive down finding costs. The following table provides information about the joint ventures (\$ in millions):

Shale Play	Joint Venture Partner[a]	Joint Venture Date	Proceeds Received at Closing	Total Drilling Carries	Drilling Carries Remaining
Haynesville and Bossier	PXP	July 2008	\$ 1,650	\$ 1,508[b]	\$ —
Fayetteville	BP	September 2008	1,100	800	—
Marcellus	STO	November 2008	1,250	2,125	1,963[c]
Barnett	TOT	January 2010	800	1,450	1,450[d]
			\$ 4,800	\$ 5,883	\$ 3,413

(a) Joint venture partners include Plains Exploration & Production Company (PXP), BP America (BP), Statoil (STO) and Total S.A. (TOT).

(b) In August 2009, we amended our Haynesville Shale joint venture agreement with Plains Exploration & Production Company (PXP). As part of the amendment, PXP accelerated the payment of its remaining joint venture drilling carries as of September 30, 2009 in exchange for an approximate 12% reduction in the total amount of drilling carry obligations due to Chesapeake. As a result, on September 29, 2009, Chesapeake received \$1.1 billion in cash from PXP and beginning in the 2009 fourth quarter Chesapeake and PXP each began paying their proportionate working interest costs on drilling.

(c) As of December 31, 2009

(d) As of January 26, 2010

Collectively, in these four joint ventures, we received upfront cash payments of \$4.8 billion and future drilling cost carries of up to \$5.9 billion for total consideration of up to \$10.7 billion against a cost basis of approximately \$2.7 billion in the property interests we sold. Moreover, Chesapeake retained an 80% interest in the Haynesville and Bossier Shale properties, a 75% interest in the Fayetteville Shale properties, a 67.5% interest in the Marcellus Shale properties and a 75% interest in the Barnett Shale properties.

The joint ventures in our Big 6 shale plays are a complementary part of our business strategy to maximize the value of our leasehold inventory and minimize our investment risk. There are other new plays we are identifying and developing which may become additional joint venture opportunities. Our 50/50 joint venture with Global Infrastructure Partners in 2009 is another example of our joining with a strong partner to develop key assets, in this case, our midstream assets in the Barnett Shale and other midstream assets in the Mid-Continent. At the closing of this transaction, we received proceeds of \$588 million. During 2009, we sold non-core natural gas and oil assets for proceeds of \$418 million. Over the next two years, we expect to be a net seller of leasehold and producing properties.

Apart from asset monetizations, cash flow from operations is our primary source of liquidity used to fund operating expenses and capital expenditures. Our $3.5 billion corporate revolving bank credit facility, our $250 million midstream revolving bank credit facility and the company's $500 million midstream joint venture revolving bank credit facility, discussed more fully in *Liquidity and Capital Resources,* provide us with additional liquidity. In February 2009, we issued $1.425 billion principal amount of our 9.5% senior notes due 2015. Net proceeds of $1.346 billion were used to repay outstanding indebtedness under our revolving bank credit facility, which we reborrow from time to time to fund drilling and leasehold acquisition initiatives and for general corporate purposes. At December 31, 2009, we had borrowings of $1.936 billion and letters of credit of $41 million outstanding under our credit facilities.

We plan to continue to evaluate asset monetization transactions in order to create additional value from our proved and unproved properties and to increase our financial flexibility. Management believes that our leasehold and development joint ventures and various asset monetization programs benefit the company by improving our asset base, reducing our financial risk, decreasing our DD&A rate and increasing our profitability per unit of production, thereby increasing our returns on capital and advancing future value creation. We may also consider alternative sources of public or private investment in the company or its subsidiaries. While we believe that our anticipated internally generated cash flow, cash resources and other sources of liquidity will allow us to fully fund our 2010 operating and capital expenditure requirements, further deterioration of the economy and other factors could require us to fund these expenditures from monetization transactions or further curtail our spending.

Liquidity and Capital Resources

Sources and Uses of Funds

Cash flow from operations is a significant source of liquidity used to fund operating expenses and capital expenditures. Cash provided by operating activities was $4.356 billion in 2009, compared to $5.357 billion in 2008 and $4.974 billion in 2007. The $1.001 billion decrease from 2008 to 2009 was primarily due to lower natural gas and oil prices. The $383 million increase from 2007 to 2008 was primarily due to higher natural gas volumes and higher oil prices. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding non-cash items such as depreciation, depletion and amortization, deferred income taxes and unrealized gains and (losses) on derivatives. See the discussion below under *Results of Operations.*

Changes in market prices for natural gas and oil directly impact the level of our cash flow from operations. To mitigate the risk of declines in natural gas or oil prices and to provide more predictable future cash flow from operations, as of February 17, 2010, we have hedged through swaps and collars approximately 60% of our expected natural gas and oil production in 2010 at average prices of $8.16 per mcfe. Our natural gas and oil hedges as of December 31, 2009 are detailed in Item 7A of this report. Depending on changes in natural gas and oil futures markets and management's view of underlying natural gas and oil supply and demand trends, we may increase or decrease our current hedging positions.

Our $3.5 billion corporate revolving bank credit facility, our $250 million midstream revolving bank credit facility, our $500 million midstream joint venture revolving bank credit facility and cash and cash equivalents are other sources of liquidity. Following the January 2010 closing of our Barnett Shale joint venture with Total for $800 million in cash and the February 2010 closing of our sixth VPP transaction for $180 million in cash, as of February 26, 2010, there was $2.245 billion of borrowing capacity under the corporate credit facility, $237 million of borrowing capacity under the midstream credit facility and $482 million under the midstream joint venture credit facility. We use the facilities and cash on hand to fund daily operating activities and acquisitions as needed. We borrowed $7.8 billion and repaid $9.8

billion in 2009, we borrowed $13.3 billion and repaid $11.3 billion in 2008 and we borrowed $7.9 billion and repaid $6.2 billion in 2007 under our bank credit facilities. A substantial portion of our natural gas and oil properties is currently unencumbered and therefore available to be pledged as additional collateral under our corporate revolving bank credit facility if needed based on our periodic borrowing base and collateral redeterminations. Accordingly, we believe our borrowing capacity under this facility will not be reduced as a result of any such future periodic redeterminations. Our two midstream facilities are secured by substantially all of our midstream assets and are not subject to periodic borrowing base redeterminations.

The following table reflects the proceeds from sales of securities we issued in 2009, 2008 and 2007 ($ in millions):

	2009		2008		2007	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
Senior notes	$ 1,425	$ 1,346	$ 800	$ 787	$ —	$ —
Contingent convertible senior notes	—	—	1,380	1,349	1,650	1,607
Common stock	—	—	2,698	2,598	—	—
Total	$ 1,425	$ 1,346	$ 4,878	$ 4,734	$ 1,650	$ 1,607

The following table reflects proceeds we received from our major natural gas and oil asset monetizations in 2009, 2008 and 2007 ($ in millions).

	2009	2008	2007
Natural gas and oil property monetizations:			
STO (Marcellus) joint venture[(a)]	$ 162	$1,250	$ —
PXP (Haynesville) joint venture[(b)]	1,490	1,722	—
BP (Fayetteville) joint venture[(c)]	601	1,299	—
BP (Mid-Continent) divestiture	—	1,688	—
Volumetric production payments	408	1,579	1,089
Other divestitures	418	403	—
Total	$3,079	$7,941	$1,089

(a) 2009 proceeds were in the form of drilling carries. As of December 31, 2009, $2.0 billion of drilling carry obligations remained outstanding.

(b) 2009 and 2008 included $390 million and $72 million of drilling carries, respectively. 2009 also included a $1.1 billion acceleration of future drilling carries.

(c) 2009 and 2008 included $601 million and $199 million of drilling carries, respectively.

In September 2009, we formed a joint venture with Global Infrastructure Partners (GIP), a New York-based private equity fund, to own and operate natural gas midstream assets. As part of the transaction, we contributed certain natural gas gathering and processing assets into a new entity, Chesapeake Midstream Partners, L.L.C. (CMP), and GIP purchased a 50% interest in CMP for $588 million in cash.

In June 2009, we received net proceeds of $54 million from the mortgage financing of our regional Barnett Shale headquarters building in Fort Worth, Texas. The interest-only loan has a five-year term at a floating rate of prime plus 275 basis points. At our option, we may prepay the loan in full without penalty beginning in year four.

In April 2009, we financed 113 real estate surface assets in the Barnett Shale area in and around Fort Worth, Texas for net proceeds of approximately $145 million and entered into a master lease agreement under which we agreed to lease the assets for 40 years for approximately $15 million to $27 million annually. This lease transaction was recorded as a financing lease.

Our primary use of funds is for capital expenditures related to exploration, development and acquisition of natural gas and oil properties. We refer you to the table under *Investing Activities* below, which sets forth the components of our natural gas and oil investing activities and other investing activities for 2009, 2008 and 2007. We retain a significant degree of control over the timing of our capital expenditures which permits us to defer or accelerate certain capital expenditures if necessary to address any potential liquidity issues. In addition, higher drilling and field operating costs, drilling results that alter planned development schedules, acquisitions or other factors could cause us to revise our drilling program, which is largely discretionary.

We paid dividends on our common stock of $181 million, $148 million and $115 million in 2009, 2008 and 2007, respectively. The Board of Directors increased the quarterly dividend of common stock from $0.0675 to $0.075 per share beginning with the dividend paid in July 2008. Dividends paid on our preferred stock decreased to $23 million in 2009 from $35 million in 2008 and $95 million in 2007 as a result of conversions and exchanges of preferred stock into common stock during 2007, 2008 and 2009.

In 2009, 2008 and 2007, we received $24 million, and paid $167 million and $91 million, respectively, to settle a portion of the derivative liabilities assumed in our 2005 acquisition of Columbia Natural Resources, LLC. Additionally in 2009, we received $85 million for settlements of derivatives which were classified as financing derivatives.

Credit Risk

A significant portion of our liquidity is concentrated in derivative instruments that enable us to hedge a portion of our exposure to natural gas and oil prices and interest rate volatility. These arrangements expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with investment-grade rated counterparties deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. During the more than 15 years we have engaged in hedging activities, we have experienced a counterparty default only once (Lehman Brothers in September 2008), and the total loss recorded in that instance was immaterial. On December 31, 2009, our commodity and interest rate derivative instruments were spread among 14 counterparties. Additionally, our multi-counterparty secured hedging facility requires our counterparties to secure their natural gas and oil hedging obligations in excess of defined thresholds.

Our accounts receivable are primarily from purchasers of natural gas and oil ($743 million at December 31, 2009) and exploration and production companies which own interests in properties we operate ($394 million at December 31, 2009). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit or parent guarantees for receivables from parties which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. During 2009, we recognized $12 million of bad debt expense related to potentially uncollectible receivables.

Investing Activities

While we continue to maintain an active drilling program and acquire leasehold and unproved property needed for planned natural gas and oil development, cash used in investing activities declined significantly in 2009. Cash used in investing activities decreased to $5.462 billion in 2009, compared to $9.965 billion in 2008 and $7.964 billion in 2007. Our investing activities in 2007 and 2008 reflected our increasing focus on acquiring unproved leasehold, converting our resource inventory into production, redeploying our capital by selling natural gas and oil properties with lower rates of return and increasing our investment in properties with higher return potential. We also invested in drilling rigs, gathering systems, compressors, and other property and equipment to support our natural gas and oil exploration, development and production activities. These activities continued in 2009, but at a reduced rate in response to a low natural gas price environment, lower demand and the benefit of our joint venture carries. The following table details our cash used in (provided by) investing activities during 2009, 2008 and 2007 ($ in millions):

	2009	2008	2007
Natural Gas and Oil Investing Activities:			
Acquisitions of natural gas and oil companies and proved properties, net of cash acquired	$ 5	$ 372	$ 520
Acquisition of leasehold and unproved properties	1,666	7,660	2,187
Exploration and development of natural gas and oil properties	3,410	5,789	4,962
Geological and geophysical costs[(a)]	162	315	343
Interest capitalized on unproved properties	598	561	296
Proceeds from sale of volumetric production payments	(408)	(1,579)	(1,089)
Deposits for acquisitions	—	12	15
Divestitures of proved and unproved properties and leasehold	(1,518)	(6,091)	—
Total natural gas and oil investing activities	3,915	7,039	7,234
Other Investing Activities:			
Additions to other property and equipment	1,683	3,073	1,439
Proceeds from sale of drilling rigs and equipment	—	(64)	(369)
Proceeds from sale of compressors	(68)	(114)	(188)
Additions to investments	40	74	8
Proceeds from sale of investments	—	(2)	(124)
Sale of other assets	(108)	(41)	(36)
Total other investing activities	1,547	2,926	730
Total cash used in investing activities	$ 5,462	$ 9,965	$ 7,964

(a) Including related capitalized interest.

In connection with our reduced budget for acquisitions, we used 24,822,832 and 1,677,000 shares of our common stock to acquire leasehold and mineral interests in 2009 and 2008, respectively, pursuant to an acquisition shelf registration statement.

Bank Credit Facilities

We utilize three revolving bank credit facilities, described below, as sources of liquidity.

	Corporate Credit Facility	Midstream Credit Facility	Midstream Joint Venture Credit Facility
		($ in millions)	
Borrowing capacity	$ 3,500	$ 250	$ 500
Maturity date	November 2012	September 2012	September 2012
Borrowers	Chesapeake Exploration, L.L.C. and Chesapeake Appalachia, L.L.C.	Chesapeake Midstream Operating, L.L.C. (CMO)	Chesapeake Midstream Partners, L.L.C. (CMP)
Facility structure	Senior secured revolving	Senior secured revolving	Senior secured revolving
Amount outstanding as of December 31, 2009	$ 1,892	$ —	$ 44
Letters of credit outstanding as of December 31, 2009	$ 41	$ —	$ —

Our credit facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates under our corporate credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, none of our credit facilities contains provisions which would trigger an acceleration of amounts due under the facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

Corporate Credit Facility

Our $3.5 billion syndicated revolving bank credit facility is used for general corporate purposes. Borrowings under the facility are secured by certain producing natural gas and oil properties and bear interest at our option at either (i) the greater of the reference rate of Union Bank, N.A., or the federal funds effective rate plus 0.50%, both of which are subject to a margin that varies from 0.00% to 0.75% per annum according to our senior unsecured long-term debt ratings, or (ii) the London Interbank Offered Rate (LIBOR), plus a margin that varies from 1.50% to 2.25% per annum according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are redetermined periodically. The unused portion of the facility is subject to a commitment fee of 0.50%. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which, among other things, limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness (excluding discount on senior notes) to total capitalization ratio (as defined) not to exceed 0.70 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.75 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.44 to 1 and our indebtedness to EBITDA ratio was 3.18 to 1 at December 31, 2009. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness of Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $75 million.

The facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and all of our other wholly-owned restricted subsidiaries other than minor subsidiaries.

Midstream Credit Facility

Our midstream $250 million syndicated revolving bank credit facility is used to fund capital expenditures to build natural gas gathering and other systems to support our drilling program and for general corporate purposes associated with our midstream operations. Borrowings under the midstream credit facility are secured by all of the assets of the wholly-owned subsidiaries (the restricted subsidiaries) of Chesapeake Midstream Development, L.P. (CMD), itself a wholly-owned subsidiary of Chesapeake, and bear interest at our option at either (i) the greater of the reference rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50%, and the one-month LIBOR plus 1.00%, all of which are subject to a margin that varies from 2.00% to 2.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined) or (ii) the LIBOR plus a margin that varies from 3.00% to 3.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined). The unused portion of the facility is subject to a commitment fee of 0.50% per annum according to the most recent indebtedness to EBITDA ratio (as defined). Interest is payable quarterly or, if LIBOR applies, it may be paid at more frequent intervals.

The midstream credit facility agreement contains various covenants and restrictive provisions which, among other things, limit the ability of CMD and its restricted subsidiaries to incur additional indebtedness, make investments or loans, create liens and pay dividends or distributions to Chesapeake. The credit facility agreement requires maintenance of an indebtedness to EBITDA ratio (as defined) not to exceed 3.50 to 1, and an EBITDA (as defined) to interest expense coverage ratio of not less than 3.00 to 1. As defined by the credit facility agreement, our indebtedness to EBITDA ratio was 0.01 to 1 and our EBITDA to interest expense coverage ratio was 6.87 to 1 at December 31, 2009. If CMD or its restricted subsidiaries should fail to perform their obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the midstream facility could be declared immediately due and payable. The midstream credit facility agreement also has cross default provisions that apply to other indebtedness CMD and its subsidiaries may have with an outstanding principal amount in excess of $15 million.

Midstream Joint Venture Credit Facility

Our midstream joint venture $500 million syndicated revolving bank credit facility was established concurrent with the midstream joint venture we formed on September 30, 2009 (see Note 11 for discussion regarding the midstream joint venture). As a result of that transaction, our existing midstream credit facility was amended and restated as described above. Borrowings under the midstream joint venture credit facility are secured by all of the assets of the midstream companies organized under the joint venture, which is 50% owned by Chesapeake and 50% owned by our joint venture partner Global Infrastructure Partners, and bear interest at our option at either (i) the greater of the reference rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50%, and the one-month LIBOR plus 1.00%, all of which are subject to a margin that varies from 2.00% to 2.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined) or (ii) the LIBOR plus a margin that varies from 3.00% to 3.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined). The unused portion of the facility is subject to a commitment fee of 0.50% per annum according to the most recent indebtedness to EBITDA ratio (as defined). Interest is payable quarterly or, if LIBOR applies, it may be paid at more frequent intervals.

The midstream joint venture credit facility agreement contains various covenants and restrictive provisions which, among other things, limit the ability of the joint venture and its subsidiaries to incur additional indebtedness, make investments or loans, create liens and pay dividends or distributions to

Chesapeake. The credit facility agreement requires maintenance of an indebtedness to EBITDA ratio (as defined) not to exceed 3.50 to 1, and an EBITDA (as defined) to interest expense coverage ratio of not less than 3.00 to 1. As defined by the credit facility agreement, our indebtedness to EBITDA ratio was 0.19 to 1 and our EBITDA to interest expense coverage ratio was 21.75 to 1 at December 31, 2009. If CMP or its subsidiaries should fail to perform their obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the midstream joint venture facility could be declared immediately due and payable. The midstream joint venture credit facility agreement also has cross default provisions that apply to other indebtedness CMP and its subsidiaries may have with an outstanding principal amount in excess of $15 million.

Hedging Facilities

We began 2009 with six secured hedging facilities, each of which permitted us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to a stated maximum value. Outstanding transactions under each of the facilities were collateralized by certain of our natural gas and oil properties that did not secure any of our other obligations. On June 11, 2009, we entered into a multi-counterparty hedge facility with 13 counterparties that have committed to provide approximately 3.9 tcfe of trading capacity and an aggregate mark-to-market capacity of $10.4 billion under the terms of the facility. The new multi-counterparty facility has consolidated and replaced the six secured hedge facilities. All prior trades with these counterparties have been novated and pledged collateral transferred to the multi-counterparty facility, which had a total of 1.7 tcfe hedged and collateral value of approximately $5.3 billion as of December 31, 2009. Trades from the original six secured hedging facilities will continue to be subject to pre-existing exposure fees, but we are not required to pay an exposure fee for any new trades in the multi-counterparty facility.

The multi-counterparty facility allows us to enter into cash-settled natural gas and oil price and basis hedges with the counterparties. Our obligations under the multi-counterparty facility are secured by natural gas and oil proved reserves, the value of which must cover the fair value of the transactions outstanding under the facility by at least 1.65 times, and guarantees by certain subsidiaries that also guarantee our corporate revolving bank credit facility and indentures. The counterparties' obligations under the facility must be secured by cash or short-term U.S. Treasury instruments to the extent that any mark-to-market amounts they owe to Chesapeake exceed defined thresholds. The maximum volume-based trading capacity under the facility is governed by the expected production of the pledged reserve collateral, and volume-based trading limits are applied separately to price and basis hedges. In addition, there are volume-based sub-limits for natural gas and oil hedges. Chesapeake has significant flexibility with regard to releases and/or substitutions of pledged reserves, provided that certain collateral coverage and other requirements are met. The facility does not have a maturity date. Counterparties to the agreement have the right to cease trading with the company on a prospective basis as long as obligations associated with any existing trades in the facility continue to be satisfied in accordance with the terms of the agreement.

Senior Note Obligations

In addition to outstanding revolving bank credit facility borrowings discussed above, as of December 31, 2009, senior notes represented approximately \$10.4 billion of our long-term debt and consisted of the following (\$ in millions):

7.5% senior notes due 2013	$ 364
7.625% senior notes due 2013	500
7.0% senior notes due 2014	300
7.5% senior notes due 2014	300
6.375% senior notes due 2015	600
9.5% senior notes due 2015	1,425
6.625% senior notes due 2016	600
6.875% senior notes due 2016	670
6.25% Euro-denominated senior notes due 2017[(a)]	860
6.5% senior notes due 2017	1,100
6.25% senior notes due 2018	600
7.25% senior notes due 2018	800
6.875% senior notes due 2020	500
2.75% contingent convertible senior notes due 2035[(b)]	451
2.5% contingent convertible senior notes due 2037[(b)]	1,378
2.25% contingent convertible senior notes due 2038[(b)]	763
Discount on senior notes[(c)]	(921)
Interest rate derivatives[(d)]	69
	$ 10,359

(a) The principal amount shown is based on the dollar/euro exchange rate of \$1.4332 to €1.00 as of December 31, 2009. See Note 9 for information on our related cross currency swap.

(b) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder's option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. One such triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarter by quarter. In the fourth quarter of 2009, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes during the specified period and, as a result, the holders do not have the option to convert their notes into cash and common stock in the first quarter of 2010 under this provision. The notes are also convertible, at the holder's option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. In general, upon conversion of a contingent convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note's conversion value in excess of such principal amount. We will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years, under certain conditions. We may redeem the convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash. The optional repurchase dates, the common stock price conversion threshold amounts and the ending date of the first six-month period contingent interest may be payable for the contingent convertible senior notes are as follows:

Contingent Convertible Senior Notes	Repurchase Dates	Common Stock Price Conversion Thresholds	Contingent Interest First Payable (if applicable)
2.75% due 2035	November 15, 2015, 2020, 2025, 2030	$ 48.71	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$ 64.36	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 107.36	June 14, 2019

(c) Included in this discount is $794 million associated with the equity component of our contingent convertible senior notes. See Note 3 of our consolidated financial statements for a description of the accounting treatment applied to these notes.

(d) See Note 9 of our consolidated financial statements included in this report for further discussion related to these instruments.

No scheduled principal payments are required under our senior notes until 2013 when $864 million is due.

As of December 31, 2009 and currently, debt ratings for the senior notes are Ba3 by Moody's Investor Service (stable outlook), BB by Standard & Poor's Ratings Services (stable outlook) and BB by Fitch Ratings (negative outlook).

Our senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. Chesapeake Energy Corporation is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our senior note obligations are guaranteed by certain of our wholly-owned subsidiaries. See Note 18 of the financial statements included in this report for condensed consolidating financial information regarding guarantor and non-guarantor subsidiaries. We may redeem the senior notes, other than the contingent convertible senior notes, at any time at specified redemption or make-whole prices. Senior notes issued before July 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries' ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; incur liens; enter into sale/leaseback transactions; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. Senior notes issued after June 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries' ability to incur certain secured indebtedness; enter into sale/leaseback transactions; and consolidate, merge or transfer assets. The debt incurrence covenants do not presently restrict our ability to borrow under or expand our corporate revolving credit facility. As of December 31, 2009, we estimate that corporate commercial bank indebtedness of approximately $4.4 billion could have been incurred under the most restrictive indenture covenant.

Conversions and Exchanges of Contingent Convertible Senior Notes and Preferred Stock

In 2009 and 2008, holders of certain of our contingent convertible senior notes exchanged or converted their senior notes for shares of common stock in privately negotiated exchanges as summarized below ($ in millions):

Year	Contingent Convertible Senior Notes	Principal Amount	Number of Common Shares
2009	2.25% due 2038	$ 364	10,210,169
2008	2.75% due 2035	$ 239	8,841,526
2008	2.50% due 2037	272	8,416,865
2008	2.25% due 2038	254	6,654,821
		$ 765	23,913,212

In 2009, 2008 and 2007, shares of our cumulative convertible preferred stock were exchanged for or converted into shares of common stock as summarized below:

Year of Exchange/ Conversion	Cumulative Convertible Preferred Stock	Number of Preferred Shares	Number of Common Shares	Type of Transaction
2009	6.25%	143,768	1,239,538	Conversion
	4.125%	3,033	182,887	Conversion
			1,422,425	
2008	5.0% (series 2005B)	3,654,385	10,443,642	Exchange
	4.5%	891,100	2,227,750	Exchange
	4.125%	29	1,743	Conversion
			12,673,135	
2007	5.0% (series 2005)	4,595,000	19,283,311	Exchange
	6.25%	2,156,184	17,367,823	Exchange
	6.25%	48	344	Conversion
	4.125%	3	180	Conversion
			36,651,658	

Contractual Obligations

The table below summarizes our cash contractual obligations as of December 31, 2009 ($ in millions):

		Payments Due By Period			
	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-term debt:					
Principal	$ 13,147	$ —	$ 1,936	$ 1,464	$ 9,747
Interest	5,780	694	1,387	1,276	2,423
Financing lease obligations and other	930	20	38	92	780
Operating lease obligations	882	147	290	278	167
Asset retirement obligations[(a)]	282	35	29	8	210
Purchase obligations[(b)]	3,082	482	674	538	1,388
Unrecognized tax benefits[(c)]	231	—	196	35	—
Standby letters of credit	41	41	—	—	—
Total contractual cash obligations	$ 24,375	$ 1,419	$ 4,550	$ 3,691	$ 14,715

(a) Asset retirement obligations represent estimated discounted costs for future dismantlement and abandonment costs. These obligations are recorded as liabilities on our December 31, 2009 balance sheet.

(b) See Note 4 of the notes to our consolidated financial statements for a description of transportation and drilling contract commitments.

(c) See Note 5 of the notes to our consolidated financial statements for a description of unrecognized tax benefits.

Chesapeake has commitments to purchase any natural gas and oil associated with certain volumetric production payment transactions based on market prices at the time of production and the purchased gas will be resold.

Under minimum volume throughput agreements, Chesapeake has agreed to move fixed volumes of natural gas over certain time periods, usually multiple years, through certain midstream systems. At the end of the term or annually, Chesapeake will be invoiced for any shortfalls in such volume commitments.

Hedging Activities

Natural Gas and Oil Hedging Activities

Our results of operations and cash flows are impacted by changes in market prices for natural gas and oil. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. Executive management is involved in all risk management activities and the Board of Directors reviews the company's hedging program at its quarterly Board meetings. We believe we have sufficient internal controls to prevent unauthorized hedging. As of December 31, 2009, our natural gas and oil derivative instruments were comprised of swaps, collars, call options, put options, knockout swaps and basis protection swaps. Item 7A – *Quantitative and Qualitative Disclosures About Market Risk* contains a description of each of these instruments. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

Hedging allows us to predict with greater certainty the effective prices we will receive for our hedged natural gas and oil production. We closely monitor the fair value of our hedging contracts and may elect to settle a contract prior to its scheduled maturity date in order to lock in a gain or loss. Commodity markets are volatile and Chesapeake's hedging activities are dynamic.

Mark-to-market positions under natural gas and oil hedging contracts fluctuate with commodity prices. As described above under *Hedging Facilities*, our secured multi-counterparty hedging facility allows us to minimize the potential liquidity impact of significant mark-to-market fluctuations in the value of our natural gas and oil hedges by pledging natural gas and oil properties.

Our realized and unrealized gains and losses on natural gas and oil derivatives during 2009, 2008 and 2007 were as follows:

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
Natural gas and oil sales	$ 3,291	$ 7,069	$ 4,795
Realized gains (losses) on natural gas and oil derivatives	2,346	(8)	1,203
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(624)	887	(252)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	36	(90)	(122)
Total natural gas and oil sales	$ 5,049	$ 7,858	$ 5,624

Changes in the fair value of natural gas and oil derivative instruments designated as cash flow hedges, to the extent effective in offsetting cash flows attributable to the hedged commodities, and locked-in gains and losses of derivative contracts are recorded in accumulated other comprehensive income and are transferred to earnings in the month of related production. These unrealized gains (losses), net of related tax effects, totaled $94 million, $386 million and $53 million as of December 31, 2009, 2008 and 2007, respectively. Based upon the market prices at December 31, 2009, we expect to transfer to earnings approximately $202 million of the net gain included in the balance of accumulated other comprehensive income during the next 12 months. A detailed explanation of accounting for natural gas and oil derivatives appears under *Application of Critical Accounting Policies – Hedging* elsewhere in this Item 7.

The estimated fair values of our natural gas and oil derivative instruments as of December 31, 2009 and 2008 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	December 31, 2009	December 31, 2008
	($ in millions)	
Derivative assets (liabilities)[(a)]:		
Fixed-price natural gas swaps	$ 662	$ 863
Fixed-price natural gas collars	92	402
Fixed-price natural gas knockout swaps	17	141
Natural gas call options	(541)	(178)
Natural gas put options	(50)	(39)
Natural gas basis protection swaps	(50)	93
Fixed-price oil swaps	3	31
Fixed-price oil collars	—	5
Fixed-price oil knockout swaps	32	19
Fixed-price oil cap-swaps	—	3
Oil call options	(144)	(35)
Estimated fair value	$ 21	$ 1,305

(a) See Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* of this report for additional information concerning any associated premiums received, or discounts paid, in connection with certain derivative transactions.

Additional information concerning the changes in fair value of our natural gas and oil derivative instruments is as follows:

	2009	2008	2007
		($ in millions)	
Fair value of contracts outstanding, as of January 1	$ 1,305	$ (369)	$ 345
Change in fair value of contracts	1,266	1,880	972
Fair value of contracts when entered into	(21)	(569)	(295)
Contracts realized or otherwise settled	(2,102)	9	(1,203)
Fair value of contracts when closed	(427)	354	(188)
Fair value of contracts outstanding, as of December 31	$ 21	$ 1,305	$ (369)

Interest Rate Derivatives

To mitigate our exposure to volatility in interest rates related to our senior notes and credit facilities, we enter into interest rate derivatives.

For interest rate derivative instruments designated as fair value hedges, changes in fair value are recorded on the consolidated balance sheets as assets (liabilities), and the debt's carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Changes in the fair value of non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized (gains) losses within interest expense.

Gains or losses from interest rate derivative transactions are reflected as adjustments to interest expense on the consolidated statements of operations. The components of interest expense for the years ended December 31, 2009, 2008 and 2007 are presented below.

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
Interest expense on senior notes	$ 765	$ 637	$ 538
Interest expense on credit facilities	60	117	113
Capitalized interest	(633)	(585)	(311)
Realized (gains) losses on interest rate derivatives	(23)	(6)	1
Unrealized (gains) losses on interest rate derivatives	(91)	85	40
Amortization of loan discount and other	35	23	20
Total interest expense	$ 113	$ 271	$ 401

A detailed explanation of accounting for interest rate derivatives appears under *Application of Critical Accounting Policies – Hedging* elsewhere in this Item 7.

Foreign Currency Derivatives

On December 6, 2006, we issued €600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the Euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. A detailed explanation of accounting for foreign currency derivatives appears under *Application of Critical Accounting Policies – Hedging* elsewhere in this Item 7.

Results of Operations

General. For the year ended December 31, 2009, Chesapeake had a net loss of $5.830 billion, or a loss of $9.57 per diluted common share, on total revenues of $7.702 billion. This compares to net income of $604 million, or $0.93 per diluted common share, on total revenues of $11.629 billion during the year ended December 31, 2008, and net income of $1.455 billion, or $2.63 per diluted common share, on total revenues of $7.800 billion during the year ended December 31, 2007.

Natural Gas and Oil Sales. During 2009, natural gas and oil sales were $5.049 billion compared to $7.858 billion in 2008 and $5.624 billion in 2007. In 2009, Chesapeake produced and sold 905.5 bcfe of natural gas and oil at a weighted average price of $6.22 per mcfe, compared to 842.7 bcfe in 2008 at a weighted average price of $8.38 per mcfe, and 714.3 bcfe in 2007 at a weighted average price of $8.40 per mcfe (weighted average prices for all years discussed exclude the effect of unrealized gains or (losses) on derivatives of ($588) million, $797 million and ($374) million in 2009, 2008 and 2007, respectively). The decrease in prices in 2009 resulted in a decrease in revenue of $1.950 billion and increased production resulted in a $526 million increase, for a total decrease in revenues of $1.424 billion (excluding unrealized gains or losses on natural gas and oil derivatives). The increase in production from period to period was primarily generated from the drillbit.

For 2009, we realized an average price per mcf of natural gas of $5.93, compared to $8.09 in 2008 and $8.14 in 2007 (weighted average prices for all years discussed exclude the effect of unrealized gains or losses on derivatives). Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $58.38, $70.48 and $67.50 in 2009, 2008 and 2007, respectively. Realized gains or losses from our natural gas and oil derivatives resulted in a net increase in natural gas and oil revenues of $2.346 billion or $2.59 per mcfe in 2009, a net decrease of ($8) million or ($0.01) per mcfe in 2008 and a net increase of $1.203 billion or $1.68 per mcfe in 2007.

A change in natural gas and oil prices has a significant impact on our natural gas and oil revenues and cash flows. Assuming 2009 production levels, a change of $0.10 per mcf of natural gas sold would result in an increase or decrease in 2009 revenues and cash flows of approximately $91 million and $88 million, respectively, and a change of $1.00 per barrel of oil sold would result in an increase or decrease in 2009 revenues and cash flows of approximately $12 million and $11 million, without considering the effect of hedging activities.

The following tables show our production and prices by region for 2009, 2008 and 2007:

	2009						
	Natural Gas		Oil		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(bcfe)	%	($/mcfe)[a]
Big 6 Shales:							
Barnett Shale	237.9	$ 2.10	0.1	$ 54.80	238.1	26%	$ 2.11
Fayetteville Shale[c]	90.7	3.02	—	—	90.7	10	3.02
Haynesville Shale	85.0	3.32	0.1	48.34	85.5	10	3.35
Marcellus Shale[d]	14.8	4.05	—	—	14.8	2	4.05
Bossier Shale	—	—	—	—	—	—	—
Eagle Ford Shale	—	—	—	—	—	—	—
Other:							
Mid-Continent[b] [e]	258.7	3.77	7.7	55.33	305.0	34	4.60
Permian and Delaware Basins	56.7	3.49	3.0	57.25	74.9	8	4.96
South Texas/Gulf Coast/Ark-La-Tex[f]	62.5	3.75	0.7	53.19	66.7	7	4.06
Appalachian Basin[g]	28.5	3.87	0.2	53.49	29.8	3	4.08
Total	834.8	$ 3.16	11.8	$ 55.60	905.5	100%	$ 3.63

	2008						
	Natural Gas		Oil		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(bcfe)	%	($/mcfe)[a]
Big 6 Shales:							
Barnett Shale	181.2	$ 6.73	—	$ —	181.2	22%	$ 6.73
Fayetteville Shale[c]	54.8	7.23	—	—	54.8	7	7.23
Haynesville Shale	27.0	8.14	0.2	91.02	28.0	3	8.39
Marcellus Shale[d]	2.7	10.13	—	—	2.7	—	10.13
Bossier Shale	—	—	—	—	—	—	—
Eagle Ford Shale	—	—	—	—	—	—	—
Other:							
Mid-Continent[b][e]	315.9	7.87	6.9	93.66	357.3	42	8.77
Permian and Delaware Basins	63.0	7.80	2.9	97.46	80.4	10	9.63
South Texas/Gulf Coast/Ark-La-Tex	98.1	8.71	1.1	98.45	104.6	12	9.19
Appalachian Basin[g]	32.7	9.41	0.1	91.52	33.7	4	9.57
Total	775.4	$ 7.74	11.2	$ 95.04	842.7	100%	$ 8.39

	2007						
	Natural Gas		Oil		Total		
	(bcf)	($/mcf)[(a)]	(mmbbl)	($/bbl)[(a)]	(bcfe)	%	($/mcfe)[(a)]
Big 6 Shales:							
Barnett Shale	93.3	$ 5.21	—	$ —	93.3	13%	$ 5.21
Fayetteville Shale	14.7	5.15	—	—	14.7	2	5.15
Haynesville Shale	21.6	6.72	0.2	61.40	22.9	3	6.92
Marcellus Shale	—	—	—	—	—	—	—
Bossier Shale	—	—	—	—	—	—	—
Eagle Ford Shale	—	—	—	—	—	—	—
Other:							
Mid-Continent	327.5	6.27	5.6	68.26	360.9	50	6.75
Permian and Delaware Basins	47.2	6.51	2.7	69.77	63.4	9	7.82
South Texas/Gulf Coast/Ark-La-Tex	103.6	6.74	1.3	71.29	111.1	16	7.09
Appalachian Basin	47.1	7.42	0.1	47.67	48.0	7	7.43
Total	655.0	$ 6.29	9.9	$ 68.64	714.3	100%	$ 6.71

(a) The average sales price excludes gains (losses) on derivatives.

(b) 2009 and 2008 were impacted by the sale of 10.1 bcfe and 6.6 bcfe of production, respectively, related to the BP Arkoma divestiture that closed in August 2008.

(c) 2009 and 2008 were impacted by the sale of 30.3 bcfe and 5.2 bcfe of production, respectively, related to the BP Fayetteville joint venture that closed in September 2008.

(d) 2009 and 2008 were impacted by the sale of 5.4 bcfe and 0.1 bcfe of production, respectively, related to the STO Marcellus joint venture that closed in November 2008.

(e) 2009 and 2008 were impacted by the sale of 49.6 bcfe and 18.2 bcfe of production, respectively, related to various VPP transactions that closed in 2008.

(f) 2009 was impacted by the sale of 7.8 bcfe of production related to a VPP transaction that closed in 2009.

(g) 2009 and 2008 were impacted by the sale of 17.0 bcfe and 18.3 bcfe of production, respectively, related to a VPP transaction that closed in 2007.

Natural gas production represented approximately 92% of our total production volume on a natural gas equivalent basis in 2009, 2008 and 2007.

Marketing, Gathering and Compression. Marketing, gathering and compression activities are substantially for third parties who are owners in Chesapeake-operated wells. Chesapeake realized $2.463 billion in marketing, gathering and compression sales in 2009, with corresponding marketing, gathering and compression expenses of $2.316 billion, for a net margin before depreciation of $147 million. This compares to sales of $3.598 billion and $2.040 billion, expenses of $3.505 billion and $1.969 billion, and margins before depreciation of $93 million and $71 million in 2008 and 2007, respectively. In 2009 and 2008, Chesapeake realized an increase in marketing, gathering and compression net margin primarily due to an increase in third party marketing volumes.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. Chesapeake recognized $190 million in service operations revenue in 2009 with corresponding service operations expenses of $182 million, for a net margin before depreciation of $8 million. This compares to revenue of $173 million and $136 million, expenses of $143 million and $94 million and a net margin before depreciation of $30 million and $42 million in 2008 and 2007, respectively. These operations have grown as a result of assets and businesses we acquired and leased as seen in the growth in revenues. However, the net margins have decreased each of the previous three years. This is the result of increased expenses associated with the leasing cost of the numerous rigs we have sold and leased back in the previous three years.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $876 million in 2009, compared to $889 million and $640 million in 2008 and 2007, respectively. On a unit-of-production basis, production expenses were $0.97 per mcfe in 2009 compared to $1.05 and $0.90 per mcfe in 2008 and 2007, respectively. The expense decrease in 2009 was primarily due to lower service costs in the field as a result of the economic downturn. Our per unit decrease in 2009 was also affected by the increase in production. We expect that production expenses per mcfe produced for 2010 will range from $0.85 to $0.95.

The following table shows our production expenses by region and our ad valorem tax expenses for 2009, 2008 and 2007 ($ in millions, except per unit):

	2009		2008		2007	
	Production Expenses	$/mcfe	Production Expenses	$/mcfe	Production Expenses	$/mcfe
Big 6 Shales:						
Barnett Shale	$ 158	$ 0.66	$ 128	$ 0.71	$ 58	$ 0.62
Fayetteville Shale	23	0.25	13	0.24	7	0.41
Haynesville Shale	33	0.39	37	1.33	—	—
Marcellus Shale	24	1.67	4	1.63	—	—
Bossier Shale	—	—	—	—	—	—
Eagle Ford Shale	—	—	—	—	—	—
Other:						
Mid-Continent	300	0.98	362	1.01	285	0.80
Permian and Delaware Basins	114	1.52	134	1.67	104	1.60
South Texas/Gulf Coast/Ark-La-Tex	68	1.02	95	0.91	120	0.89
Appalachian Basin	76	2.50	42	1.24	27	0.56
Ad valorem tax	80	0.09	74	0.09	39	0.05
Total	$ 876	$ 0.97	$ 889	$ 1.05	$ 640	$ 0.90

Production Taxes. Production taxes were $107 million in 2009 compared to $284 million in 2008 and $216 million in 2007. On a unit-of-production basis, production taxes were $0.12 per mcfe in 2009 compared to $0.34 per mcfe in 2008 and $0.30 per mcfe in 2007. The $177 million decrease in production taxes from 2008 to 2009 is due to a decrease in the realized average sales price of natural gas and oil of $4.76 per mcfe (excluding gains or losses on derivatives), which more than offset the production increase of 63 bcfe. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas and oil prices are higher. We expect production taxes for 2010 to range from $0.25 to $0.30 per mcfe based on estimated NYMEX prices ranging from $5.25 to $6.75 per mcf of natural gas and an oil price of $80.00 per barrel.

General and Administrative Expense. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our natural gas and oil properties (see Note 10 of notes to consolidated financial statements), were $349 million in 2009, $377 million in 2008 and $243 million in 2007. General and administrative expenses were $0.38, $0.45 and $0.34 per mcfe for 2009, 2008 and 2007, respectively. The decrease in 2009 was primarily the result of decreased spending related to media relations. Included in general and administrative expenses is stock-based compensation of $83 million in 2009, $85 million in 2008 and $58 million in 2007. Restricted stock grants are expensed at the price of our common stock on the date of grant. The increase in 2008 was the result of a larger number of unvested shares being expensed during 2008 compared to 2007. We anticipate that general and administrative expenses for 2010 will be between $0.39 and $0.46 per mcfe produced, including stock-based compensation ranging from $0.09 to $0.11 per mcfe produced.

Our stock-based compensation for employees and non-employee directors is in the form of restricted stock. Employee restricted stock awards generally vest over a period of four or five years. Our non-employee director awards vest over a period of three years. The discussion of stock-based compensation in Note 1 and Note 8 of notes to the consolidated financial statements included in Item 8 of this report provides additional detail on the accounting for and reporting of our stock-based compensation.

Chesapeake follows the full-cost method of accounting under which all costs associated with natural gas and oil property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $354 million, $352 million and $262 million of internal costs in 2009, 2008 and 2007, respectively, directly related to our natural gas and oil property acquisition, exploration and development efforts.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of natural gas and oil properties was $1.371 billion, $1.970 billion and $1.835 billion during 2009, 2008 and 2007, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs, and the related underlying reserves in the periods presented, was $1.51, $2.34 and $2.57 in 2009, 2008 and 2007, respectively. The decrease in the average rate from $2.57 in 2007 to $1.51 in 2009 is due primarily to reductions of our natural gas and oil full-cost pool resulting from our divestitures in 2008 and 2009 and impairments of our full-cost pool in 2008 and 2009 as well as the addition of reserves through our drilling activities. We expect the 2010 DD&A rate to be between $1.35 and $1.55 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $244 million in 2009, compared to $174 million in 2008 and $153 million in 2007. The average DD&A rate per mcfe was $0.27, $0.21 and $0.21 in 2009, 2008 and 2007, respectively. The increase from 2008 to 2009 was mainly due to the significant increase in our investment in gathering systems, compressors, buildings and drilling rigs. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 10 to 39 years, gathering facilities are depreciated over 20 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to twenty years. To the extent company-owned drilling rigs are used to drill our wells, a substantial portion of the depreciation is capitalized in natural gas and oil properties as exploration or development costs. We expect 2010 depreciation and amortization of other assets to be between $0.20 and $0.25 per mcfe produced.

Impairment of Natural Gas and Oil Properties and Other Assets. Due to lower commodity prices in the second half of 2008 and throughout 2009, we reported a non-cash impairment charge on our natural gas and oil properties of $11.0 billion in 2009 and $2.8 billion in 2008. We account for our natural gas and oil properties using the full-cost method of accounting, which limits the amount of costs we can capitalize and requires us to write off these costs if the carrying value of natural gas and oil assets in the evaluated portion of our full-cost pool exceeds the sum of the present value of expected future net cash flows of proved reserves using a 10% pre-tax discount rate based on pricing and cost assumptions and the present value of certain natural gas and oil hedges. Additionally, in 2009, we recorded an impairment of $90 million associated with certain of our midstream assets and $27 million associated with certain of our service operations assets.

Other Income (Expense). Other income (expense) was ($28) million, ($11) million and $15 million in 2009, 2008 and 2007, respectively. The 2009 loss consisted of $8 million of interest income, a $39 million loss related to our equity in the net losses of certain investments, a $1 million gain on sale of assets and $2 million of miscellaneous income. The 2008 loss consisted of $22 million of interest income, a $38 million loss related to our equity in the net losses of certain investments, a $4 million gain on sale of assets, $10 million of expense related to consent solicitation fees and $11 million of miscellaneous income. The 2007 income consisted of $8 million of interest income and $7 million of miscellaneous income. Income related to equity investments was not significant in 2007.

Interest Expense. Interest expense decreased to $113 million in 2009 compared to $271 million in 2008 and $401 million in 2007 as follows:

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
Interest expense on senior notes	$ 765	$ 637	$ 538
Interest expense on credit facilities	60	117	113
Capitalized interest	(633)	(585)	(311)
Realized (gain) loss on interest rate derivatives	(23)	(6)	1
Unrealized (gain) loss on interest rate derivatives	(91)	85	40
Amortization of loan discount and other	35	23	20
Total interest expense	$ 113	$ 271	$ 401
Average long-term borrowings	$ 11,167	$ 10,044	$ 8,224

Interest expense, excluding unrealized (gains) losses on interest rate derivatives was $0.22 per mcfe in 2009 compared to $0.22 per mcfe in 2008 and $0.50 per mcfe in 2007. The decrease in interest expense per mcfe for 2009 and 2008 is due to increased production volumes and an increase in capitalized interest. Capitalized interest increased in 2009 and 2008 as a result of a significant increase in unevaluated properties, the base on which interest is capitalized. We expect interest expense for 2010 to be between $0.30 and $0.35 per mcfe produced (before considering the effect of interest rate derivatives).

Impairment of Investments. We recorded a $162 million and $180 million impairment of certain investments in 2009 and 2008, respectively. Each of our investees has been impacted by the dramatic slowing of the worldwide economy and the freezing of the credit markets in the fourth quarter of 2008 and into 2009. The economic weakness has resulted in significantly reduced natural gas and oil prices leading to a meaningful decline in the overall level of activity in the markets served by our investees. Associated with the weakness in performance of certain of the investees, as well as an evaluation of their financial condition and near-term prospects, we recognized that an other than temporary impairment had occurred on the following investments in 2009: Gastar Exploration, Ltd., $70 million; Chaparral Energy, Inc., $51 million; DHS Drilling Company, $19 million; Ventura Refining, Transmission LLC, Inc., $13 million; and Mountain Drilling Company, $9 million. We recognized that an other than temporary impairment had occurred on the following investments in 2008: Chaparral Energy, Inc., $100 million; DHS Drilling Company, $20 million; Mountain Drilling Company, $10 million; and Ventura Refining and Transmission LLC, Inc., $50 million.

Loss on Exchanges or Repurchases of Chesapeake Debt. During 2009, we privately exchanged approximately $364 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 10,210,169 shares of our common stock valued at approximately $262 million. Through these transactions, we were able to redeem this debt for common stock valued at less than 75% of the face value of the notes. Associated with these exchanges, we recorded a loss of $40 million. In connection with accounting guidance for debt with conversion and other options, we are required to account for the liability and equity components of our convertible debt instruments separately. Of the $364 million principal amount of convertible notes exchanged in 2009, $227 million was allocated to the debt component and the remaining $137 million was allocated to the equity conversion feature and was recorded as an adjustment to paid-in-capital. The difference between the debt component and the value of the common stock exchanged in these transactions resulted in a $35 million loss. In addition, we expensed $5 million in deferred charges associated with these exchanges.

During 2008, we exchanged approximately $254 million, $272 million and $239 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038, 2.50% Contingent Convertible Senior Notes due 2037, and 2.75% Contingent Convertible Senior Notes due 2035, respectively, for an aggregate of 23,913,212 shares of our common stock valued at approximately $480 million. Through these transactions, we were able to redeem this debt for common stock valued at less than 65% of the face value of the notes. Associated with these exchanges, we recorded a gain of $27 million. Of the combined $765 million principal amount of convertible notes exchanged in 2008, $515 million was allocated to the debt component and the remaining $250 million was allocated to the equity conversion feature and was recorded as an adjustment to paid-in-capital. The difference between the debt component and the value of the common stock exchanged in these transactions resulted in a $35 million gain. This gain was partially offset by the write-off of $8 million in deferred charges associated with these exchanges.

Also during 2008, we repurchased $300 million of our 7.75% Senior Notes due 2015 in order to re-finance a portion of our long-term debt at a lower rate of interest. In connection with the transaction, we recorded a $31 million loss, which consisted of a $12 million premium and $19 million of discounts, interest rate derivatives and deferred charges associated with the notes.

Gain on Sale of Investments. In 2007, we sold our 33% limited partnership interest in Eagle Energy Partners I, L.P., which we first acquired in 2003, for proceeds of $124 million and a gain of $83 million.

Income Tax Expense (Benefit). Chesapeake recorded an income tax benefit of $3.483 billion in 2009 compared to income tax expense of $387 million in 2008 and $892 million in 2007. Of the income tax benefit recorded in 2009, $4 million is reflected as current income tax expense and $3.487 billion is reflected as a deferred income tax benefit. Of the $3.870 billion decrease in 2009, $4.009 billion was the result of the decrease in net income before taxes which was offset by $139 million as the result of a decrease in the effective tax rate. Our effective income tax rate was 37.5% in 2009 compared to 39% in 2008 and 38% in 2007. Our effective tax rate fluctuates as a result of the impact of state income taxes and permanent differences. We expect our effective income tax rate to be 38.5% in 2010.

Loss on Conversion/Exchange of Preferred Stock. Loss on conversion/exchange of preferred stock was $0, $67 million and $128 million in 2009, 2008 and 2007, respectively. The loss on the exchanges represented the excess of the fair value of the common stock issued over the fair value of the securities issuable pursuant to the original conversion terms. See Note 8 of notes to the consolidated financial statements in Item 8 for further detail regarding these transactions.

Application of Critical Accounting Policies

Readers of this report and users of the information contained in it should be aware of how certain events may impact our financial results based on the accounting policies in place. The three policies we consider to be the most significant are discussed below. The company's management has discussed each critical accounting policy with the Audit Committee of the company's Board of Directors.

The selection and application of accounting policies are an important process that changes as our business changes and as accounting rules are developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules and the use of judgment to the specific set of circumstances existing in our business.

Hedging. Chesapeake uses commodity price and financial risk management instruments to mitigate our exposure to price fluctuations in natural gas and oil, changes in interest rates and changes in foreign exchange rates. Recognized gains and losses on derivative contracts are reported as a component of the related transaction. Results of natural gas and oil derivative transactions are reflected in natural gas and oil sales, and results of interest rate and foreign exchange rate hedging transactions are reflected in interest expense. The changes in the fair value of derivative instruments not qualifying for designation as either cash flow or fair value hedges that occur prior to maturity are reported currently in the consolidated statement of operations as unrealized gains (losses) within natural gas and oil sales or interest expense. Cash flows from derivative instruments are classified in the same category within the statement of cash flows as the items being hedged, or on a basis consistent with the nature of the instruments.

Accounting guidance for derivatives and hedging establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the consolidated balance sheet as assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Any change in the fair value resulting from ineffectiveness is recognized immediately in natural gas and oil sales. For derivative instruments designated as fair value hedges, changes in fair value, as well as the offsetting changes in the estimated fair value of the hedged item attributable to the hedged risk, are recognized currently in earnings. Differences between the changes in the fair values of the hedged item and the derivative instrument, if any, represent gains or losses on ineffectiveness and are reflected currently in interest expense. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Changes in fair value of contracts that do not qualify as hedges or are not designated as hedges are also recognized currently in earnings. See *Hedging Activities* above and Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* for additional information regarding our hedging activities.

One of the primary factors that can have an impact on our results of operations is the method used to value our derivatives. We have established the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors.

Another factor that can impact our results of operations each period is our ability to estimate the level of correlation between future changes in the fair value of the hedge instruments and the transactions being hedged, both at inception and on an ongoing basis. This correlation is complicated since energy commodity prices, the primary risk we hedge, have quality and location differences that can be difficult to hedge effectively. The factors underlying our estimates of fair value and our assessment of correlation of our hedging derivatives are impacted by actual results and changes in conditions that affect these factors, many of which are beyond our control.

Due to the volatility of natural gas and oil prices and, to a lesser extent, interest rates and foreign exchange rates, the company's financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2009, 2008 and 2007, the fair value of our derivatives was a liability of $63 million, an asset of $1.166 billion and a liability of $375 million, respectively. The derivatives that we acquired in our CNR acquisition represented $17 million and $184 million of liability at December 31, 2008 and 2007.

Natural Gas and Oil Properties. The accounting for our business is subject to special accounting rules that are unique to the natural gas and oil industry. There are two allowable methods of accounting for natural gas and oil business activities: the successful efforts method and the full-cost method. Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities.

Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion, amortization and impairment of natural gas and oil properties are generally calculated on a well by well or lease or field basis versus the aggregated "full-cost" pool basis. Additionally, gain or loss is generally recognized on all sales of natural gas and oil properties under the successful efforts method. As a result, our financial statements will differ from companies that apply the successful efforts method since we will generally reflect a higher level of capitalized costs as well as a higher natural gas and oil depreciation, depletion and amortization rate, and we will not have exploration expenses that successful efforts companies frequently have.

Under the full-cost method, capitalized costs are amortized on a composite unit-of-production method based on proved natural gas and oil reserves. If we maintain the same level of production year over year, the depreciation, depletion and amortization expense may be significantly different if our estimate of remaining reserves or future development costs changes significantly. Proceeds from the sale of properties are accounted for as reductions of capitalized costs unless such sales involve a significant change in the relationship between costs and proved reserves, in which case a gain or loss is recognized. The costs of unproved properties are excluded from amortization until the properties are evaluated. We review all of our unevaluated properties quarterly to determine whether or not and to what extent proved reserves have been assigned to the properties, and otherwise if impairment has occurred. Unevaluated properties are grouped by major producing area where individual property costs are not significant and are assessed individually when individual costs are significant.

We review the carrying value of our natural gas and oil properties under the full-cost accounting rules of the Securities and Exchange Commission on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. For 2009, capitalized costs of natural gas and oil properties exceeded the estimated present value of future net revenues from our proved reserves, net of related income tax considerations, resulting in a write-down in the carrying value of natural gas and oil properties of $6.9 billion, net of tax. In calculating future net revenues, effective December 31, 2009, current prices are calculated as the average natural gas and oil prices during the preceding 12-month period prior to the end of the current reporting period, determined as the unweighted arithmetical average of prices on the first day of each month within the 12-month period and costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. Based on the average prices for natural gas and oil during the 12-months of 2009, these cash flow hedges increased the full-cost ceiling by $1.1 billion, thereby reducing the ceiling test write-down by the same amount.

Two primary factors impacting this test are reserve levels and natural gas and oil prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of natural gas and oil reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense.

In December 2008, the SEC issued its final rule for *Modernization of Oil and Gas Reporting*. Pursuant to this rule the SEC adopted revisions to its oil and gas reporting disclosures effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves, which should help investors evaluate the relative value of oil and gas companies. In the three decades that have passed since the original adoption of oil and gas disclosure items, there have been significant changes in the oil and gas industry. These revisions are designed to modernize and update the oil and gas disclosure requirements to align them with current practices and changes in technology. The new rules include provisions that permit the use of new technologies to determine proved reserves. The requirements also require companies to report the independence and qualifications of the technical person(s) primarily responsible for the preparation or audit of reserve estimations and to file reports when a third party is relied upon to prepare or audit reserve estimates. In addition, the new rules require that oil and gas reserves be reported and the full-cost ceiling value calculated using average first-of-the-month natural gas and oil prices during the 12-month period ending in the reporting period, compared to prices at period end under prior SEC rules. It is not practicable for Chesapeake to estimate the effect of adopting the new reserve rules; however, these revisions and requirements affect the comparability between reporting periods for reserve volume and value estimates, full-cost pool write-down calculations and the calculation of depreciation, depletion and amortization of oil and gas assets.

The process of estimating natural gas and oil reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates.

As of December 31, 2008, Chesapeake had proved reserves of 12.051 tcfe at NYMEX spot prices of $5.71 per mcf and $44.61 per barrel before price differential adjustments. As of December 31, 2009, we had proved reserves of 14.254 tcfe at 2009 12-month average prices of $3.87 per mcf and $61.14 per barrel before price differential adjustments. The increase in proved reserves is, in part, due to the new reserve rules in effect for this filing.

Our December 31, 2008 proved undeveloped (PUD) reserve volume was 3.960 tcfe and our December 31, 2009 PUD reserve volume was 5.923 tcfe. This increase is partially attributable to the modernized rules, which allow for the reporting of PUD reserves more than one direct spacing area offsetting producing wells if reasonable certainty can be shown using reliable technology. Chesapeake has utilized and developed reliable geologic and engineering technology to book PUD reserves more than one location offsetting production in the Barnett Shale and Fayetteville Shale.

Within the Barnett and Fayetteville Shale plays, we used both public and proprietary geologic data to establish continuity of the formation and its producing properties. This included seismic data and interpretations (2-D, 3-D and micro seismic); open hole log information (both vertical and horizontally collected) and petrophysical analysis of the log data; mud logs; gas sample analysis; drill cutting samples; measurements of total organic content; thermal maturity; sidewall cores; whole cores and data measured from internal core analysis facility. Once the continuous geologic area was established, statistical analysis of established producing wells was used to generate reasonable certainty (defined as 90% probability aggregated to the field level). The analysis required a statistically significant number of producing wells within the defined geologic area and then tested for confidence by insuring the variance in results over time, area and distance was evaluated. Proper development spacing was also statistically analyzed.

Income Taxes. As part of the process of preparing the consolidated financial statements, we are required to estimate the federal and state income taxes in each of the jurisdictions in which Chesapeake operates. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as derivative instruments, depreciation, depletion and amortization, and certain accrued liabilities for tax and accounting purposes. These differences and our net operating loss carryforwards result in deferred tax assets and liabilities, which are included in our consolidated balance sheet. We must then assess, using all available positive and negative evidence, the likelihood that the deferred tax assets will be recovered from future taxable income. If we believe that recovery is not likely, we must establish a valuation allowance. Generally, to the extent Chesapeake establishes a valuation allowance or increases or decreases this allowance in a period, we must include an expense or reduction of expense within the tax provision in the consolidated statement of operations.

Under accounting guidance for income taxes, an enterprise must use judgment in considering the relative impact of negative and positive evidence. The weight given to the potential effect of negative and positive evidence should be commensurate with the extent to which it can be objectively verified. The more negative evidence that exists (i) the more positive evidence is necessary and (ii) the more difficult it is to support a conclusion that a valuation allowance is not needed for some portion or all of the deferred tax asset. Among the more significant types of evidence that we consider are:

- taxable income projections in future years;
- whether the carryforward period is so brief that it would limit realization of tax benefit;
- future sales and operating cost projections that will produce more than enough taxable income to realize the deferred tax asset based on existing sales prices and cost structures; and
- our earnings history exclusive of the loss that created the future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition.

If (i) natural gas and oil prices were to decrease significantly below present levels (and if such decreases were considered other than temporary), (ii) exploration, drilling and operating costs were to increase significantly beyond current levels, or (iii) we were confronted with any other significantly negative evidence pertaining to our ability to realize our NOL carryforwards prior to their expiration, we may be required to provide a valuation allowance against our deferred tax assets. As of December 31, 2009, we had deferred tax assets of $934 million.

Accounting guidance for recognizing and measuring uncertain tax positions prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. Based on this guidance, we regularly analyze tax positions taken or expected to be taken in a tax return based on the threshold condition prescribed. Tax positions that do not meet or exceed this threshold condition are considered uncertain tax positions. We accrue interest related to these uncertain tax positions which is recognized in interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses. Additional information about uncertain tax positions appears in Note 5 of the notes to our consolidated financial statements.

Disclosures About Effects of Transactions with Related Parties

Since Chesapeake was founded in 1989, our CEO, Aubrey K. McClendon, has acquired working interests in virtually all of our natural gas and oil properties by participating in our drilling activities under the terms of the Founder Well Participation Program (FWPP) and predecessor participation arrangements provided for in Mr. McClendon's employment agreements. Under the FWPP, approved by our shareholders in June 2005, Mr. McClendon may elect to participate in all or none of the wells drilled by or on behalf of Chesapeake during a calendar year, but he is not allowed to participate only in selected wells. A participation election is required to be received by the Compensation Committee of Chesapeake's Board of Directors not less than 30 days prior to the start of each calendar year. His participation is permitted only under the terms outlined in the FWPP, which, among other things, limits his individual participation to a maximum working interest of 2.5% in a well and prohibits participation in situations where Chesapeake's working interest would be reduced below 12.5% as a result of his participation. In addition, the company is reimbursed for costs associated with leasehold acquired by Mr. McClendon as a result of his well participation.

On December 31, 2008, we entered into a new five-year employment agreement with Mr. McClendon that contained a one-time well cost incentive award to him. The total cost of the award to Chesapeake was $75 million plus employment taxes in the amount of approximately $1 million. We will recognize the incentive award as general and administrative expense over the five-year vesting period for the clawback described below, resulting in an expense of approximately $15 million per year that began in 2009. In addition to state and federal income tax withholding, similar employment taxes were imposed on Mr. McClendon and withheld from the award. The net incentive award of approximately $44 million was fully applied against costs attributable to interests in company wells acquired by Mr. McClendon or his affiliates under the FWPP in 2009. The incentive award is subject to a clawback if during the initial five-year term of the employment agreement, Mr. McClendon resigns from the company or is terminated for cause by the company.

As disclosed in Note 17, in 2007, Chesapeake had revenues of $1.1 billion from natural gas and oil sales to Eagle Energy Partners I, L.P., a former affiliated entity. We sold our 33% limited partnership interest in Eagle Energy in June 2007.

Recently Issued Accounting Standards

In June 2009, the FASB issued amendments to the consolidation standard applicable to variable interest entities in response to concerns about the transparency of involvement with variable interest entities. The amended standard is effective for calendar year companies beginning on January 1, 2010. Beginning January 1, 2010, we will deconsolidate our joint venture with GIP and account for the investment in the joint venture under the equity method going forward. Adoption of this guidance will result in a cumulative effect adjustment for the difference in our equity in the joint venture at January 1, 2010, which was originally recorded at carryover basis, and the fair value of our equity at the formation of the joint venture based on the then fair value. This cumulative effect adjustment will create a basis difference between our equity investment balance and the underlying equity in the net assets of the joint venture. This difference will be accreted through earnings over the expected useful life of the underlying assets held by the joint venture.

In January 2010, the FASB updated its oil and gas estimation and disclosure requirements to align its requirements with the SEC's modernized oil and gas reporting rules, which are described above under *Application of Critical Accounting Policies.* The update amends the definition of proved reserves to use the average of first-day-of-the-month prices during the 12 months preceding the end of the reporting period, adds definitions used in estimating and disclosing proved oil and natural gas quantities and expands the disclosures required for equity-method investments. The update must be applied prospectively as a change in accounting principle that is inseparable from a change in accounting estimate and is effective for entities with annual reporting periods ending on or after December 31, 2009. See Note 10 of the notes to our consolidated financial statements for disclosures regarding our natural gas and oil reserves.

Forward-Looking Statements

This report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements give our current expectations or forecasts of future events. They include estimates of natural gas and oil reserves, expected natural gas and oil production and future expenses, assumptions regarding future natural gas and oil prices, planned capital expenditures, and anticipated asset acquisitions and sales, as well as statements concerning anticipated cash flow and liquidity, business strategy and other plans and objectives for future operations. Disclosures concerning the fair values of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility.

Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under *Risk Factors* in Item 1A of this report and include:

- the volatility of natural gas and oil prices;
- the limitations our level of indebtedness may have on our financial flexibility;
- declines in the values of our natural gas and oil properties resulting in ceiling test write-downs;
- the availability of capital on an economic basis, including planned asset monetization transactions, to fund reserve replacement costs;
- our ability to replace reserves and sustain production;
- uncertainties inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and the timing of development expenditures;
- potential differences in our interpretations of new reserve disclosure rules and future SEC guidance;
- inability to generate profits or achieve targeted results in our development and exploratory drilling and well operations;
- leasehold terms expiring before production can be established;
- hedging activities resulting in lower prices realized on natural gas and oil sales and the need to secure hedging liabilities;
- a reduced ability to borrow or raise additional capital as a result of lower natural gas and oil prices;
- drilling and operating risks, including potential environmental liabilities;
- legislation and regulation adversely affecting our industry and our business;
- general economic conditions negatively impacting us and our business counterparties;
- transportation capacity constraints and interruptions that could adversely affect our cash flow; and
- losses possible from pending or future litigation.

We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this report, and we undertake no obligation to update this information. We urge you to carefully review and consider the disclosures made in this report and our other filings with the Securities and Exchange Commission that attempt to advise interested parties of the risks and factors that may affect our business.

ITEM 7A. *Quantitative and Qualitative Disclosures About Market Risk*

Natural Gas and Oil Hedging Activities

Our results of operations and cash flows are impacted by changes in market prices for natural gas and oil. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. These instruments allow us to predict with greater certainty the effective natural gas and oil prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving our risk management objectives.

Our general strategy for attempting to mitigate exposure to adverse natural gas and oil price changes is to hedge into strengthening natural gas and oil futures markets when prices allow us to generate high cash margins and when we view prices to be in the upper range of our predicted most likely future price range. Information we consider in forming an opinion about future prices includes general economic conditions, industrial output levels and expectations, producer breakeven cost structures, liquefied natural gas import trends, natural gas and oil storage inventory levels, industry decline rates for base production and weather trends.

Throughout 2008 and 2009, we restructured many of our trades that included knockout features as commodity prices decreased. The knockouts were typically restructured into straight swaps or collars based on strip prices at the time of the restructure. Additionally, in the latter half of 2009 we took advantage of attractive strip prices in 2012 through 2014 and sold natural gas and oil call options to our counterparties in exchange for 2010 and 2011 natural gas swaps with strike prices above the then current market price. This effectively allowed us to sell out-year volatility through call options at terms acceptable to us in exchange for straight natural gas swaps with strike prices well in excess of the then current market price for natural gas.

We use a wide range of derivative instruments to achieve our risk management objectives, including swaps, various collar arrangements and options (puts or calls). All of these are described in more detail below. We typically use swaps or collars for a large portion of the natural gas and oil volume we hedge. Swaps are used when the price level is acceptable and collars are used when the downside protection from the bought put is meaningful and the cap on upside from the sold call is at a satisfactory level. We also sell calls, taking advantage of market volatility for a portion of our projected production volumes when the strike price levels and the premiums are attractive to us. Typically, we sell call options when we would be satisfied to sell our production at the price being capped by the call strike or believe it to be more likely than not that the future natural gas or oil price will stay below the call strike price plus the premium we will receive.

We determine the volume we may potentially hedge by reviewing the company's estimated future production levels, which are derived from extensive examination of existing producing reserve estimates and estimates of likely production (risked) from new drilling. Production forecasts are updated at least monthly and adjusted if necessary to actual results and activity levels. We do not hedge more volumes than we expect to produce, and if production estimates are lowered for future periods and hedges are already executed for some volume above the new production forecasts, the hedges are reversed. The actual fixed hedge price on our derivative instruments is derived from bidding and the reference NYMEX price, as reflected in current NYMEX trading. The pricing dates of our derivative contracts follow NYMEX futures. All of our derivative instruments are net settled based on the difference between the fixed price payment and the floating-price payment, resulting in a net amount due to or from the counterparty.

Hedging positions, including swaps and collars, are adjusted in response to changes in prices and market conditions as part of an ongoing dynamic process. We review our hedging positions continuously and if future market conditions change and prices have fallen to levels we believe could jeopardize the effectiveness of a position, we will mitigate such risk by either doing a cash settlement with our counterparty, restructuring the position, or by entering into a new swap that effectively reverses the current position (a counter-swap). The factors we consider in closing or restructuring a position before the settlement date are identical to those we reviewed when deciding to enter into the original hedge position.

As of December 31, 2009, our natural gas and oil derivative instruments were comprised of the following:

- Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.
- Collars: These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the put and the call strike price, no payments are due from either party. Three-way collars include an additional put option in exchange for a more favorable strike price on the collar. This eliminates the counterparty's downside exposure below the second put option.
- Call options: Chesapeake sells call options in exchange for a premium from the counterparty. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess and if the market price settles below the fixed price of the call option, no payment is due from either party.
- Put options: Chesapeake receives a premium from the counterparty in exchange for the sale of a put option. If the market price falls below the fixed price of the put option, Chesapeake pays the counterparty such shortfall. If the market price settles above the fixed price of the put option, no payment is due from either party.
- Knockout swaps: Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty's exposure to zero, in any given month, if the floating market price is lower than certain pre-determined knockout prices.
- Basis protection swaps: These instruments are arrangements that guarantee a price differential to NYMEX for natural gas from a specified delivery point. For non-Appalachian Basin basis protection swaps, which typically have negative differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. For Appalachian Basin basis protection swaps, which typically have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.

In accordance with accounting guidance for hedging and derivatives, to the extent that a legal right of set-off exists, Chesapeake nets the value of its derivative arrangements with the same counterparty in the accompanying consolidated balance sheets. Cash settlements of our derivative arrangements are generally classified as operating cash flows unless the derivative contains a significant financing element at contract inception, in which case, all cash settlements are classified as financing cash flows in the accompanying consolidated statement of cash flows.

As of December 31, 2009, we had the following open natural gas and oil derivative instruments designed to hedge a portion of our natural gas and oil production for periods after December 31, 2009:

	Volume	Weighted Average Price Fixed	Weighted Average Price Put	Weighted Average Price Call	Weighted Average Price Differential	Cash Flow Hedge	Net Premiums	Fair Value
	(bbtu)	(per mmbtu)					($ in millions)	
Natural Gas:								
Swaps:								
Q1 2010	63,478	$ 7.59	$ —	$ —	$ —	Yes	$ —	$ 124
Q2 2010	64,781	7.27	—	—	—	Yes	—	111
Q3 2010	51,972	7.32	—	—	—	Yes	—	81
Q4 2010	53,212	7.40	—	—	—	Yes	—	62
2011	22,210	7.99	—	—	—	Yes	—	36
Other Swaps[(a)]:								
Q1 2010	33,890	7.22	—	—	—	No	—	54
Q2 2010	43,680	7.61	—	—	—	No	—	59
Q3 2010	44,160	7.69	—	—	—	No	—	57
Q4 2010	44,160	8.04	—	—	—	No	—	51
2011	70,510	9.52	—	—	—	No	—	27
Collars:								
Q1 2010	29,700	—	6.24	8.06	—	Yes	—	19
Q2 2010	7,280	—	7.00	8.25	—	Yes	—	11
Other Collars[(b)]:								
Q1 2010	13,500	—	4.29/7.05	9.49	—	No	—	19
Q2 2010	9,100	—	4.35/7.07	9.91	—	No	5	15
Q3 2010	3,680	—	7.60	11.75	—	No	4	8
Q4 2010	3,680	—	7.60	11.75	—	No	4	7
2011	7,300	—	7.60	11.50	—	No	7	13
Knockout Swaps:								
Q3 2010	7,360	9.79	6.32	—	—	No	—	4
Q4 2010	7,360	9.79	6.31	—	—	No	—	3
2011	23,650	9.86	6.29	—	—	No	—	10
Call Options:								
Q1 2010	18,585	—	—	10.19	—	No	41	—
Q2 2010	28,665	—	—	10.19	—	No	41	(1)
Q3 2010	34,040	—	—	10.22	—	No	43	(3)
Q4 2010	34,040	—	—	10.30	—	No	43	(6)
2011	20,987	—	—	10.73	—	No	42	(4)
2012	262,605	—	—	8.46	—	No	16	(150)
2013 – 2020	597,828	—	—	9.10	—	No	102	(377)
Put Options:								
Q3 2010	(16,560)	—	5.73	—	—	No	6	(12)
Q4 2010	(16,560)	—	5.73	—	—	No	6	(12)
2011	(36,500)	—	5.75	—	—	No	25	(26)
Basis Protection Swaps (Non-Appalachian Basin):								
2011	45,090	—	—	—	(0.82)	No	(3)	(22)
2012 – 2018	57,961	—	—	—	(0.90)	No	(3)	(29)
Basis Protection Swaps (Appalachian Basin):								
Q1 2010	2,293	—	—	—	0.27	No	—	—
Q2 2010	2,513	—	—	—	0.27	No	—	—
Q3 2010	2,660	—	—	—	0.26	No	—	—
Q4 2010	2,732	—	—	—	0.26	No	—	—
2011	12,086	—	—	—	0.25	No	—	1
2012 – 2022	134	—	—	—	0.11	No	—	—
Total Natural Gas							379	130

		Weighted Average Price				Cash Flow	Net	Fair
	Volume	Fixed	Put	Call	Differential	Hedge	Premiums	Value
	(mbbls)	(per bbl)					($ in millions)	
Oil:								
Swaps:								
Q1 2010	450	$ 85.86	$ —	$ —	$ —	Yes	$ —	$ 3
Q2 2010	455	85.86	—	—	—	Yes	—	2
Q3 2010	460	85.86	—	—	—	Yes	—	1
Q4 2010	460	85.86	—	—	—	Yes	—	1
Other Swaps[(c)]:								
Q1 2010	360	91.96	—	—	—	No	—	4
Q2 2010	364	91.96	—	—	—	No	—	4
Q3 2010	368	91.96	—	—	—	No	—	3
Q4 2010	368	91.96	—	—	—	No	—	3
2011	2,190	91.76	—	—	—	No	—	(18)
Knock-Out Swaps:								
Q1 2010	1,170	90.25	60.00	—	—	No	—	12
Q2 2010	1,183	90.25	60.00	—	—	No	—	7
Q3 2010	1,196	90.25	60.00	—	—	No	—	3
Q4 2010	1,196	90.25	60.00	—	—	No	—	(1)
2011	1,095	104.75	60.00	—	—	No	—	7
2012	732	109.50	60.00	—	—	No	—	4
Call Options:								
Q1 2010	630	—	—	105.00	—	No	(1)	—
Q2 2010	637	—	—	105.00	—	No	(1)	(1)
Q3 2010	644	—	—	105.00	—	No	(1)	(2)
Q4 2010	644	—	—	105.00	—	No	(1)	(3)
2011	3,650	—	—	105.00	—	No	16	(25)
2012 – 2014	8,770	—	—	99.59	—	No	16	(113)
Total Oil							28	(109)
Total Natural Gas and Oil							$ 407	$ 21

(a) Included in Other Swaps are options to extend existing swaps for an additional 12 months. The volume of such extendables in 2010 is 27,500 bbtu at a weighted average fixed swap price of $9.03/mmbtu, and in 2011 is 51,950 bbtu at an average fixed price of $10.05/mmbtu.

(b) Included in Other Collars for 2010 are 11,740 bbtu of three-way collars which have written put options with weighted average prices of $4.31/mmbtu, which limits the counterparty's exposure.

(c) Included in Other Swaps are options to extend existing swaps for an additional 12 months. The volume of such extendables in 2011 is 2,190 mbbl at a weighted average fixed price of $91.76/bbl.

We have determined the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. Future risk related to counterparties not being able to meet their obligations has been mitigated under our new secured hedging facility which requires counterparties to post collateral if their obligations to Chesapeake are in excess of defined thresholds. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors.

The table below reconciles the years ended December 31, 2009, 2008 and 2007 changes in fair value of our natural gas and oil derivatives. Of the $21 million fair value asset as of December 31, 2009, $686 million relates to contracts maturing in the next 12 months, of which we expect to transfer approximately $202 million (net of income taxes) from accumulated other comprehensive income to net income (loss), and ($665) million relates to contracts maturing after 12 months. All transactions hedged as of December 31, 2009 are expected to mature by December 31, 2022.

	2009	2008	2007
	($ in millions)		
Fair value of contracts outstanding, as of January 1	$ 1,305	$ (369)	$ 345
Change in fair value of contracts	1,266	1,880	972
Fair value of contracts when entered into	(21)	(569)	(295)
Contracts realized or otherwise settled	(2,102)	9	(1,203)
Fair value of contracts when closed	(427)	354	(188)
Fair value of contracts outstanding, as of December 31	$ 21	$1,305	$ (369)

The change in natural gas and oil prices during the year ended December 31, 2009 increased the value of our derivative assets by $1.3 billion. This gain is recorded in natural gas and oil sales or in accumulated other comprehensive income. We entered into new contracts which had premiums of $21 million, and a liability was recorded. We settled and closed out contracts, reducing our assets by $2.1 billion and $427 million, respectively, and the realized gain is recorded in natural gas and oil sales in the month of related production.

Pursuant to accounting guidance for derivatives and hedging, certain derivatives qualify for designation as cash flow hedges. Following these provisions, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in accumulated other comprehensive income until the hedged item is recognized in earnings as the physical transactions being hedged occur. Any change in fair value resulting from ineffectiveness is currently recognized in natural gas and oil sales as unrealized gains (losses). Changes in the fair value of non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within natural gas and oil sales. Realized gains (losses) are included in natural gas and oil sales in the month of related production.

Chesapeake enters into counter-swaps from time to time for the purpose of locking-in the value of a swap. Under the counter-swap, Chesapeake receives a floating price for the hedged commodity and pays a fixed price to the counterparty. The counter-swap is 100% effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap. Generally, at the time Chesapeake enters into a counter-swap, Chesapeake removes the original swap's designation as a cash flow hedge and classifies the original swap as a non-qualifying hedge. The reason for this new designation is that collectively the swap and the counter-swap no longer hedge the exposure to variability in expected future cash flows. Instead, the swap and counter-swap effectively lock-in a specific gain or loss that will be unaffected by subsequent variability in natural gas and oil prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to natural gas and oil sales in the month of related production.

The components of natural gas and oil sales for the years ended December 31, 2009, 2008 and 2007 are presented below.

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
Natural gas and oil sales	$ 3,291	$ 7,069	$4,795
Realized gains (losses) on natural gas and oil derivatives	2,346	(8)	1,203
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(624)	887	(252)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	36	(90)	(122)
Total natural gas and oil sales	$ 5,049	$ 7,858	$5,624

To mitigate our exposure to the fluctuation in price of diesel fuel which is used in our exploration and development activities, we have entered into diesel swaps from January 2010 to March 2010 for a total of 10.4 million gallons with an average fixed price of $1.58 per gallon. Chesapeake pays the fixed price and receives the floating price. The fair value of these swaps as of December 31, 2009 was an asset of $5 million.

Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates.

	Years of Maturity						
	2010	2011	2012	2013	2014	Thereafter	Total
	($ in millions)						
Liabilities:							
Long-term debt – fixed rate[(a)]	$ —	$ —	$ —	$864	$600	$ 9,747	$11,211
Average interest rate	—	—	—	7.6%	7.3%	6.0%	6.2%
Long-term debt – variable rate	$ —	$ —	$1,936	$ —	$ —	$ —	$ 1,936
Average interest rate	—	—	2.2%	—	—	—	2.2%

(a) This amount does not include the discount included in long-term debt of ($921) million and interest rate derivatives of $69 million.

Changes in interest rates affect the amount of interest we earn on our cash, cash equivalents and short-term investments and the interest rate we pay on borrowings under our revolving bank credit facilities. All of our other long-term indebtedness is fixed rate and, therefore, does not expose us to the risk of fluctuations in earnings or cash flow due to changes in market interest rates. However, changes in interest rates do affect the fair value of our fixed rate debt.

Interest Rate Derivatives

To mitigate our exposure to volatility in interest rates related to our senior notes and credit facilities, we enter into interest rate derivatives. As of December 31, 2009, our interest rate derivative instruments were comprised of the following types of instruments:

- Swaps: Chesapeake enters into fixed-to-floating interest rate swaps (we receive a fixed interest rate and pay a floating market rate) to mitigate our exposure to changes in the fair value of our senior notes. We enter into floating-to-fixed interest rate swaps (we receive a floating market rate and a pay fixed interest rate) to manage our interest rate exposure related to our bank credit facility borrowings.

- Collars: These instruments contain a fixed floor rate (floor) and a ceiling rate (cap). If the floating rate is above the cap, we have a net receivable from the counterparty and if the floating rate is below the floor, we have a net payable to the counterparty. If the floating rate is between the floor and the cap, there is no payment due from either party. Collars are used to manage our interest rate exposure related to our bank credit facilities borrowings.
- Call options: Occasionally we sell call options for a premium when we think it is more likely that the option will expire unexercised. The option allows the counterparty to terminate an open swap at a specific date.
- Swaptions: Occasionally we sell an option to a counterparty for a premium which allows the counterparty to enter into a swap with us on a specific date.

As of December 31, 2009, the following interest rate derivatives were outstanding:

	Notional Amount	Weighted Average Rate		Fair Value Hedge	Net Premiums	Fair Value
		Fixed	Floating[b]			
	($ in millions)				($ in millions)	
Fixed to Floating:						
Swaps						
Mature 2015	$ 550	9.50%	1– 3 mL plus 657 bp	Yes	$ —	$ (11)
Mature 2013 – 2020	$ 1,000	7.06%	3 – 6 mL plus 417 bp	No	9	(61)
Call Options						
Expire May 2010	$ 250	6.88%	3 mL plus 287 bp	No	4	(2)
Swaption						
Expire June 2010	$ 500	6.88%	3 mL plus 254 bp	No	5	(11)
Floating to Fixed:						
Swaps						
Mature 2010 – 2012	$ 1,375	3.30%	1– 6 mL	No	—	(41)
Collars[a]						
Mature 2010	$ 250	4.52%	6 mL	No	—	(6)
					$ 18	$(132)

(a) The collars have ceiling and floor fixed interest rates of 5.37% and 4.52%, respectively.

(b) Month LIBOR has been abbreviated "mL" and basis points has been abbreviated "bp".

In 2009, we closed interest rate derivatives for gains totaling $49 million of which $23 million was recognized in interest expense. The remaining $26 million was from interest rate derivatives designated as fair value hedges which are accounted for as a reduction to our senior notes. The settlement amounts received will be amortized as a reduction to realized interest expense over the remaining term of the related senior notes ranging from four to eleven years.

For interest rate derivative instruments designated as fair value hedges, changes in fair value are recorded on the consolidated balance sheets as assets (liabilities), and the debt's carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Changes in the fair value of non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized (gains) losses within interest expense.

Gains or losses from interest rate derivative transactions are reflected as adjustments to interest expense on the consolidated statements of operations. The components of interest expense for the years ended December 31, 2009, 2008 and 2007 are presented below.

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
Interest expense on senior notes	$ 765	$ 637	$538
Interest expense on credit facilities	60	117	113
Capitalized interest	(633)	(585)	(311)
Realized (gains) losses on interest rate derivatives	(23)	(6)	1
Unrealized (gains) losses on interest rate derivatives	(91)	85	40
Amortization of loan discount and other	35	23	20
Total interest expense	$ 113	$ 271	$401

Foreign Currency Derivatives

On December 6, 2006, we issued €600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the Euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties pay Chesapeake €19 million and Chesapeake pays the counterparties $30 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake €600 million and Chesapeake will pay the counterparties $800 million. The terms of the cross currency swap were based on the dollar/euro exchange rate on the issuance date of $1.3325 to €1.00. Through the cross currency swap, we have eliminated any potential variability in Chesapeake's expected cash flows related to changes in foreign exchange rates and therefore the swap qualifies as a cash flow hedge. The fair value of the cross currency swap is recorded on the consolidated balance sheet as an asset of $43 million at December 31, 2009. The euro-denominated debt in notes payable has been adjusted to $860 million at December 31, 2009 using an exchange rate of $1.4332 to €1.00.

ITEM 8. *Financial Statements and Supplementary Data*

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CHESAPEAKE ENERGY CORPORATION

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

It is the responsibility of the management of Chesapeake Energy Corporation to establish and maintain adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Management utilized the Committee of Sponsoring Organizations of the Treadway Commission's *Internal Control-Integrated Framework* (COSO framework) in conducting the required assessment of effectiveness of the company's internal control over financial reporting.

Management has performed an assessment of the effectiveness of the company's internal control over financial reporting and has determined the company's internal control over financial reporting was effective as of December 31, 2009.

The effectiveness of the company's internal control over financial reporting as of December 31, 2009 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report which appears herein.

/s/ AUBREY K. MCCLENDON

Aubrey K. McClendon
Chairman of the Board and Chief Executive Officer

/s/ MARCUS C. ROWLAND

Marcus C. Rowland
Executive Vice President and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Chesapeake Energy Corporation,

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Chesapeake Energy Corporation and its subsidiaries at December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 20 to the consolidated financial statements, the Company changed the manner in which it estimates the quantities of oil and gas reserves in 2009 and the limitation on its capitalized costs as of December 31, 2009. Also as discussed in Note 3 to the consolidated financial statements, the Company changed the manner in which it accounts for contingent convertible debt instruments as of January 1, 2009, and retrospectively applied the impact to prior periods.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Tulsa, Oklahoma

March 1, 2010

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents	$ 307	$ 1,749
Accounts receivable	1,325	1,324
Short-term derivative instruments	692	1,082
Deferred income tax asset	24	—
Inventory	25	58
Other	73	79
Total Current Assets	2,446	4,292
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full-cost accounting:		
Evaluated natural gas and oil properties	35,007	28,965
Unevaluated properties	10,005	11,379
Less: accumulated depreciation, depletion and amortization of natural gas and oil properties	(24,220)	(11,866)
Total natural gas and oil properties, at cost based on full-cost accounting	20,792	28,478
Other property and equipment:		
Natural gas gathering systems and treating plants	3,516	2,717
Buildings and land	1,673	1,513
Drilling rigs and equipment	687	430
Natural gas compressors	325	184
Other	550	482
Less: accumulated depreciation and amortization of other property and equipment	(833)	(496)
Total Other Property and Equipment	5,918	4,830
Total Property and Equipment	26,710	33,308
OTHER ASSETS:		
Investments	404	444
Long-term derivative instruments	60	261
Other assets	294	288
Total Other Assets	758	993
TOTAL ASSETS	$ 29,914	$ 38,593

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS – (Continued)

	December 31, 2009	December 31, 2008
	($ in millions)	
CURRENT LIABILITIES:		
Accounts payable	$ 957	$ 1,611
Short-term derivative instruments	27	66
Accrued liabilities	920	880
Deferred income taxes	—	358
Income taxes payable	1	108
Revenues and royalties due others	565	431
Accrued interest	218	167
Total Current Liabilities	2,688	3,621
LONG-TERM LIABILITIES:		
Long-term debt, net	12,295	13,175
Deferred income tax liabilities	1,059	4,200
Asset retirement obligations	282	269
Long-term derivative instruments	787	111
Revenues and royalties due others	73	49
Other liabilities	389	151
Total Long-Term Liabilities	14,885	17,955
CONTINGENCIES AND COMMITMENTS (Note 4)		
EQUITY:		
Chesapeake stockholders' equity:		
Preferred Stock, $0.01 par value, 20,000,000 shares authorized:		
4.50% cumulative convertible preferred stock 2,558,900 shares issued and outstanding as of December 31, 2009 and 2008, respectively, entitled in liquidation to $256 million	256	256
5.00% cumulative convertible preferred stock (series 2005B) 2,095,615 shares issued and outstanding as of December 31, 2009 and 2008, respectively, entitled in liquidation to $209 million	209	209
5.00% cumulative convertible preferred stock (series 2005), 5,000 shares issued and outstanding as of December 31, 2009 and 2008, entitled in liquidation to $1 million	1	1
6.25% mandatory convertible preferred stock, 0 and 143,768 shares issued and outstanding as of December 31, 2009 and 2008, entitled in liquidation to $0 and $36 million	—	36
4.125% cumulative convertible preferred stock, 0 and 3,033 shares issued and outstanding as of December 31, 2009 and 2008, respectively, entitled in liquidation to $0 and $3 million	—	3
Common stock, $0.01 par value, 1,000,000,000 and 750,000,000 shares authorized, 648,549,165 and 607,953,437 shares issued December 31, 2009 and 2008, respectively	6	6
Paid-in capital	12,146	11,680
Retained earnings (deficit)	(1,261)	4,569
Accumulated other comprehensive income (loss), net of tax of ($62) million and ($163) million, respectively	102	267
Less: treasury stock, at cost; 877,205 and 657,276 common shares as of December 31, 2009 and 2008, respectively	(15)	(10)
Total Chesapeake Stockholders' Equity	11,444	17,017
Noncontrolling interest	897	—
Total Equity	12,341	17,017
TOTAL LIABILITIES AND EQUITY	$ 29,914	$ 38,593

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2009	2008	2007
	($ in millions, except per share data)		
REVENUES:			
Natural gas and oil sales	$ 5,049	$ 7,858	$ 5,624
Marketing, gathering and compression sales	2,463	3,598	2,040
Service operations revenue	190	173	136
Total Revenues	7,702	11,629	7,800
OPERATING COSTS:			
Production expenses	876	889	640
Production taxes	107	284	216
General and administrative expenses	349	377	243
Marketing, gathering and compression expenses	2,316	3,505	1,969
Service operations expense	182	143	94
Natural gas and oil depreciation, depletion and amortization	1,371	1,970	1,835
Depreciation and amortization of other assets	244	174	153
Impairment of natural gas and oil properties and other assets	11,130	2,830	—
Loss on sale of other property and equipment	38	—	—
Restructuring costs	34	—	—
Total Operating Costs	16,647	10,172	5,150
INCOME (LOSS) FROM OPERATIONS	(8,945)	1,457	2,650
OTHER INCOME (EXPENSE):			
Other income (expense)	(28)	(11)	15
Interest expense	(113)	(271)	(401)
Impairment of investments	(162)	(180)	—
Loss on exchanges or repurchases of Chesapeake debt	(40)	(4)	—
Gain on sale of investments	—	—	83
Total Other Income (Expense)	(343)	(466)	(303)
INCOME (LOSS) BEFORE INCOME TAXES	(9,288)	991	2,347
INCOME TAX EXPENSE (BENEFIT):			
Current income taxes	4	423	29
Deferred income taxes	(3,487)	(36)	863
Total Income Tax Expense (Benefit)	(3,483)	387	892
NET INCOME(LOSS)	(5,805)	604	1,455
Net (income) attributable to noncontrolling interest	(25)	—	—
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(5,830)	604	1,455
Preferred stock dividends	(23)	(33)	(94)
Loss on conversion/exchange of preferred stock	—	(67)	(128)
NET INCOME (LOSS) AVAILABLE TO CHESAPEAKE COMMON STOCKHOLDERS	$ (5,853)	$ 504	$ 1,233
EARNINGS (LOSS) PER COMMON SHARE:			
Basic	$ (9.57)	$ 0.94	$ 2.70
Assuming dilution	$ (9.57)	$ 0.93	$ 2.63
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.30	$ 0.2925	$ 0.2625
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):			
Basic	612	536	456
Assuming dilution	612	545	487

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME (LOSS)	$ (5,805)	$ 604	$ 1,455
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion and amortization	1,615	2,144	1,988
Deferred income tax expense (benefit)	(3,487)	(36)	863
Unrealized (gains) losses on derivatives	497	(712)	415
Realized (gains) losses on financing derivatives	(154)	38	(92)
Stock-based compensation	140	132	84
Accretion of discount on contingent convertible notes	79	79	37
Restructuring costs	12	—	—
Loss on sale of other property and equipment	38	—	—
Gain on sale of investments	—	—	(83)
Loss from equity investments	39	38	—
Loss repurchases or exchanges of Chesapeake debt	40	4	—
Impairment of natural gas and oil properties and other fixed assets	11,130	2,830	—
Impairment of investments	162	180	—
Other	27	(2)	8
(Increase) decrease in accounts receivable	—	(78)	(192)
(Increase) decrease in inventory and other assets	(31)	56	(65)
Increase (decrease) in accounts payable, accrued liabilities and other	(105)	76	430
Increase (decrease) in current and non-current revenues and royalties due others	159	4	126
Cash provided by operating activities	4,356	5,357	4,974
CASH FLOWS FROM INVESTING ACTIVITIES:			
Acquisitions of natural gas and oil companies, proved and unproved properties, net of cash acquired	(2,298)	(8,593)	(3,003)
Exploration and development of natural gas and oil properties	(3,543)	(6,104)	(5,305)
Additions to other property and equipment	(1,683)	(3,073)	(1,439)
Additions to investments	(40)	(74)	(8)
Proceeds from divestitures of proved and unproved properties and leasehold	1,518	6,091	—
Proceeds from sale of volumetric production payments	408	1,579	1,089
Proceeds from sale of compressors	68	114	188
Proceeds from sale of drilling rigs and equipment	—	64	369
Proceeds from sale of investments	—	2	124
Deposits for acquisitions	—	(12)	(15)
Proceeds from sale of other assets and other	108	41	36
Cash used in investing activities	(5,462)	(9,965)	(7,964)

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS—(Continued)

	Years Ended December 31, 2009	2008	2007
	($ in millions)		
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from credit facilities borrowings	7,761	13,291	7,932
Payments on credit facilities borrowings	(9,758)	(11,307)	(6,160)
Proceeds from issuance of senior notes, net of offering costs	1,346	2,136	1,607
Proceeds from issuance of common stock, net of offering costs	—	2,598	—
Cash paid to purchase Chesapeake senior notes	—	(312)	—
Cash paid for common stock dividends	(181)	(148)	(115)
Cash paid for preferred stock dividends	(23)	(35)	(95)
Cash paid for treasury stock	(7)	(5)	—
Proceeds from sale of noncontrolling interest in midstream joint venture	588	—	—
Distribution to midstream joint venture partner	(10)	—	—
Midstream joint venture transaction costs	(16)	—	—
Derivative settlements	109	(167)	(91)
Net increase (decrease) in outstanding payments in excess of cash balance	(249)	330	(98)
Proceeds from mortgage of building	54	—	—
Proceeds from financing of real estate surface assets	145	—	—
Cash received from exercise of stock options	4	9	15
Excess tax benefit from stock-based compensation	—	43	20
Other	(99)	(77)	(27)
Cash provided by (used in) financing activities	(336)	6,356	2,988
Net increase (decrease) in cash and cash equivalents	(1,442)	1,748	(2)
Cash and cash equivalents, beginning of period	1,749	1	3
Cash and cash equivalents, end of period	$ 307	$ 1,749	$ 1
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:			
Interest, net of capitalized interest	$ 64	$ 97	$ 273
Income taxes, net of refunds received	$ 7	$ 296	$ 55

SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:

As of December 31, 2009, 2008 and 2007, dividends payable on our common and preferred stock were $53 million, $50 million and $53 million, respectively.

In 2009, 2008 and 2007, natural gas and oil properties were adjusted by a nominal amount, $13 million and $131 million, respectively, for net income tax liabilities related to acquisitions.

During 2009, 2008 and 2007, natural gas and oil properties were adjusted by ($93) million, ($4) million and $97 million, respectively, as a result of an increase (decrease) in accrued acquisition, exploration and development costs.

During 2009, 2008 and 2007, other property and equipment were adjusted by ($53) million, $125 million and $3 million, respectively, as a result in an increase (decrease) in accrued costs.

We recorded non-cash asset additions (reductions) to net natural gas and oil properties of ($2) million, $10 million and $29 million in 2009, 2008 and 2007, respectively, for asset retirement obligations.

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS–(Continued)

In 2009 and 2008, holders of certain of our contingent convertible senior notes exchanged or converted their senior notes for shares of common stock in privately negotiated exchanges as summarized below ($ in millions):

Year	Contingent Convertible Senior Notes	Principal Amount	Number of Common Shares
2009	2.25% due 2038	$ 364	10,210,169
2008	2.75% due 2035	$ 239	8,841,526
	2.50% due 2037	272	8,416,865
	2.25% due 2038	254	6,654,821
		$ 765	23,913,212

In 2009 and 2008, we issued 24,822,832 and 1,677,000 shares of common stock, valued at $421 million and $34 million, respectively, for the purchase of leasehold and unproved properties pursuant to an acquisition shelf registration statement.

In 2009, 2008 and 2007, shares of our cumulative convertible preferred stock were exchanged for or converted into shares of common stock as summarized below:

Year of Exchange/ Conversion	Cumulative Convertible Preferred Stock	Number of Preferred Shares	Number of Common Shares	Type of Transaction
2009	6.25%	143,768	1,239,538	Conversion
	4.125%	3,033	182,887	Conversion
			1,422,425	
2008	5.0% (series 2005B)	3,654,385	10,443,642	Exchange
	4.5%	891,100	2,227,750	Exchange
	4.125%	29	1,743	Conversion
			12,673,135	
2007	5.0% (series 2005)	4,595,000	19,283,311	Exchange
	6.25%	2,156,184	17,367,823	Exchange
	6.25%	48	344	Conversion
	4.125%	3	180	Conversion
			36,651,658	

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
PREFERRED STOCK:			
Balance, beginning of period	$ 505	$ 960	$1,958
Exchange of common stock for 0, 3,654,385 and 0 shares of 5.00% preferred stock (series 2005B)	—	(366)	—
Exchange of common stock for 0, 891,000 and 0 shares of 4.50% preferred stock	—	(89)	—
Exchange of common stock for 0, 0 and 4,595,000 shares of 5.00% preferred stock (series 2005)	—	—	(459)
Exchange of common stock for 143,768, 0 and 2,156,232 shares of 6.25% preferred stock	(36)	—	(539)
Exchange of common stock for 3,033, 29 and 3 shares of 4.125% preferred stock	(3)	—	—
Balance, end of period	466	505	960
COMMON STOCK:			
Balance, beginning of period	6	5	5
Issuance of 0, 51,750,000 and 0 shares of common stock	—	1	—
Issuance of 24,822,832, 1,677,000 and 0 shares of common stock for the purchase of leasehold and unproved properties	—	—	—
Exchange of 1,422,425, 12,673,135 and 36,651,658 shares of common stock for preferred stock	—	—	—
Exchange of 10,210,169, 23,913,212 and 0 shares of common stock for convertible notes	—	—	—
Balance, end of period	6	6	5
PAID-IN CAPITAL:			
Balance, beginning of period	11,680	7,532	5,998
Issuance of 0, 51,750,000 and 0 shares of common stock	—	2,697	—
Issuance of 24,822,832, 1,677,000 and 0 shares of common stock for the purchase of leasehold and unproved properties	421	34	—
Issuance of 2.50% contingent convertible senior notes due 2037	—	—	375
Issuance of 2.25% contingent convertible senior notes due 2038	—	345	—
Exchange of 10,210,169, 23,913,212 and 0 shares of common stock for convertible notes	262	480	—
Exchange of 1,422,425, 12,673,135 and 36,651,658 shares of common stock for preferred stock	39	454	998
Stock-based compensation	199	188	129
Offering/transaction expenses	(16)	(101)	—
Dividends on common stock	(185)	—	—
Dividends on preferred stock	(22)	—	—
Exercise of stock options	4	8	15
Equalization of partners' capital accounts	(294)	—	—
Tax effect on equalization of partners' capital	106	—	—
Tax benefit (reduction in tax benefit) from exercise of stock options and restricted stock	(48)	43	20
Preferred stock conversion/exchange expenses	—	—	(3)
Balance, end of period	12,146	11,680	7,532

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY – (Continued)

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
RETAINED EARNINGS (DEFICIT):			
Balance, beginning of period	$ 4,569	$ 4,144	$ 2,903
Net income (loss) attributable to Chesapeake	(5,830)	604	1,455
Dividends on common stock	—	(158)	(121)
Dividends on preferred stock	—	(21)	(89)
Other	—	—	(4)
Balance, end of period	(1,261)	4,569	4,144
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance, beginning of period	267	(11)	528
Hedging activity	(231)	297	(520)
Investment activity	66	(19)	(19)
Balance, end of period	102	267	(11)
TREASURY STOCK – COMMON:			
Balance, beginning of period	(10)	(6)	(26)
Purchase of 227,827, 159,430 and 0 shares of treasury stock	(5)	(4)	—
Release of 7,898, 2,975 and 666,186 shares for company benefit plans	—	—	20
Balance, end of period	(15)	(10)	(6)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY	11,444	17,017	12,624
NONCONTROLLING INTEREST:			
Balance, beginning of period	—	—	—
Sale of noncontrolling interest in midstream joint venture	588	—	—
Equalization of partners' capital accounts	294	—	—
Distribution to partner	(10)	—	—
Chesapeake Midstream Partners net income attributable to Global Infrastructure Partners	25	—	—
Balance, end of period	897	—	—
TOTAL EQUITY	$12,341	$17,017	$12,624

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
Net income (loss)	$ (5,805)	$ 604	$ 1,455
Other comprehensive income (loss), net of income tax:			
Change in fair value of derivative instruments, net of income taxes of $413 million, $113 million and ($56) million, respectively	677	186	(92)
Reclassification of (gain) loss on settled contracts, net of income taxes of ($540) million, $35 million and ($308) million, respectively	(885)	55	(504)
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of ($14) million, $34 million and $46 million, respectively	(23)	56	76
Unrealized (gain) loss on marketable securities, net of income taxes of $14 million, ($12) million and ($11) million, respectively	23	(19)	(19)
Reclassification of loss on investments, net of income taxes of $26 million, $0 and $0, respectively	43	—	—
Comprehensive income (loss)	(5,970)	882	916
(Income) attributable to noncontrolling interest	(25)	—	—
Comprehensive income (loss) available to Chesapeake	$ (5,995)	$ 882	$ 916

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Summary of Significant Accounting Policies

Description of Company

Chesapeake Energy Corporation ("Chesapeake" or the "company") is a natural gas and oil exploration and production company engaged in the exploration, development and acquisition of properties for the production of natural gas and crude oil from underground reservoirs, and we provide marketing and other midstream services. Our properties are located in Alabama, Arkansas, Colorado, Kansas, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Montana, Nebraska, New Mexico, New York, North Dakota, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia and Wyoming.

Principles of Consolidation

The accompanying consolidated financial statements of Chesapeake include the accounts of our direct and indirect wholly-owned subsidiaries, as well as our 50/50 joint venture with Global Infrastructure Partners (GIP). Because of certain commitments and contractual arrangements with GIP, the joint venture partnership qualifies as a variable interest entity and must be consolidated by the company, as the primary beneficiary. All significant intercompany accounts and transactions have been eliminated.

Change in Accounting Principle

On January 1, 2009, we adopted and applied retrospectively new accounting and reporting standards for debt with conversion and other options. As a result, our prior year consolidated financial statements have been retrospectively adjusted. See Note 3 for additional information on the application of this accounting principle.

Accounting Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

Cash Equivalents

For purposes of the consolidated financial statements, Chesapeake considers investments in all highly liquid instruments with original maturities of three months or less at date of purchase to be cash equivalents.

Accounts Receivable

Our accounts receivable are primarily from purchasers of natural gas and oil and exploration and production companies which own interests in properties we operate. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

Accounts receivable consists of the following components:

	December 31, 2009	December 31, 2008
	($ in millions)	
Natural gas and oil sales	$ 743	$ 738
Joint interest	394	424
Service operations	7	20
Related parties[a]	15	—
Other	190	154
Allowance for doubtful accounts	(24)	(12)
Total accounts receivable	$ 1,325	$ 1,324

(a) See Note 6 for discussion of related party transactions.

Natural Gas and Oil Properties

Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities (see Note 10). Capitalized costs are amortized on a composite unit-of-production method based on proved natural gas and oil reserves. Estimates of our proved reserves as of December 31, 2009 were prepared by both third party engineering firms and Chesapeake's internal staff. Approximately 83% of these proved reserves estimates (by volume) at year-end 2009 were prepared by independent engineering firms. In addition, our internal engineers review and update our reserves on a quarterly basis. The average composite rates used for depreciation, depletion and amortization were $1.51 per mcfe in 2009, $2.34 per mcfe in 2008 and $2.57 per mcfe in 2007.

Proceeds from the sale of properties are accounted for as reductions of capitalized costs unless such sales involve a significant change in the relationship between costs and the value of proved reserves or the underlying value of unproved properties, in which case a gain or loss is recognized.

The costs of unproved properties are excluded from amortization until the properties are evaluated. We review all of our unevaluated properties quarterly to determine whether or not and to what extent proved reserves have been assigned to the properties and otherwise if impairment has occurred. Unevaluated properties are grouped by major prospect area where individual property costs are not significant and are assessed individually when individual costs are significant.

We review the carrying value of our natural gas and oil properties under the full-cost accounting rules of the Securities and Exchange Commission on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In 2009, capitalized costs of natural gas and oil properties exceeded the estimated present value of future net revenues from our proved reserves, net of related income tax considerations, resulting in a write-down in the carrying value of natural gas and oil properties of $6.9 billion, net of tax. In calculating future net revenues, effective December 31, 2009, current prices are calculated as the average natural gas and oil prices during the preceding 12-month period prior to the end of the current reporting period, determined as the unweighted arithmetical average of prices on the first day of each month within the 12-month period and costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. Based on average prices for the prior 12-month period for natural gas and oil as of December 31, 2009, these cash flow hedges increased the full-cost ceiling by $1.1 billion, thereby reducing the ceiling test write-down by the same amount. Our qualifying cash flow hedges as of December 31, 2009, which consisted of swaps and collars, covered 281 bcfe and 22 bcfe in 2010 and 2011, respectively. Our natural gas and oil hedging activities are discussed in Note 9 of these consolidated financial statements.

Two primary factors impacting the ceiling test are reserve levels and natural gas and oil prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of natural gas and oil reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense.

We account for seismic costs in accordance with Rule 4-10 of Regulation S-X. Specifically, Rule 4-10 requires that all companies that use the full-cost method capitalize exploration costs as part of their natural gas and oil properties (i.e., full-cost pool). Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Further, exploration costs include, among other things, geological and geophysical studies and salaries and other expenses of geologists, geophysical crews and others conducting those studies. Such costs are capitalized as incurred. Seismic costs directly associated with the acquisition and evaluation of unproved properties are excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the properties. The company reviews its unproved properties and associated seismic costs quarterly in order to ascertain whether impairment has occurred. To the extent that seismic costs cannot be directly associated with specific unevaluated properties, they are included in the amortization base as incurred.

Other Property and Equipment

Other property and equipment consists primarily of natural gas gathering and processing facilities, drilling rigs, land, buildings and improvements, natural gas compressors, vehicles and office equipment. Major renewals and betterments are capitalized while the costs of repairs and maintenance are charged to expense as incurred. The costs of assets retired or otherwise disposed of and the applicable accumulated depreciation are removed from the accounts, and the resulting gain or loss is reflected in operations. Other property and equipment costs are depreciated on a straight-line basis. A summary of other property and equipment and the useful lives is as follows:

	December 31,		
	2009	**2008**	**Useful Life**
	($ in millions)		(in years)
Natural gas gathering systems and treating plants	$ 3,516	$ 2,717	20
Buildings and improvements	805	681	10 – 39
Drilling rigs and equipment	687	430	3 – 15
Natural gas compressors	325	184	20
Land	868	832	—
Other	550	482	2 – 7
Total	$ 6,751	$ 5,326	

Realization of the carrying value of other property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset including disposal value if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. For 2009, we recorded an impairment of $86 million associated with certain of our midstream assets and $27 million associated with certain of our service operations assets.

Investments

Investments in securities are accounted for under the equity method in circumstances where we are deemed to exercise significant influence over the operating and investing policies of the investee but do not have control. Under the equity method, we recognize our share of the investee's earnings in our consolidated statements of operations. Investments in securities not accounted for under the equity method are accounted for under the cost method. Investments in marketable equity securities accounted for under the cost method have been designated as available for sale and, as such, are recorded at fair value. We evaluate our investments for impairment in value and recognize a charge to earnings when any identified impairment is judged to be other than temporary. For 2009, we recorded an impairment of $162 million associated with certain of our investments. See Note 14 for further discussion of investments.

Capitalized Interest

During 2009, 2008 and 2007, interest of approximately $627 million, $585 million and $311 million, respectively, was capitalized on significant investments in unproved properties that were not being currently depreciated, depleted or amortized and on which exploration activities were in progress. An additional $6 million was capitalized in 2009 on midstream assets which were under construction. Interest is capitalized using a weighted average interest rate based on our outstanding borrowings.

Accounts Payable and Accrued Liabilities

Included in accounts payable at December 31, 2009 and 2008, respectively, are liabilities of approximately $231 million and $480 million representing the amount by which checks issued, but not yet presented to our banks for collection, exceeded balances in applicable bank accounts. Other accrued liabilities include $198 million and $258 million of accrued drilling costs as of December 31, 2009 and 2008, respectively.

Debt Issuance Costs

Included in other assets are costs associated with the issuance of our senior notes and costs associated with our revolving bank credit facilities and hedging facilities. The remaining unamortized debt issue costs at December 31, 2009 and 2008 totaled $162 million and $142 million, respectively, and are being amortized over the life of the senior notes, revolving credit facilities or hedging facilities.

Asset Retirement Obligations

We recognize liabilities for retirement obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets. We recognize the fair value of a liability for a retirement obligation in the period in which the liability is incurred. For natural gas and oil properties, this is the period in which a natural gas or oil well is acquired or drilled. The asset retirement obligation is capitalized as part of the carrying amount of our natural gas and oil properties at its discounted fair value. The liability is then accreted each period until the liability is settled or the well is sold, at which time the liability is reversed.

Revenue Recognition

Natural Gas and Oil Sales. Revenue from the sale of natural gas and oil is recognized when title passes, net of royalties.

Natural Gas Imbalances. We follow the "sales method" of accounting for our natural gas revenue whereby we recognize sales revenue on all natural gas sold to our purchasers, regardless of whether the sales are proportionate to our ownership in the property. An asset or a liability is recognized to the extent that we have an imbalance in excess of the remaining natural gas reserves on the underlying properties. The natural gas imbalance net position at December 31, 2009 and 2008 was a liability of $7 million and $6 million, respectively.

Marketing Sales. Chesapeake takes title to the natural gas it purchases from other working interest owners in operated wells, arranges for transportation and delivers the natural gas to third parties, at which time revenues are recorded. Chesapeake's results of operations related to its natural gas and oil marketing activities are presented on a "gross" basis, because we act as a principal rather than an agent. All significant intercompany accounts and transactions have been eliminated.

Hedging

Chesapeake uses commodity price and financial risk management instruments to mitigate our exposure to price fluctuations in natural gas and oil and interest rates. Recognized gains and losses on derivative contracts are reported as a component of the related transaction. Results of natural gas and oil derivative transactions are reflected in natural gas and oil sales and results of interest rate hedging transactions are reflected in interest expense. The changes in fair value of derivative instruments not qualifying for designation as either cash flow or fair value hedges that occur prior to maturity are reported currently in the consolidated statement of operations as unrealized gains (losses) within natural gas and oil sales or interest expense.

We have established the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors.

Accounting guidance for derivative instruments and hedging activities, establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the consolidated balance sheet as assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Any change in the fair value resulting from ineffectiveness is recognized immediately in natural gas and oil sales. For interest rate derivative instruments designated as fair value hedges, changes in fair value are recorded on the consolidated balance sheets as assets (liabilities), and the debt's carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Differences between the changes in the fair values of the hedged item and the derivative instrument, if any, represent gains or losses on ineffectiveness and are reflected currently in interest expense. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Changes in fair value of contracts that do not qualify as hedges or are not designated as hedges are also recognized currently in earnings. Cash settlements of our derivative arrangements are generally classified as operating cash flows unless the derivative contains a significant financing element at contract inception, in which case, all cash settlements are classified as financing cash flows in the accompanying consolidated statement of cash flows.

Stock-Based Compensation

Chesapeake's stock-based compensation programs consist of restricted stock and stock options issued to employees and non-employee directors. We recognize in our financial statements the cost of employee services received in exchange for awards of equity instruments based on the fair value at grant date of those awards. For equity-based compensation awards granted or modified, compensation expense based on the fair value on the date of grant or modification is recognized in our financial statements over the vesting period. We utilize the Black-Scholes option pricing model to measure the fair value of stock options. To the extent compensation cost relates to employees directly involved in natural gas and oil exploration and development activities, such amounts are capitalized to natural gas and oil properties. Amounts not capitalized to natural gas and oil properties are recognized as general and administrative expenses, production expenses, marketing, gathering and compression expenses or service operations expense.

For the years ended December 31, 2009, 2008 and 2007, we recorded the following stock-based compensation ($ in millions):

	2009	2008	2007
Natural gas and oil properties	$ 112	$ 109	$ 68
General and administrative expenses	83	85	57
Production expenses	34	30	19
Marketing, gathering and compression expenses	16	11	5
Service operations expense	8	6	3
Total	$ 253	$ 241	$ 152

Cash inflows resulting from tax deductions in excess of compensation expense recognized for stock options and restricted stock ("excess tax benefits") are classified as financing cash inflows in our statements of cash flows. For the year ended December 31, 2009, we recognized a reduction in tax benefits related to stock-based compensation of $48 million which is reported in operating activities on our consolidated statements of cash flows. For the years ended December 31, 2008 and 2007, we recognized $43 million and $20 million, respectively, of excess tax benefits from stock-based compensation as cash provided by financing activities on our statements of cash flows.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for 2008 and 2007 to conform to the presentation used for the 2009 consolidated financial statements.

2. Net Income Per Share

Accounting guidance for Earnings Per Share (EPS), requires presentation of "basic" and "diluted" earnings per share on the face of the statements of operations for all entities with complex capital structures as well as a reconciliation of the numerator and denominator of the basic and diluted EPS computations.

For the years ended December 31, 2009, 2008 and 2007, the following securities and associated adjustments to net income comprised of dividends and loss on conversions/exchanges were not included in the calculation of diluted EPS, as the effect was antidilutive:

	Shares (in millions)	Net Income Adjustments ($ in millions)
Year Ended December 31, 2009:		
Common stock equivalent of our preferred stock outstanding:		
4.50% cumulative convertible preferred stock	6	$ 12
5.00% cumulative convertible preferred stock (series 2005)	—	$ —
5.00% cumulative convertible preferred stock (series 2005B)	5	$ 10
Common stock equivalent of our preferred stock outstanding prior to conversion:		
6.25% mandatory convertible preferred stock	1	$ 1
4.125% cumulative convertible preferred stock	—	$ —
Year Ended December 31, 2008:		
Common stock equivalent of our preferred stock outstanding:		
4.50% cumulative convertible preferred stock	6	$ 12
5.00% cumulative convertible preferred stock (series 2005)	—	$ —
5.00% cumulative convertible preferred stock (series 2005B)	5	$ 10
6.25% mandatory convertible preferred stock	1	$ 2
Common stock equivalent of our preferred stock outstanding prior to conversion:		
4.50% cumulative convertible preferred stock	1	$ 14
5.00% cumulative convertible preferred stock (series 2005B)	4	$ 62
Year Ended December 31, 2007:		
Common stock equivalent of our preferred stock outstanding prior to conversion:		
5.00% cumulative convertible preferred stock (series 2005)	16	$ 76
6.25% mandatory convertible preferred stock	14	$ 99

For the year ended December 31, 2009, both basic weighted average shares outstanding, which are used in computing basic EPS, and diluted weighted average shares which are used in computing EPS assuming dilution were 612 million shares as a result of the net loss to common stockholders. The basic and diluted loss per common share was $9.57.

A reconciliation for the years ended December 31, 2008 and 2007 is as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
For the Year Ended December 31, 2008:			
Basic EPS:			
Income available to common stockholders	$ 504	536	$0.94
Effect of Dilutive Securities			
Effect of contingent convertible senior notes outstanding during the period	—	1	
Employee stock options	—	2	
Restricted stock	—	6	
Diluted EPS Income available to common stockholders and assumed conversions	$ 504	545	$0.93
For the Year Ended December 31, 2007:			
Basic EPS:			
Income available to common stockholders	$ 1,233	456	$2.70
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.50% convertible preferred stock	—	8	
Common shares assumed issued for 5.00% convertible preferred stock (series 2005B)	—	15	
Common shares assumed issued for 6.25% mandatory convertible preferred stock	—	1	
Employee stock options	—	4	
Restricted stock	—	3	
Preferred stock dividends	47	—	
Diluted EPS income available to common stockholders and assumed conversions	$ 1,280	487	$2.63

3. Senior Notes and Revolving Bank Credit Facilities

Our long-term debt consisted of the following at December 31, 2009 and 2008:

	December 31, 2009	December 31, 2008
	($ in millions)	
7.5% senior notes due 2013	$ 364	$ 364
7.625% senior notes due 2013	500	500
7.0% senior notes due 2014	300	300
7.5% senior notes due 2014	300	300
6.375% senior notes due 2015	600	600
9.5% senior notes due 2015	1,425	—
6.625% senior notes due 2016	600	600
6.875% senior notes due 2016	670	670
6.25% Euro-denominated senior notes due 2017[a]	860	835
6.5% senior notes due 2017	1,100	1,100
6.25% senior notes due 2018	600	600
7.25% senior notes due 2018	800	800
6.875% senior Notes due 2020	500	500
2.75% contingent convertible senior notes due 2035[b]	451	451
2.5% contingent convertible senior notes due 2037[b]	1,378	1,378
2.25% contingent convertible senior notes due 2038[b]	763	1,126
Corporate revolving bank credit facility	1,892	3,474
Midstream revolving bank credit facility	—	—
Midstream joint venture revolving bank credit facility	44	460
Discount on senior notes[c]	(921)	(1,094)
Interest rate derivatives[d]	69	211
Total notes payable and long-term debt	$ 12,295	$13,175

(a) The principal amount shown is based on the dollar/euro exchange rate of \$1.4332 to €1.00 and \$1.3919 to €1.00 as of December 31, 2009 and 2008, respectively. See Note 10 for information on our related cross currency swap.

(b) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder's option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. One such triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarter by quarter. In the fourth quarter of 2009, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes during the specified period and, as a result, the holders do not have the option to convert their notes into cash and common stock in the first quarter of 2010 under this provision. The notes are also convertible, at the holder's option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. In general, upon conversion of a contingent convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note's conversion value in excess of such principal amount. We will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years, under certain conditions. We may redeem the convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash. The optional repurchase dates, the common stock price conversion threshold amounts and the ending date of the first six-month period contingent interest may be payable for the contingent convertible senior notes are as follows:

Contingent Convertible Senior Notes	Repurchase Dates	Common Stock Price Conversion Thresholds	Contingent Interest First Payable (if applicable)
2.75% due 2035	November 15, 2015, 2020, 2025, 2030	$ 48.81	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$ 64.36	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$107.36	June 14, 2019

(c) Discount at December 31, 2008 is adjusted for the retrospective application of accounting guidance for debt with conversion and other options. Discount at December 31, 2009 and 2008 included $794 million and $1.009 billion, respectively, associated with the equity component of our contingent convertible senior notes.

(d) See Note 9 for further discussion related to these instruments.

Senior Notes

Our senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our existing and future senior indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. Our senior note obligations are guaranteed by certain of our wholly-owned subsidiaries. See Note 18 for condensed consolidating financial information regarding our guarantor and non-guarantor subsidiaries. We may redeem the senior notes, other than the contingent convertible senior notes, at any time at specified make-whole or redemption prices. Senior notes issued before July 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries' ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; incur liens; enter into sale/leaseback transactions; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. Senior notes issued after June 2005 are governed by indentures containing covenants that limit our ability and our subsidiaries' ability to incur certain secured indebtedness; enter into sale/leaseback transactions; and consolidate, merge or transfer assets.

Chesapeake Energy Corporation is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. As of September 30, 2008, our obligations under our outstanding senior notes and contingent convertible notes were fully and unconditionally guaranteed, jointly and severally, by all of our wholly-owned restricted subsidiaries, other than minor subsidiaries, on a senior unsecured basis. In October 2008, we restructured our midstream operations. As a result, beginning in the fourth quarter of 2008, our wholly-owned midstream subsidiaries having significant assets and operations do not guarantee our outstanding senior notes.

No scheduled principal payments are required under our senior notes until 2013 when $864 million is due.

On January 1, 2009, we adopted and applied retrospectively new accounting and reporting standards for debt with conversion and other options. We have three debt issuances affected by this change: our 2.75% Contingent Convertible Senior Notes due 2035, our 2.5% Contingent Convertible Senior Notes due 2037 and our 2.25% Contingent Convertible Senior Notes due 2038. These standards require us to account for the liability and equity components of our convertible debt instruments separately and to reflect interest expense at the interest rate of similar nonconvertible debt at the time of issuance (6.86%, 8.0% and 8.0%, respectively). Additionally, debt issuance costs are required to be allocated in proportion to the liability and equity components and accounted for as debt issuance costs and equity issuance costs, respectively. The allocation to the equity component of the convertible notes was $845 million (net of tax) at December 31, 2008. The accretion of the resulting discount on the debt is recognized as a part of interest expense, thereby increasing the amount of interest expense required to be recognized with respect to such instruments. Given the increase in our overall effective interest rate after adoption of these standards, we also capitalized additional interest which largely offset the increase in interest expense.

The following table summarizes the effect of the change in accounting principle related to our contingent convertible notes on the consolidated balance sheet:

	December 31, 2008		
	Previously Reported	Adjustment	Adjusted
	($ in millions)		
Unevaluated properties	$ 11,216	$ 163	$ 11,379
Other long-term assets	$ 1,007	$ (14)	$ 993
Long-term debt, net	$ 14,184	$ (1,009)	$ 13,175
Deferred income tax liability	$ 3,763	$ 437	$ 4,200
Paid-in-capital	$ 10,835	$ 845	$ 11,680
Retained earnings	$ 4,694	$ (125)	$ 4,569

The following table summarizes the effect of the change in accounting principle related to our contingent convertible notes on the consolidated statements of operations ($ in millions, except per share data):

	Previously Reported	Adjustment	Adjusted
Year Ended December 31, 2008:			
Depreciation and amortization of other assets	$ 177	$ (3)	$ 174
Interest expense	$ 314	$ (43)	$ 271
Gain (loss) on exchanges or repurchases of Chesapeake debt	$ 237	$ (241)	$ (4)
Income tax expense	$ 463	$ (76)	$ 387
Net income	$ 723	$ (119)	$ 604
Weighted average common and common equivalent shares outstanding – assuming dilution (in millions)	545	—	545
Earnings per common share:			
Basic	$ 1.16	$ (0.22)	$ 0.94
Diluted	$ 1.14	$ (0.21)	$ 0.93

	Previously Reported	Adjustment	Adjusted
Year Ended December 31, 2007:			
Depreciation and amortization of other assets	$ 154	$ (1)	$ 153
Interest expense	$ 406	$ (5)	$ 401
Income tax expense	$ 890	$ 2	$ 892
Net income	$ 1,451	$ 4	$ 1,455
Weighted average common and common equivalent shares outstanding – assuming dilution (in millions)	487	—	487
Earnings per common share:			
Basic	$ 2.69	$ 0.01	$ 2.70
Diluted	$ 2.62	$ 0.01	$ 2.63

The following table summarizes the effect of the change in accounting principle related to our contingent convertible notes on the consolidated statement of cash flows for the years ended December 31, 2008 and 2007, respectively ($ in millions):

	Previously Reported	Adjustment	Adjusted
Year Ended December 31, 2008:			
Cash flows provided by operating activities	$ 5,236	$ 121	$ 5,357
Cash flows used in investing activities	$ (9,844)	$ (121)	$ (9,965)
Cash flows provided by financing activities	$ 6,356	$ —	$ 6,356
Year Ended December 31, 2007:			
Cash flows provided by operating activities	$ 4,932	$ 42	$ 4,974
Cash flows used in investing activities	$ (7,922)	$ (42)	$ (7,964)
Cash flows provided by financing activities	$ 2,988	$ —	$ 2,988

Bank Credit Facilities

We utilize three revolving bank credit facilities, described below, as sources of liquidity.

	Corporate Credit Facility	Midstream Credit Facility	Midstream Joint Venture Credit Facility
		($ in millions)	
Borrowing capacity	$ 3,500	$ 250	$ 500
Maturity date	November 2012	September 2012	September 2012
Borrowers	Chesapeake Exploration, L.L.C. and Chesapeake Appalachia, L.L.C.	Chesapeake Midstream Operating, L.L.C. (CMO)	Chesapeake Midstream Partners, L.L.C. (CMP)
Facility structure	Senior secured revolving	Senior secured revolving	Senior secured revolving
Amount outstanding as of December 31, 2009	$ 1,892	$ —	$ 44
Letters of credit outstanding as of December 31, 2009	$ 41	$ —	$ —

Our credit facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates under our corporate credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, none of our credit facilities contains provisions which would trigger an acceleration of amounts due under the facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

Corporate Credit Facility

Our $3.5 billion syndicated revolving bank credit facility is used for general corporate purposes. Borrowings under the facility are secured by certain producing natural gas and oil properties and bear interest at our option at either (i) the greater of the reference rate of Union Bank, N.A. or the federal funds effective rate plus 0.50%, both of which are subject to a margin that varies from 0.00% to

0.75% per annum according to our senior unsecured long-term debt ratings, or (ii) the London Interbank Offered Rate (LIBOR), plus a margin that varies from 1.50% to 2.25% per annum according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are determined periodically. The unused portion of the facility is subject to a commitment fee of 0.50%. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which, among other things, limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness (excluding discount on senior notes) to total capitalization ratio (as defined) not to exceed 0.70 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.75 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.44 to 1 and our indebtedness to EBITDA ratio was 3.18 to 1 at December 31, 2009. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness of Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $75 million.

The facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and all of our other wholly-owned restricted subsidiaries other than minor subsidiaries.

Midstream Credit Facility

Our midstream $250 million syndicated revolving bank credit facility is used to fund capital expenditures to build natural gas gathering and other systems to support our drilling program and for general corporate purposes associated with our midstream operations. Borrowings under the midstream credit facility are secured by all of the assets of the wholly-owned subsidiaries (the restricted subsidiaries) of Chesapeake Midstream Development L.P. (CMD), itself a wholly-owned subsidiary of Chesapeake, and bear interest at our option at either (i) the greater of the reference rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50%, and the one-month LIBOR plus 1.00%, all of which are subject to a margin that varies from 2.00% to 2.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined) or (ii) the LIBOR plus a margin that varies from 3.00% to 3.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined). The unused portion of the facility is subject to a commitment fee of 0.50% per annum according to the most recent indebtedness to EBITDA ratio (as defined). Interest is payable quarterly or, if LIBOR applies, it may be paid at more frequent intervals.

The midstream credit facility agreement contains various covenants and restrictive provisions which, among other things, limit the ability of CMD and its restricted subsidiaries to incur additional indebtedness, make investments or loans, create liens and pay dividends or distributions to Chesapeake. The credit facility agreement requires maintenance of an indebtedness to EBITDA ratio (as defined) not to exceed 3.50 to 1, and an EBITDA (as defined) to interest expense coverage ratio of not less than 3.00 to 1. As defined by the credit facility agreement, our indebtedness to EBITDA ratio was 0.01 to 1 and our EBITDA to interest expense coverage ratio was 6.87 to 1 at December 31, 2009. If CMD or its restricted subsidiaries should fail to perform their obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the midstream facility could be declared immediately due and payable. The midstream credit facility agreement also has cross default provisions that apply to other indebtedness CMD and its restricted subsidiaries may have with an outstanding principal amount in excess of $15 million.

Midstream Joint Venture Credit Facility

Our midstream joint venture $500 million syndicated revolving bank credit facility was established concurrent with the midstream joint venture we formed on September 30, 2009 (see Note 11 for discussion regarding the midstream joint venture). As a result of that transaction, our existing midstream credit facility was amended and restated as described above. Borrowings under the midstream joint venture credit facility are secured by all of the assets of the companies organized under the joint venture, which is 50% owned by Chesapeake and 50% owned by our joint venture partner Global Infrastructure Partners, and bear interest at our option at either (i) the greater of the reference rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50%, and the one-month LIBOR plus 1.00%, all of which are subject to a margin that varies from 2.00% to 2.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined) or (ii) the LIBOR plus a margin that varies from 3.00% to 3.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined). The unused portion of the facility is subject to a commitment fee of 0.50% per annum according to the most recent indebtedness to EBITDA ratio (as defined). Interest is payable quarterly or, if LIBOR applies, it may be paid at more frequent intervals.

The midstream joint venture credit facility agreement contains various covenants and restrictive provisions which, among other things, limit the ability of the joint venture and its subsidiaries to incur additional indebtedness, make investments or loans, create liens and pay dividends or distributions to Chesapeake. The credit facility agreement requires maintenance of an indebtedness to EBITDA ratio (as defined) not to exceed 3.50 to 1, and an EBITDA (as defined) to interest expense coverage ratio of not less than 3.00 to 1. As defined by the credit facility agreement, our indebtedness to EBITDA ratio was 0.19 to 1 and our EBITDA to interest expense coverage ratio was 21.75 to 1 at December 31, 2009. If CMP or its subsidiaries should fail to perform their obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the midstream joint venture facility could be declared immediately due and payable. The midstream joint venture credit facility agreement also has cross default provisions that apply to other indebtedness CMP and its subsidiaries may have with an outstanding principal amount in excess of $15 million.

4. Contingencies and Commitments

Litigation

On February 25, 2009, a putative class action was filed in the U.S. District Court for the Southern District of New York against the company and certain of its officers and directors along with certain underwriters of the company's July 2008 common stock offering. Following the appointment of a lead plaintiff and counsel, the plaintiff filed an amended complaint on September 11, 2009 alleging that the registration statement for the offering contained material misstatements and omissions and seeking damages under Sections 11, 12 and 15 of the Securities Act of 1933 of an unspecified amount and rescission. The action was transferred to the U.S. District Court for the Western District of Oklahoma on October 13, 2009. The company has filed a motion to dismiss which has not been fully briefed. A derivative action was also filed in the District Court of Oklahoma County, Oklahoma on March 10, 2009 against the company's directors and certain of its officers alleging breaches of fiduciary duties relating to the disclosure matters alleged in the securities case.

On March 26, 2009, a shareholder filed a petition in the District Court of Oklahoma County, Oklahoma seeking to compel inspection of company books and records relating to compensation of the company's CEO. On August 20, 2009, the court denied the inspection demand, dismissed the petition and entered judgment in favor of Chesapeake. The shareholder is appealing the court's ruling.

Three derivative actions were filed in the District Court of Oklahoma County, Oklahoma on April 28, May 7, and May 20, 2009 against the company's directors alleging breaches of fiduciary duties relating to compensation of the company's CEO and alleged insider trading, among other things, and seeking unspecified damages, equitable relief and disgorgement. These three derivative actions were consolidated and a Consolidated Derivative Shareholder Petition was filed on June 23, 2009. Chesapeake is named as a nominal defendant. Chesapeake has filed a motion to dismiss which was heard on February 1, 2010. On February 26, 2010, the court ordered that plaintiffs' claims be dismissed and granted plaintiffs leave to file an amended petition within 90 days.

It is inherently difficult to predict the outcome of litigation, and we are currently unable to estimate the amount of any potential liabilities associated with the foregoing cases, which are all in preliminary stages.

Chesapeake is also involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, claims for underpayment of royalties, property damage claims and contract actions. With regard to the latter, several mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their oil and natural gas interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The company has satisfactorily resolved several of the suits but some remain pending. The remaining leasehold acquisition cases are in various stages of discovery. The company believes that it has substantial defenses to the claims made in all these cases.

The company records an associated liability when a loss is probable and the amount is reasonably estimable. Although the outcome of litigation cannot be predicted with certainty, management is of the opinion that no pending or threatened lawsuit or dispute incidental to its business operations is likely to have a material adverse effect on the company's consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management's estimates.

Employment Agreements with Officers

Chesapeake has employment agreements with its chief executive officer, chief operating officer, chief financial officer and other executive officers, which provide for annual base salaries, various benefits and eligibility for bonus compensation. The agreement with the chief executive officer has an initial term of five years which is automatically extended for one additional year on each December 31 unless the company provides 30 days notice of non-extension. The agreement contains a cap on cash salary and bonus compensation for the next five years at 2008 levels. In the event of termination of employment without cause, the chief executive officer's base compensation (defined as base salary plus bonus compensation received during the preceding 12 months) and benefits would continue during the remaining term of the agreement. The chief executive officer is entitled to receive a payment in the amount of three times his base compensation upon the happening of certain events following a change of control. The agreement further provides that any stock-based awards held by the chief executive officer and deferred compensation will immediately become 100% vested upon termination of employment without cause, or in the event of his incapacity, death or retirement at or after age 55. The agreement also provides for a one-time $75 million well cost incentive award with a five-year clawback. The well cost incentive award was fully applied against the CEO's obligations under the Founder Well Participation Program in 2009. See Note 6 for a description of the Founder Well Participation Program and the incentive award. The agreements with the chief operating officer, chief financial officer and other executive officers expire on September 30, 2012. The agreements with our COO, CFO and other executive vice presidents contain a cap on cash salary for the three-year term of the agreement. In addition, annual cash bonuses will not exceed the sum of the individual EVP's cash bonus compensation for (a) the last half of 2008 and (b) the first half of 2009. These agreements provide for the continuation of salary for one year in the event of termination of employment without cause or death and, in the event of a change of control, a payment in the amount of two times the executive officer's base compensation. These executive officers are entitled to receive a lump sum payment equal to 26 weeks of cash salary following termination of employment as a result of incapacity. Any stock-based awards held by such executive officers will immediately become 100% vested upon termination of employment without cause, a change of control, death or retirement at or after age 55. The agreements also provide for a 2008 incentive award payable in four equal annual installments, the first of which was paid on September 30, 2009. The payment of each installment of the award is subject to the individual's continued employment on the date of payment, except that the unpaid installments of the award would be accelerated and paid in lump sum in the event of a change of control or a termination of employment without cause, a voluntary termination by the executive due to a material breach of contract by the company, or termination due to incapacity or death.

Environmental Risk

Due to the nature of the natural gas and oil business, Chesapeake and its subsidiaries are exposed to possible environmental risks. Chesapeake has implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. Chesapeake conducts periodic reviews, on a company-wide basis, to identify changes in our environmental risk profile. These reviews evaluate whether there is a contingent liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. Depending on the extent of an identified environmental problem, Chesapeake may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property. Chesapeake has historically not experienced any significant environmental liability, and is not aware of any potential material environmental issues or claims at December 31, 2009.

Rig Leases

In a series of transactions in 2006, 2007 and 2008, our drilling subsidiaries sold 83 drilling rigs and related equipment for $677 million and entered into a master lease agreement under which we agreed to lease the rigs from the buyer for initial terms of seven to ten years for lease payments of approximately $93 million annually. The lease obligations are guaranteed by Chesapeake and its other material restricted subsidiaries. These transactions were recorded as sales and operating leasebacks and any related gain or loss is amortized to service operations expense over the lease term. Under the rig leases, we can exercise an early purchase option after six or seven years or on the expiration of the lease term for a purchase price equal to the then fair market value of the rigs. Additionally, we have the option to renew the rig lease for a negotiated renewal term at a periodic lease equal to the fair market rental value of the rigs as determined at the time of renewal.

Compressor Leases

In 2007, 2008 and 2009, our compression subsidiary sold a significant portion of its existing compressor fleet, consisting of 1,685 compressors, for $370 million and entered into a master lease agreement. The term of the agreement varies by buyer ranging from seven to ten years for aggregate lease payments of approximately $46 million annually. The lease obligations are guaranteed by Chesapeake and its other material restricted subsidiaries. These transactions were recorded as sales and operating leasebacks and any related gain or loss is amortized to natural gas and oil marketing expenses over the lease term. Under the leases, we can exercise an early purchase option after six to nine years or we can purchase the compressors at expiration of the lease for the fair market value at the time. In addition, we have the option to renew the lease for negotiated new terms at the expiration of the lease. As of December 31, 2009, approximately 324 new compressors were on order for delivery in 2010 at a cost of approximately $100 million. Our intent is to sell and lease back those compressors as they are delivered if acceptable leasing arrangements are available to us.

Future operating lease obligations related to rigs, compressors and other equipment or property are not recorded in the accompanying consolidated balance sheets. As of December 31, 2009, minimum future lease payments were as follows ($ in millions):

	Rigs	Compressors	Other	Total
2010	$ 95	$ 45	$ 7	$ 147
2011	95	45	5	145
2012	96	46	3	145
2013	97	49	2	148
2014	82	47	1	130
After 2014	60	106	1	167
Total	$ 525	$ 338	$ 19	$ 882

Rent expense, including short-term rentals, for the years ended December 31, 2009, 2008 and 2007 was $149 million, $133 million and $81 million, respectively.

Real Estate Surface Asset Leases

In April 2009, we financed 113 real estate surface assets in the Barnett Shale area in and around Fort Worth, Texas for approximately $145 million and entered into a 40-year master lease agreement under which we agreed to lease the sites for approximately $15 million to $27 million annually. This lease transaction was recorded as a financing lease and the cash received was recorded with an offsetting long-term liability on the consolidated balance sheet. As of December 31, 2009, the minimum aggregate future lease payments were approximately $859 million. Chesapeake has the option to repurchase up to a specified number of assets at any time during the term of the lease.

Transportation Contracts

Chesapeake has various "firm" pipeline transportation service agreements with expiration dates ranging from 2010 to 2099. These commitments are not recorded in the accompanying consolidated balance sheets. Under the terms of these contracts, we are obligated to pay demand charges as set forth in the transporter's Federal Energy Regulatory Commission (FERC) gas tariff. In exchange, the company receives rights to flow natural gas production through pipelines located in highly competitive markets. Excluded from this summary are demand charges for pipeline projects that are currently seeking regulatory approval. The aggregate amounts of such required demand payments as of December 31, 2009 are as follows ($ in millions):

2010	$ 253
2011	303
2012	297
2013	277
2014	262
After 2014	1,388
Total	$ 2,780

Drilling Contracts

We have contracts with various drilling contractors to use 26 drilling rigs with terms of one to three years. These commitments are not recorded in the accompanying consolidated balance sheets. Minimum future commitments as of December 31, 2009 are as follows ($ in millions):

2010	$ 107
2011	74
After 2011	—
Total	$ 181

Natural Gas and Oil Purchase Obligations

Our marketing segment regularly commits to purchase natural gas from other owners in our properties and such commitments typically are short-term in nature. We have also committed to purchase any natural gas and oil associated with certain volumetric production payment transactions. The purchase commitments are based on market prices at the time of production, and the purchased natural gas and oil will be resold.

Other Commitments

In 2009, we financed our regional Barnett Shale headquarters building in Fort Worth, Texas for approximately $54 million with a five-year term loan which has a floating rate of prime plus 275 basis points. At our option, we may prepay in full without penalty beginning in year four. The payment obligation is guaranteed by Chesapeake.

Under minimum volume throughput agreements, Chesapeake has agreed to move fixed volumes of natural gas over certain time periods, usually multiple years, through certain midstream systems. At the end of the term or annually, Chesapeake will be invoiced for any shortfalls in such volume commitments.

5. Income Taxes

The components of the income tax provision (benefit) for each of the periods presented below are as follows:

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
Current	$ 4	$ 423	$ 29
Deferred	(3,487)	(36)	863
Total	$ (3,483)	$ 387	$892

The effective income tax expense (benefit) differed from the computed "expected" federal income tax expense on earnings before income taxes for the following reasons:

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
Income tax expense (benefit) at the federal statutory rate (35%)	$ (3,251)	$ 347	$ 821
State income taxes (net of federal income tax benefit)	(275)	24	56
Other	43	16	15
	$ (3,483)	$ 387	$ 892

Deferred income taxes are provided to reflect temporary differences in the basis of net assets for income tax and financial reporting purposes. The tax-effected temporary differences and tax loss carryforwards which comprise deferred taxes are as follows:

	Years Ended December 31	
	2009	2008
	($ in millions)	
Deferred tax liabilities:		
Natural gas and oil properties	$ (96)	$ (2,755)
Other property and equipment	(184)	(281)
Derivative instruments	(265)	(550)
Volumetric production payments	(937)	(943)
Contingent convertible debt	(464)	(450)
Other	(23)	—
Deferred tax liabilities	(1,969)	(4,979)
Deferred tax assets:		
Net operating loss carryforwards	592	5
Asset retirement obligation	107	102
Investments	131	117
Deferred stock compensation	57	85
Accrued liabilities	22	22
Alternative minimum tax credits	25	—
Other	—	90
Deferred tax assets	934	421
Total deferred tax asset (liability)	$ (1,035)[(a)]	$ (4,558)
Reflected in accompanying balance sheets as:		
Current deferred income tax asset	$ 24	$ —
Current deferred income tax liability	—	(358)
Non-current deferred income tax liability	(1,059)	(4,200)
	$ (1,035)	$ (4,558)

(a) In addition to the income tax benefit of $3.483 billion, activity during 2009 includes net liabilities of $48 million related to stock-based compensation and $41 million related to investments, deferred tax assets for $141 million related to derivative instruments and $106 million related to the equalization of partners' capital. These items were not recorded as part of the provision for income taxes. In addition, the activity includes an increase to deferred tax liabilities of $157 million related to federal and state income tax refunds and a reduction of $39 million related to uncertain tax positions.

As of December 31, 2009, we classified $24 million of deferred tax assets as current that were attributable to the current portion of net operating losses, which was offset by current temporary differences associated with derivative assets and other items. As of December 31, 2008, we classified $358 million of deferred tax liabilities as current that were attributable to the current portion of derivative assets and other current temporary differences.

At December 31, 2009, Chesapeake had federal income tax net operating loss (NOL) carryforwards and carrybacks of approximately $889 million and $681 million, respectively. Additionally, we had $3 million of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income and $333 million of AMT NOL carrybacks to be used against prior year AMT income. The NOL carryforwards expire from 2019 through 2029. The value of these carryforwards depends on the ability of Chesapeake to generate taxable income.

The ability of Chesapeake to utilize NOL carryforwards to reduce future federal taxable income and federal income tax of Chesapeake is subject to various limitations under the Internal Revenue Code of 1986, as amended. The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the issuance or exercise of rights to acquire stock, the purchase or sale of stock by 5% stockholders, as defined in the Treasury regulations, and the offering of stock by us during any three-year period resulting in an aggregate change of more than 50% in the beneficial ownership of Chesapeake.

In the event of an ownership change (as defined for income tax purposes), Section 382 of the Code imposes an annual limitation on the amount of a corporation's taxable income that can be offset by these carryforwards. The limitation is generally equal to the product of (i) the fair market value of the equity of the company multiplied by (ii) a percentage approximately equivalent to the yield on long-term tax exempt bonds during the month in which an ownership change occurs. In addition, the limitation is increased if there are recognized built-in gains during any post-change year, but only to the extent of any net unrealized built-in gains (as defined in the Code) inherent in the assets sold. Certain NOLs acquired through various acquisitions are also subject to limitations.

The following table summarizes our net operating losses as of December 31, 2009 and any related limitations:

	Total	Limited	Annual Limitation
		($ in millions)	
Net operating loss	$1,570	$ 2	$ 1
AMT net operating loss	$336	$ 2	$ 1

As of December 31, 2009, we do not believe that an ownership change has occurred. Future equity transactions by Chesapeake or by 5% stockholders (including relatively small transactions and transactions beyond our control) could cause an ownership change and therefore a limitation on the annual utilization of NOLs.

Accounting guidance for recognizing and measuring uncertain tax positions prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions.

As of December 31, 2008, the amount of unrecognized tax benefits related to regular tax liabilities and AMT associated with uncertain tax positions was $60 million. Of this amount, $48 million was related to regular tax liabilities and $12 million was related to AMT. As of December 31, 2009, the amount of unrecognized tax benefits related to regular tax liabilities and AMT associated with uncertain tax positions was $231 million. Of this amount, $87 million is related to regular tax liabilities and $144 million is related to AMT. These unrecognized tax benefits are associated with temporary differences. If these unrecognized tax benefits are disallowed and we are required to pay additional taxes, the reversal of the temporary differences associated with the regular tax liabilities will increase our tax basis which will increase our future tax deductions. Any AMT payments can be utilized as credits against future regular tax liabilities. The uncertain tax positions identified would not have a material effect on the effective tax rate. At December 31, 2009, we had an accrued liability of $10 million for interest related to these uncertain tax positions. Chesapeake recognizes interest related to uncertain tax positions in interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses.

A reconciliation of the beginning and ending balances of unrecognized tax benefits is as follows:

	2009	2008	2007
	($ in millions)		
Unrecognized tax benefits at beginning of period	$ 60	$ 133	$ 142
Additions based on tax positions related to the current year	171	48	64
Reductions for tax positions of prior years	—	(120)	(52)
Settlements	—	(1)	(21)
Unrecognized tax benefits at end of period	$ 231	$ 60	$ 133

Chesapeake files income tax returns in the U.S. federal jurisdiction and various state and local jurisdictions. With few exceptions, Chesapeake is no longer subject to U.S. federal, state and local income tax examinations by tax authorities for years prior to 2006. The Internal Revenue Service (IRS) commenced an examination of Chesapeake's 2007 and 2008 U.S. income tax returns in October 2009.

6. Related Party Transactions

As of December 31, 2009, we had accrued accounts receivable from our CEO, Aubrey K. McClendon, of $14 million representing joint interest billings from December 2009 which were invoiced and timely paid in January 2010. Since Chesapeake was founded in 1989, Mr. McClendon, has acquired working interests in virtually all of our natural gas and oil properties by participating in our drilling activities under the terms of the Founder Well Participation Program ("FWPP") and predecessor participation arrangements provided for in Mr. McClendon's employment agreements. Under the FWPP, approved by our shareholders in June 2005, Mr. McClendon may elect to participate in all or none of the wells drilled by or on behalf of Chesapeake during a calendar year, but he is not allowed to participate only in selected wells. A participation election is required to be received by the Compensation Committee of Chesapeake's Board of Directors not less than 30 days prior to the start of each calendar year. His participation is permitted only under the terms outlined in the FWPP, which, among other things, limits his individual participation to a maximum working interest of 2.5% in a well and prohibits participation in situations where Chesapeake's working interest would be reduced below 12.5% as a result of his participation. In addition, the company is reimbursed for costs associated with leasehold acquired by Mr. McClendon as a result of his well participation.

On December 31, 2008, we entered into a new five-year employment agreement with Mr. McClendon that contained a one-time well cost incentive award to him. The total cost of the award to Chesapeake was $75 million plus employment taxes in the amount of approximately $1 million. We will recognize the incentive award as general and administrative expense over the five-year vesting period for the clawback described below, resulting in an expense of approximately $15 million per year that began in 2009. In addition to state and federal income tax withholding, similar employment taxes were imposed on Mr. McClendon and withheld from the award. The net incentive award of approximately $44 million was fully applied against costs attributable to interests in company wells acquired by Mr. McClendon or his affiliates under the FWPP. The incentive award is subject to a clawback if during the initial five-year term of the employment agreement, Mr. McClendon resigns from the company or is terminated for cause by the company.

As disclosed in Note 17, in 2007 Chesapeake had revenues of $1.1 billion from natural gas and oil sales to Eagle Energy Partners I, L.P., a former affiliated entity. We sold our 33% limited partnership interest in Eagle Energy in June 2007.

7. Employee Benefit Plans

Our qualified 401(k) profit sharing plan is the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan, which is open to employees of Chesapeake and all our subsidiaries except certain employees of Chesapeake Appalachia, L.L.C. Eligible employees may elect to defer compensation through voluntary contributions to their 401(k) plan accounts, subject to plan limits and those set by the Internal Revenue Service. Chesapeake matches employee contributions dollar for dollar (subject to a maximum contribution of 15% of an employee's annual salary and bonus compensation) with Chesapeake common stock purchased in the open market. The company contributed $48 million, $40 million and $28 million to the Chesapeake plan in 2009, 2008 and 2007, respectively.

In November 2005, Chesapeake acquired Columbia Natural Resources, LLC (CNR), which sponsored the Columbia Natural Resources, LLC 401(k) Plan. Chesapeake's 401(k) plan was amended effective January 1, 2006 to honor previous service by employees with CNR and predecessor companies and was open to CNR employees in the Charleston, West Virginia headquarters office as well as exempt, administrative field employees. The CNR plan was adopted by the new employer entity, Chesapeake Appalachia, L.L.C., and was open to all non-administrative field employees, including union employees. Effective January 1, 2007, these employees, other than union employees, became eligible to participate in the Chesapeake plan.

Prior to 2008, we maintained two nonqualified deferred compensation plans, the 401(k) make-up plan and the deferred compensation plan. Effective on January 1, 2008, the deferred compensation plans were merged into the Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan (DC Plan). Prior to 2009, to be eligible to participate in the DC Plan, an employee must have received annual compensation (base salary and bonus combined in the prior 12 months) of at least $100,000, had a minimum of one year of service as a company employee and have made the maximum contribution allowable under the 401(k) plan. For employees with at least five years of service as a company employee, the company matched employee contributions to the plan in Chesapeake common stock. On January 1, 2009, the plan was amended to allow for participation for any employees who received compensation (base salary only) of at least $150,000 and had an employment agreement with the company. In addition, the company begins matching employee contributions with Chesapeake common stock once the employee has at least three years of service as a company employee.

Chesapeake matches 100% of employee contributions up to 15% of base salary and bonus in the aggregate for the 401(k) plan and the DC Plan. We contributed $7 million, $6 million and $4 million to the DC Plan during 2009, 2008 and 2007, respectively, to fund the match. The company's non-employee directors are able to defer up to 100% of director fees into the DC Plan. The maximum compensation that can be deferred by employees under all company deferred compensation plans, including the Chesapeake 401(k) plan, is a total of 75% of base salary and 100% of performance bonus.

Any assets placed in trust by Chesapeake to fund future obligations of the company's nonqualified deferred compensation plans are subject to the claims of creditors in the event of insolvency or bankruptcy, and participants are general creditors of the company as to their deferred compensation in the plans.

Chesapeake maintains no post-employment benefit plans except those sponsored by Chesapeake Appalachia, L.L.C. Participation in these plans is limited to existing and former employees who were union members. The Chesapeake Appalachia, L.L.C. benefit plans provide health care and life insurance benefits to eligible employees upon retirement. We account for these benefits on an accrual basis. As of December 31, 2009, the company had accrued approximately $2 million in accumulated post-employment benefit liability.

8. Stockholders' Equity, Restricted Stock and Stock Options

Common Stock

The following is a summary of the changes in our common shares outstanding for 2009, 2008 and 2007:

	2009	2008	2007
	(in thousands)		
Shares issued at January 1	607,953	511,648	458,601
Common stock issuances for cash	—	51,750	—
Convertible note conversions/exchanges	10,210	23,913	—
Preferred stock conversions/exchanges	1,423	12,673	36,652
Restricted stock issuances (net of forfeitures)	3,632	4,708	14,268
Stock option exercises	508	1,584	2,127
Common stock issued for the purchase of leasehold and unproved properties	24,823	1,677	—
Shares issued at December 31	648,549	607,953	511,648

Contingent Convertible Senior Notes

In 2009 and 2008, holders of certain of our contingent convertible senior notes exchanged or converted their senior notes for shares of common stock in privately negotiated exchanges as summarized below ($ in millions):

Year	Contingent Convertible Senior Notes	Principal Amount	Number of Common Shares
2009	2.25% due 2038	$ 364	10,210,169
2008	2.75% due 2035	$ 239	8,841,526
	2.50% due 2037	272	8,416,865
	2.25% due 2038	254	6,654,821
		$ 765	23,913,212

The difference between the allocated debt value of the notes that were exchanged and the fair value of the common stock issued resulted in a loss of $40 million and $27 million, respectively, on the cancellation of indebtedness for the years ended December 31, 2009 and 2008. There were no contingent convertible senior notes exchanged or converted in 2007.

Preferred Stock

The following is a summary of the changes in our preferred shares outstanding for 2009, 2008 and 2007:

	4.125%	5.00% (2005)	4.50%	5.00% (2005B)	6.25%
		(in thousands)			
Shares outstanding at January 1, 2009	3	5	2,559	2,096	144
Conversion/exchange of preferred for common stock	3	—	—	—	144
Shares outstanding at December 31, 2009	—	5	2,559	2,096	—
Shares outstanding at January 1, 2008	3	5	3,450	5,750	144
Conversion/exchange of preferred for common stock	—	—	(891)	(3,654)	—
Shares outstanding at December 31, 2008	3	5	2,559	2,096	144
Shares outstanding at January 1, 2007	3	4,600	3,450	5,750	2,300
Conversion/exchange of preferred for common stock	—	(4,595)	—	—	(2,156)
Shares outstanding at December 31, 2007	3	5	3,450	5,750	144

Dividends

Dividends declared on our common stock and preferred stock are reflected as adjustments to retained earnings to the extent a surplus of retained earnings will exist after giving effect to the dividends. To the extent retained earnings are insufficient to fund the distributions, such payments constitute a return of contributed capital rather than earnings and are accounted for as a reduction to paid-in capital.

In 2009, 2008 and 2007, shares of our cumulative convertible preferred stock were exchanged for or converted into shares of common stock as summarized below:

Year of Exchange/ Conversion	Cumulative Convertible Preferred Stock	Number of Preferred Shares	Number of Common Shares	Type of Transaction
2009	6.25%	143,768	1,239,538	Conversion
	4.125%	3,033	182,887	Conversion
			1,422,425	
2008	5.0% (series 2005B)	3,654,385	10,443,642	Exchange
	4.5%	891,100	2,227,750	Exchange
	4.125%	29	1,743	Conversion
			12,673,135	
2007	5.0% (series 2005)	4,595,000	19,283,311	Exchange
	6.25%	2,156,184	17,367,823	Exchange
	6.25%	48	344	Conversion
	4.125%	3	180	Conversion
			36,651,658	

In connection with the exchanges and conversions noted above, we recorded losses of $0, $67 million and $128 million in 2009, 2008 and 2007, respectively. In general, the loss is equal to the excess of the fair value of all common stock exchanged over the fair value of the common stock issuable pursuant to the original terms of the preferred stock.

Dividends on our outstanding preferred stock are payable quarterly in cash, common stock or a combination thereof. Following is a summary of our preferred stock, including the primary conversion terms as of December 31, 2009:

Preferred Stock Series	Issue Date	Liquidation Preference per Share	Holder's Conversion Right	Conversion Rate	Conversion Price	Company's Conversion Right From	Company's Market Conversion Trigger
5.00% cumulative convertible (series 2005)	April 2005	$ 100	Any time	3.8964	$ 25.6647	April 15, 2010	$ 33.3641(a)
4.50% cumulative convertible	September 2005	$ 100	Any time	2.2692	$ 44.0692	September 15, 2010	$ 57.2900(a)
5.00%cumulative convertible (series 2005B)	November 2005	$ 100	Any time	2.5664	$ 38.9652	November 15, 2010	$ 50.6548(a)

(a) Convertible at the company's option if the company's common stock equals or exceeds the trigger price for a specified time period or after the conversion date indicated if there are less than 250,000 shares of preferred stock outstanding.

Stock-Based Compensation Plans

Under Chesapeake's Long Term Incentive Plan, restricted stock, stock options, stock appreciation rights, performance shares and other stock awards may be awarded to employees, directors and consultants of Chesapeake. Subject to any adjustments as provided by the plan, the aggregate number of shares of common stock available for awards under the plan may not exceed 31,500,000 shares. The maximum period for exercise of an option or stock appreciation right may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the option or stock appreciation right on the date of grant. Awards granted under the plan become vested at specified dates or upon the satisfaction of certain performance or other criteria determined by a committee of the Board of Directors. No awards may be granted under this plan after September 30, 2014. This plan has been approved by our shareholders. There were 87,500 shares of restricted stock issued to our directors from this plan in each of 2009, 2008 and 2007. Additionally, there were 4.0 million, 4.5 million and 14.7 million restricted shares issued, net of forfeitures, to employees and consultants during 2009, 2008 and 2007, respectively, from this plan. As of December 31, 2009, there were 8.0 million shares remaining available for issuance under the plan.

Under Chesapeake's 2003 Stock Incentive Plan, restricted stock and incentive and nonqualified stock options to purchase our common stock may be awarded to employees and consultants of Chesapeake. Subject to any adjustments as provided by the plan, the aggregate number of shares available for awards under the plan may not exceed 10,000,000 shares. The maximum period for exercise of an option may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the option on the date of grant. Restricted stock and options granted become vested at dates determined by a committee of the Board of Directors. No awards may be granted under this plan after April 14, 2013. This plan has been approved by our shareholders. There were (0.4) million, 0.2 million and 0.2 million restricted shares, net of forfeitures, issued during 2009, 2008 and 2007, respectively, from this plan. As of December 31, 2009, there were 618,282 shares remaining available for issuance under the plan.

Under Chesapeake's 2003 Stock Award Plan for Non-Employee Directors, 10,000 shares of Chesapeake's common stock are awarded to each newly appointed non-employee director on his or her first day of service. Subject to any adjustments as provided by the plan, the aggregate number of shares which may be issued may not exceed 100,000 shares. This plan has been approved by our shareholders. In each of 2008 and 2007, 10,000 shares of common stock were awarded to new directors from this plan. As of December 31, 2009, there were 50,000 shares remaining available for issuance under this plan.

In addition to the plans described above, we have stock options outstanding to employees under a number of employee stock option plans which are described below. All outstanding options under these plans were at-the-money when granted, with an exercise price equal to the closing price of our common stock on the date of grant and have a ten-year exercise period. These plans were terminated in prior years and therefore no shares remain available for stock option grants under the plans.

Name of Plan	Eligible Participants	Type of Options	Shares Covered	Shareholder Approved	Outstanding Options at December 31, 2009
2002 and 2001 Stock Option Plans	Employees and consultants	Incentive and nonqualified	3,000,000/ 3,200,000	Yes	625,636
2002 and 2001 Nonqualified Stock Option Plans	Employees and consultants	Nonqualified	4,000,000/ 3,000,000	No	890,377
2000 and 1999 Employee Stock Option Plans	Employees and consultants	Nonqualified	3,000,000 (each plan)	No	262,428
1996 and 1994 Stock Option Plans	Employees and consultants	Incentive and nonqualified	6,000,000/ 4,886,910	Yes	73,161

Restricted Stock

Chesapeake began issuing shares of restricted common stock to employees in January 2004 and to non-employee directors in July 2005. The fair value of the awards issued is determined based on the fair market value of the shares on the date of grant. This value is amortized over the vesting period, which is generally four years from the date of grant for employees and three years for non-employee directors. To the extent amortization of compensation cost relates to employees directly involved in acquisition, exploration and development activities, such amounts are capitalized to natural gas and oil properties. Amounts not capitalized to natural gas and oil properties are recognized in general and administrative expense or production expense. Note 1 details the accounting for our stock-based compensation expense in 2009, 2008 and 2007.

A summary of the status of the unvested shares of restricted stock and changes during 2009, 2008 and 2007 is presented below:

	Number of Unvested Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2009	21,622,202	$ 38.85
Granted	8,018,409	18.65
Vested	(9,213,910)	36.38
Forfeited	(1,202,094)	34.46
Unvested shares as of December 31, 2009	19,224,607	$ 31.89
Unvested shares as of January 1, 2008	19,688,759	$ 32.42
Granted	6,800,027	51.14
Vested	(3,942,326)	28.27
Forfeited	(924,258)	37.33
Unvested shares as of December 31, 2008	21,622,202	$ 38.85
Unvested shares as of January 1, 2007	7,074,761	$ 25.85
Granted	15,560,570	34.25
Vested	(2,255,384)	24.34
Forfeited	(691,188)	33.29
Unvested shares as of December 31, 2007	19,688,759	$ 32.42

The aggregate intrinsic value of restricted stock vested during 2009 was approximately $193 million based on the stock price at the time of vesting.

As of December 31, 2009, there was $444 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of 2.34 years.

The vesting of certain restricted stock grants results in state and federal income tax benefits related to the difference between the market price of the common stock at the date of vesting and the date of grant. During the year ended December 31, 2009, we recognized a reduction in tax benefits related to restricted stock of $49 million. During the years ended December 31, 2008 and 2007, we recognized excess tax benefits related to restricted stock of $28 million and $5 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

Stock Options

We granted stock options prior to 2006 under several stock compensation plans. Outstanding options expire ten years from the date of grant and vested over a four-year period. All stock options outstanding are fully vested and exercisable.

The following table provides information related to stock option activity for 2009, 2008 and 2007:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[(a)] ($ in millions)
Outstanding at January 1, 2009	2,802,421	$ 8.13		
Exercised	(508,369)	7.12		$ 8
Forfeited / Canceled	(11,200)	6.4		
Outstanding at December 31, 2009	2,282,852	$ 8.36	2.75	$ 40
Exercisable at December 31, 2009	2,282,852	$ 8.36	2.75	$ 40
Shares authorized for future grants	—			
Outstanding at January 1, 2008	4,445,455	$ 7.55		
Exercised	(1,639,401)	6.54		$ 66
Forfeited / Canceled	(3,633)	15.26		
Outstanding at December 31, 2008	2,802,421	$ 8.13	3.59	$ 23
Exercisable at December 31, 2008	2,801,796	$ 8.13	3.59	$ 23
Shares authorized for future grants	5,762,679			
Outstanding at January 1, 2007	6,605,703	$ 7.43		
Exercised	(2,146,640)	7.16		$ 61
Forfeited / Canceled	(13,608)	9.90		
Outstanding at December 31, 2007	4,445,455	$ 7.55	4.37	$ 141
Exercisable at December 31, 2007	4,422,519	$ 7.51	4.36	$ 140
Shares authorized for future grants	2,460,562			

(a) The intrinsic value of a stock option is the amount by which the current market value or the market value upon exercise of the underlying stock exceeds the exercise price of the option.

As of December 31, 2009, there was no remaining unrecognized compensation cost related to unvested stock options.

During the years ended December 31, 2009, 2008 and 2007, we recognized excess tax benefits related to stock options of $1 million, $15 million and $15 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

The following table summarizes information about stock options outstanding at December 31, 2009:

Range of Exercise Prices			Outstanding Options			Options Exercisable	
			Number Outstanding	Weighted-Avg. Remaining Contractual Life	Weighted-Avg. Exercise Price	Number Exercisable	Weighted-Avg. Exercise Price
$2.25	–	$4.00	125,611	0.31	$ 3.82	125,611	$ 3.82
5.20	–	5.20	260,208	2.56	5.20	260,208	5.20
5.35	–	5.89	121,492	1.22	5.54	121,492	5.54
6.11	–	6.11	422,573	1.80	6.11	422,573	6.11
6.40	–	7.74	85,355	1.96	6.95	85,355	6.95
7.80	–	7.80	383,151	3.02	7.80	383,151	7.80
7.86	–	10.01	111,575	2.82	8.58	111,575	8.58
10.08	–	10.08	430,742	3.47	10.08	430,742	10.08
10.10	–	15.47	254,270	4.23	13.31	254,270	13.31
15.48	–	22.49	87,875	5.03	19.72	87,875	19.72
$2.25	–	$22.49	2,282,852	2.75	$ 8.36	2,282,852	$ 8.36

9. Financial Instruments and Hedging Activities

Natural Gas and Oil Derivatives

Our results of operations and cash flows are impacted by changes in market prices for natural gas and oil. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. These instruments allow us to predict with greater certainty the effective natural gas and oil prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving our risk management objectives. As of December 31, 2009 and 2008, our natural gas and oil derivative instruments were comprised of the following types of instruments:

- Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.
- Collars: These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the put and the call strike price, no payments are due from either party. Three-way collars include an additional put option in exchange for a more favorable strike price on the collar. This eliminates the counterparty's downside exposure below the second put option.
- Call options: Chesapeake sells call options in exchange for a premium from the counterparty. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess and if the market price settles below the fixed price of the call option, no payment is due from either party.

- Put options: Chesapeake receives a premium from the counterparty in exchange for the sale of a put option. If the market price falls below the fixed price of the put option, Chesapeake pays the counterparty such shortfall. If the market price settles above the fixed price of the put option, no payment is due from either party.
- Knockout swaps: Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty's exposure to zero, in any given month, if the floating market price is lower than certain pre-determined knockout prices.
- Cap-swaps: Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a "cap" limiting the counterparty's exposure. In other words, there is no limit to Chesapeake's exposure but there is a limit to the downside exposure of the counterparty.
- Basis protection swaps: These instruments are arrangements that guarantee a price differential to NYMEX for natural gas from a specified delivery point. For non-Appalachian Basin basis protection swaps, which typically have negative differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. For Appalachian Basin basis protection swaps, which typically have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.

All of our derivative instruments are net settled based on the difference between the fixed price payment and the floating-price payment, resulting in a net amount due to or from the counterparty.

The estimated fair values of our natural gas and oil derivative instruments as of December 31, 2009 and 2008 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	December 31, 2009		December 31, 2008	
	Volume Hedged	Fair Value	Volume Hedged	Fair Value
		($ in millions)		($ in millions)
Natural gas (bbtu):				
Fixed-price swaps	492,053	$ 662	466,800	$ 863
Fixed-price collars	74,240	92	457,715	402
Fixed-price knockout swaps	38,370	17	532,660	141
Call options	996,750	(541)	551,555	(178)
Put options	(69,620)	(50)	(73,000)	(39)
Basis protection swaps	125,469	(50)	219,487	93
Total natural gas	1,657,262	$ 130	2,155,217	$ 1,282
Oil (mbbl):				
Fixed-price swaps	5,475	3	(310)	31
Fixed-price collars	—	—	730	5
Fixed-price knockout swaps	6,572	32	12,248	19
Fixed-price cap-swaps	—	—	362	3
Call options	14,975	(144)	19,355	(35)
Total oil	27,022	$ (109)	32,385	$ 23
Total estimated fair value[(a)]		$ 21		$ 1,305

(a) After adjusting for $407 million and $736 million of unrealized premiums, the value to be realized for these derivatives as of December 31, 2009 and 2008 was $428 million and $2.041 billion, respectively.

Pursuant to accounting guidance for hedging and derivatives, certain derivatives qualify for designation as cash flow hedges. Following this guidance, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in accumulated other comprehensive income until the hedged item is recognized in earnings as the physical transactions being hedged occur. Any change in fair value resulting from ineffectiveness is currently recognized in natural gas and oil sales as unrealized gains (losses). Changes in the fair value of non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are currently reported in the consolidated statements of operations as unrealized gains (losses) within natural gas and oil sales. Realized gains (losses) are included in natural gas and oil sales in the month of related production.

Chesapeake enters into counter-swaps from time to time for the purpose of locking-in the value of a swap. Under the counter-swap, Chesapeake receives a floating price for the hedged commodity and pays a fixed price to the counterparty. The counter-swap is 100% effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap. Generally, at the time Chesapeake enters into a counter-swap, Chesapeake removes the original swap's designation as a cash flow hedge and classifies the original swap as a non-qualifying hedge. The reason for this new designation is that collectively the swap and the counter-swap no longer hedge the exposure to variability in expected future cash flows. Instead, the swap and counter-swap effectively lock-in a specific gain or loss that will be unaffected by subsequent variability in natural gas and oil prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to natural gas and oil sales in the month of related production.

The components of natural gas and oil sales for the years ended December 31, 2009, 2008 and 2007 are presented below.

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
Natural gas and oil sales	$ 3,291	$ 7,069	$ 4,795
Realized gains (losses) on natural gas and oil derivatives	2,346	(8)	1,203
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(624)	887	(252)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	36	(90)	(122)
Total natural gas and oil sales	$ 5,049	$ 7,858	$ 5,624

Based upon the market prices at December 31, 2009, we expect to transfer approximately $202 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to net income (loss) during the next 12 months in the related month of production. All transactions hedged as of December 31, 2009 are expected to mature by December 31, 2022.

We began 2009 with six secured hedging facilities, each of which permitted us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to a stated maximum value. Outstanding transactions under each of the facilities were collateralized by certain of our natural gas and oil properties that did not secure any of our other obligations. On June 11, 2009, we entered into a multi-counterparty hedge facility with 13 counterparties that have committed to provide approximately 3.9 tcfe of trading capacity and an aggregate mark-to-market capacity of $10.4 billion under the terms of the facility. The new multi-counterparty facility has consolidated and replaced the six secured hedge facilities. All trades have been novated and pledged collateral transferred to the multi-counterparty facility, which had a total of 1.7 tcfe hedged and collateral value of approximately $5.3 billion as of December 31, 2009. Trades from the original six secured hedging facilities will continue to be subject to pre-existing exposure fees, but we are not required to pay an exposure fee for any new trades in the multi-counterparty facility.

The multi-counterparty facility allows us to enter into cash-settled natural gas and oil price and basis hedges with the counterparties. Our obligations under the multi-counterparty facility are secured by natural gas and oil proved reserves, the value of which must cover the fair value of the transactions outstanding under the facility by at least 1.65 times, and guarantees by certain subsidiaries that also guarantee our corporate revolving bank credit facility and indentures. The counterparties' obligations under the facility must be secured by cash or short-term U.S. Treasury instruments to the extent that any mark-to-market amounts they owe to Chesapeake exceed defined thresholds. The maximum volume-based trading capacity under the facility is governed by the expected production of the pledged reserve collateral, and volume-based trading limits are applied separately to price and basis hedges. In addition, there are volume-based sub-limits for natural gas and oil hedges. Chesapeake has significant flexibility with regard to releases and/or substitutions of pledged reserves, provided that certain collateral coverage and other requirements are met. The facility does not have a maturity date. Counterparties to the agreement have the right to cease trading with the company on a prospective basis as long as obligations associated with any existing trades in the facility continue to be satisfied in accordance with the terms of the agreement.

To mitigate our exposure to the fluctuation in prices of diesel fuel which is used in our exploration and development activities, we have entered into diesel swaps from January 2010 to March 2010 for a total of 10.4 million gallons with an average fixed price of $1.58 per gallon. Chesapeake pays the fixed price and receives a floating price. The fair value of these swaps as of December 31, 2009 was an asset of $5 million.

Interest Rate Derivatives

To mitigate our exposure to volatility in interest rates related to our senior notes and bank credit facilities, we enter into interest rate derivatives. As of December 31, 2009 and 2008, our interest rate derivative instruments were comprised of the following types of instruments:

- Swaps: Chesapeake enters into fixed-to-floating interest rate swaps (we receive a fixed interest rate and pay a floating market rate) to mitigate our exposure to changes in the fair value of our senior notes. We enter into floating-to-fixed interest rate swaps (we receive a floating market rate and pay a fixed interest rate) to manage our interest rate exposure related to our bank credit facilities borrowings.
- Collars: These instruments contain a fixed floor rate (floor) and a ceiling rate (cap). If the floating rate is above the cap, we have a net receivable from the counterparty and if the floating rate is below the floor, we have a net payable to the counterparty. If the floating rate is between the floor and the cap, there is no payment due from either party. Collars are used to manage our interest rate exposure related to our bank credit facilities borrowings.

- Call options: Occasionally we sell call options for a premium when we think it is more likely that the option will expire unexercised. The option allows the counterparty to terminate an open swap at a specific date.
- Swaptions: Occasionally we sell an option to a counterparty for a premium which allows the counterparty to enter into a swap with us on a specific date.

The notional amount of debt hedged and the estimated fair value of our interest rate derivatives outstanding as of December 31, 2009 and 2008 are provided below.

	December 31, 2009		December 31, 2008	
	Notional Amount	Fair Value	Notional Amount	Fair Value
	($ in millions)			
Interest rate				
Swaps	$ 2,925	$ (113)	$ 1,575	$ 88
Collars	250	(6)	800	(35)
Call options	250	(2)	750	(105)
Swaptions	500	(11)	750	(10)
Totals	$ 3,925	$ (132)	$ 3,875	$ (62)

For interest rate derivative instruments designated as fair value hedges, changes in fair value are recorded on the consolidated balance sheets as assets (liabilities), and the debt's carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Changes in the fair value of non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are currently reported in the consolidated statements of operations as unrealized (gains) losses within interest expense.

Gains or losses from interest rate derivative transactions are reflected as adjustments to interest expense in the consolidated statements of operations. The components of interest expense for the years ended December 31, 2009, 2008 and 2007 are presented below.

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
Interest expense on senior notes	$ 765	$ 637	$ 538
Interest expense on credit facilities	60	117	113
Capitalized interest	(633)	(585)	(311)
Realized (gains) losses on interest rate derivatives	(23)	(6)	1
Unrealized (gains) losses on interest rate derivatives	(91)	85	40
Amortization of loan discount and other	35	23	20
Total interest expense	$ 113	$ 271	$ 401

Our qualifying interest rate swaps are considered 100% effective and therefore no ineffectiveness was recorded for the periods presented above.

Gains and losses related to terminated qualifying interest rate derivative transactions will be amortized as an adjustment to interest expense over the remaining term of the related senior notes. Over the next eleven years we will be realizing $106 million in gains related to such trades.

Foreign Currency Derivatives

On December 6, 2006, we issued €600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties pay Chesapeake €19 million and Chesapeake pays the counterparties $30 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake €600 million and Chesapeake will pay the counterparties $800 million. The terms of the cross currency swap were based on the dollar/euro exchange rate on the issuance date of $1.3325 to €1.00. Through the cross currency swap, we have eliminated any potential variability in Chesapeake's expected cash flows related to changes in foreign exchange rates and therefore the swap qualifies as a cash flow hedge. The fair value of the cross currency swap is recorded on the consolidated balance sheet as an asset of $43 million at December 31, 2009. The euro-denominated debt in notes payable has been adjusted to $860 million at December 31, 2009 using an exchange rate of $1.4332 to €1.00.

Additional Disclosures About Derivative Instruments and Hedging Activities

In accordance with accounting guidance for hedging and derivatives, to the extent that a legal right of set-off exists, Chesapeake nets the value of its derivative arrangements with the same counterparty in the accompanying consolidated balance sheets. Derivative instruments reflected as current in the consolidated balance sheet represent the estimated fair value of derivatives scheduled to settle over the next 12 months based on market prices/rates as of the balance sheet date. The derivative settlement amounts are not due until the month in which the related underlying hedged transaction occurs. Cash settlements of our derivative arrangements are generally classified as operating cash flows unless the derivative contains a significant financing element at contract inception, in which case, all cash settlements are classified as financing cash flows in the accompanying consolidated statement of cash flows.

The following table sets forth the fair value of each classification of derivative instrument as of December 31, 2009 on a gross basis without regard to same-counterparty netting:

	December 31, 2009	
	Balance Sheet Location	Fair Value
	($ in millions)	
ASSET DERIVATIVES:		
Derivatives designated as hedging instruments:		
Commodity contracts	Short-term derivative instruments	$ 417
Commodity contracts	Long-term derivative instruments	36
Foreign exchange contracts	Long-term derivative instruments	43
Total		496
Derivatives not designated as hedging instruments:		
Commodity contracts	Short-term derivative instruments	318
Commodity contracts	Long-term derivative instruments	66
Total		384
LIABILITY DERIVATIVES:		
Derivatives designated as hedging instruments:		
Commodity contracts	Short-term derivative instruments	(1)
Interest rate contracts	Long-term derivative instruments	(11)
Total		(12)
Derivatives not designated as hedging instruments:		
Commodity contracts	Short-term derivative instruments	(42)
Commodity contracts	Long-term derivative instruments	(768)
Interest rate contracts	Short-term derivative instruments	(27)
Interest rate contracts	Long-term derivative instruments	(94)
Total		(931)
Total derivative instruments		$ (63)

A consolidated summary of the effect of derivative instruments on the consolidated statements of operations for the year ended December 31, 2009 is provided below, separating fair value, cash flow and non-qualifying derivatives.

The following table presents the gain (loss) recognized in net income (loss) for instruments designated as fair value derivatives ($ in millions):

Fair Value Derivatives	Location of Gain (Loss)	Year Ended December 31, 2009
Interest rate contracts	Interest expense[(a)]	$ 37

(a) Interest expense on the hedged items for the year ended December 31, 2009 was $71 million, which is included in interest expense on the consolidated statement of operations.

The following table presents the pre-tax gain (loss) recognized in, and reclassified from, accumulated other comprehensive income (AOCI) and recognized in net income (loss), including any hedge ineffectiveness, for derivative instruments designated as cash flow derivatives ($ in millions):

Cash Flow Derivatives	Location of Gain (Loss)	Year Ended December 31, 2009
Gain (Loss) Recognized in AOCI (Effective Portion)		
Commodity contracts	AOCI	$ 958
Foreign exchange contracts	AOCI	96
		$ 1,054
Gain (Loss) Reclassified from AOCI (Effective Portion)		
Commodity contracts	Natural gas and oil sales	$ 1,425
		$ 1,425
Gain (Loss) Recognized (Ineffective Portion and amount excluded from effectiveness testing)(a)		
Commodity contracts	Natural gas and oil sales	$ 193
		$ 193

(a) The amount of gain (loss) recognized in net income (loss) represents $36 million related to the ineffective portion of our cash flow derivatives, and $157 million related to the amount excluded from the assessment of hedge effectiveness.

The following table presents the gain (loss) recognized in net income (loss) for instruments not qualifying as cash flow or fair value derivatives ($ in millions):

Non-Qualifying Derivatives	Location of Gain (Loss)	Year Ended December 31, 2009
Commodity contracts	Natural gas and oil sales	$ 139
Interest rate contracts	Interest expense	77
	Total	$ 216

Concentration of Credit Risk

A significant portion of our liquidity is concentrated in derivative instruments that enable us to hedge a portion of our exposure to natural gas and oil price and interest rate volatility. These arrangements expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with investment-grade rated counterparties deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. On December 31, 2009, our commodity and interest rate derivative instruments were spread among 14 counterparties. Additionally, our multi-counterparty secured hedging facility described previously requires our counterparties to secure their natural gas and oil hedging obligations in excess of defined thresholds. We now use this facility for substantially all of our commodity hedging.

Other financial instruments which potentially subject us to concentrations of credit risk consist principally of investments in equity instruments and accounts receivable. Our accounts receivable are primarily from purchasers of natural gas and oil and exploration and production companies which own interests in properties we operate. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We monitor the creditworthiness of all our counterparties. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. In 2009, we recognized $12 million of bad debt expense related to potentially uncollectible receivables.

10. Supplemental Disclosures About Natural Gas and Oil Producing Activities

Net Capitalized Costs

Evaluated and unevaluated capitalized costs related to Chesapeake's natural gas and oil producing activities are summarized as follows:

	December 31,	
	2009	2008
	($ in millions)	
Natural gas and oil properties:		
Proved	$ 35,007	$ 28,965
Unproved	10,005	11,379
Total	45,012	40,344
Less accumulated depreciation, depletion and amortization	(24,220)	(11,866)
Net capitalized costs	$ 20,792	$ 28,478

Unproved properties not subject to amortization at December 31, 2009, 2008 and 2007 consisted mainly of leasehold acquired through corporate and significant natural gas and oil property acquisitions and through direct purchases of leasehold. We capitalized approximately $627 million, $585 million and $311 million of interest during 2009, 2008 and 2007, respectively, on significant investments in unproved properties that were not yet included in the amortization base of the full-cost pool. We will continue to evaluate our unevaluated properties; however, the timing of the ultimate evaluation and disposition of the properties has not been determined.

The table below sets forth the cost of unproved properties excluded from the amortization base as of December 31, 2009 and notes the year in which the associated costs were incurred:

	Year of Acquisition				
	2009	2008	2007	Prior	Total
	($ in millions)				
Leasehold acquisition cost	$ 1,803	$ 4,948	$ 1,059	$ 636	$ 8,446
Exploration cost	346	152	120	—	618
Capitalized interest	201	551	118	71	941
Total	$ 2,350	$ 5,651	$ 1,297	$ 707	$ 10,005

Costs Incurred in Natural Gas and Oil Exploration and Development, Acquisitions and Divestitures

Costs incurred in natural gas and oil property exploration and development, acquisitions and divestitures activities which have been capitalized are summarized as follows:

	December 31,		
	2009	2008	2007
	($ in millions)		
Development and exploration costs:			
Development drilling[a]	$ 2,729	$ 5,185	$ 4,402
Exploratory drilling	651	612	653
Geological and geophysical costs[b][c]	162	314	343
Asset retirement obligation and other	(2)	10	29
Total	3,540	6,121	5,427
Acquisition costs:			
Unproved properties[d]	2,793	8,250	2,507
Proved properties	61	355	671
Deferred income taxes	—	13	131
Total	2,854	8,618	3,309
Proceeds from divestitures:			
Unproved properties	(1,265)	(5,302)	—
Proved properties	(461)	(2,433)	(1,142)
Total	$ 4,668	$ 7,004	$ 7,594

(a) Includes capitalized internal cost of $332 million, $326 million and $243 million, respectively.

(b) Includes capitalized internal cost of $22 million, $26 million and $19 million, respectively

(c) Includes $29 million, $25 million and $16 million of related capitalized interest, respectively.

(d) Includes $598 million, $561 million and $296 million of related capitalized interest, respectively.

Results of Operations from Natural Gas and Oil Producing Activities (unaudited)

Chesapeake's results of operations from natural gas and oil producing activities are presented below for 2009, 2008 and 2007. The following table includes revenues and expenses associated directly with our natural gas and oil producing activities. It does not include any interest costs or general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our natural gas and oil operations.

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
Natural gas and oil sales[a]	$ 5,049	$ 7,858	$ 5,624
Production expenses	(876)	(889)	(640)
Production taxes	(107)	(284)	(216)
Impairment of natural gas and oil properties	(11,000)	(2,800)	—
Depletion and depreciation	(1,371)	(1,970)	(1,835)
Imputed income tax provision[b]	3,114	(747)	(1,115)
Results of operations from natural gas and oil producing activities	$ (5,191)	$ 1,168	$ 1,818

(a) Includes ($587) million, $797 million and ($374) million of unrealized gains (losses) on natural gas and oil derivatives for the years ended December 31, 2009, 2008 and 2007, respectively.

(b) The imputed income tax provision is hypothetical (at the effective income tax rate) and determined without regard to our deduction for general and administrative expenses, interest costs and other income tax credits and deductions, nor whether the hypothetical tax provision will be payable.

Natural Gas and Oil Reserve Quantities (unaudited)

Chesapeake's petroleum engineers, internal staff and independent petroleum engineering firms estimated all of our proved reserves as of December 31, 2009. The independent petroleum engineering firms estimated an aggregate of 83% of our estimated proved reserves (by volume), as set forth below.

	December 31, 2009
Netherland, Sewell & Associates, Inc.	59%
Lee Keeling and Associates, Inc.	10%
Data and Consulting Services, Division of Schlumberger Technology Corporation	7%
Ryder Scott Company L.P.	7%

Chesapeake's petroleum engineers and internal staff estimated all of our proved reserves as of December 31, 2008, and independent petroleum engineering firms audited an aggregate 76% of our estimated proved reserves (by volume), as set forth below. A reserve audit is not the same as a financial audit and a reserve audit is less rigorous in nature than a reserve report prepared by an independent petroleum engineering firm containing its own estimates of reserves.

	December 31, 2008
Netherland, Sewell & Associates, Inc.	42%
Lee Keeling and Associates, Inc.	13%
Data and Consulting Services, Division of Schlumberger Technology Corporation	8%
Ryder Scott Company L.P.	8%
LaRoche Petroleum Consultants, Ltd.	5%

Chesapeake's petroleum engineers, internal staff and independent petroleum engineering firms estimated all of our proved reserves as of December 31, 2007. The independent petroleum engineering firms estimated an aggregate 79% of our estimated proved reserves (by volume) as set forth below.

	December 31, 2007
Netherland, Sewell & Associates, Inc.	34%
Lee Keeling and Associates, Inc.	11%
Data and Consulting Services, Division of Schlumberger Technology Corporation	12%
Ryder Scott Company L.P.	11%
LaRoche Petroleum Consultants, Ltd.	11%

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Proved developed oil and gas reserves are reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

The information below on our natural gas and oil reserves is presented in accordance with regulations prescribed by the Securities and Exchange Commission as in effect as of the date of such estimates. Chesapeake emphasizes that reserve estimates are inherently imprecise. Our reserve estimates were generally based upon extrapolation of historical production trends, analogy to similar properties and volumetric calculations. Accordingly, these estimates are expected to change, and such changes could be material and occur in the near term as future information becomes available.

Presented below is a summary of changes in estimated reserves of Chesapeake for 2009, 2008 and 2007:

	Gas (bcf)	Oil (mmbbl)	Total (bcfe)
December 31, 2009			
Proved reserves, beginning of period	11,327	120.6	12,051
Extensions, discoveries and other additions	4,530	27.1	4,693
Revisions of previous estimates	(1,335)	(10.3)	(1,397)
Production	(835)	(11.8)	(906)
Sale of reserves-in-place	(209)	(1.8)	(220)
Purchase of reserves-in-place	32	0.2	33
Proved reserves, end of period	13,510	124.0	14,254
Proved developed reserves:			
Beginning of period	7,582	84.9	8,091
End of period	7,859	78.8	8,331
December 31, 2008			
Proved reserves, beginning of period	10,137	123.6	10,879
Extensions, discoveries and other additions	1,526	11.5	1,595
Revisions of previous estimates	957	(1.2)	950
Production	(775)	(11.2)	(843)
Sale of reserves-in-place	(674)	(4.6)	(702)
Purchase of reserves-in-place	156	2.5	172
Proved reserves, end of period	11,327	120.6	12,051
Proved developed reserves:			
Beginning of period	6,409	88.8	6,942
End of period	7,582	84.9	8,091
December 31, 2007			
Proved reserves, beginning of period	8,319	106.0	8,956
Extensions, discoveries and other additions	1,053	11.7	1,123
Revisions of previous estimates	1,299	7.7	1,345
Production	(655)	(9.9)	(714)
Sale of reserves-in-place	(208)	—	(208)
Purchase of reserves-in-place	329	8.1	377
Proved reserves, end of period	10,137	123.6	10,879
Proved developed reserves:			
Beginning of period	5,113	76.7	5,573
End of period	6,409	88.8	6,942

During 2009, Chesapeake acquired approximately 33 bcfe of proved reserves through purchases of natural gas and oil properties for consideration of $61 million (primarily in two separate transactions of greater than $10 million each) and we sold 221 bcfe of our proved reserves for approximately $576 million. During 2009, we recorded downward revisions of 1.397 tcfe to the December 31, 2008 estimates of our reserves. Included in the revisions were 952 bcfe of downward revisions resulting from lower natural gas prices using the average 12-month price in 2009 compared to the spot price as of December 31, 2008, and 445 bcfe of downward revisions resulting from changes to previous estimates. Lower prices decrease the economic lives of the underlying natural gas and oil properties and thereby decrease the estimated future reserves. The natural gas and oil prices used in computing our reserves as of December 31, 2009 were $3.87 per mcf and $61.14 per barrel before price differentials.

During 2008, Chesapeake acquired approximately 172 bcfe of proved reserves through purchases of natural gas and oil properties for consideration of $355 million (primarily in five separate transactions of greater than $10 million each) and we sold 702 bcfe of our proved reserves for approximately $2.433 billion. During 2008, we recorded positive revisions of 950 bcfe to the December 31, 2007 estimates of our reserves. Included in the revisions were 298 bcfe of negative adjustments caused by lower natural gas prices at December 31, 2008, and 1.248 tcfe of positive performance related revisions. Lower prices decrease the economic lives of the underlying natural gas and oil properties and thereby decrease the estimated future reserves. The natural gas and oil prices used in computing our reserves as of December 31, 2008 were $5.71 per mcf and $44.61 per barrel before price differentials.

During 2007, Chesapeake acquired approximately 377 bcfe of proved reserves through purchases of natural gas and oil properties for consideration of $671 million (primarily in 10 separate transactions of greater than $10 million each). In December 2007, we sold 208 bcfe of our proved reserves in certain Chesapeake-operated producing assets in Kentucky and West Virginia for approximately $1.142 billion. During 2007, we recorded positive revisions of 1.345 tcfe to the December 31, 2006 estimates of our reserves. Included in the revisions were 97 bcfe of positive adjustments caused by higher natural gas prices at December 31, 2007, and 1.248 tcfe of positive performance related revisions of which 1.207 tcfe relate to infill drilling and increased density locations. Higher prices extend the economic lives of the underlying natural gas and oil properties and thereby increase the estimated future reserves. The natural gas and oil prices used in computing our reserves as of December 31, 2007 were $6.80 per mcf and $96.01 per barrel before price differentials.

Standardized Measure of Discounted Future Net Cash Flows (unaudited)

Accounting Standards Topic 932 prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. Chesapeake has followed these guidelines which are briefly discussed below.

Future cash inflows and future production and development costs as of December 31, 2009 are determined by applying the trailing average 12-month prices and year-end costs to the estimated quantities of natural gas and oil to be produced. Actual future prices and costs may be materially higher or lower than the 12-month average prices and year-end costs used. Amounts as of December 31, 2007 and 2008 were determined using year-end prices and costs. For each year, estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on continuation of the economic conditions applied for such year. Estimated future income taxes are computed using current statutory income tax rates including consideration for the current tax basis of the properties and related carryforwards, giving effect to permanent differences and tax credits. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board and, as such, do not necessarily reflect our expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates reflect the valuation process.

The following summary sets forth our future net cash flows relating to proved natural gas and oil reserves based on the standardized measure:

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
Future cash inflows	$ 49,322[(a)]	$ 62,995[(b)]	$ 73,955[(c)]
Future production costs	(16,620)	(18,828)	(19,319)
Future development costs	(8,881)	(7,378)	(8,315)
Future income tax provisions	(4,106)	(9,813)	(14,056)
Future net cash flows	19,715	26,976	32,265
Less effect of a 10% discount factor	(11,512)	(15,143)	(17,303)
Standardized measure of discounted future net cash flows	$ 8,203	$ 11,833	$ 14,962

(a) Calculated using prices of $61.14 per barrel of oil and $3.87 per mcf of natural gas, before field differentials.

(b) Calculated using prices of $44.61 per barrel of oil and $5.71 per mcf of natural gas, before field differentials.

(c) Calculated using prices of $96.01 per barrel of oil and $6.80 per mcf of natural gas, before field differentials.

The principal sources of change in the standardized measure of discounted future net cash flows are as follows:

	Years Ended December 31,		
	2009	2008	2007
	($ in millions)		
Standardized measure, beginning of period[(a)]	$ 11,833	$ 14,962	$ 10,007
Sales of natural gas and oil produced, net of production costs[(b)]	(2,307)	(5,896)	(3,939)
Net changes in prices and production costs	(7,297)	(5,025)	3,277
Extensions and discoveries, net of production and development costs	2,374	2,752	2,424
Changes in future development costs	1,910	1,043	(639)
Development costs incurred during the period that reduced future development costs	650	1,130	1,410
Revisions of previous quantity estimates	(1,290)	1,524	2,960
Purchase of reserves-in-place	41	362	1,166
Sales of reserves-in-place	(377)	(1,696)	(708)
Accretion of discount	1,560	2,057	1,365
Net change in income taxes	2,521	1,843	(1,970)
Changes in production rates and other	(1,415)	(1,223)	(391)
Standardized measure, end of period[(a)]	$ 8,203	$ 11,833	$ 14,962

(a) The impact of cash flow hedges has not been included in any of the periods presented.

(b) Excluding gains (losses) on derivatives.

11. Midstream Joint Venture

On September 30, 2009, we formed a joint venture with Global Infrastructure Partners (GIP), a New York-based private equity fund, to own and operate natural gas midstream assets. As part of the transaction, Chesapeake contributed certain natural gas gathering and processing assets to a new entity, Chesapeake Midstream Partners, L.L.C. (CMP), and GIP purchased a 50% interest in CMP.

The assets we contributed to the joint venture were substantially all of our midstream assets in the Barnett Shale and also the majority of our non-shale midstream assets in the Arkoma, Anadarko, Delaware and Permian Basins. The financial results of CMP are consolidated and GIP's 50% ownership interest is reflected as a noncontrolling interest as of December 31, 2009 in our consolidated financial statements.

CMP focuses on unregulated business activities in service to both Chesapeake and third-party natural gas producers and its revenues are generated almost entirely from fixed fee-based arrangements for gathering, compression, dehydration and treating services. CMP has entered into various agreements with Chesapeake, including a long-term gas gathering agreement at rates consistent with current market pricing. CMP operates the contributed assets. Certain Chesapeake employees provide services to CMP through an employee secondment agreement. In return for certain cost reimbursements, CMP utilizes various support functions within Chesapeake, including accounting, human resources and information technology.

Subsidiaries of our wholly-owned subsidiary CMD continue to operate our midstream assets outside of the CMP joint venture. These include natural gas gathering assets in the Fayetteville Shale, Haynesville Shale, Marcellus Shale and other areas in Appalachia.

Concurrent with GIP's funding of its interest in the joint venture, CMP closed a new $500 million secured revolving bank credit facility to partially fund capital expenditures associated with the building of additional natural gas gathering systems and for general corporate purposes. Additionally, we amended and restated the existing midstream lending agreement to reduce the total capacity from $460 million to $250 million, among other changes. This separate secured revolving bank credit facility supports CMD's continuing midstream activities. These facilities are described in Note 3.

In 2009, we recorded an $86 million impairment of certain of the gathering systems contributed to CMP prior to the formation of the joint venture, and we expensed $4 million of debt issuance costs associated with the portion of our $460 million midstream credit facility that was reduced to $250 million. The combined impairment of $90 million was included in impairment of natural gas and oil properties and other assets on our consolidated statement of operations. Additionally, an estimated post-closing adjustment related to the joint venture transaction was recorded at December 31, 2009, and is expected to be finalized in the first quarter of 2010.

The $897 million noncontrolling interest included in our consolidated equity at December 31, 2009 represents GIP's 50% interest in the net assets of CMP, which were recorded by CMP at Chesapeake's historical cost basis. This noncontrolling interest includes the $588 million GIP contributed in exchange for a 50% ownership interest in CMP, $294 million of Chesapeake partners' capital allocated to GIP in order to properly reflect GIP's 50% interest in the carrying value of CMP's net assets, $25 million of pre-tax net income allocated to GIP from CMP's operations and a $10 million distribution to GIP for its proportionate share of transaction costs associated with the formation of the joint venture.

Beginning January 1, 2010, we will deconsolidate our joint venture with GIP and account for the investment in the joint venture under the equity method going forward. Adoption of this guidance will result in a cumulative effect adjustment for the difference in our equity in the joint venture at January 1, 2010, which was originally recorded at carryover basis, and the fair value of our equity at the formation of the joint venture based on the then fair value. This cumulative effect adjustment will create a basis difference between our equity investment balance and the underlying equity in the net assets of the joint venture. This difference will be accreted through earnings over the expected useful life of the underlying assets held by the joint venture.

12. Divestitures

Joint Ventures

In 2008, we entered into three joint ventures to sell a portion of our leasehold in the joint venture areas, which allowed us to recover much or all of our initial leasehold investments in the plays, reduce our ongoing capital costs and reduce future risks. The transactions are detailed below.

On July 1, 2008, we entered into a joint venture with Plains Exploration & Production Company (PXP) to develop our Haynesville and Bossier Shale leasehold in Northwest Louisiana and East Texas. Under the terms of the joint venture, PXP acquired a 20% interest in approximately 550,000 net acres of our Haynesville and Bossier Shale leasehold for $1.65 billion in cash. PXP also agreed to fund 50% of our remaining 80% share of the costs associated with drilling and completing future Haynesville and Bossier Shale joint venture wells over a multi-year period, up to an additional $1.65 billion. In addition, PXP has the right to a 20% participation in any additional leasehold we acquire in the Haynesville and Bossier Shales at our cost plus a fee. In August 2009, Chesapeake and PXP amended their joint venture agreement to accelerate the payment of PXP's remaining joint venture drilling carries as of September 30, 2009, in exchange for an approximate 12% reduction in the total amount of drilling carry obligations due to Chesapeake. As a result, on September 29, 2009, Chesapeake received $1.1 billion in cash from PXP and beginning in the 2009 fourth quarter Chesapeake and PXP each began paying their proportionate working interest costs on drilling.

On September 5, 2008, we entered into a joint venture with BP America Inc. to develop our Fayetteville Shale leasehold in Arkansas. Under the terms of the joint venture, BP acquired a 25% interest in approximately 540,000 net acres of our Fayetteville Shale leasehold for $1.1 billion in cash. BP also paid an additional $800 million by funding 100% of Chesapeake's 75% share of drilling and completion expenditures during 2008 and 2009. In addition, BP has the right to a 25% participation in any additional leasehold we acquire in the Fayetteville Shale at our cost plus a fee.

On November 25, 2008, we entered into a joint venture with Statoil to develop our Marcellus Shale leasehold in Appalachia. Under the terms of the joint venture, Statoil acquired a 32.5% interest in our Marcellus Shale assets for $3.375 billion. The assets included approximately 1.8 million net acres of leasehold, of which Statoil now owns approximately 0.6 million net acres and Chesapeake owns approximately 1.2 million net acres. Chesapeake received $1.25 billion in cash from Statoil and agreed to fund 75% of Chesapeake's 67.5% share of drilling and completion expenditures until the $2.125 billion obligation has been funded, subject to certain conditions. In addition, Statoil has the right to a 32.5% participation in any additional leasehold we acquire in the Marcellus Shale. Statoil's commitment to fund 75% of our share of future drilling and completion costs (up to $2.125 billion) is expected to reduce future DD&A expense by reducing the amount of capital we will invest to develop our Marcellus properties.

For accounting purposes, cash proceeds from these transactions were reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

Volumetric Production Payments

On August 4, 2009, we sold certain Chesapeake-operated long-lived producing assets in South Texas in our fifth volumetric production payment transaction for proceeds of approximately $370 million. The assets included proved reserves of approximately 68 bcfe, valued at $5.46 per mcfe, and had net production (at the time of sale) of approximately 55 mmcfe per day. The VPP had an original term of approximately seven and half years. As of December 31, 2009, there was approximately 60 bcfe of production expected to be delivered over the remaining term. Chesapeake retained drilling rights on the properties below currently producing intervals.

On December 31, 2008, we sold certain long-lived producing assets in the Anadarko and Arkoma Basins in a volumetric production payment transaction for net proceeds of approximately $412 million. These assets had estimated proved reserves of approximately 98 bcfe, valued at $4.19 / mcfe and current net production (at the time of sale) of approximately 60 mmcfe per day. The VPP had an original term of eight years. As of December 31, 2009, there was approximately 79 bcfe of production expected to be delivered over the remaining term. Chesapeake retained drilling rights on the properties below currently producing intervals.

On August 1, 2008, we completed a volumetric production payment transaction for net proceeds of approximately $594 million with estimated proved reserves of approximately 93 bcfe, valued at $6.38/mcfe, and current net production (at the time of sale) of approximately 50 mmcfe per day from wells in the Anadarko Basin of Oklahoma. The VPP had an original term of 11 years. As of December 31, 2009, we have approximately 72 bcfe of production expected to be delivered over the remaining term. Chesapeake retained drilling rights on the properties below currently producing intervals.

On May 1, 2008, we sold certain long-lived producing assets in Texas, Oklahoma and Kansas in a volumetric production payment transaction for net proceeds of approximately $616 million. These assets had estimated proved reserves of approximately 94 bcfe, valued at $6.53/mcfe, and current net production (at the time of sale) of approximately 47 mmcfe per day. The VPP had an original term of 11 years. As of December 31, 2009, we have approximately 68 bcfe of production expected to be delivered over the remaining term. Chesapeake retained drilling rights on the properties below currently producing intervals.

On December 31, 2007, we sold a portion of our proved reserves and production in certain Chesapeake-operated producing assets in Kentucky and West Virginia in a volumetric production payment for net proceeds of approximately $1.1 billion. These assets had estimated proved reserves of approximately 208 bcfe, valued at $5.29/mcfe, and current net production (at the time of sale) of approximately 55 mmcfe per day. The VPP had an original term of 15 years. As of December 31, 2009, we have approximately 170 bcfe of production expected to be produced over the remaining term. Chesapeake retained drilling rights on the properties below currently producing intervals.

For accounting purposes, cash proceeds from these transactions were reflected as a reduction of natural gas and oil properties with no gain or loss recognized and our proved reserves were reduced accordingly.

Other Divestitures

In 2009, we sold non-core natural gas assets for proceeds of approximately $418 million.

On August 8, 2008, BP America Inc. acquired all of our interests in approximately 90,000 net acres of leasehold and producing natural gas properties in the Arkoma Basin Woodford Shale play for $1.7 billion in cash. The properties were producing approximately 50 mmcfe per day (at the time of sale).

Also in 2008, we sold non-core natural gas and oil assets in the Rocky Mountains and in the Mid-Continent for proceeds of approximately $400 million.

13. Restructuring

In 2009, we restructured our Charleston, West Virginia-based Eastern Division from a regional corporate headquarters to a regional field office consistent with the business model the company uses elsewhere in the country. As a result, we consolidated the management of our Eastern Division land, legal, accounting, information technology, geoscience and engineering departments into our corporate offices in Oklahoma City. The costs of the reorganization include termination benefits, consolidating or closing facilities and relocating employees. In addition, we had certain other workforce reductions that resulted in termination benefits.

A summary of Chesapeake's restructuring charges is presented below ($ in millions):

	Restructuring Costs Through December 31, 2009	Restructuring Costs To Be Incurred	Total Restructuring Costs
Restructuring Costs:			
Termination and relocation costs	$ 21	$ 1	$ 22
Acceleration of restricted stock awards	9	—	9
Other associated costs	3	—	3
Total Restructuring Costs	$ 33	$ 1	$ 34

14. Investments

At December 31, 2009, investments accounted for under the equity method totaled $370 million and investments accounted for under the cost method totaled $34 million. Following is a summary of our investments:

	Approximate % Owned	Accounting Method	December 31, 2009 Carrying Value	December 31, 2008 Carrying Value
			($ in millions)	
Frac Tech Services, Ltd.[(a)]	20%	Equity	$ 239	$ 223
Chaparral Energy, Inc.[(b)(c)]	32%	Equity	103	152
DHS Drilling Company[(b)]	47%	Equity	—	19
Sierra Mid-Con, L.P.	49%	Equity	14	12
Gastar Exploration Ltd.[(d)]	14%	Cost	32	11
Mountain Drilling Company[(b)]	49%	Equity	—	9
Other	—	—	16	18
			$ 404	$ 444

(a) The carrying value of our investment in Frac Tech is in excess of our underlying equity in net assets by approximately $169 million as of December 31, 2009. This excess amount is attributed to certain intangibles associated with the specialty services provided by Frac Tech and is being amortized over the estimated life of the intangibles.

(b) Our investees have been impacted by the dramatic slowing of the worldwide economy and the tightening of the credit markets in the fourth quarter of 2008 and into 2009. The economic weakness has resulted in significantly reduced natural gas and oil prices leading to a meaningful decline in the overall level of activity in the markets served by our investees. Associated with the weakness in performance of certain of the investees, as well as an evaluation of their financial condition and near-term prospects, we recognized during 2009 that an other than temporary impairment had occurred on March 31, 2009 on the following investments: Chaparral Energy, Inc. of $51 million, DHS Drilling Company of $19 million, Gastar Exploration Ltd. of $70 million and Mountain Drilling Company of $9 million. On December 31, 2008, we recognized that an other than temporary impairment occurred on the following investments: Chaparral Energy, Inc., $100 million; DHS Drilling Company, $20 million; Mountain Drilling Company, $10 million; and Ventura Refining and Transmission LLC, Inc., $50 million. We have monitored and will continue to monitor the performance of our investments, and it is reasonably possible that we may experience additional impairments, although we do not believe that our exposure to future charges would be material to our consolidated results of operations.

(c) The carrying value of our investment in Chaparral is in excess of our underlying equity in net assets by approximately $43 million as of December 31, 2009. This excess is attributed to the natural gas and oil reserves held by Chaparral and is being amortized over the estimated life of these reserves based on a unit of production rate.

(d) Our investment in Gastar had an associated cost basis of $89 million as of December 31, 2009 and 2008.

The table below presents summarized financial information for our significant equity method investments, including Chaparral, Frac-Tech, Ventura, Mountain Drilling and DHS. The investee financial information reflects the most current financial information available to investors and includes lags in financial reporting of up to one quarter.

	December 31,		
	2009	2008	2007
	($ in millions)		
Current assets	$ 393	$ 411	$ 274
Noncurrent assets	$ 2,078	$ 2,490	$ 2,185
Current liabilities	$ 670	$ 429	$ 312
Noncurrent liabilities	$ 1,339	$ 1,883	$ 1,673
Gross revenue	$ 876	$ 1,523	$ 972
Operating expense	$ 1,106	$ 1,261	$ 739
Net income	$ (289)	$ 105	$ 67

15. Fair Value Measurements

Effective January 1, 2008, we adopted accounting standards for fair value measurements for our financial assets and liabilities measured on a recurring basis. Our nonfinancial assets and liabilities became subject to the standards effective January 1, 2009. This guidance establishes a framework for measuring fair value of assets and liabilities and expands disclosures about fair value measurements for financial instruments reported at fair value on the consolidated balance sheet.

Under the guidance fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the financial asset or liability and have the lowest priority. Chesapeake uses appropriate valuation techniques based on available inputs, including counterparty quotes, to measure the fair values of its assets and liabilities. Counterparty quotes are generally assessed as a Level 3 input.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2009:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
Financial Assets (Liabilities):				
Cash equivalents	$ 307	$ —	$ —	$ 307
Derivatives, net	$ —	$ 692	$ (755)	$ (63)
Investments	$ 32	$ —	$ —	$ 32
Other long-term assets	$ 34	$ —	$ —	$ 34
Long-term debt	$ —	$ —	$ (1,398)	$ (1,398)
Other long-term liabilities	$ (34)	$ —	$ —	$ (34)

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Level 1 Fair Value Measurements

Cash Equivalents. The fair value of cash equivalents is based on quoted market prices.

Investments. The fair value of Chesapeake's investment in Gastar Exploration Ltd. common stock is based on a quoted market price.

Other Long-Term Assets and Liabilities. The fair value of other long-term assets and liabilities, consisting of obligations under our Deferred Compensation Plan, is based on quoted market prices.

Level 2 Fair Value Measurements

Derivatives. The fair values of our natural gas, oil and diesel swaps are measured internally using established index prices and other sources. These values are based upon, among other things, futures prices and time to maturity. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives.

Level 3 Fair Value Measurements

Derivatives. The fair value of our derivative instruments, excluding natural gas, oil and diesel swaps, have been established utilizing established index prices, volatility curves, discount factors and options pricing models. These estimates are compared to our counterparty values for reasonableness.

Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives.

Debt. The fair value of certain of our long-term debt is based on face value of the debt along with the value of the related interest rate swaps. The interest rate swap values are based on estimates provided by our respective counterparties and reviewed internally for reasonableness using future interest rate curves and time to maturity.

A summary of the changes in Chesapeake's assets (liabilities) classified as Level 3 measurements for the years ended December 31, 2009 and 2008, respectively, is presented below.

	Derivatives	Debt	Total
		($ in millions)	
Balance of Level 3 as of January 1, 2009	$ 292	$ (1,470)	$ (1,178)
Total gains (losses) (realized/unrealized):			
Included in earnings[(a)]	30	(128)	(98)
Included in other comprehensive income (loss)	123	—	123
Purchases, issuances and settlements	(1,200)	200[(b)]	(1,000)
Transfers in and out of Level 3	—	—	—
Balance of Level 3 as of December 31, 2009	$ (755)	$ (1,398)	$ (2,153)
Balance of Level 3 as of January 1, 2008	$ (340)	$ (2,404)	$ (2,744)
Total gains (losses) (realized/unrealized):			
Included in earnings[(a)]	744	184	928
Included in other comprehensive income (loss)	(82)	—	(82)
Purchases, issuances and settlements	(30)	750 (b)	720
Transfers in and out of Level 3	—	—	—
Balance of Level 3 as of December 31, 2008	$ 292	$ (1,470)	$ (1,178)

(a)

	Natural Gas and Oil Sales		Interest Expense	
	2009	2008	2009	2008
		($ in millions)		
Total gains (losses) related to derivatives included in earnings for the period	$ (108)	$ 876	$ 138	$ (132)
Change in unrealized gains (losses) relating to assets still held at reporting date	$ (988)	$ 815	$ 115	$ (126)

(b) Amount represents a reduction in debt not recorded at fair value as a result of interest rate swaps that were terminated in 2009 and 2008, respectively.

Fair Value of Other Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with accounting guidance for financial instruments. We have determined the estimated fair values by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values of financial instruments comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term debt and our convertible preferred stock primarily using quoted market prices. Our carrying amounts for such debt, excluding the impact of interest rate derivatives, at December 31, 2009 and 2008 were $12.2 billion and $13.0 billion, respectively, compared to approximate fair values of $12.8 billion and $10.5 billion, respectively. The carrying amounts for our convertible preferred stock as of December 31, 2009 and 2008 were $466 million and $505 million, respectively, compared to approximate fair values of $401 million and $294 million, respectively.

16. Asset Retirement Obligations

The components of the change in our asset retirement obligations are shown below.

	Years Ended December 31.	
	2009	2008
	($ in millions)	
Asset retirement obligations, beginning of period	$ 269	$ 236
Additions	14	21
Revisions	(3)	—
Settlements and disposals	(15)	(5)
Accretion expense	17	17
Asset retirement obligations, end of period	$ 282	$ 269

17. Major Customers and Segment Information

Sales to individual customers constituting 10% or more of total revenues (before the effects of hedging) were as follows:

Year Ended December 31,	Customer	Amount	Percent of Total Revenues
		($ in millions)	
2009	EDF Trading North America LLC	$ 571	10%
2008	Eagle Energy Partners I, L.P.	$ 1,283	12%
2007	Eagle Energy Partners I, L.P.	$ 1,072	15%

In September 2003, Chesapeake invested in Eagle Energy Partners I, L.P. and received a 25% limited partnership interest. Through additional investments, Chesapeake increased its limited partner ownership interest to approximately 33% as of December 31, 2006. In 2007, we sold our 33% limited partnership interest for proceeds of $124 million and a gain of $83 million.

In accordance with accounting guidance for disclosures about segments of an enterprise and related information, we have two reportable operating segments. Our exploration and production operational segment and natural gas and oil midstream segment are managed separately because of the nature of their products and services. The exploration and production segment is responsible for finding and producing natural gas and oil. The midstream segment is responsible for marketing, gathering and compression of natural gas and oil primarily from Chesapeake-operated wells. We also have drilling rig and trucking operations which are responsible for providing drilling rigs primarily used on Chesapeake-operated wells and trucking services utilized in the transportation of drilling rigs on both Chesapeake-operated wells and wells operated by third parties. Our drilling rig and trucking service operations are presented in "Other Operations" in the table below.

Management evaluates the performance of our segments based upon income (loss) before income taxes. Revenues from the midstream segment's sale of natural gas and oil related to Chesapeake's ownership interests are reflected as exploration and production revenues. Such amounts totaled $2.9 billion, $5.5 billion and $3.5 billion for 2009, 2008 and 2007, respectively. The following tables present selected financial information for Chesapeake's operating segments.

	Exploration and Production	Midstream	Other Operations	Inter-Company Eliminations	Consolidated Total
			($ in millions)		
For the Year Ended December 31, 2009:					
Revenues	$ 5,049	$ 5,341	$ 414	$ (3,102)	$ 7,702
Intersegment revenues	—	(2,878)	(224)	3,102	—
Total Revenues	5,049	2,463	190	—	7,702
Depreciation, depletion and amortization	1,556	44	50	(35)	1,615
Other income (expense)	(30)	3	1	(2)	(28)
Interest expense	(113)	(1)	—	1	(113)
Impairment of natural gas and oil properties and other assets	11,013	90	27	—	11,130
Impairment of investments	(162)	—	—	—	(162)
Loss on sale of other property and equipment	—	38	—	—	38
Loss on exchanges or repurchases of Chesapeake debt	(40)	—	—	—	(40)
INCOME (LOSS) BEFORE INCOME TAXES	$ (9,173)	$ (48)	$ (70)	$ 3	$ (9,288)
TOTAL ASSETS	$ 25,637	$ 4,323	$ 660	$ (706)	$ 29,914
NET CAPITAL EXPENDITURES	$ 4,837	$ 966	$ 290	$ —	$ 6,093
For the Year Ended December 31, 2008:					
Revenues	$ 7,858	$ 9,126	$ 631	$ (5,986)	$ 11,629
Intersegment revenues	—	(5,528)	(458)	5,986	—
Total Revenues	7,858	3,598	173	—	11,629
Depreciation, depletion and amortization	2,108	28	35	(27)	2,144
Other income (expense)	(11)	6	—	(6)	(11)
Interest expense	(271)	(2)	—	2	(271)
Impairment of natural gas and oil properties and other assets	2,800	30	—	—	2,830
Impairment of investments	(180)	—	—	—	(180)
Loss on exchanges or repurchases of Chesapeake debt	(4)	—	—	—	(4)
INCOME BEFORE INCOME TAXES	$ 968	$ 28	$ 82	$ (87)	$ 991
TOTAL ASSETS	$ 35,415	$ 3,416	$ 465	$ (703)	$ 38,593
NET CAPITAL EXPENDITURES	$ 7,658	$ 1,765	$ 229	$ —	$ 9,652
For the Year Ended December 31, 2007:					
Revenues	$ 5,624	$ 5,508	$ 493	$ (3,825)	$ 7,800
Intersegment revenues	—	(3,468)	(357)	3,825	—
Total Revenues	5,624	2,040	136	—	7,800
Depreciation, depletion and amortization	1,953	25	26	(16)	1,988
Other income (expense)	14	1	—	—	15
Interest expense	(401)	—	—	—	(401)
Gain on sale of investments	83	—	—	—	83
INCOME BEFORE INCOME TAXES	$ 2,293	$ 41	$ 135	$ (122)	$ 2,347
TOTAL ASSETS	$ 29,584	$ 1,759	$ 250	$ (829)	$ 30,764
NET CAPITAL EXPENDITURES	$ 7,977	$ 534	$ (163)	$ —	$ 8,348

18. Condensed Consolidating Financial Information

Chesapeake Energy Corporation is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. As of December 31, 2007, our obligations under our outstanding senior notes and contingent convertible notes listed in Note 3 were fully and unconditionally guaranteed, jointly and severally, by all of our wholly-owned subsidiaries, other than minor subsidiaries, on a senior unsecured basis. Since October 2008, following the restructuring of our non-Appalachian midstream operations, as described in Note 3, certain of our wholly-owned subsidiaries having significant assets and operations have not guaranteed our outstanding notes. Our midstream subsidiaries are subject to covenants in our midstream revolving credit facilities referred to in Note 3 that restrict them from paying dividends or distributions or making loans to Chesapeake.

Set forth below are condensed consolidating financial statements for Chesapeake Energy Corporation (the "parent") on a stand-alone, unconsolidated basis, and its combined guarantor and combined non-guarantor subsidiaries as of and for the years ended December 31, 2009 and 2008. We have not provided comparative financial statements for 2007 because the non-guarantor subsidiaries as of December 31, 2007 were minor subsidiaries individually or in the aggregate. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had the subsidiaries operated as independent entities.

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2009
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 293	$ 14	$ —	$ 307
Other	27	2,031	166	(85)	2,139
Total Current Assets	27	2,324	180	(85)	2,446
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full-cost accounting	—	20,781	11	—	20,792
Other property and equipment, net	—	2,903	3,015	—	5,918
Total Property and Equipment	—	23,684	3,026	—	26,710
Other assets	197	540	21	—	758
Investments in subsidiaries and intercompany advance	3,029	222	—	(3,251)	—
TOTAL ASSETS	$ 3,253	$ 26,770	$ 3,227	$ (3,336)	$ 29,914
CURRENT LIABILITIES:					
Current liabilities	$ 277	$ 2,261	$ 235	$ (85)	$ 2,688
Intercompany payable (receivable) from parent	(19,388)	17,501	1,800	87	—
Total Current Liabilities	(19,111)	19,762	2,035	2	2,688
LONG-TERM LIABILITIES:					
Long-term debt, net	10,359	1,892	44	—	12,295
Deferred income tax liabilities	393	727	26	(87)	1,059
Other liabilities	168	1,360	3	—	1,531
Total Long-Term Liabilities	10,920	3,979	73	(87)	14,885
EQUITY:					
Chesapeake stockholders' equity	11,444	3,029	222	(3,251)	11,444
Noncontrolling interest	—	—	897	—	897
Total Equity	11,444	3,029	1,119	(3,251)	12,341
TOTAL LIABILITIES AND EQUITY	$ 3,253	$ 26,770	$ 3,227	$ (3,336)	$ 29,914

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2008
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 1,749	$ —	$ —	$ 1,749
Other	13	2,392	169	(31)	2,543
Total Current Assets	13	4,141	169	(31)	4,292
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full-cost accounting	—	28,474	4	—	28,478
Other property and equipment, net	—	2,481	2,349	—	4,830
Total Property and Equipment	—	30,955	2,353	—	33,308
Other assets	140	838	15	—	993
Investments in subsidiaries and intercompany advance	8,452	143	—	(8,595)	—
TOTAL ASSETS	$ 8,605	$ 36,077	$ 2,537	$ (8,626)	$ 38,593
CURRENT LIABILITIES:					
Current liabilities	$ 257	$ 3,324	$ 131	$ (91)	$ 3,621
Intercompany payable (receivable) from parent	(18,274)	16,636	1,578	60	—
Total Current Liabilities	(18,017)	19,960	1,709	(31)	3,621
LONG-TERM LIABILITIES:					
Long-term debt, net	9,241	3,474	460	—	13,175
Deferred income tax liabilities	438	3,543	219	—	4,200
Other liabilities	(74)	648	6	—	580
Total Long-Term Liabilities	9,605	7,665	685	—	17,955
EQUITY:					
Chesapeake stockholders' equity	17,017	8,452	143	(8,595)	17,017
Noncontrolling interest	—	—	—	—	—
Total Equity	17,017	8,452	143	(8,595)	17,017
TOTAL LIABILITIES AND EQUITY	$ 8,605	$ 36,077	$ 2,537	$ (8,626)	$ 38,593

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
For the Year Ended December 31, 2009:					
REVENUES:					
Natural gas and oil sales	$ —	$ 5,049	$ —	$ —	$ 5,049
Marketing, gathering and compression sales	—	2,181	510	(228)	2,463
Service operations revenue	—	190	—	—	190
Total Revenues	—	7,420	510	(228)	7,702
OPERATING COSTS:					
Production expenses	—	877	(1)	—	876
Production taxes	—	107	—	—	107
General and administrative expenses	—	318	31	—	349
Marketing, gathering and compression expenses	—	2,125	201	(10)	2,316
Service operations expense	—	182	—	—	182
Natural gas and oil depreciation, depletion and amortization	—	1,371	—	—	1,371
Depreciation and amortization of other assets	—	149	95	—	244
Impairment of natural gas and oil properties and other assets	—	11,040	90	—	11,130
Loss on sale of other property and equipment	—	—	38	—	38
Restructuring costs	—	34	—	—	34
Total Operating Costs	—	16,203	454	(10)	16,647
INCOME (LOSS) FROM OPERATIONS	—	(8,783)	56	(218)	(8,945)
OTHER INCOME (EXPENSE):					
Other income (expense)	685	(30)	2	(685)	(28)
Interest expense	(652)	(143)	(3)	685	(113)
Impairment of investments	—	(148)	(14)	—	(162)
Loss on exchanges or repurchases of Chesapeake debt	(40)	—	—	—	(40)
Equity in net earnings of subsidiary	(5,826)	(2)	—	5,828	—
Total Other Income (Expense)	(5,833)	(323)	(15)	5,828	(343)
INCOME (LOSS) BEFORE INCOME TAXES	(5,833)	(9,106)	41	5,610	(9,288)
INCOME TAX EXPENSE (BENEFIT)	(3)	(3,413)	15	(82)	(3,483)
NET INCOME (LOSS)	(5,830)	(5,693)	26	5,692	(5,805)
Net (income) loss attributable to noncontrolling interest	—	—	(25)	—	(25)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$(5,830)	$ (5,693)	$ 1	$ 5,692	$ (5,830)

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
For the Year Ended December 31, 2008:					
REVENUES:					
Natural gas and oil sales	$ —	$ 7,858	$ —	$ —	$ 7,858
Marketing, gathering and compression sales	—	3,420	333	(155)	3,598
Service operations revenue	—	173	—	—	173
Total Revenues	—	11,451	333	(155)	11,629
OPERATING COSTS:					
Production expenses	—	890	(1)	—	889
Production taxes	—	284	—	—	284
General and administrative expenses	—	364	13	—	377
Marketing, gathering and compression expenses	—	3,363	142	—	3,505
Service operations expense	—	143	—	—	143
Natural gas and oil depreciation, depletion and amortization	—	1,970	—	—	1,970
Depreciation and amortization of other assets	14	129	48	(17)	174
Impairment of natural gas and oil properties and other assets	—	2,800	30	—	2,830
Total Operating Costs	14	9,943	232	(17)	10,172
INCOME (LOSS) FROM OPERATIONS	(14)	1,508	101	(138)	1,457
OTHER INCOME (EXPENSE):					
Other income (expense)	558	(17)	6	(558)	(11)
Interest expense	(630)	(197)	(2)	558	(271)
Impairment of investments	—	(130)	(50)	—	(180)
Loss on exchanges or repurchases of Chesapeake debt	(4)	—	—	—	(4)
Equity in net earnings of subsidiary	659	(50)	—	(609)	—
Total Other Income (Expense)	583	(394)	(46)	(609)	(466)
INCOME (LOSS) BEFORE INCOME TAXES	569	1,114	55	(747)	991
INCOME TAX EXPENSE (BENEFIT)	(35)	455	21	(54)	387
NET INCOME (LOSS)	604	659	34	(693)	604
Net (income) loss attributable to noncontrolling interest	—	—	—	—	—
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ 604	$ 659	$ 34	$ (693)	$ 604

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
For the Year Ended December 31, 2009:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ —	$ 4,537	$ (181)	$ —	$ 4,356
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties	—	(5,834)	(7)	—	(5,841)
Proceeds from divestitures of natural gas and oil properties	—	1,926	—	—	1,926
Additions to other property and equipment	—	(884)	(799)	—	(1,683)
Other investing activities	—	80	56	—	136
Cash used in investing activities	—	(4,712)	(750)	—	(5,462)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facility borrowings	—	6,933	828	—	7,761
Payments on credit facility borrowings	—	(8,514)	(1,244)	—	(9,758)
Proceeds from issuance of senior notes, net of offering costs	1,346	—	—	—	1,346
Proceeds from sales of noncontrolling interest in midstream joint venture	—	—	588	—	588
Other financing activities	(276)	67	(64)	—	(273)
Intercompany advances, net	(1,070)	233	837	—	—
Cash provided by financing activities	—	(1,281)	945	—	(336)
Net increase (decrease) in cash and cash equivalents	—	(1,456)	14	—	(1,442)
Cash and cash equivalents, beginning of period	—	1,749	—	—	1,749
Cash and cash equivalents, end of period	$ —	$ 293	$ 14	$ —	$ 307

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
For the Year Ended December 31, 2008:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 156	$ 5,688	$ 206	$ (693)	$ 5,357
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties	—	(14,688)	(9)	—	(14,697)
Proceeds from divestitures of natural gas and oil properties	—	7,652	18	—	7,670
Additions to other property and equipment	—	(1,749)	(1,324)	—	(3,073)
Other investing activities	—	163	(28)	—	135
Cash used in investing activities	—	(8,622)	(1,343)	—	(9,965)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facility borrowings	—	12,831	460	—	13,291
Payments on credit facility borrowings	—	(11,307)	—	—	(11,307)
Proceeds from issuance of senior notes, net of offering costs	2,136	—	—	—	2,136
Proceeds from issuance of common stock, net of offering costs	2,598	—	—	—	2,598
Other financing activities	(514)	162	(10)	—	(362)
Intercompany advances, net	(4,376)	2,996	687	693	—
Cash provided by financing activities	(156)	4,682	1,137	693	6,356
Net increase (decrease) in cash and cash equivalents	—	1,748	—	—	1,748
Cash and cash equivalents, beginning of period	—	1	—	—	1
Cash and cash equivalents, end of period	$ —	$ 1,749	$ —	$ —	$ 1,749

19. Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 2009 and 2008 are as follows ($ in millions except per share data):

	Quarters Ended			
	March 31, 2009	June 30, 2009	September 30, 2009	December 31, 2009
Total revenues	$ 1,995	$ 1,673	$ 1,811	$ 2,222
Gross profit (loss)[(a)(b)]	(9,053)	424	397	(713)
Net income (loss) attributable to Chesapeake[(b)]	(5,740)	243	192	(524)
Net income (loss) available to common stockholders[(b)]	(5,746)	237	186	(530)
Net earnings (loss) per common share:				
Basic	$ (9.63)	$ 0.39	$ 0.30	$ (0.84)
Diluted	$ (9.63)	$ 0.39	$ 0.30	$ (0.84)

	Quarters Ended			
	March 31, 2008	June 30, 2008	September 30, 2008	December 31, 2008
Total revenues	$ 1,611	$ (455)	$ 7,491	$ 2,981
Gross profit[(a)]	(104)	(2,532)	5,478	(1,385)
Net income (loss) attributable to Chesapeake	(130)	(1,592)	3,322	(995)
Net income (loss) available to common stockholders	(142)	(1,643)	3,291	(1,001)
Net earnings per common share:				
Basic	$ (0.29)	$ (3.16)	$ 5.94	$ (1.74)
Diluted	$ (0.29)	$ (3.16)	$ 5.62	$ (1.74)

(a) Total revenue less operating costs.

(b) Includes a $9.6 billion and $1.4 billion ceiling test write-down on our natural gas and oil properties for the quarters ended March 31, 2009 and December 31, 2009, respectively.

20. Recently Issued Accounting Standards

In June 2009, the FASB issued amendments to the consolidation standard applicable to variable interest entities in response to concerns about the transparency of involvement with variable interest entities. The amended standard is effective for calendar year companies beginning on January 1, 2010. Beginning January 1, 2010, we will deconsolidate our joint venture with GIP and account for the investment in the joint venture under the equity method going forward. Adoption of this guidance will result in a cumulative effect adjustment for the difference in our equity in the joint venture at January 1, 2010, which was originally recorded at carryover basis, and the fair value of our equity at the formation of the joint venture based on the then fair value. This cumulative effect adjustment will create a basis difference between our equity investment balance and the underlying equity in the net assets of the joint venture. This difference will be accreted through earnings over the expected useful life of the underlying assets held by the joint venture.

In January 2010, the FASB updated its oil and gas estimation and disclosure requirements to align its requirements with the SEC's modernized oil and gas reporting rules, which are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. The update amends the definition of proved reserves to use the average of first-day-of-the-month prices during the 12 months preceding the end of the reporting period, adds definitions used in estimating and disclosing proved oil and natural gas quantities and expands the disclosures required for equity-method investments. The update must be applied prospectively as a change in accounting principle that is inseparable from a change in accounting estimate and is effective for entities with annual reporting periods ending on or after December 31, 2009. See Note 10 for disclosures regarding our natural gas and oil reserves. The company is not able to disclose the effects resulting from the implementation of these changes on the financial statements or on the amount of proved reserves and disclosed quantities because personnel and time constraints made it infeasible for the company to perform a second reserve estimation process under the prior standards.

21. Subsequent Events

On January 26, 2010, Chesapeake and Total E&P USA, Inc., a wholly-owned subsidiary of Total S.A. (NYSE: TOT, FP: FP) (Total), closed a $2.25 billion Barnett Shale joint venture transaction, whereby Total acquired a 25% interest in our upstream Barnett Shale assets. Total paid us approximately $800 million in cash at closing and will pay a further $1.45 billion over time by funding 60% of our share of future drilling and completion expenditures. We expect this drilling carry to be funded by year-end 2012.

On February 5, 2010, we sold certain Chesapeake-operated long-lived producing assets in East Texas and the Texas Gulf Coast in our sixth volumetric production payment (VPP) transaction for proceeds of $180 million, or $3.95 per mcfe of proved reserves. The assets in the VPP included proved reserves of approximately 45.5 bcfe and current net production of approximately 20 mmcfe per day.

On February 16, 2010, Chesapeake Midstream Partners, L.P. (the Partnership) filed a registration statement on Form S-1 with the SEC relating to a proposed underwritten initial public offering of common units, representing limited partnership interests in the Partnership. The Partnership was formed by Chesapeake and GIP, equal indirect owners of the general partner of the Partnership, to own, operate, develop and acquire midstream assets. Upon the closing of the offering, Chesapeake and GIP will contribute CMP's interests to the Partnership and the Partnership will continue CMP's business. It is expected that the Partnership will succeed to CMP's $500 million revolving credit facility, with certain amendments, and a portion of the proceeds of the offering will be used to repay the outstanding borrowings under the midstream joint venture revolving credit facility.

Schedule II

CHESAPEAKE ENERGY CORPORATION
VALUATION AND QUALIFYING ACCOUNTS
($ in millions)

Description	Balance at Beginning of Period	Additions: Charged To Expense	Additions: Charged To Other Accounts	Deductions	Balance at End of Period
December 31, 2009:					
Allowance for doubtful accounts	$ 12	$ 12	$ —	$ —	$ 24
Valuation allowance for deferred tax assets	$ —	$ —	$ —	$ —	$ —
December 31, 2008:					
Allowance for doubtful accounts	$ 8	$ 4	$ —	$ —	$ 12
Valuation allowance for deferred tax assets	$ —	$ —	$ —	$ —	$ —
December 31, 2007:					
Allowance for doubtful accounts	$ 6	$ 2	$ —	$ —	$ 8
Valuation allowance for deferred tax assets	$ —	$ —	$ —	$ —	$ —

ITEM 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

Not applicable.

ITEM 9A. ***Controls and Procedures***

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed by Chesapeake in reports filed or submitted by it under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. As of December 31, 2009, we carried out an evaluation, under the supervision and with the participation of Chesapeake management, including Chesapeake's Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of Chesapeake's disclosure controls and procedures pursuant to Securities Exchange Act Rule 13a-15(b). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective as of December 31, 2009, to ensure that information required to be disclosed by Chesapeake is accumulated and communicated to Chesapeake management, including Chesapeake's Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Controls

No changes in the company's internal control over financial reporting occurred during the quarter ended December 31, 2009 that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Management's annual report on internal control over financial reporting and the audit report on our internal control over financial reporting of our independent registered public accounting firm are included in Item 8 of this report.

ITEM 9B. ***Other Information***

Not applicable.

PART III

ITEM 10. *Directors, Executive Officers and Corporate Governance*

The information called for by this Item 10 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2010.

ITEM 11. *Executive Compensation*

The information called for by this Item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2010.

ITEM 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2010.

ITEM 13. *Certain Relationships and Related Transactions and Director Independence*

The information called for by this Item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2010.

ITEM 14. *Principal Accountant Fees and Services*

The information called for by this Item 14 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2010.

PART IV

ITEM 15. *Exhibits and Financial Statement Schedules*

(a) The following documents are filed as part of this report:

1. Financial Statements. Chesapeake's consolidated financial statements are included in Item 8 of this report. Reference is made to the accompanying Index to Financial Statements.

2. Financial Statement Schedules. Schedule II is included in Item 8 of this report with our consolidated financial statements. No other financial statement schedules are applicable or required.

3. Exhibits. The following exhibits are filed herewith pursuant to the requirements of Item 601 of Regulation S-K:

		Incorporated by Reference				
Exhibit Number	**Exhibit Description**	**Form**	**SEC File Number**	**Exhibit**	**Filing Date**	**Filed Herewith**
3.1.1	Chesapeake's Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	08/10/2009	
3.1.2	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B), as amended.	10-Q	001-13726	3.1.4	11/10/2008	
3.1.3	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005), as amended.	S-8	333-151762	4.1.6	06/18/2008	
3.1.4	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.6	08/11/2008	
3.2	Chesapeake's Amended and Restated Bylaws.	8-K	001-13726	3.1	11/17/2008	
4.1*	Indenture dated as of May 27, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.5% senior notes due 2014.	S-4	333-116555	4.1	06/17/2004	
4.2*	Indenture dated as of August 2, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.0% senior notes due 2014.	S-4	333-118378	4.1	08/20/2004	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
4.4*	Seventh Amended and Restated Credit Agreement, dated as of November 2, 2007, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., as Co-Borrowers, Union Bank of California, N.A., as Administrative Agent, The Royal Bank of Scotland, as Syndication Agent, and Bank of America, N.A., SunTrust Bank and BNP Paribas, as Co-Documentation Agents, and the several lenders from time to time parties thereto.	8-K	001-13726	4.1	11/08/2007	
4.4.1*	Consent & Waiver Letter dated December 12, 2007 with respect to the Seventh Amended and Restated Credit Agreement, dated as of November 2, 2007, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., as Co-Borrowers, Union Bank of California, N.A., as Administrative Agent, The Royal Bank of Scotland, as Syndication Agent, and Bank of America, N.A., SunTrust Bank and BNP Paribas, as Co-Documentation Agents, and the several lenders from time to time parties thereto.	10-K	001-13726	4.4.1	02/29/2008	
4.4.2	Fourth Amendment dated as of March 31, 2009 to Seventh Amended and Restated Credit Agreement, dated as of November 2, 2007, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., as Co-Borrowers, Union Bank of California, N.A., as Administrative Agent, The Royal Bank of Scotland, as Syndication Agent, and Bank of America, N.A., SunTrust Bank and BNP Paribas, as Co-Documentation Agents, and the several lenders from time to time parties thereto.	10-Q	001-13726	4.4.1	05/11/2009	
4.5*	Indenture dated as of March 5, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.5% Senior Notes due 2013.	S-4	333-104396	4.7	04/08/2003	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
4.6*	Indenture dated as of November 26, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.875% senior notes due 2016.	S-4/A	333-110668	4.2	12/01/2003	
4.7*	Indenture dated as of December 8, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A. Trust Company, N.A., as Trustee, with respect to 6.375% senior notes due 2015.	8-K	001-13726	4.1	12/14/2004	
4.8*	Indenture dated as of April 19, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.625% senior notes due 2016.	10-Q	001-13726	4.12	05/10/2005	
4.9*	Indenture dated as of June 20, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.25% senior notes due 2018.	10-Q	001-13726	4.1	08/08/2005	
4.10*	Indenture dated as of August 16, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.50% senior notes due 2017.	8-K	001-13726	4.1	08/16/2005	
4.11*	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.875% senior notes due 2020.	8-K	001-13726	4.1.1	11/08/2005	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
4.12*	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.75% contingent convertible senior notes due 2035.	8-K	001-13726	4.1.2	11/08/2005	
4.13*	Indenture dated as of June 30, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.625% senior notes due 2013.	8-K	001-13726	4.1	06/30/2006	
4.14*	Indenture dated as of December 6, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, The Bank of New York Mellon Trust Company, N.A., as Trustee, AIB/BNY Fund Management (Ireland) Limited, as Irish Paying Agent and Transfer Agent, and The Bank of New York, London Branch, as Registrar, Transfer Agent and Paying Agent, with respect to 6.25% senior notes due 2017.	8-K	001-13726	4.1	12/06/2006	
4.15*	Indenture dated as of May 15, 2007 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.50% contingent convertible senior notes due 2037.	8-K	001-13726	4.1	05/15/2007	
4.16*	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.25% senior notes due 2018.	8-K	001-13726	4.1	05/29/2008	
4.17*	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.25% contingent convertible senior notes due 2038.	8-K	001-13726	4.2	05/29/2008	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
4.18	Indenture dated as of February 2, 2009 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 9.50% contingent convertible senior notes due 2015.	8-K	001-13726	4.1	02/03/2009	
4.18.1	First Supplemental Indenture dated as of February 10, 2009 to Indenture dated as of February 2, 2009.	8-K	001-13726	4.2	02/17/2009	
4.18.2	Second Supplemental Indenture dated as of March 31, 2009 to Indenture dated of February 2, 2009.	10-Q	001-13726	4.18.2	05/11/2009	
10.1.1†	Chesapeake's 2003 Stock Incentive Plan, as amended.	10-Q	001-13726	10.1.1	11/09/2009	
10.1.2†	Chesapeake's 1992 Nonstatutory Stock Option Plan, as amended.	10-Q	001-13726	10.1.2	02/14/1997	
10.1.3†	Chesapeake's 1994 Stock Option Plan, as amended.	10-Q	001-13726	10.1.3	11/07/2006	
10.1.4†	Chesapeake's 1996 Stock Option Plan, as amended.	10-Q	001-13726	10.1.4	11/07/2006	
10.1.5†	Chesapeake's 1999 Stock Option Plan, as amended.	10-Q	001-13726	10.1.5	08/11/2008	
10.1.6†	Chesapeake's 2000 Employee Stock Option Plan, as amended.	10-Q	001-13726	10.1.6	08/11/2008	
10.1.7†	Chesapeake's 2001 Stock Option Plan, as amended.	10-Q	001-13726	10.1.8	08/11/2008	
10.1.8†	Chesapeake's 2001 Nonqualified Stock Option Plan, as amended.	10-Q	001-13726	10.1.10	08/11/2008	
10.1.9†	Chesapeake's 2002 Stock Option Plan, as amended.	10-Q	001-13726	10.1.11	08/11/2008	
10.1.10†	Chesapeake's 2002 Non-Employee Director Stock Option Plan.	10-Q	001-13726	10.1.12	08/11/2008	
10.1.11†	Chesapeake's 2002 Nonqualified Stock Option Plan, as amended.	10-Q	001-13726	10.1.13	08/11/2008	
10.1.12†	Chesapeake's 2003 Stock Award Plan for Non-Employee Directors, as amended.	10-K	001-13726	10.1.14	02/29/2008	
10.1.13†	Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan.	10-K	001-13726	10.1.16	02/29/2008	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
10.1.14†	Chesapeake's Amended and Restated Long Term Incentive Plan.	10-Q	001-13726	10.1.14	11/09/2009	
10.1.14.1†	Form of Restricted Stock Award Agreement for the Long Term Incentive Plan.	8-K	001-13726	10.1.18.2	06/16/2005	
10.1.14.2†	Form of Non-Employee Director Restricted Stock Award Agreement for the Long Term `Incentive Plan.	8-K	001-13726	10.1.18.3	06/16/2005	
10.1.15†	Founder Well Participation Program.	DEF-14A	001-13726	B	04/29/2005	
10.2.1†	Employment Agreement dated as of March 1, 2009, between Aubrey K. McClendon and Chesapeake Energy Corporation.	10-Q	001-13726	10.2.1	05/11/2009	
10.2.2†	Employment Agreement dated as of October 1, 2009 between Marcus C. Rowland and Chesapeake Energy Corporation.	8-K	001-13726	10.2.2	10/01/2009	
10.2.3†	Employment Agreement dated as of October 1, 2009 between Steven C. Dixon and Chesapeake Energy Corporation.	8-K	001-13726	10.2.3	10/01/2009	
10.2.4†	Employment Agreement dated as of October 1, 2009 between J. Mark Lester and Chesapeake Energy Corporation.	8-K	001-13726	10.2.4	10/01/2009	
10.2.5†	Employment Agreement dated as of October 1, 2009 between Douglas J. Jacobson and Chesapeake Energy Corporation.	8-K	001-13726	10.2.5	10/01/2009	
10.2.6†	Form of Employment Agreement between Senior Vice President and Chesapeake Energy Corporation.	10-Q	001-13726	10.2	11/09/2009	
10.3†	Form of Indemnity Agreement for officers and directors of Chesapeake and its subsidiaries.	10-K	001-13726	10.3	02/29/2008	
10.4†	Consulting Agreement dated as of February 1, 2010 between J. Mark Lester and Chesapeake Energy Corporation.					X
12	Ratios of Earnings to Fixed Charges and Preferred Dividends.					X

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith
		Form	SEC File Number	Exhibit	Filing Date	
21	Subsidiaries of Chesapeake.					X
23.1	Consent of PricewaterhouseCoopers, LLP.					X
23.2	Consent of Netherland, Sewell & Associates, Inc.					X
23.3	Consent of Data & Consulting Services, Division of Schlumberger Technology Corporation.					X
23.4	Consent of Lee Keeling and Associates, Inc.					X
23.5	Consent of Ryder Scott Company, L.P.					X
31.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
32.2	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
99.1	Report of Netherland, Sewell & Associates, Inc.					X
99.2	Report of Data & Consulting Services, Division of Schlumberger Technology Corporation.					X
99.3	Report of Lee Keeling and Associates, Inc.					X
99.4	Report of Ryder Scott Company, L.P.					X
101.INS#	XBRL Instance Document.					X

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith
		Form	SEC File Number	Exhibit	Filing Date	
101.SCH#	XBRL Taxonomy Extension Schema Document.					X
101.CAL#	XBRL Taxonomy Extension Calculation Linkbase Document.					X
101.DEF#	XBRL Taxonomy Extension Definition Linkbase Document.					X
101.LAB#	XBRL Taxonomy Extension Labels Linkbase Document.					X
101.PRE#	XBRL Taxonomy Extension Presentation Linkbase Document.					X

* Chesapeake agrees to furnish a copy of any of its unfiled long-term debt instruments to the Securities and Exchange Commission upon request.

† Management contract or compensatory plan or arrangement.

\# Furnished herewith.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CHESAPEAKE ENERGY CORPORATION

Date: March 1, 2010

By /s/ AUBREY K. MCCLENDON

Aubrey K. McClendon
Chairman of the Board and
Chief Executive Officer

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints Aubrey K. McClendon and Marcus C. Rowland, and each of them, either one of whom may act without joinder of the other, his true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any or all amendments to this Annual Report on Form 10-K, and to file the same, with all, exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each, and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, and each of them, or the substitute or substitutes of any or all of them, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Capacity	Date
/s/ AUBREY K. MCCLENDON **Aubrey K. McClendon**	Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)	March 1, 2010
/s/ MARCUS C. ROWLAND **Marcus C. Rowland**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 1, 2010
/s/ MICHAEL A. JOHNSON **Michael A. Johnson**	Senior Vice President – Accounting, Controller and Chief Accounting Officer (Principal Accounting Officer)	March 1, 2010
/s/ RICHARD K. DAVIDSON **Richard K. Davidson**	Director	March 1, 2010
/s/ V. BURNS HARGIS **V. Burns Hargis**	Director	March 1, 2010
/s/ FRANK KEATING **Frank Keating**	Director	March 1, 2010
/s/ CHARLES T. MAXWELL **Charles T. Maxwell**	Director	March 1, 2010
/s/ MERRILL A. MILLER, JR. **Merrill A. Miller, Jr.**	Director	March 1, 2010
/s/ DON NICKLES **Don Nickles**	Director	March 1, 2010
/s/ FREDERICK B. WHITTEMORE **Frederick B. Whittemore**	Director	March 1, 2010

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