Table of Contents

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

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of report (Date of earliest event reported):
May 6, 2011

RANGE RESOURCES CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	001-12209	34-1312571
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

100 Throckmorton, Suite 1200 Ft. Worth, Texas	76102
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (817) 870-2601

(Former name or former address, if changed since last report): Not applicable

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligations of the registrant under any of the following provisions (see General Instruction A.2. below):

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

TABLE OF CONTENTS

[Table of Contents](#)

Index to Financial Statements

ITEM 8.01. OTHER EVENTS

On April 29, 2011, we completed our previously announced sale of substantially all of our oil and gas leases, wells and related assets in the Barnett Shale play located in North Central Texas (Dallas, Denton, Ellis, Hill, Hood, Johnson, Parker, Tarrant and Wise Counties) for cash proceeds of $900.0 million including the assumption of certain derivative contracts and before normal closing adjustments. We reported our operations with respect to these properties as discontinued operations in our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2011.

This Current Report on Form 8-K was prepared to provide revised financial information that presents these properties as discontinued operations for all periods presented in our Annual Report on Form 10-K for the year ended December 31, 2010, filed on March 1, 2011 ("2010 Form 10-K"). It should be noted that our net income (loss) was not impacted by the reclassification of our operations with respect to these properties to discontinued operations.

Please note, we have not otherwise updated our financial information or business discussion for activities or events occurring after the date this information was presented in our 2010 Form 10-K. You should read our Quarterly Report on Form 10-Q for the period ended March 31, 2011 and our Current Reports on Form 8-K filed or furnished after the date of our 2010 Form 10-K and any amendments thereto, for updated information.

This filing includes updated information for the following items included in our 2010 Form 10-K:

ITEM 6. SELECTED FINANCIAL DATA

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONIDTION AND RESULTS OF OPERATIONS

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Unaffected items of our 2010 Form 10-K have not been repeated in this Current Report on Form 8-K.

Cross-references that are included in the above items and that refer to information included on page numbers that are preceded by an "F" refer to the corresponding page included in this filing. Other cross-references are to pages in our 2010 Form 10-K.

ITEM 6. SELECTED FINANCIAL DATA

The following table shows selected financial information for the five years ended December 31, 2010. Significant producing property acquisitions and dispositions may affect the comparability of year-to-year financial and operating data. In the first half of 2010, we sold our Ohio properties for proceeds of $323.0 million. The financial and statistical data contained in the following discussion reflect our Barnett Shale operations, which were sold in April 2011 and our Gulf of Mexico operations, which were sold in 2007, as discontinued operations. This information should be read in conjunction with Item 7 of this report “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” and our consolidated financial statements and related notes included elsewhere in this report.

	Year Ended December 31,				
	2010	2009	2008	2007	2006
	(in thousands, except per share data)				
Balance Sheet Data:					
Current assets [a]	$ 1,100,442	$ 175,280	$ 404,311	$ 261,814	$ 388,925
Current liabilities [b]	430,562	314,104	353,514	305,433	251,685
Natural gas and oil properties, net	4,084,013	3,551,635	3,466,028	2,665,324	2,076,637
Total assets	5,498,586	5,395,881	5,551,879	4,005,293	3,183,382
Bank debt	274,000	324,000	693,000	303,500	452,000
Subordinated notes	1,686,536	1,383,833	1,097,562	847,158	596,782
Stockholders’ equity [c]	2,223,761	2,378,589	2,451,342	1,717,736	1,258,089
Weighted average diluted shares outstanding	158,428	158,778	155,943	149,911	138,711
Cash dividends declared per common share	0.16	0.16	0.16	0.13	0.09
Statement of Cash Flow Data:					
Net cash provided from operating activities	$ 513,322	$ 591,675	$ 824,767	$ 642,291	$ 479,875
Net cash used in investing activities	(798,858)	(473,807)	(1,731,777)	(1,020,572)	(911,659)
Net cash provided from (used in) financing activities	287,617	(117,854)	903,745	379,917	429,416

(a) 2010 includes $876.3 million assets of discontinued operations compared to $43.5 million in 2009. 2009 includes $8.1 million deferred tax assets compared to $26.9 million in 2007. 2010 includes $123.3 million of unrealized derivative assets compared to $21.5 million in 2009, $221.4 million in 2008, $53.0 million in 2007 and $93.6 million in 2006.

(b) 2010 includes $352,000 of unrealized derivative liabilities compared to $14.5 million in 2009, $10,000 in 2008, $30.5 million in 2007 and $4.6 million in 2006. 2010 includes an $11.8 million deferred tax liability compared to $33.0 million in 2008.

(c) Stockholders’ equity includes other comprehensive income (loss) of $67.5 million in 2010 compared to $6.4 million in 2009, $77.5 million in 2008, ($26.8 million) in 2007 and $36.5 million in 2006.

Table of Contents

Statement of Operations Data:

	Year Ended December 31, 2010	2009	2008	2007	2006
	(in thousands, except per share data)				
Revenues and other income:					
Natural gas, NGL and oil sales	$ 760,453	$ 714,564	$ 989,307	$ 743,166	$ 572,268
Transportation and gathering	1,033	486	4,577	2,290	2,422
Derivative fair value income (loss)	51,634	66,446	71,861	(9,493)	142,395
Gain on the sale of assets	76,642	10,413	20,166	20	21
Other	(963)	(9,928)	1,509	5,028	835
Total revenues and other income	888,799	781,981	1,087,420	741,011	717,941
Costs and expenses:					
Direct operating	96,274	98,251	112,983	95,713	77,129
Production and ad valorem taxes	26,107	25,536	49,371	39,237	35,697
Exploration	60,506	44,276	56,956	43,437	39,662
Abandonment and impairment of unproved properties	49,738	36,935	15,292	7,282	1,427
General and administrative	140,571	115,319	92,308	69,670	49,886
Termination costs	8,452	2,479	—	—	—
Deferred compensation plan	(10,216)	31,073	(24,689)	35,438	(233)
Interest expense	90,665	75,261	63,963	57,099	41,022
Loss on early extinguishment of debt	5,351	—	—	—	—
Depletion, depreciation and amortization	275,238	267,148	210,963	174,574	140,182
Impairment of proved properties	6,505	930	—	—	—
Total costs and expenses	749,191	697,208	577,147	522,450	384,772
Income from continuing operations before income taxes	139,608	84,773	510,273	218,561	333,169
Income tax (benefit) expense					
Current	(836)	(636)	4,268	320	1,912
Deferred	51,746	46,429	176,912	84,688	125,904
	50,910	45,793	181,180	85,008	127,816
Income from continuing operations	88,698	38,980	329,093	133,553	205,353
Discontinued operations, net of taxes	(327,954)	(92,850)	21,947	83,715	(44,723)
Net (loss) income	$ (239,256)	$ (53,870)	$ 351,040	$ 217,268	$ 160,630
(Loss) income per common share:					
Basic— income from continuing operations	$ 0.56	$ 0.25	$ 2.18	$ 0.93	$ 1.53
—discontinued operations	(2.09)	(0.60)	0.14	0.58	(0.33)
—net (loss) income	$ (1.53)	$ (0.35)	$ 2.32	$ 1.51	$ 1.20
Diluted— income from continuing operations	$ 0.55	$ 0.24	$ 2.11	$ 0.89	$ 1.48
—discontinued operations	(2.07)	(0.58)	0.14	0.56	(0.32)
—net (loss) income	$ (1.52)	$ (0.34)	$ 2.25	$ 1.45	$ 1.16

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. Certain sections of Management's Discussion and Analysis of Financial Condition and Results of Operations include forward-looking statements concerning trends or events potentially affecting our business. These statements typically contain words such as "anticipates," "believes," "expects," "targets," "plans," "projects," "could," "may," "should," "would" or similar words indicating that future outcomes are uncertain. In accordance with "safe harbor" provisions for the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in the forward-looking statements. Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the information under Item 1.Business, Item 1A. Risk Factors, Item 6.Selected Financial Data and Item 8. Financial Statements Data in this report. Unless otherwise indicated, the information included herein relates to our continuing operations.

Overview of Our Business

We are an independent natural gas and oil company engaged in the exploration, development and acquisition of primarily natural gas and oil properties, mostly in the Appalachian and Southwestern regions of the United States. We operate in one segment and have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis.

Our objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. Our strategy to achieve our objective is to increase reserves and production through internally generated drilling projects occasionally coupled with complementary acquisitions. Our revenues, profitability and future growth depend substantially on prevailing prices for natural gas and oil and on our ability to economically find, develop, acquire and produce natural gas and oil reserves. We use the successful efforts method of accounting for our natural gas, natural gas liquids and oil activities. Our corporate headquarters is located in Fort Worth, Texas.

Industry Environment

We operate entirely within the United States. As traditional basins in the U.S. have matured, exploration and production has shifted to unconventional "resource" plays, typically shale reservoirs that historically were not thought to be productive for natural gas and oil. These plays cover large areas, provide multi-year inventories of drilling opportunities and, with modern oil and gas technology, have sustainable lower risk growth profiles. The economics of these plays have been enhanced by continued advancements in drilling and completion technologies. These advancements make these plays more resilient to lower commodity prices while increasing the domestic supply of natural gas and, with increased supply, an expected reduction in the volatility of natural gas prices. Examples of such technological advancements include advanced 3-D seismic processing, hydraulic reservoir fracture stimulation using almost one hundred percent sand and water, advances in well logging and analysis, horizontal drilling and completion technologies and automated remote well monitoring and control devices.

Natural gas and oil are commodities. The price that we receive for the natural gas we produce is largely a function of market supply and demand in the United States. Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of natural gas can result in price volatility. Factors impacting the future supply balance are the growth in domestic gas production and the increase in the United States' LNG import capacity. Gas supplies in the United States have increased as a result of recent expansion in domestic unconventional gas production. Existing LNG import capacity may result in lower natural gas prices. Crude oil prices are generally determined by global supply and demand.

The reduced liquidity provided by the worldwide financial markets and other factors that resulted in an economic slowdown in the United States and other industrialized countries in 2008 also resulted in reductions in worldwide energy demand. At the same time, North American gas supply increased as a result of the expansion in domestic unconventional natural gas production. The combination of lower demand due to the economic slowdown and higher North American gas supply resulted in declines in natural gas prices from their highs in mid-2008. Prices in 2010 and 2009 were more stable than in 2008. However, natural gas prices continue to be under pressure as a result of lower domestic demand and concerns over excess supply of natural gas due to high productivity of several emerging plays in the United States.

Natural gas and oil gas prices affect:

- the amount of cash flow available to us for capital expenditures;
- our ability to borrow and raise additional capital;
- the quantity of natural gas and oil that we can economically produce;
- revenues and profitability; and
- the accounting for our natural gas and oil activities.

Any continued or extended decline in natural gas and oil prices could have a material adverse effect on our financial position, results of operations, cash flows and access to capital.

Capital Budget for 2011

Our capital budget for 2011 is currently set at $1.38 billion, excluding acquisitions. The 2011 capital budget is more than the 2010 capital spending levels with higher expected operating cash flows resulting from higher production. For 2011, we expect our operating cash flow and proceeds from asset sales to fund our capital budget. As has been our historical practice, we will periodically review our capital expenditures throughout the year and adjust the budget based on commodity prices, drilling success and other factors.

Source of Our Revenues

We derive our revenues from the sale of natural gas, natural gas liquids ("NGLs") and oil that is produced from our properties. Revenues are a function of the volume produced, the prevailing market price at the time of sale, quality, Btu content and transportation costs to market. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we use derivative instruments to hedge future sales prices on a substantial, but varying, portion of our natural gas and oil production. The use of derivative instruments has in the past and may in the future, prevent us from realizing the full benefit of upward price movements but also protects us from declining price movements. Our average realized price calculations (including all derivative settlements) include the effects of the settlement of all derivative contracts regardless of the accounting treatment. Discontinued operations include our Barnett Shale properties which were sold in April 2011. Unless indicated otherwise, the information included herein relates to our continuing operations.

Principal Components of Our Cost Structure

- *Direct Operating Expenses.* These are day-to-day costs incurred to bring hydrocarbons out of the ground and to the market together with the daily costs incurred to maintain our producing properties. Such costs also include maintenance, repairs and workovers expenses related to our natural gas and oil properties. These costs are expected to remain a function of supply and demand. Direct operating expenses also include stock-based compensation expense (non-cash) associated with grants of stock appreciation rights (SARs) and the amortization of restricted stock grants as part of employee compensation.
- *Production and Ad Valorem Taxes.* Production taxes are paid on produced natural gas and oil based on a percentage of market prices (not hedged prices) or at fixed rates established by federal, state or local taxing authorities. Ad valorem taxes are generally based on reserve values at the end of each year.
- *Exploration Expenses.* These are geological and geophysical costs, including payroll and benefits for the geological and geophysical staff, seismic costs, delay rentals and the costs of unsuccessful exploratory dry holes. Exploration expense also includes stock-based compensation expense (non-cash) associated with grants of SARs and the amortization of restricted stock grants as part of employee compensation.
- *Abandonment and impairment of unproved properties.* This category includes unproved property impairment and costs associated with lease expirations.
- *General and Administrative Expenses.* These costs include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other professional fees and legal compliance. Included in this category are overhead expense reimbursements we receive from working interest owners of properties, for which we serve as the operator. These reimbursements are received during both the drilling and operational stages of a property's life. General and administrative expense also includes stock-based compensation expense (non-cash) associated with grants of SARs and the amortization of restricted stock grants as part of employee compensation.
- *Deferred Compensation Plan Expense.* These costs relate to the increase or decrease in the value of the liability associated with our deferred compensation plan. Our deferred compensation plan gives directors, officers and key employees the ability to defer all or a portion of their salaries and bonuses and invest in Range common stock or make other investments at the individual's discretion.

- *Interest.* We typically finance a portion of our working capital requirements and acquisitions with borrowings under our bank credit facility and with longer-term debt securities. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We will likely continue to incur interest expense as we continue to grow.
- *Depreciation, Depletion and Amortization Expense.* This includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop natural gas, NGLs and oil. As a successful efforts company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and apportion these costs to each unit of production through depreciation, depletion and amortization expense. This expense also includes the systematic, monthly accretion of the future abandonment costs of tangible assets such as wells, service assets, pipelines, and other facilities.
- *Income Taxes.* We are subject to state and federal income taxes but are currently not in a cash taxpaying position for federal income taxes, primarily due to the current deductibility of intangible drilling costs ("IDC"). We do pay some state income taxes where our IDC deductions do not exceed our taxable income or where state income taxes are determined on a basis other than federal taxable income. Currently, substantially all of our federal taxes are deferred and we anticipate using all of our net operating loss carryforwards. For additional information, see "Risk Factors-*Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated, and additional state taxes on natural gas extraction may be imposed, as a result of future legislation*," in Item 1A of this report.

Management's Discussion and Analysis of Income and Operations

Market Conditions

Prices for various quantities of natural gas, natural gas liquids ("NGLs") and oil that we produce significantly impact our revenues and cash flows. Commodity prices have been volatile in recent years. The following table lists average New York Mercantile Exchange ("NYMEX") prices for natural gas and oil for the year ended December 31, 2010, 2009 and 2008.

	Year Ended December 31,		
	2010	2009	2008
Average NYMEX prices (a)			
Natural gas (per mcf)	$ 4.39	$ 4.02	$ 8.94
Oil (per bbl)	$ 79.59	$ 60.48	$ 100.49

(a) Based on average of bid week prompt month prices.

Overview of 2010 Results

During 2010, we achieved the following financial and operating results:

- achieved 21% production growth;
- achieved 42% proved reserve growth (including our Barnett Shale properties);
- drilled 266 net wells with a 98% success rate (including our Barnett Shale properties);
- continued expansion of our activities in the Marcellus Shale by growing production, proving up acreage and acquiring additional unproved acreage;
- reduced direct operating expenses per mcfe 19%;
- reduced DD&A rate 15%;
- maintained a strong balance sheet by retaining a debt to capitalization ratio of 47% and issuing $500.0 million of new senior subordinated notes;
- used a portion of the proceeds from the issuance of $500.0 million of our 6.75% senior subordinated notes due 2020 to redeem all $200.0 million aggregate principal amount of our 7.375% senior subordinated notes due 2013;
- entered into additional derivative contracts for 2011 and 2012;
- received proceeds of $327.8 million from asset sales;
- realized $513.3 million of cash flow from operating activities; and
- ended the year with stockholders' equity of $2.2 billion.

Operationally, our 2010 performance reflects another year of successfully executing our strategy of growth through drilling. Our success enabled us to increase proved reserves by 1.3 Tcf, which is more than seven times 2010 production (including production and reserves from our Barnett Shale properties). During 2010, we also purchased 125.0 Bcfe of proved reserves through acquisitions. As evidenced by history, commodity prices are inherently volatile. To maintain our competitive advantage, we have focused our efforts on improving operating efficiency. As reservoirs are depleted and production rates decline, per unit production costs will generally increase. Our production is focused in core areas where we can achieve economies of scale to help manage our operating costs. Our efforts resulted in lower direct operating expense on an absolute dollar basis and on a per mcfe basis for 2010 when compared to 2009 and 2008. We also have continued to expand and develop our natural gas shale plays with most of our focus on the Marcellus Shale. We exited the year producing approximately 212.0 Mmcfe per day in the Marcellus Shale. We drilled 117 net wells, increasing our Marcellus reserves to over 1.9 Tcfe. We will continue to evaluate our Marcellus Shale leases and formulate our development plans for this area.

Total revenues increased 14% in 2010 over the same period of 2009. This increase was due to higher production and a gain on the sale of assets somewhat offset by lower realized natural gas and oil prices. Our 2010 production growth was due to the continued success of our drilling program. Average realized prices (including all derivative settlements) were 27% lower in 2010. As discussed in Item 1A of this report, significant changes in natural gas and oil prices can have a material impact on our results of operations and our balance sheet, including the fair value of our derivatives.

2011 Outlook

For 2011, the Board has approved a $1.38 billion capital budget for natural gas and oil related activities, excluding proved property acquisitions. We expect to fund our 2011 capital budget expenditures with cash flows from operations and proceeds from asset sales. The price risk on a portion of our forecasted natural gas and oil production for 2011 is mitigated using commodity derivative contracts and we intend to continue to enter into these transactions. The prices we receive for our natural gas and oil production are largely based on current market prices, which are beyond our control. In October 2010, we announced our plan to offer for sale our Barnett Shale properties in North Texas and the data room opened in December 2010. These properties included approximately 360 producing wells and 700 proven and unproven drilling locations. On February 28, 2011, we announced that we had entered into a definitive agreement to sell these assets along with certain derivative contracts for a price of $900.0 million, subject to typical post-closing adjustments. On April 29, 2011, we sold substantially all of the Barnett Shale properties. The approximate net book value of these assets at December 31, 2010 was $835.9 million, which excludes the derivative contracts being sold. For additional information related to this sale, see Note 3 and Note 4 to the consolidated financial statements.

Natural Gas, NGL and Oil Sales, Production and Realized Price Calculations

Our revenues vary from year to year as a result of changes in realized commodity prices and production volumes. Hedges included in natural gas, NGL and oil sales reflect settlements on those derivatives that qualify for hedge accounting. Cash settlements of derivative contracts that are not accounted for as hedges are included in derivative fair value income in the accompanying statements of operations. In 2010, natural gas, NGL and oil sales increased 6% from 2009 with a 21% increase in production partially offset by a 12% decrease in realized prices. In 2009, natural gas, NGL and oil sales decreased 28% from 2008 due to a 33% decrease in realized prices partially offset by a 8% increase in production. The following table illustrates the primary components of natural gas, NGL and oil sales for each of the last three years (in thousands):

	2010	2009	2008
Natural gas, NGL and oil sales			
Gas wellhead	$418,727	$324,943	$ 704,770
Gas hedges realized	64,749	190,934	8,561
Total gas revenue	$483,476	$515,877	$ 713,331
Total NGL revenue	$143,132	$ 48,094	$ 52,351
Oil wellhead	$133,822	$138,597	$ 294,608
Oil hedges realized	23	11,996	(70,983)
Total oil revenue	$133,845	$150,593	$ 223,625
Combined wellhead	$695,681	$511,634	$1,051,729
Combined hedges	64,772	202,930	(62,422)
Total natural gas, NGL and oil sales	$760,453	$714,564	$ 989,307

Our production continues to grow through drilling success as we place new wells into production and through additions from acquisitions partially offset by the natural decline of our natural gas and oil wells and asset sales. For 2010, our production volumes increased 43% in the Appalachian region and declined 8% in our Southwestern region. Included in the 2010 increase in our Appalachian region is the effect of the sale of our Ohio tight gas sand properties. For 2009, our production volumes increased 28% in the Appalachian region and declined 10% in the Southwestern region. Crude oil production declined from 2008 primarily due to the sale of certain oil properties in West Texas. Our production for each of the last three years is set forth in the following table:

	2010	2009	2008
Production (a)			
Natural gas (mcf)	106,147,511	90,570,364	82,158,559
NGLs (bbls)	3,600,469	1,585,332	1,032,071
Crude oil (bbls)	1,934,417	2,522,784	3,045,710
Total (mcfe) (b)	139,356,832	115,219,062	106,625,245
Average daily production (a)			
Natural gas (mcf)	290,815	248,138	224,477
NGLs (bbls)	9,864	4,343	2,820
Crude oil (bbls)	5,300	6,912	8,322
Total (mcfe) (b)	381,800	315,668	291,326

(a) Represents volumes sold regardless of when produced.

(b) Oil and NGLs are converted to mcfe at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil and natural gas, which is not necessarily indicative of the relationship of oil and natural gas prices.

Our average realized price (including all derivative settlements) received during 2010 was $5.71 per mcfe compared to $7.80 per mcfe in 2009 and $9.13 per mcfe in 2008. Our average realized price (including all derivative settlements) calculation includes all cash settlements for derivatives, whether or not they qualify for hedge accounting, except for the year ended December 31, 2010, we have excluded from average realized price calculations a $15.7 million gain related to an early settlement of oil collars. The average prices below reflect average realized prices included in continuing operations, which includes all derivatives not specifically designated to discontinued operations. Average price calculations for each of the last three years are shown below:

	2010	2009	2008
Average Prices			
Average sales prices (wellhead):			
Natural gas (per mcf)	$ 3.94	$ 3.60	$ 8.58
NGLs (per bbl)	39.75	30.34	50.72
Crude oil (per bbl)	69.18	54.94	96.73
Total (per mcfe) (a)	4.99	4.44	9.86
Average realized prices (including derivatives that qualify for hedge accounting):			
Natural gas (per mcf)	4.55	5.70	8.68
NGLs (per bbl)	39.75	30.34	50.72
Crude oil (per bbl)	69.19	59.69	73.42
Total (per mcfe) (a)	5.46	6.20	9.28
Average realized prices (including all derivative settlements):			
Natural gas (per mcf)	4.89	7.65	8.69
NGLs (per bbl)	39.75	30.34	50.72
Crude oil (per bbl)	69.19	62.57	68.17
Total (per mcfe) (a)	5.71	7.80	9.13

(a) Oil and NGLs are converted at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil to natural gas, which is not necessarily indicative of the relationship of oil and natural gas prices.

Derivative fair value income was $51.6 million in 2010 compared to $66.4 million in 2009 and to $71.9 million in 2008. Some of our derivatives do not qualify for hedge accounting and are accounted for using the mark-to-market accounting method whereby all realized and unrealized gains and losses related to these contracts are included in derivative fair value income in the accompanying consolidated statements of operations. Mark-to-market accounting treatment creates volatility in our revenues as unrealized gains and losses from derivatives are included in total revenues and are not included in accumulated other comprehensive income in the accompanying consolidated balance sheets. As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our derivatives. Any gains on our derivatives will be offset by lower wellhead revenues in the future or any losses will be offset by higher future wellhead revenues based on the value at the settlement date. At December 31, 2010, all of our derivative contracts are recorded at their fair value, which was a net asset of $117.7 million (including $8.2 million related to discontinued operations), an increase of $106.8 million from the $10.9 million net asset recorded as of December 31, 2009. We have also entered into basis swap agreements to limit volatility caused by changing differentials between index and regional prices received. These basis swaps do not qualify for hedge accounting and are marked to market. Hedge ineffectiveness, also included in derivative fair value income, is associated with contracts that qualify for hedge accounting. The ineffective portion is calculated as the difference between the change in the fair value of the derivative and the estimated change in future cash flows from the item being hedged.

The following table presents information about the components of derivative fair value income for each of the years in the three-year period ended December 31, 2010 (in thousands):

	2010	2009	2008
Change in fair value of derivatives that do not qualify for hedge accounting (a)	$ (2,086)	$ (115,909)	$ 85,594
Realized gain (loss) on settlements — natural gas (b) (c)	35,988	171,998	(1,383)
Realized gain (loss) on settlements — oil (b) (c)	—	7,304	(15,431)
Realized gain on early settlement of oil derivatives (d)	15,697	—	—
Hedge ineffectiveness — realized (c)	(352)	4,749	1,386
— unrealized (a)	2,387	(1,696)	1,695
Derivative fair value income	$ 51,634	$ 66,446	$ 71,861

(a) These amounts are unrealized and are not included in average sales price calculations.

(b) These amounts represent realized gains and losses on settled derivatives that do not qualify for hedge accounting.

(c) These settlements are included in average realized price calculations (including all derivative settlements).

(d) This early settlement is not included in average realized price calculations.

Gain on the sale of assets was $76.6 million in 2010 compared to $10.4 million in 2009 and $20.2 million in 2008. During 2010, we sold our tight gas sand properties in Ohio for proceeds of approximately $323.0 million and recorded a gain of $77.6 million. The 2009 period includes a $10.4 million gain on the sale of Marcellus acreage. The 2008 period includes the sale of East Texas properties for proceeds of $64.0 million and a gain of $20.2 million was recorded.

Other revenue in 2010 was a loss of $963,000 compared to a loss of $9.9 million in 2009 and income of $1.5 million in 2008. The 2010 period includes a loss from equity method investments of $1.5 million partially offset by proceeds of $486,000 from a lawsuit settlement. The 2009 period includes a loss from equity method investments of $13.7 million partially offset by proceeds of $3.8 million from a lawsuit settlement. The 2008 period includes a loss from equity method investments of $218,000.

We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per mcfe, basis. The following presents information about certain of our expenses on a per mcfe basis for 2010, 2009 and 2008.

	Year Ended December 31,				Year Ended December 31,			
	2010	2009	Change	% Change	2009	2008	Change	% Change
Direct operating expense	$ 0.69	$ 0.85	$ (0.16)	(19%)	$ 0.85	$ 1.06	$ (0.21)	(20%)
Production and ad valorem tax expense	0.19	0.22	(0.03)	(14%)	0.22	0.46	(0.24)	(52%)
General and administrative expense	1.01	1.00	0.01	1%	1.00	0.87	0.13	15%
Interest expense	0.65	0.65	—	—	0.65	0.60	0.05	8%
Depletion, depreciation and amortization expense	1.98	2.32	(0.34)	(15%)	2.32	1.98	0.34	17%

Direct operating expense was $96.3 million in 2010 compared to $98.3 million in 2009 and $113.0 million in 2008. We experience increases in operating expenses as we add new wells and maintain production from existing properties. In 2010 and 2009, this effect was more than offset by asset sales, lower overall industry costs and lower workover expenses. On an absolute dollar basis, our spending for direct operating expenses for 2010 was lower when compared to 2009 despite higher production levels, reflecting our asset sales and lower overall industry costs. The sale of our Ohio properties in 2010 and the sale of our New York and West Texas properties in 2009 make comparisons of 2010 to 2009 difficult. On a pro forma basis, excluding our Ohio, New York and West Texas sold properties, 2009 direct operating expenses from continuing operations would have been $75.7 million and 2010 direct operating expense from continuing operations would have been $93.6 million. On an absolute dollar basis, our spending for direct operating expenses for 2009 was lower when compared to 2008 despite higher production levels reflecting cost containment measures and lower overall industry costs. We incurred $3.4 million of workover costs in 2010 compared to $5.0 million in 2009 and $5.9 million in 2008.

On a per mcfe basis, direct operating expense for 2010 decreased $0.16 or 19% from the same period of 2009, with the decrease consisting of primarily lower workover costs ($0.02 per mcfe), lower overall well service costs and asset sales. On a pro forma basis, excluding the sale of our Ohio properties in 2010 and the sale of our New York and West Texas properties in 2009, 2009 direct operating expense from continuing operations would have been $0.74 per mcfe and 2010 direct operating expense from continuing operations would have been $0.68 per mcfe. On a per mcfe basis, direct operating expense for 2009 decreased $0.21 or 20% from the same period of 2008 with the decrease consisting primarily of lower workover costs ($0.02

per mcfe), lower utility costs ($0.03 per mcfe), lower well service costs, asset sales and our focus on cost containment. We expect to continue to experience lower costs per mcfe as we increase production from our Marcellus Shale wells due to their lower operations cost relative to our other operating areas. Stock-based compensation expense represents the amortization of restricted stock grants and SARs as part of employee compensation. The following table summarizes direct operating expenses per mcfe for 2010, 2009 and 2008:

	Year Ended December 31,				Year Ended December 31,			
	2010	2009	Change	% Change	2009	2008	Change	% Change
Lease operating expense	$ 0.66	$ 0.79	$ (0.13)	(16%)	$ 0.79	$ 0.97	$ (0.18)	(19%)
Workovers	0.02	0.04	(0.02)	(50%)	0.04	0.06	(0.02)	(33%)
Stock-based compensation (non-cash)	0.01	0.02	(0.01)	(50%)	0.02	0.03	(0.01)	(33%)
Total direct operating expenses	$ 0.69	$ 0.85	$ (0.16)	(19%)	$ 0.85	$ 1.06	$ (0.21)	(20%)

Production and ad valorem taxes are paid based on market prices, not hedged prices. These costs were $26.1 million in 2010 compared to $25.5 million in 2009 and $49.4 million in 2008. On a per mcfe basis, production and ad valorem taxes decreased to $0.19 in 2010 compared to $0.22 in 2009 due to an increase in production volumes not subject to production or ad valorem taxes. On a per mcfe basis, production and ad valorem taxes decreased to $0.22 in 2009 from $0.46 in 2008 due to a 55% decrease in pre-hedge prices.

General and administrative expense was $140.6 million for 2010 compared to $115.3 million for 2009 and $92.3 million in 2008. The 2010 increase of $25.3 million when compared to 2009 is due to higher salaries and benefits ($4.6 million), an increase in legal fees and legal settlements ($4.2 million), an increase in community relations costs ($6.5 million), higher bad debt expense ($2.3 million), higher office expenses, including information technology ($1.8 million), and higher industry trade association dues and inventory adjustments. While our number of employees declined 9% during 2010 due to our asset sales, we continue to incur higher wages which we consider necessary to remain competitive in the industry. The 2009 increase of $23.0 million when compared to 2008 is due primarily to higher salaries and benefits ($11.7 million) due to an increase in the number of employees (4%) and salary increases, higher stock based compensation ($9.7 million), higher legal fees and office expenses, including rent and information technology and higher bad debt expense ($1.4 million). Our personnel costs continue to increase as we invest in our technical teams and other staffing to support our expansion into the Marcellus Shale in Appalachia. Stock-based compensation expense represents the amortization of restricted stock grants and SARs granted to our employees and directors as part of compensation. The following table summarizes general and administrative expenses per mcfe for 2010, 2009 and 2008:

	Year Ended December 31,				Year Ended December 31,			
	2010	2009	Change	% Change	2009	2008	Change	% Change
General and administrative	$ 0.76	$ 0.71	$ 0.05	7%	$ 0.71	$ 0.65	$ 0.06	9%
Stock-based compensation (non-cash)	0.25	0.29	(0.04)	(14%)	0.29	0.22	0.07	32%
Total general and administrative expenses	$ 1.01	$ 1.00	$ 0.01	1%	$ 1.00	$ 0.87	$ 0.13	15%

Interest expense was $90.7 million for 2010 compared to $75.3 million for 2009 and $64.0 million in 2008. Interest expense for 2010 increased $15.4 million from the same period of 2009 due to the refinancing of certain debt from floating rates to higher fixed rates. In August 2010, we issued $500.0 million of 6.75% senior subordinated notes due 2020, which added $13.0 million of interest costs in 2010. The proceeds from this issuance was used to retire bank debt which carried a lower interest rate and to redeem all $200.0 million of our 7.375% senior subordinated notes due 2013. Interest expense for 2009 increased $11.3 million from the same period of 2008 due to the refinancing of certain debt from floating rates to higher fixed rates and higher average debt balances. In May 2009, we issued $300.0 million of 8% senior subordinated notes due 2019, which added $15.1 million of interest costs in 2009. In May 2008, we issued $250.0 million of 7.25% senior subordinated notes due 2018, which added $11.8 million of interest costs in 2008. The 2010, 2009 and 2008 note issuances were undertaken to better match the maturities of our debt with the life of our properties and to give us greater liquidity for the near term. Average debt outstanding on the bank credit facility for 2010 was $351.1 million compared to $584.5 million for 2009 and $494.2 million for 2008 and the weighted average interest rate was 2.2% in 2010 compared to 2.4% in 2009 and 4.4% in 2008.

Depletion, depreciation and amortization (“DD&A”) was $275.2 million in 2010 compared to $267.1 million in 2009 and $211.0 million in 2008. The decrease in 2010 compared to 2009 is due to a 9% decrease in depletion rates and lower depreciation expense partially offset by a 21% increase in production. 2009 included accelerated depreciation expense of $10.3 million on an interim processing plant in Appalachia that was dismantled in the first quarter of 2010 and replaced with permanent facilities. The increase in DD&A for 2009 compared to 2008 is due to a 8% increase in production, a 11% increase in depletion rates and accelerated depreciation expense of $10.3 million on an interim processing plant in Appalachia. On a per mcfe basis, DD&A decreased to $1.98 in 2010 compared to $2.32 in 2009 and $1.98 in 2008. Depletion expense, the largest component of DD&A, was $1.82 per mcfe in 2010 compared to $1.99 per mcfe in 2009 and $1.80 per mcfe in 2008. We have historically adjusted our depletion rates in the fourth quarter of each year based on the year-end reserve report and other times during the year when circumstances indicate there has been a significant change in reserves or costs. In areas where we are actively drilling, such as the Marcellus area, fourth quarter 2010 depletion rates were lower than 2009. Depletion rates in new plays tend to be higher in the beginning as increased initial outlays are amortized over proved reserves based on early stages of evaluations. The decrease in the DD&A per mcfe in 2010 when compared to 2009 is related to lower depreciation expense and the mix of our production. The increase in DD&A per mcfe in 2009 when compared to 2008 was related to the accelerated depreciation expense on an interim processing plant ($0.09) and the mix of our production. The following table summarizes DD&A expense per mcfe for 2010, 2009 and 2008:

	Year Ended December 31,				Year Ended December 31,			
	2010	2009	Change	% Change	2009	2008	Change	% Change
Depletion and amortization	$ 1.82	$ 1.99	$ (0.17)	(9%)	$ 1.99	$ 1.80	$ 0.19	11%
Depreciation	0.12	0.28	(0.16)	(57%)	0.28	0.13	0.15	115%
Accretion and other	0.04	0.05	(0.01)	(20%)	0.05	0.05	—	—%
Total DD&A expense	$ 1.98	$ 2.32	$ (0.34)	(15%)	$ 2.32	$ 1.98	$ 0.34	17%

Other Operating Expenses

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include stock-based compensation, exploration expense, abandonment and impairment of unproved properties and deferred compensation plan expenses. In 2010, stock-based compensation was a component of direct operating expense ($2.0 million), exploration expense ($4.2 million), general and administrative expense ($34.2 million) and termination costs ($2.8 million) for a total of $44.4 million. In 2009, stock-based compensation was a component of direct operating expense ($2.5 million), exploration expense ($4.7 million) and general and administrative expense ($33.3 million) and termination costs of $332,000 for a total of $41.6 million. In 2008, stock-based compensation was a component of direct operating expense ($2.7 million), exploration expense ($4.1 million) and general and administrative expense ($23.8 million) for a total of $31.1 million. Stock-based compensation includes the amortization of restricted stock grants and SARs grants.

Exploration expense was $60.5 million in 2010 compared to $44.3 million in 2009 and $57.0 million in 2008. The following table details our exploration-related expenses for 2010, 2009 and 2008. Exploration expense was significantly higher in 2010 when compared to 2009 due to higher delay rental costs, or the costs we incur to defer the commencement of drilling, primarily in our Marcellus Shale operations. Exploration expense was significantly lower in 2009 when compared to 2008 due to our focus on development of our large shale and coal bed methane projects and the closure of our Gulf Coast office. The following table details our exploration related expenses for 2010, 2009 and 2008 (in thousands):

	Year Ended December 31,				Year Ended December 31,			
	2010	2009	Change	% Change	2009	2008	Change	% Change
Seismic	$ 22,393	$ 19,834	$ 2,559	13%	$ 19,834	$ 24,985	$ (5,151)	(21%)
Delay rentals and other	19,075	6,836	12,239	179%	6,836	5,103	1,733	(34%)
Personnel expense	11,129	10,743	386	4%	10,743	11,804	(1,061)	(9%)
Stock-based compensation expense	4,209	4,703	(494)	(11%)	4,703	4,130	573	14%
Dry hole expense	3,700	2,160	1,540	71%	2,160	10,934	(8,774)	(80%)
Total exploration expense	$ 60,506	$ 44,276	$ 16,230	37%	$ 44,276	$ 56,956	$ (12,680)	(22%)

Abandonment and impairment of unproved properties was $49.7 million in 2010 compared to $36.9 million in 2009 and $15.3 million in 2008. We assess individually significant unproved properties for impairment on a quarterly basis and recognize a loss where circumstances indicate impairment in value. In determining whether a significant unproved property is impaired we consider numerous factors including, but not limited to, current exploration plans, favorable or unfavorable activity on the property being evaluated and/or adjacent properties, our geologists' evaluation of the property and the remaining months in the lease term for the property. Impairment of individually insignificant unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. As we continue to review our acreage positions and high grade our drilling inventory based on the current price environment, additional leasehold impairments and abandonments will likely be recorded.

Termination costs in 2010 includes severance costs of $5.1 million related to the sale of our Ohio properties and $2.8 million of non-cash stock-based compensation expense related to the accelerated vesting of SARs and restricted stock as part of the severance agreement for our Ohio personnel. Termination costs in 2009 represent severance costs related to the closing of our Houston office ($1.6 million), $332,000 of non-cash stock-based compensation expense related to the accelerated vesting of SARs and restricted stock as part of the severance agreement for our Houston personnel and $635,000 of severance costs related to the sale of our New York properties.

Deferred compensation plan expense was a gain of $10.2 million in 2010 compared to a loss of $31.1 million in 2009 and a gain of $24.7 million in 2008. Our stock price decreased to $44.98 at December 31, 2010 compared to $49.85 at December 31, 2009. Our stock price increased to $49.85 at December 31, 2009 compared to $34.39 at December 31, 2008. This non-cash item relates to the increase or decrease in value of the liability associated with our common stock that is vested and held in our deferred compensation plan. The deferred compensation liability is adjusted to fair value by a charge or a credit to deferred compensation plan expense.

Loss on early extinguishment of debt expense for 2010 was $5.4 million. In August 2010, we redeemed our 7.375% senior subordinated notes due 2013 at a redemption price equal to 101.229%. We recorded a loss on extinguishment of debt of $5.4 million which includes call premium costs of $2.5 million and expensing of related deferred financing costs on the repurchased debt.

Impairment of proved properties increased to $6.5 million compared to $930,000 in 2009. The year ended 2010 includes a $6.5 million impairment related to our onshore Gulf Coast properties. In 2009, we recognized $930,000 impairment related to our Michigan properties. These assets were reviewed for impairment due to declining reserves and natural gas prices.

Income tax expense was $50.9 million compared to $45.8 million in 2009 and $181.2 million in 2008. The 2010 increase in income taxes reflects a 65% increase in income from continuing operations before income taxes when compared to the same period of 2009. The effective tax rate in 2010 was 36.5% compared to an effective tax rate of 54.0% in 2009. For the year ended December 31, 2010, the current income tax benefit of $836,000 is related to state income taxes. The 2010 effective tax rate was different than the statutory rate of 35% due to an increase in our valuation allowances related to our deferred tax asset for future deferred compensation plan distributions of top executives to the extent their estimated future compensation (including these distributions) would exceed the $1.0 million deductible limit provided under section 162(M) of the Internal Revenue Code. The 2009 decrease reflects an 83% decrease in continuing income before income taxes compared to the same period of 2008. The year ended December 31, 2009 also includes an unfavorable $16.3 million charge to reflect updated state tax rates used to establish deferred taxes due to a change in our state apportionment factors to states with higher rates, particularly in Pennsylvania, with our increased focus on development of the Marcellus Shale, along with increased proved reserves and acreage in Pennsylvania. The 2009 effective tax rate was 54% compared to an effective tax rate in 2008 of 35.5%. For the year ended December 31, 2009, the current income tax benefit of $636,000 includes state income taxes of $364,000 and a federal income tax benefit of $1.0 million. The effective tax rate was different than the statutory rate of 35% due to an increase in our state apportionment factors in certain higher-rate states, offset by a benefit related to a partial release of valuation allowance on our capital loss carryforward. The 2008 current income taxes of $4.3 million include state income taxes of $3.3 million and $1.0 million of federal income taxes and the effective tax rate was different than the statutory rate of 35% due to state income taxes. We expect our effective tax rate to be approximately 38-39% for 2011.

Discontinued operations include the operating results and impairment losses related to our Barnett properties. These properties were sold on April 29, 2011 for proceeds of $900.0 million including certain derivatives and before normal closing adjustments. Discontinued operations in 2010 was a loss of $328.0 million compared to a loss of $92.9 million in 2009 and income of $21.9 million in 2008. The twelve months ended 2010 includes an impairment charge of $463.2 million. While these properties did not meet held for sale criteria as of December 31, 2010, our analysis reflected undiscounted cash flows for these properties were less than their carrying value. Therefore, we compared the carrying value of these properties to their estimated fair value and recognized an impairment charge. For the year ended 2010, price realizations increased 26% somewhat offset by a 6% decline in production, when compared to the same period of the prior year. Price realization in 2009 declined 58% from the same period of 2008 somewhat offset by a 27% increase in production. See also Note 4 to the accompanying financial statements. Interest expense is allocated to discontinued operations based on the ratio of net assets of discontinued operations to our consolidated net assets plus long-term debt.

Management's Discussion and Analysis of Financial Condition, Capital Resources and Liquidity

Our main sources of liquidity and capital resources are internally generated cash flow from operations, a bank credit facility with uncommitted and committed availability, asset sales and access to the debt and equity capital markets. We continue to take steps to ensure adequate capital resources and liquidity to fund our capital expenditure program. During 2010, we sold our shallow tight gas sand Ohio properties for proceeds of approximately $323.0 million. We used a portion of these proceeds to purchase proved and unproved properties primarily in Virginia. The remainder of these proceeds was used to repay amounts under our bank credit facility. In 2010, we entered into additional commodity derivative contracts for 2011 and 2012 to protect future cash flows. As part of our semi-annual bank review completed October 8, 2010, our borrowing base and facility amounts were reaffirmed at $1.5 billion and $1.25 billion. On February 18, 2011, we announced we have entered into an amended and restated revolving bank facility, which replaced our previous bank credit facility. The new facility, secured by substantially all of our assets, provides for an initial commitment equal to the lesser of the facility amount or the borrowing base. At closing, the borrowing base amount was $2.0 billion and the facility amount was $1.5 billion.

During 2010, our net cash provided from continuing operations of $433.9 million, proceeds from the sale of assets of $327.8 million and borrowings under our bank credit facility were used to fund $1.0 billion of capital expenditures (including acquisitions and equity investments). At December 31, 2010, we had $2.8 million in cash and total assets of $5.5 billion. Our debt to capitalization ratio was 47%. As of December 31, 2010 and 2009, our total debt and capitalization were as follows (in thousands):

	2010	2009
Bank debt	$ 274,000	$ 324,000
Senior subordinated notes	1,686,536	1,383,833
Total debt	1,960,536	1,707,833
Stockholders' equity	2,223,761	2,378,589
Total capitalization	$4,184,297	$4,086,422
Debt to capitalization ratio	46.9%	41.8%

Long-term debt at December 31, 2010 totaled $2.0 billion, including $274.0 million of bank credit facility debt and $1.7 billion of senior subordinated notes. Our available committed borrowing capacity at December 31, 2010 was $970.6 million. Cash is required to fund capital expenditures necessary to offset inherent declines in production and reserves that are typical in the oil and natural gas industry. Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding or acquiring additional reserves. We currently believe that net cash generated from operating activities, unused committed borrowing capacity under the bank credit facility and proceeds from asset sales combined with our natural gas and oil hedges currently in place will be adequate to satisfy near-term financial obligations and liquidity needs. However, long-term cash flows are subject to a number of variables including the level of production and prices as well as various economic conditions that have historically affected the oil and natural gas business. A material drop in natural gas and oil prices or a reduction in production and reserves would reduce our ability to fund capital expenditures, reduce debt, meet financial obligations and remain profitable. We operate in an environment with numerous financial and operating risks, including, but not limited to, the inherent risks of the search for, development and production of natural gas and oil, the ability to buy properties and sell production at prices which provide an attractive return and the highly competitive nature of the industry. Our ability to expand our reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, bank borrowings, asset sales or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to offset inherent declines in production and proven reserves.

Our opinions concerning liquidity and our ability to avail ourselves in the future of the financing options mentioned in the above forward-looking statements are based on currently available information. If this information proves to be inaccurate, future availability of financing may be adversely affected. Factors that affect the availability of financing include our performance, the state of the worldwide debt and equity markets, investor perceptions and expectations of past and future performance, the global financial climate and, in particular, with respect to borrowings, the level of our working capital or outstanding debt and credit ratings by rating agencies. For additional information, see "Risk Factors-*Difficult Conditions in the global capital markets, the credit markets and the economy generally may materially adversely affect our business and results of operations*" in Item 1A of this report.

Credit Arrangements

As of December 31, 2010, we maintained a $1.25 billion revolving credit facility, which we refer to as our bank credit facility. The bank credit facility was secured by substantially all of our assets with a maturity of October 25, 2012. Availability under the bank credit facility was subject to a borrowing base set by the lenders semi-annually with an option to set more often in certain circumstances. The borrowing base was dependent on a number of factors but primarily the lenders' assessment of future cash flows. Redeterminations of the borrowing base required approval of 2/3rds of the lenders; increases required unanimous approval.

On February 18, 2011, we entered into an amended and restated revolving credit facility, which replaced our previous bank credit facility. The new bank credit facility, secured by substantially all of our assets, provides for an initial commitment equal to the lesser of the facility amount or the borrowing base. The new bank credit facility provides for a borrowing base subject to redeterminations semi-annually each April and October and for event-driven unscheduled redeterminations. At February 25, 2011, the bank credit facility had a $2.0 billion borrowing base and a $1.5 billion facility amount. Borrowings under the new credit facility can either be, at our election: (i) at the Alternate Base Rate (as defined in the credit agreement) plus a spread ranging from 0.5% to 1.5% or (ii) LIBOR borrowings at the Adjusted LIBO Rate (as defined in the credit agreement) plus a spread ranging from 1.5% to 2.5%. Remaining credit availability was $1.1 billion on February 25, 2011. Our new bank group is comprised of twenty-seven commercial banks, with no one bank holding more than 7.0% of the bank credit facility. The new credit facility matures on February 18, 2016. For additional information, see Note 8 to our consolidated financial statements.

Our bank debt and our subordinated notes impose limitations on the payment of dividends and other restricted payments (as defined under the debt agreements for our bank debt and our subordinated notes). The debt agreements also contain customary covenants relating to debt incurrence, working capital, dividends and financial ratios. We were in compliance with all covenants at December 31, 2010.

Capital Requirements

Our primary needs for cash are for exploration, development and acquisition of natural gas and oil properties, repayment of principal and interest on outstanding debt and payment of dividends. During 2010, $838.7 million of capital was expended on drilling projects. Also in 2010, $151.6 million was expended on acquisitions of unproved acreage, primarily in the Marcellus Shale and $134.5 million was expended to purchase proved and unproved properties in Virginia. Our 2010 capital program, excluding acquisitions, was funded by net cash flow from operations, proceeds from asset sales and borrowings under our credit facility. Our capital expenditure budget for 2011 is currently set at $1.38 billion, excluding acquisitions. Development and exploration activities are highly discretionary, and, for the near term, we expect such activities to be maintained at levels equal to internal cash flow and asset sales. To the extent, capital requirements exceed internal cash flow and proceeds from asset sales, debt or equity may be issued to fund these requirements. We monitor our capital expenditures on a regular basis, adjusting the amount up or down and also between our operating regions, depending on commodity prices, cash flow and projected returns. Also, our obligations may change due to acquisitions, divestitures and continued growth. We may issue additional shares of stock, subordinated notes or other debt securities to fund capital expenditures, acquisitions, extend maturities or to repay debt.

The forward-looking statements about our capital budget are based on current expectations, estimates and projections and are not guarantees of future performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially include prices of and demand for natural gas and oil, actions of competitors, disruptions or interruptions of our production and unforeseen hazards such as weather conditions, acts of war or terrorists acts and the government or military response, and other operating and economic considerations.

Cash Flow

Cash flows from operations are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivatives. Our cash flows from operations also are impacted by changes in working capital. We generally maintain low cash and cash equivalent balances because we use available funds to reduce our bank debt. Short-term liquidity needs are satisfied by borrowings under our bank credit facility. Because of this, and since our principal source of operating cash flows (or proved reserves to be produced in the following year) cannot be reported as working capital, we often have low or negative working capital. We sell substantially all of our production at the wellhead under floating market contracts. However, we generally hedge a substantial, but varying portion of our anticipated future natural gas and oil production for the next 12 to 24 months. Any payments due to counterparties under our derivative contracts should ultimately be funded by prices received from the sale of our production. Production receipts, however, often lag payments to the counterparties. Any interim cash needs are funded by borrowings under the credit facility. As of December 31, 2010, we have entered into hedging agreements covering 161.0 Bcfe for 2011 (which includes agreements related to our Barnett Shale properties) and 58.5 Bcfe for 2012.

Net cash provided from continuing operations in 2010 was $433.9 million compared to $554.2 million in 2009 and $655.5 million in 2008. Cash provided from continuing operations is largely dependent upon commodity prices and production, net of the effects of settlement of our derivative contracts. The decrease in cash provided from operating activities from 2009 to 2010 reflects lower price realization (a decline of 27%) somewhat offset by a 21% increase in production. The decrease in cash provided from continuing operations from 2008 to 2009 reflects lower price realizations (a decline of 15%) somewhat offset by a 8% increase in production. As of December 31, 2010, we have hedged approximately 81% of our projected 2011 production and 24% of our projected 2012 production. Net cash provided from continuing operations is also affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital (as reflected in our consolidated statements of cash flows) for 2010 was a negative $14.9 compared to a negative $42.8 million for 2009 and positive $8.9 million in 2008.

Net cash used in investing activities from continuing operations in 2010 was $714.7 million compared to $289.0 million in 2009 and $1.1 billion in 2008.

During 2010, we:

- spent $732.9 million on natural gas and oil property additions;
- spent $296.5 million on acquisitions, including purchasing unproved and proved properties in Virginia for $134.5 million and Marcellus Shale leaseholds; and
- received proceeds of $327.8 million primarily from the sale of our Ohio tight gas sand properties.

During 2009, we:

- spent $356.3 million on natural gas and oil property additions;
- spent $139.3 million on acreage primarily in the Marcellus Shale;
- received proceeds of $234.1 million primarily from the sale of West Texas and New York natural gas and oil properties; and
- contributed $6.4 million of capital to Nora Gathering, LLC, an equity method investment.

During 2008, we:

- spent $558.0 million on natural gas and oil property additions;
- spent $485.3 million on acquisitions, including the purchase of Marcellus Shale leasehold;
- contributed $29.0 million of capital to Nora Gathering, LLC, an equity method investment; and
- received proceeds of $68.2 million primarily from the sale of East Texas oil and gas properties.

Net cash provided from discontinued operations for 2010 was $79.4 million compared to $37.5 million in 2009 and $169.3 million in 2008. The increase in cash provided from discontinued operations from 2009 to 2010 reflects a 26% increase in price realizations somewhat offset by a 6% decline is production. The decrease in cash provided from discontinued operations from 2008 to 2009 reflects a 58% decrease in price realizations somewhat offset by a 27% increase in production.

Net cash (used in) provided from financing activities in 2010 was an increase of $287.6 million compared to a decrease of $117.9 million in 2009 and an increase of $903.7 million in 2008. Historically, sources of financing have been primarily bank borrowings and capital raised through equity and debt offerings.

During 2010, we:

- borrowed $1.1 billion and repaid $1.1 billion under our bank credit facility, ending the year with $50.0 million lower bank debt;
- issued $500.0 million aggregate principal amounts of our 6.75% senior subordinated notes due 2020; and
- used some of the proceeds from the sale of 6.75% senior subordinated notes to redeem all $200.0 million aggregate principal amount of our 7.375% senior subordinated notes due 2013.

During 2009, we:

- borrowed $707.0 million and repaid $1.1 billion under our bank credit facility, ending the year with $369 million lower bank debt; and
- issued $300.0 million aggregate principal amounts of our 8% senior subordinated notes due 2019, at a discount.

During 2008, we:

- borrowed $1.5 billion and repaid $1.1 billion under our bank credit facility, ending the year with $390 million higher bank debt; and
- issued $250.0 million aggregate principal amount of our 7.25% senior subordinated notes due 2018; and
- received proceeds of $282.2 million from a common stock offering.

Net cash used in investing activities from discontinued operations for 2010 was $84.2 million compared to $184.9 million in 2009 and $673.5 million in 2008. We spent $80.2 million on natural gas and oil property additions in 2010 compared to $170.0 million in 2009 and $281.2 million in 2008. The year ended 2008 also includes $349.5 million spent on proved and unproved property acquisitions.

Cash Dividend Payments

The amount of future dividends is subject to declaration by the Board of Directors and primarily depends on earnings, capital expenditures and various other factors. In 2010, we paid $25.6 million in dividends to our common shareholders ($0.04 per share each quarter). In 2009, we paid $25.2 million in dividends to our common shareholders ($0.04 per share in each quarter). In 2008, we paid $24.6 million in dividends to our common shareholders ($0.04 per share in each quarter).

Cash Contractual Obligations

Our contractual obligations include long-term debt, operating leases, drilling commitments, derivative obligations, asset retirement obligations and transportation commitments. As of December 31, 2010, we do not have any capital leases. As of December 31, 2010, we do not have any significant off-balance sheet debt or other such unrecorded obligations and we have not guaranteed any material debt of any unrelated party. As of December 31, 2010, we had a total of $5.4 million of letters of credit outstanding under our bank credit facility. The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2010. In addition to the contractual obligations listed on the table below, our balance sheet at December 31, 2010 reflects accrued interest payable on our bank debt of $1.3 million which is payable in first quarter 2011. We expect to make interest payments of $9.6 million per year on our 6.375% senior subordinated notes, $18.8 million per year on our 7.5% senior subordinated notes due 2016, $18.8 million per year on our 7.5% senior subordinated notes due 2017, $18.1 million per year on our 7.25% senior subordinated notes, $24.0 million per year on our 8% senior subordinated notes and $33.8 million per year on our 6.75% senior subordinated notes.

The following summarizes our contractual financial obligations at December 31, 2010 and their future maturities. We expect to fund these contractual obligations with cash generated from operating activities, borrowings under our bank credit facility, additional debt issuances and proceeds from asset sales (in thousands).

	Payment due by period					
	2011	2012	2013	2014 and 2015	Thereafter	Total
Bank debt due 2012	$ —	$ 274,000 (a)	$ —	$ —	$ —	$ 274,000
6.375% senior subordinated notes due 2015	—	—	—	150,000	—	150,000
7.5% senior subordinated notes due 2016	—	—	—	—	250,000	250,000
7.5% senior subordinated notes due 2017	—	—	—	—	250,000	250,000
7.25% senior subordinated notes due 2018	—	—	—	—	250,000	250,000
8.0% senior subordinated notes due 2019	—	—	—	—	300,000	300,000
6.75% senior subordinated notes due 2020	—	—	—	—	500,000	500,000
Operating leases	9,676	9,826	6,917	12,763	27,833	67,015
Drilling rig commitments	72,927	53,730	14,673	896	—	142,226
Transportation commitments	61,925	61,937	61,404	120,840	381,697	687,803
Transportation commitments-discontinued operations	6,662	3,887	3,390	381	—	14,320
Other purchase obligations	50,975	42,975	2,727	—	—	96,677
Seismic agreements	11,838	6,042	645	—	—	18,525
Derivative obligations (b)	352	13,412	—	—	—	13,764
Asset retirement obligation liability (c)	4,020	8,801	522	3,255	46,075	62,673
Total contractual obligations (d)	$ 218,375	$ 474,610	$ 90,278	$ 288,135	$ 2,005,605	$ 3,077,003

(a) Due at termination date of our bank credit facility. Interest paid on our bank credit facility would be approximately $7.4 million each year assuming no change in the interest rate or outstanding balance. On February 18, 2011, we entered into an amended and restated bank credit agreement which replaced our previous bank credit facility and will mature in 2016.

(b) Derivative obligations represent net open derivative contracts valued as of December 31, 2010. While such payments will be funded by higher prices received from the sale of our production, production receipts may be received after our payments to counterparties, which can result in borrowings under our bank credit facility.

(c) The ultimate settlement amount and timing cannot be precisely determined in advance. See Note 9 to our consolidated financial statements. Includes $2.0 million related to discontinued operations.

(d) This table excludes the liability for the deferred compensation plans since these obligations will be funded with existing plan assets.

In addition to the amounts included in the above table, we have contracted with several pipeline companies through 2030 to deliver natural gas production volumes in Appalachia from certain Marcellus Shale wells. The agreements call for total incremental increases of 683,000 Mmbtu per day over the 284,905 Mmbtu per day at December 31, 2010. These increases, which are contingent on certain pipeline modifications, are for 350,000 Mmbtu per day in February 2011, 150,000 Mmbtu per day in September 2011, 108,000 Mmbtu per day in November 2012 and 75,000 Mmbtu per day for November 2013.

Delivery Commitments-Discontinued Operations

Under a sales agreement, we have an obligation to deliver 30,000 Mmbtu per day of volume at various delivery points within the Barnett Shale basin. The contract, which began in 2008, extends for five years ending March 2013. As of December 31, 2010, remaining volumes to be delivered under this commitment are approximately 24.6 Bcf.

Other

We have agreements in place to purchase seismic data. These agreements total $11.8 million in 2011, $6.0 million in 2012 and $645,000 in 2013. We also have a two-year agreement to lease equipment, material and labor for hydraulic fracturing services for $48.0 million in 2011 and $40.0 million in 2012. We have lease acreage that is generally subject to lease expiration if initial wells are not drilled within a specified period, generally between three to five years. We do not expect to lose significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, including the cost of infrastructure to connect production, we have allowed acreage to expire and will allow additional acreage to expire in the future. To date, our expenditures to comply with environmental or safety regulations have not been significant and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

Hedging — Oil and Gas Prices

We use commodity-based derivative contracts to manage exposures to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. We do not utilize complex derivatives such as swaptions, knockouts or extendable swaps. We typically utilize commodity swap and collar contracts to (1) reduce the effect of price volatility on the commodities we produce and sell and (2) support our annual capital budget and expenditure plans. In third quarter 2010, we also entered into call option derivative contracts. While there is a risk that the financial benefit of rising natural gas and oil prices may not be captured, we believe the benefits of stable and predictable cash flow are more important. Among these benefits are a more efficient utilization of existing personnel and planning for future staff additions, the flexibility to enter into long-term projects requiring substantial committed capital, smoother and more efficient execution of our ongoing development drilling and production enhancement programs, more consistent returns on invested capital, and better access to bank and other credit markets.

At December 31, 2010, we had collars covering 192.8 Bcf of gas at weighted average floor and cap prices of $5.54 to $6.43 and 0.7 million barrels of oil at weighted average floor and cap prices of $70.00 to $80.00. We also have sold call options covering 3.7 millions of barrels of oil at a weighted average price of $82.31. The fair value, represented by the estimated amount that would be realized or payable on termination, based on a comparison of the contract price and a reference price, generally NYMEX, approximated a pretax gain of $118.0 million at December 31, 2010 (including $8.2 million related to discontinued operations). The contracts expire monthly through December 2012. Included in the table below for 2011 natural gas collars is 22,797 Mmbtu/day related to discontinued operations.

At December 31, 2010, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price	
Natural Gas				
2011	Collars	408,200 Mmbtu/day	$	5.56—$6.48
2012	Collars	119,641 Mmbtu/day	$	5.50—$6.25
Crude Oil				
2012	Collars	2,000 bbls/day	$	70.00—$80.00
2011	Call Options	5,500 bbls/day	$	80.00
2012	Call Options	4,700 bbls/day	$	85.00

In addition to the collars above, we have entered into basis swap agreements. The price we receive for our production can be less than NYMEX price because of adjustments for delivery location ("basis"), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix the basis adjustments. The fair value of the basis swaps was a net unrealized pre-tax loss of $352,000 at December 31, 2010. These basis swaps expire first quarter 2011.

Interest Rates

At December 31, 2010, we had $2.0 billion of debt outstanding. Of this amount, $1.7 billion bears interest at fixed rates averaging 7.2%. Bank debt totaling $274.0 million bears interest at floating rates, which averaged 2.7% at year-end 2010. The

30-day LIBOR rate on December 31, 2010 was 0.3%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2010 would cost us approximately $2.7 million in additional annual interest expense.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance our liquidity or capital resource position, or for any other purpose. However, as is customary in the oil and gas industry, we have various contractual work commitments some of which are described above under cash contractual obligations.

Inflation and Changes in Prices

Our revenues, the value of our assets and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in natural gas and oil prices and the costs to produce our reserves. Natural gas and oil prices are subject to significant fluctuations that are beyond our ability to control or predict. Although certain of our costs and expenses are affected by general inflation, inflation does not normally have a significant effect on our business. In a trend that began in 2004 and accelerated through the middle of 2008, commodity prices for natural gas and oil increased significantly. The higher prices led to increased activity in the industry and, consequently, rising costs. These cost trends put pressure on our operating costs and also on our capital costs. Due to the decline in commodity prices that began in the last half of 2008 and continued into 2010, costs have moderated. We expect costs in 2011 to continue to be a function of supply and demand.

The following table indicates the average natural gas and oil prices received over the last five years and quarterly for 2010, 2009 and 2008. Average price calculations exclude all derivative settlements whether or not they qualify for hedge accounting.

	Average Sales Prices (Wellhead)			Average NYMEX Prices (a)	
	Natural Gas (Per mcf)	Crude Oil (Per bbl)	Equivalent Mcf (Per mcfe) (b)	Natural Gas (Per mcf)	Crude Oil (Per bbl)
Annual					
010	$ 3.94	$ 69.18	$ 4.99	$ 4.39	$ 79.59
009	3.60	54.94	4.44	4.02	60.48
008	8.58	96.73	9.86	8.94	100.49
007	6.75	67.47	7.69	6.92	72.34
006	6.74	62.36	7.39	7.26	66.22
Quarterly					
2010					
First	$ 5.06	$ 69.62	$ 5.99	$ 5.37	$ 78.82
Second	3.75	67.76	4.75	4.08	77.71
Third	3.86	66.74	4.73	4.42	76.18
Fourth	3.27	72.29	4.65	3.82	85.24
2009					
First	$ 4.16	$ 38.92	$ 4.45	$ 4.88	$ 43.20
Second	3.03	54.61	4.03	3.59	59.79
Third	3.01	63.34	4.01	3.42	68.18
Fourth	4.15	67.88	5.22	4.26	76.12
2008					
First	$ 8.32	$ 94.57	$ 9.64	$ 8.07	$ 97.90
Second	10.64	120.28	12.28	10.80	123.98
Third	9.86	113.91	11.37	10.09	117.86
Fourth	5.62	54.99	6.23	6.81	58.80

(a) Based on average of bid week prompt month prices.

(b) Oil is converted at a rate of one barrel equals six mcf based upon the approximate relative energy content of oil to natural gas, which is not necessarily indicative of the relationship of all oil and natural gas prices.

Management's Discussion of Critical Accounting Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end, the reported amounts of revenues and expenses during the year and proved natural gas and oil reserves. Some accounting policies involve judgments and uncertainties to such an extent there is a reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. Actual results could differ from the estimates and assumptions used.

Certain accounting estimates are considered to be critical if (a) the nature of the estimates and assumptions is material due to the level of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (b) the impact of the estimates and assumptions on financial condition or operating performance is material.

Natural Gas and Oil Properties

We follow the successful efforts method of accounting for natural gas and oil producing activities. Unsuccessful exploration drilling costs are expensed and can have a significant effect on reported operating results. Successful exploration drilling costs and all development costs are capitalized and systematically charged to expense using the units of production method based on proved developed natural gas and oil reserves as estimated by our engineers and reviewed by independent engineers. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized on our balance sheet if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. Proven property leasehold costs are amortized to expense using the units of production method based on total proved reserves. Properties are assessed for impairment as circumstances warrant (at least annually) and impairments to value are charged to expense. The successful efforts method inherently relies upon the estimation of proved reserves, which includes proved developed and proved undeveloped volumes.

Proved reserves are defined by the SEC as those volumes of natural gas, natural gas liquids, condensate and crude oil that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Although our engineers are knowledgeable of and follow the guidelines for reserves established by the SEC, including the recent rule revisions designed to modernize the oil and gas company reserves reporting requirements which we adopted effective December 31, 2009, the estimation of reserves requires engineers to make a significant number of assumptions based on professional judgment. Reserve estimates are updated at least annually and consider recent production levels and other technical information. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price and cost changes and other economic factors. Changes in natural gas and oil prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions in turn cause adjustments in our depletion rates. We cannot predict what reserve revisions may be required in future periods. Reserve estimates are reviewed and approved by our Senior Vice President of Reservoir Engineering who reports directly to our President. For additional discussion, see "Proved Reserves," in Item 2 of this report. To further ensure the reliability of our reserve estimates, we engage independent petroleum consultants to review our estimates of proved reserves. Independent petroleum consultants reviewed approximately 90% of our reserves in 2010 compared to 88% in 2009 and 87% in 2008. Historical variances between our reserve estimates and the aggregate estimates of our consultants have been less than 5%. The reserves included in this report are those reserves estimated by our employees. Beginning December 31, 2009, reserve estimates are based on an average of prices in the prior 12-month period, using the closing prices on the first day of each month. In previous periods, reserve estimates were based upon prices at December 31. Neither of these prices should be expected to reflect future market conditions.

Depletion rates are determined based on reserve quantity estimates and the capitalized costs of producing properties. As the estimated reserves are adjusted, the depletion expense for a property will change, assuming no change in production volumes or the capitalized costs. While total depletion expense for the life of a property is limited to the property's total cost, proved reserve revisions result in a change in the timing of when depletion expense is recognized. Downward revisions of proved reserves may result in an acceleration of depletion expense, while upward revisions tend to lower the rate of depletion expense recognition. Based on proved reserves at December 31, 2010 (which includes our Barnett Shale assets), we estimate that a 1% change in proved reserves would increase or decrease 2011 depletion expense by approximately $12.0 million (assuming a 10% production increase). Estimated reserves are used as the basis for calculating the expected future cash flows from a property, which are used to determine whether that property may be impaired. Reserves are also used to estimate the supplemental disclosure of the standardized measure of discounted future net cash flows relating to natural gas and oil producing activities and reserve quantities in Note 20 to our consolidated financial statements. Changes in the estimated reserves are considered a change in estimate for accounting purposes and are reflected on a prospective basis. We adopted the new SEC accounting and disclosure regulations for oil and gas companies effective December 31, 2009 which was accounted for prospectively. We estimated the effect of this change in estimate was an increase to depletion, depreciation and amortization expense (including our Barnett Shale properties) in fourth quarter 2009 of approximately $3.4 million primarily due to lower prices reflected in our estimated reserves.

We monitor our long-lived assets recorded in natural gas and oil properties in our consolidated balance sheets to ensure they are fairly presented. We must evaluate our properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future natural gas and oil prices, an estimate of the ultimate amount of recoverable natural gas and oil reserves that will be produced from a field, the timing of future production, future production costs, future abandonment costs, and future inflation. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for natural gas and/or oil, unfavorable adjustments to reserves, physical damage to production equipment and facilities, a change in costs, or other changes to contracts or environmental regulations. Our natural gas and oil properties are reviewed for potential impairments at the lowest levels for which there are identifiable cash flows that are largely independent of other groups of assets. All of these factors must be considered when testing a property's carrying value for impairment. The review is done by determining if the historical cost of proved properties less the applicable accumulated depreciation, depletion and amortization is less than the estimated undiscounted future net cash flows. The expected future net cash flows are estimated based on our plans to produce and develop reserves. Expected future net cash inflow from the sale of produced reserves is calculated based on estimated future prices and estimated operating and development costs. We estimate prices based upon market related information including published futures prices. The estimated future level of production is based on assumptions surrounding future levels of prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. In certain circumstances, we also consider potential sales to properties to third parties in our estimates of future cash flows. When the carrying value exceeds the sum of future net cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future net cash flows using a discount rate similar to that used by market participants) and the carrying value of the asset. We cannot predict whether impairment charges may be required in the future. Our historical impairment of producing properties has been $6.5 million in 2010, $930,000 in 2009, $74.9 million in 2006, $3.6 million in 2004, $31.1 million in 2001, $29.9 million in 1999 and $214.7 million in 1998. In 2010, an impairment was recorded on our Gulf Coast properties and in 2009, an impairment was recorded on our Michigan properties due to lower reserves and natural gas prices. While our Barnett properties did not meet held for sale criteria as of December 31, 2010, our analysis reflected undiscounted cash flows for these properties were less than their carrying value. We therefore compared the carrying value of the Barnett properties to the estimated fair value of such properties and recognized an impairment charge of $463.2 million in fourth quarter 2010, which is recorded in discontinued operations. Our estimated fair value includes an estimate of the potential sales price for these properties in the estimated future cash flows. On February 28, 2011, we announced that we had entered into a definitive agreement to sell these assets along with certain derivative contracts for a price of $900.0 million, subject to typical post-closing adjustments. On April 29, 2011, we sold substantially all of these assets. We believe that a sensitivity analysis regarding the effect of changes in assumptions on estimated impairment is impractical to provide because of the number of assumptions and variables involved which have interdependent effects on the potential outcome.

We are required to develop estimates of fair value to allocate purchase prices paid to acquire businesses to the assets acquired and liabilities assumed under the purchase method of accounting. The purchase price paid to acquire a business is allocated to its assets and liabilities based on the estimated fair values of the assets acquired and liabilities assumed as of the date of acquisition. We use all available information to make these fair value determinations. See Note 3 to our consolidated financial statements for information on these acquisitions.

We evaluate our unproved property investment periodically for impairment. The majority of these costs generally relate to the acquisition of leaseholds. The costs are capitalized and evaluated (at least quarterly) as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. Impairment of a significant portion of our unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. Potential impairment of individually significant unproved property is assessed on a property-by-property basis considering a combination of time, geologic and engineering factors. Unproved properties had a net book value of $648.1 million at December 31, 2010 compared to $572.5 million at December 31, 2009 and $485.9 million at December 31, 2008. We have recorded abandonment and impairment expense related to unproved properties of $49.7 million in 2010 compared to $36.9 million in 2009 and $15.3 million in 2008.

Natural Gas and Oil Derivatives

All derivative instruments are recorded on our consolidated balance sheets as either an asset or a liability measured at its fair value. Changes in a derivative's fair value are recognized in earnings unless specific hedge accounting criteria are met. All of our derivative instruments are issued to manage the price risk attributable to our expected natural gas and oil production. In determining the amounts to be recorded for our open hedge contracts, we are required to estimate the fair value of the derivative. Our derivatives are measured using a market approach using third-party pricing services which have been corroborated with data from active markets or broker quotes. While we remain at risk for possible changes in the market value of commodity derivatives, such risk should be mitigated by price changes in the underlying physical commodity. The determination of fair values includes various factors including the impact of our nonperformance risk on our liabilities and the credit standing of our counterparties. As of December 31, 2010, our counterparties include nine financial institutions, all of which are secured lenders in our bank credit facility.

Through December 31, 2010, we have elected to designate our commodity derivative instruments that qualify for hedge accounting as cash flow hedges. To designate a derivative as a cash flow hedge, we document at the hedge's inception our assessment that the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. This assessment, which is updated at least quarterly, is based on the most recent relevant historical correlation between the derivative and the item hedged. The ineffective portion of the hedge is calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged. If, during the derivative's term, we determine the hedge is no longer highly effective, hedge accounting is prospectively discontinued and any remaining unrealized gains or losses, based on the effective portion of the derivative at that date, are reclassified to earnings as natural gas, NGL and oil sales when the underlying transaction occurs. If it is determined that the designated hedged transaction is not probable to occur, any unrealized gains or losses are recognized immediately in derivative fair value income in our statements of operations. During 2010, there were gains of $11.6 million compared to gains of $5.4 million in 2009 and losses of $583,000 in 2008 reclassified into earnings as a result of the discontinuance of hedge accounting treatment for our derivatives.

We apply hedge accounting to qualifying derivatives used to manage price risk associated with our natural gas, NGL and oil production. Accordingly, we record changes in the fair value of our derivative contracts, including changes associated with time value, in accumulated other comprehensive income ("AOCI") in the accompanying consolidated balance sheets. Gains or losses on these swap and collar contracts are reclassified out of AOCI and into natural gas, NGL and oil sales when the underlying physical transaction occurs. Any hedge ineffectiveness associated with contracts qualifying for and designated as a cash flow hedge (which represents the amount by which the change in the fair value of the derivative differs from the change in the cash flows of the forecasted sale of production) is reported currently each period in derivative fair value income the accompanying consolidated statements of operations. Ineffectiveness can be associated with open positions (unrealized) or can be associated with closed contracts (realized).

Realized and unrealized gains and losses on derivatives that are not designated as hedges are accounted for using the mark-to-market accounting method. We recognize all unrealized and realized gains and losses related to these contracts in derivative fair value income in the accompanying consolidated statements of operations. We also enter into basis swap agreements which do not qualify for hedge accounting and are marked to market. The price we receive for our natural gas production can be more or less than the NYMEX price because of adjustments for delivery location ("basis"), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix our basis adjustments. Cash flows from our derivative contract settlements are reflected in cash flow provided from operating activities in the accompanying consolidated statements of cash flows.

Asset Retirement Obligations

We have significant obligations to remove tangible equipment and restore land at the end of natural gas and oil production operations. Removal and restoration obligations are primarily associated with plugging and abandoning wells. Estimating the future asset removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate retirement costs, inflation factors, credit-adjusted discount rates, timing of retirement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation ("ARO"), a corresponding adjustment is made to the natural gas and oil property balance. For example, as we analyze actual plugging and abandonment information, we may revise our estimate of current costs, the assumed annual inflation of the costs and/or the assumed productive lives of our wells. During 2010, we decreased our existing estimated ARO by $7.9 million or approximately 10% of the asset retirement obligation at December 31, 2009. This decrease was due to a change in the productive lives of our wells. During 2009, we increased our existing estimated asset retirement obligation by

$3.6 million or approximately 4% of the asset retirement obligation at December 31, 2008. In addition, increases in the discounted ARO liability resulting from the passage of time are reflected as accretion expense, a component of depletion, depreciation and amortization in the accompanying consolidated statements of operations. Because of the subjectivity of assumptions and the relatively long lives of most of our wells, the costs to ultimately retire our wells may vary significantly from prior estimates.

Deferred Taxes

We are subject to income and other taxes in all areas in which we operate. When recording income tax expense, certain estimates are required because income tax returns are generally filed many months after the close of a calendar year, tax returns are subject to audit, which can take years to complete, and future events often impact the timing of when income tax expenses and benefits are recognized. We have deferred tax assets relating to tax operating loss carryforwards and other deductible differences. We routinely evaluate deferred tax assets to determine the likelihood of realization and we must estimate our expected future taxable income to complete this assessment. Numerous assumptions are inherent in the estimation of future taxable income, including assumptions about matters that are dependent on future events such as future operating conditions and future financial conditions. The estimates are assumptions used in determining future taxable income are consistent with those used in our internal budgets and forecasts. A valuation allowance is recognized on deferred tax assets when we believe that certain of these assets are not likely to be realized.

In determining deferred tax liabilities, accounting rules require AOCI to be considered, even though such income or loss has not yet been earned. At year-end 2010, deferred tax liabilities exceeded deferred tax assets by $683.9 million, with $43.6 million of deferred tax liabilities related to unrealized hedging gains included in accumulated other comprehensive income. At year-end 2009, deferred tax liabilities exceeded deferred tax assets by $768.9 million, with $3.8 million of deferred tax liabilities related to unrealized hedging gains included in AOCI.

We may be challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in our various income tax returns. Although we believe that we have adequately provided for all taxes, gains or losses could occur in the future due to changes in estimates or resolution of outstanding tax matters.

Contingent Liabilities

A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost or range of cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and contingent matters. In addition, we often must estimate the amount of such losses. In many cases, our judgment is based on the input of our legal advisors and on the interpretation of laws and regulations, which can be interpreted differently by regulators and/or the courts. Actual costs can differ from estimates for many reasons. We monitor known and potential legal, environmental and other contingent matters and make our best estimate of when to record losses for these matters based on available information. Although we continue to monitor all contingencies closely, particularly our outstanding litigation, we currently have no material accruals for contingent liabilities.

Revenue Recognition

Natural gas, natural gas liquids and oil sales are recognized when the products are sold and delivery to the purchaser has occurred. We use the sales method to account for gas imbalances, recognizing revenue based on gas delivered rather than our working interest share of gas produced. We recognize the cost of revenues, such as transportation and compression expense, as a reduction of revenue.

Stock-based Compensation Arrangements

The fair value of stock options and stock-settled SARs is estimated on the date of grant using the Black-Scholes-Merton option-pricing model. The model employs various assumptions, based on management’s best estimates at the time of the grant, which impact the fair value calculated and ultimately, the expense that is recognized over the life of the award. We utilize historical data and analyze current information to reasonably support these assumptions. The fair value of restricted stock awards is determined based on the fair market value of our common stock on the date of grant.

We recognize stock-based compensation expense on a straight-line basis over the requisite service period for the entire award. The expense we recognize is net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant. Restricted stock awards are classified as a liability and are remeasured at fair value each reporting period with the resulting gain or loss recognized in deferred compensation plan expense in our consolidated statement of operations.

Accounting Standards Not Yet Adopted

In December 2010, the FASB issued ASU No. 2010-29, which updates the guidance in ASC Topic 805, *Business Combinations.* The objective of ASU No. 2010-29 is to address diversity in practice about the interpretation of the pro forma revenue and earnings disclosure requirements for business combinations. The amendments in ASU No. 2010-29 specify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The amendments also expand the supplemental pro forma disclosures to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The amendments affect any public entity as defined by ASC 805 that enters into business combinations that are material on an individual or aggregate basis. This guidance will become effective for us for acquisitions occurring on or after the beginning of our 2012 fiscal year. We do not expect the adoption of this guidance will have a material impact upon our financial position or results of operations.

ITEM 7A. QUANTITIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in natural gas and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market-risk exposure. All of our market-risk sensitive instruments were entered into for purposes other than trading. All accounts are US dollar denominated.

Market Risk

We are exposed to market risks related to the volatility of natural gas, NGL and oil prices. We employ various strategies, including the use of commodity derivative instruments, to manage the risks related to these price fluctuations. Realized prices are primarily driven by worldwide prices for oil and spot market prices for North American gas production. Natural gas and oil prices have been volatile and unpredictable for many years. We are also exposed to market risks related to changes in interest rates.

Commodity Price Risk

We use commodity-based derivative contracts to manage exposures to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. We do not utilize complex derivatives such as swaptions, knockouts or extendable swaps. At times, certain of our derivatives are swaps where we receive a fixed price for our production and pay market prices to the counterparty. Our derivatives program also includes collars, which establishes a minimum floor price and a predetermined ceiling price. We have also entered into call option derivative contracts under which we sold call options in exchange for a premium from the counterparty. At the time of settlement of these monthly call options, if the market price exceeds the fixed price of the call option, we will pay the counterparty such excess and if the market settle below the fixed price of the call option, no payment is due from either party. At December 31, 2010, our derivatives program includes collars and call options. As of December 31, 2010, we had collars covering 192.8 Bcf of gas and 0.7 million barrels of oil. We also have sold call options covering 3.7 million barrels of oil. These contracts expire monthly through December 2012. The fair value, represented by the estimated amount that would be realized upon immediate liquidation as of December 31, 2010, approximated a net unrealized pre-tax gain of $118.0 million (including $8.2 million related to discontinued operations) compared to a gain of $28.7 million at December 31, 2009. This change is primarily related to the expiration of natural gas and oil derivative contracts during 2010 and to the natural gas and oil futures prices as of December 31, 2010, in relation to the new commodity derivative contracts we entered into during 2010 for 2011 and 2012. Included in the table below for 2011 natural gas collars is 22,797 Mmbtu/day related to discontinued operations.

At December 31, 2010, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price	Fair Market Value (in thousands)
Natural Gas				
2011	Collars	408,200 Mmbtu/day	$ 5.56—$6.48	$163,354
2012	Collars	119,641 Mmbtu/day	$ 5.50—$6.25	$ 27,032
Crude Oil				
2012	Collars	2,000 bbls/day	$70.00—$80.00	$ (12,052)
2011	Call options	5,500 bbls/day	$ 80.00	$ (31,904)
2012	Call options	4,700 bbls/day	$ 85.00	$ (28,393)

We expect our NGL production to continue to increase. We currently have not entered into any NGL derivative contracts. In our Marcellus Shale operations, propane is a large product component of our NGL production and we believe NGL prices are somewhat seasonal. Therefore, the percentage of NGL prices to NTMEX WTI (or West Texas Intermediate) will vary due to product components, seasonality and geographic supply and demand.

Other Commodity Risk

We are impacted by basis risk, caused by factors that affect the relationship between commodity futures prices reflected in derivative commodity instruments and the cash market price of the underlying commodity. Natural gas transaction prices are frequently based on industry reference prices that may vary from prices experienced in local markets. If commodity price changes in one region are not reflected in other regions, derivative commodity instruments may no longer provide the expected hedge, resulting in increased basis risk. In addition to the collars and call options above, we have entered into basis swap agreements. The price we receive for our gas production can be more or less than the NYMEX price because of adjustments for delivery location (“basis”), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix the basis adjustments. The fair value of the basis swaps was a net realized pre-tax loss of $352,000 at December 31, 2010. These basis swaps expire in first quarter 2011.

The following table shows the fair value of our collars and call options and the hypothetical change in fair value that would result from a 10% and a 25% change in commodity prices at December 31, 2010. We remain at risk for possible changes in the market value of commodity derivative instruments; however, such risks should be mitigated by price changes in the underlying physical commodity (in thousands):

		Hypothetical Change in Fair Value Increase of		Hypothetical Change in Fair Value Decrease of	
	Fair Value	10%	25%	10%	25%
Collars	$ 178,335	$ (82,083)	$ (199,536)	$ 85,644	$ 219,992
Call options	(60,297)	(27,711)	(73,471)	23,800	47,432

Our commodity-based contracts expose us to the credit risk of non-performance by the counterparty to the contracts. Our exposure is diversified among major investment grade financial institutions and we have master netting agreements with the majority of our counterparties that provide for offsetting payables against receivables from separate derivative contracts. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. At December 31, 2010, our derivative counterparties include nine financial institutions, all of which are secured lenders in our bank credit facility. Counterparty credit risk is considered when determining the fair value of our derivative contracts. While counterparties are major investment grade financial institutions, the fair value of our derivative contracts have been adjusted to account for the risk of non-performance by counterparty, which was immaterial.

Interest Rate Risk

We are exposed to interest rate risk on our bank debt. We attempt to balance variable rate debt, fixed rate debt and debt maturities to manage interest costs, interest rate volatility and financing risk. This is accomplished through a mix of fixed rate senior subordinated debt and variable rate bank debt. At December 31, 2010, we had $2.0 billion of debt outstanding. Of this amount, $1.7 billion bears interest at a fixed rate averaging 7.2%. Bank debt totaling $274.0 million bears interest at floating rates, which was 2.7% on that date. On December 31, 2010, the 30-day LIBOR rate was 0.3%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2010 would cost us approximately $2.7 million in additional annual interest expense.

The fair value of our subordinated debt is based on year-end quoted market prices. The following table presents information on these fair values (in thousands):

	Carrying Value	Fair Value
Fixed rate debt:		
Senior Subordinated Notes due 2015 (The interest rate is fixed at a rate of 6.375%)	$ 150,000	$ 153,000
Senior Subordinated Notes due 2016 (The interest rate is fixed at a rate of 7.5%)	249,683	259,375
Senior Subordinated Notes due 2017 (The interest rate is fixed at a rate of 7.5%)	250,000	263,438
Senior Subordinated Notes due 2018 (The interest rate is fixed at a rate of 7.25%)	250,000	263,750
Senior Subordinated Notes due 2019 (The interest rate is fixed at a rate of 8.0%)	286,853	326,625
Senior Subordinated Notes due 2020 (The interest rate is fixed at a rate of 6.75%)	500,000	515,625
	$ 1,686,536	$ 1,781,813

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

For financial statements required by Item 8, see Item 15 in Part IV of this report.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures are effective as of December 31, 2010.

Management's Annual Report on Internal Control over Financial Reporting and Attestation Report of Registered Public Accounting Firm. Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, we have included a report of management's assessment of the design and effectiveness of its internal controls as part of this Annual Report on Form 10-K for the fiscal year ended December 31, 2010. Ernst & Young LLP, our registered public accountants, also attested to, and reported on, the effectiveness of internal control over financial reporting. Management's report and the independent public accounting firm's attestation report are included in our 2010 Financial Statements in Item 15 under the captions "Management's Report on Internal Control over Financial Reporting" and "Report of Independent Registered Public Accounting Firm on Internal Control over Financial Reporting," and are incorporated herein by reference.

Changes in Internal Control over Financial Reporting. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during fourth quarter 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on that evaluation, there were no changes in our internal control over financial reporting or in other factors that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents filed as part of the report:

1. Financial Statements:

2. All other schedules are omitted because they are not applicable, not required, or because the required information is included in the financial statements or related notes.

3. Exhibits:

(a) See Index of Exhibits on page 29 for a description of the exhibits filed as a part of this report.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Range Resources Corporation:

We have audited the accompanying consolidated balance sheets of Range Resources Corporation (the "Company") as of December 31, 2010 and 2009, and the related consolidated statements of operations, stockholders' equity, comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2010. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our 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 audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Range Resources Corporation at December 31, 2010 and 2009, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 19 to the consolidated financial statements, the Company has changed its reserve estimates and related disclosures as a result of the 2009 adoption of new oil and gas reserve estimation and disclosure requirements.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Range Resources Corporation's internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2011 expressed an unqualified opinion thereon.

Ernst & Young LLP

Fort Worth, Texas
March 1, 2011, except for Note 4 as to which the date is May 6, 2011.

RANGE RESOURCES CORPORATION
CONSOLIDATED BALANCE SHEETS
(In thousands, except per share data)

	December 31, 2010	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$ 2,848	$ 767
Accounts receivable, less allowance for doubtful accounts of $5,001 and $2,176	76,683	80,694
Assets of discontinued operations	876,304	43,481
Deferred tax asset	—	8,054
Unrealized derivative gain	123,255	21,544
Inventory and other	21,352	20,740
Total current assets	1,100,442	175,280
Unrealized derivative gain	—	4,107
Equity method investments	155,105	146,809
Natural gas and oil properties, successful efforts method	5,390,391	4,716,478
Accumulated depletion and depreciation	(1,306,378)	(1,164,843)
	4,084,013	3,551,635
Transportation and field assets	134,980	159,926
Accumulated depreciation and amortization	(60,931)	(68,886)
	74,049	91,040
Assets of discontinued operations	—	1,347,979
Other assets	84,977	79,031
Total assets	$ 5,498,586	$ 5,395,881
Liabilities		
Current liabilities:		
Accounts payable	$ 289,109	$ 191,355
Asset retirement obligations	4,020	2,001
Accrued liabilities	60,082	48,838
Liabilities of discontinued operations	32,962	33,385
Deferred tax liability	11,848	—
Accrued interest	32,189	24,037
Unrealized derivative loss	352	14,488
Total current liabilities	430,562	314,104
Bank debt	274,000	324,000
Subordinated notes	1,686,536	1,383,833
Deferred tax liability	672,041	776,965
Unrealized derivative loss	13,412	271
Liabilities of discontinued operations	3,901	4,564
Deferred compensation liability	134,488	135,541
Asset retirement obligations and other liabilities	59,885	78,014
Total liabilities	3,274,825	3,017,292
Commitments and contingencies		
Stockholders' Equity		
Preferred stock, $1 par, 10,000,000 shares authorized, none issued and outstanding	—	—
Common stock, $0.01 par, 475,000,000 shares authorized, 160,113,608 issued at December 31, 2010 and 158,336,264 issued at December 31, 2009	1,601	1,583
Common stock held in treasury, 204,556 shares at December 31, 2010 and 217,327 shares at December 31, 2009	(7,512)	(7,964)
Additional paid-in capital	1,820,503	1,772,020
Retained earnings	341,699	606,529
Accumulated other comprehensive income	67,470	6,421
Total stockholders' equity	2,223,761	2,378,589
Total liabilities and stockholders' equity	$ 5,498,586	$ 5,395,881

See accompanying notes.

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)

	Year Ended December 31,		
	2010	2009	2008
Revenues and other income:			
Natural gas, NGL and oil sales	$ 760,453	$ 714,564	$ 989,307
Transportation and gathering	1,033	486	4,577
Derivative fair value income	51,634	66,446	71,861
Gain on the sale of assets	76,642	10,413	20,166
Other	(963)	(9,928)	1,509
Total revenues and other income	888,799	781,981	1,087,420
Costs and expenses:			
Direct operating	96,274	98,251	112,983
Production and ad valorem taxes	26,107	25,536	49,371
Exploration	60,506	44,276	56,956
Abandonment and impairment of unproved properties	49,738	36,935	15,292
General and administrative	140,571	115,319	92,308
Termination costs	8,452	2,479	—
Deferred compensation plan	(10,216)	31,073	(24,689)
Interest expense	90,665	75,261	63,963
Loss on early extinguishment of debt	5,351	—	—
Depletion, depreciation and amortization	275,238	267,148	210,963
Impairment of proved properties	6,505	930	—
Total costs and expenses	749,191	697,208	577,147
Income from continuing operations before income taxes	139,608	84,773	510,273
Income tax (benefit) expense			
Current	(836)	(636)	4,268
Deferred	51,746	46,429	176,912
	50,910	45,793	181,180
Income from continuing operations	88,698	38,980	329,093
Discontinued operations, net of taxes	(327,954)	(92,850)	21,947
Net (loss) income	$ (239,256)	$ (53,870)	$ 351,040
(Loss) income per common share:			
Basic-income from continuing operations	$ 0.56	$ 0.25	$ 2.18
-discontinued operations	(2.09)	(0.60)	0.14
-net (loss) income	$ (1.53)	$ (0.35)	$ 2.32
Diluted-income from continuing operations	$ 0.55	$ 0.24	$ 2.11
-discontinued operations	(2.07)	(0.58)	0.14
-net (loss) income	$ (1.52)	$ (0.34)	$ 2.25
Weighted average common shares outstanding:			
Basic	156,874	154,514	151,116
Diluted	158,428	158,778	155,943

See accompanying notes.

Table of Contents

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31, 2010	2009	2008
Operating activities:			
Net (loss) income	$ (239,256)	$ (53,870)	$ 351,040
Adjustments to reconcile net (loss) income to net cash provided from operating activities:			
Loss (income) from discontinued operations	327,954	92,850	(21,947)
Loss from equity method investments	1,482	13,699	218
Deferred income tax expense	51,746	46,429	176,912
Depletion, depreciation and amortization and proved property impairment	281,743	268,078	210,963
Exploration dry hole costs	3,700	2,159	10,934
Mark-to-market on natural gas and oil derivatives not designated as hedges	2,086	115,909	(85,594)
Abandonment and impairment of unproved properties	49,738	36,935	15,292
Unrealized derivative (gain) loss	(2,387)	1,696	(1,695)
Allowance for bad debts	3,608	1,351	450
Amortization of deferred financing costs and other	10,072	8,755	2,900
Deferred and stock-based compensation	34,964	73,402	6,621
Gain on the sale of assets and other	(76,642)	(10,413)	(19,507)
Changes in working capital:			
Accounts receivable	(11,037)	11,673	2,776
Inventory and other	(333)	(1,463)	(9,246)
Accounts payable	2,867	(44,765)	10,663
Accrued liabilities and other	(6,419)	(8,218)	4,716
Net cash provided from continuing operations	433,886	554,207	655,496
Net cash provided from discontinued operations	79,436	37,468	169,271
Net cash provided from operating activities	513,322	591,675	824,767
Investing activities:			
Additions to natural gas and oil properties	(732,860)	(356,329)	(557,972)
Additions to field service assets	(14,944)	(33,098)	(36,076)
Acreage and proved property purchases	(296,503)	(139,288)	(485,265)
Investment in equity method investments and other assets	(45)	7,076	(44,162)
Proceeds from disposal of assets	327,765	234,076	68,231
Purchase of marketable securities held by the deferred compensation plan	(17,670)	(7,470)	(11,208)
Proceeds from the sales of marketable securities held by the deferred compensation plan	19,572	6,079	8,146
Net cash used in investing activities from continuing operations	(714,685)	(288,954)	(1,058,306)
Net cash used in investing activities from discontinued operations	(84,173)	(184,853)	(673,471)
Net cash used in investing activities	(798,858)	(473,807)	(1,731,777)
Financing activities:			
Borrowing on credit facilities	1,055,000	707,000	1,476,000
Repayment on credit facilities	(1,105,000)	(1,076,000)	(1,086,500)
Issuance of subordinated notes	500,000	285,201	250,000
Repayment of subordinated notes	(202,458)	—	—
Dividends paid	(25,574)	(25,169)	(24,625)
Debt issuance costs	(9,600)	(6,399)	(8,710)
Issuance of common stock	5,903	12,737	291,183
Change in cash overdrafts	64,100	(22,370)	4,420
Proceeds from the sales of common stock held by the deferred compensation plan	5,246	7,201	5,303
Purchases of common stock held by the deferred compensation plan and other treasury stock purchases	—	(55)	(3,326)
Net cash provided from (used in) financing activities	287,617	(117,854)	903,745
Increase (decrease) in cash and cash equivalents	2,081	14	(3,265)
Cash and cash equivalents at beginning of year	767	753	4,018
Cash and cash equivalents at end of year	$ 2,848	$ 767	753

See accompanying notes.

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In thousands, except per share data)

	Common stock		Treasury common stock	Additional paid-in capital	Retained earnings	Accumulated other comprehensive (loss) income	Total
	Shares	Par value					
Balance as of December 31, 2007	149,667	$ 1,497	$ (5,334)	$ 1,386,884	$ 360,427	$ (25,738)	**$ 1,717,736**
Issuance of common stock	5,942	59	—	291,822	—	—	**291,881**
Stock-based compensation expense	—	—	—	16,562	—	—	**16,562**
Common dividends declared ($0.16 per share)	—	—	—	—	(24,625)	—	**(24,625)**
Treasury stock purchase	—	—	(3,223)	—	—	—	**(3,223)**
Other comprehensive income	—	—	—	—	—	101,971	**101,971**
Net income	—	—	—	—	351,040	—	**351,040**
Adoption of ASC 825, net of tax	—	—	—	—	(1,274)	1,274	**—**
Balance as of December 31, 2008	155,609	1,556	(8,557)	1,695,268	685,568	77,507	**2,451,342**
Issuance of common stock	2,727	27	—	57,574	—	—	**57,601**
Stock-based compensation expense	—	—	—	19,771	—	—	**19,771**
Common dividends declared($0.16 per share)	—	—	—	—	(25,169)	—	**(25,169)**
Treasury stock issuance	—	—	593	(593)	—	—	**—**
Other comprehensive loss	—	—	—	—	—	(71,086)	**(71,086)**
Net loss	—	—	—	—	(53,870)	—	**(53,870)**
Balance as of December 31, 2009	158,336	1,583	(7,964)	1,772,020	606,529	6,421	**2,378,589**
Issuance of common stock	1,778	18	—	26,138	—	—	**26,156**
Stock-based compensation expense	—	—	—	22,797	—	—	**22,797**
Common dividends declared($0.16 per share)	—	—	—	—	(25,574)	—	**(25,574)**
Treasury stock issuance	—	—	452	(452)	—	—	**—**
Other comprehensive income	—	—	—	—	—	61,049	**61,049**
Net loss	—	—	—	—	(239,256)	—	**(239,256)**
Balance as of December 31, 2010	**160,114**	**$ 1,601**	**$ (7,512)**	**$ 1,820,503**	**$ 341,699**	**$ 67,470**	**$ 2,223,761**

See accompanying notes.

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME
(In thousands)

	December 31, 2010	2009	2008
Net (loss) income	$(239,256)	$ (53,870)	$ 351,040
Other comprehensive income (loss):			
Realized loss (gain) on hedge derivative contract settlements reclassified into earnings from other comprehensive income (loss), net of taxes	(39,931)	(127,965)	39,416
Change in unrealized deferred hedging gains (losses), net of taxes	100,980	56,879	62,555
Total comprehensive (loss) income	$(178,207)	$(124,956)	$ 453,011

See accompanying notes.

Table of Contents

RANGE RESOURCES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) SUMMARY OF ORGANIZATION AND NATURE OF BUSINESS

Range Resources Corporation (“Range,” “we,” “us,” or “our”) is a Fort Worth, Texas-based independent natural gas and oil company primarily engaged in the exploration, development and acquisition of natural gas properties in the Appalachian and Southwestern regions of the United States. Our objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. Range is a Delaware corporation with our common stock listed and traded on the New York Stock Exchange under the symbol “RRC.”

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

The accompanying consolidated financial statements include the accounts of all of our subsidiaries. Investments in entities over which we have significant influence, but not control, are accounted for using the equity method of accounting and are carried at our share of net assets plus loans and advances. Income from equity method investments represents our proportionate share of income generated by equity method investees and is included in other revenues in the accompanying consolidated statements of operations. All material intercompany balances and transactions have been eliminated.

Discontinued Operations

During February 2011, we entered into an agreement to sell our Barnett Shale assets. Accordingly, in the first quarter 2011, we classified the assets and liabilities as discontinued operations in the accompanying consolidated balance sheets along with the historical results of the operations from such properties as discontinued operations, net of tax, in the accompanying statements of operations. See also Note 3 and Note 4.

Use of Estimates

The preparation of financial statements in accordance with generally accepted accounting principles in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end, the reported amounts of revenues and expenses during the year and the reported amount of proved natural gas and oil reserves. We base our estimates on historical experience and various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments that are not readily apparent from other sources. Actual results could differ from these estimates and changes in these estimates are recorded when known.

Reclassifications

Certain reclassifications have been made to prior years’ reported amounts in order to conform with the current year presentation, which includes the reclassification of severance costs associated with the closing of our Houston office and the sale of our New York properties from direct operating expense, exploration expense and general and administrative expense to termination costs. The accompanying consolidated statements of operations also include the reclassification in all periods of the gain on sale of assets from other revenues and the reclassification of impairment of proved properties from depletion, depreciation and amortization. These reclassifications did not impact our net income or loss, stockholders’ equity or cash flows.

Income per Common Share

Basic income (loss) per common share is calculated based on the weighted average number of common shares outstanding. Diluted income (loss) per common share assumes issuance of stock compensation awards, provided the effect is not antidilutive.

Business Segment Information

We have evaluated how Range is organized and managed and have identified only one operating segment, which is the exploration and production of natural gas, natural gas liquids (“NGLs”) and oil. We consider our gathering, processing and marketing functions as ancillary to our natural gas and oil producing activities. Operating segments are defined as components of an enterprise that engage in activities from which it may earn revenues and incur expenses for which separate operational financial information is available and this information is regularly evaluated by the chief operating decision maker for the purpose of allocating resources and assessing performance.

We have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis. Throughout the year, we allocate capital resources on a project-by-project basis, across our entire asset base to maximize profitability without regard to individual areas or segments.

Revenue Recognition and Gas Imbalances

Natural gas, NGL and oil revenues are recognized when the products are sold and delivery to the purchaser has occurred. We recognize the cost of revenues, such as transportation and compression expense, as a reduction to revenue. Although receivables are concentrated in the oil and gas industry, we do not view this as an unusual credit risk. We provide for an allowance for doubtful accounts for specific receivables judged unlikely to be collected based on the age of the receivable, our experience with the debtor, potential offsets to the amount owed and economic conditions. In certain instances, we require purchasers to post stand-by letters of credit. Many of our receivables are from joint interest owners of properties we operate. Thus, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. We have allowances for doubtful accounts relating to exploration and production receivables of $5.0 million at December 31, 2010 compared to $2.2 million at December 31, 2009. During the year ended 2010, we recorded $3.6 million of bad debt expense compared to $1.4 million in the same period of the prior year.

We use the sales method to account for gas imbalances, recognizing revenue based on gas delivered rather than our working interest share of the gas produced. A liability is recognized when the imbalance exceeds the estimate of remaining reserves. Gas imbalances at December 31, 2009 were not significant. At December 31, 2010, we had recorded a net liability of $351,000 for those wells where it was determined that there were insufficient reserves to recover the imbalance situation.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with maturities of three months or less.

Marketable Securities

Holdings of equity securities held in our deferred compensation plans qualify as trading and are recorded at fair value. Investments in the deferred compensation plans are in mutual funds and consist of various publicly-traded mutual funds. These funds are made up of investments which include equities and money market instruments.

Inventories

Inventories consist primarily of tubular goods used in our operations and are stated at the lower of specific cost of each inventory item or market, on a first-in, first-out basis. Our inventory is primarily acquired for use in future drilling operations.

Natural Gas and Oil Properties

We follow the successful efforts method of accounting for natural gas and oil producing activities. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs, delay rentals and costs of carrying and retaining unproved properties are expensed. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. The status of suspended well costs is monitored continuously and reviewed not less than quarterly. We capitalize successful exploratory wells and all developmental wells, whether successful or not. NGLs and oil are converted to gas equivalent basis or mcfe at the rate of one barrel of oil equating to 6 mcf of natural gas. Depreciation, depletion and amortization of proved producing properties is provided on the units of production method. Historically, we have adjusted our depletion rates in the fourth quarter of each year based on the year-end reserve report and other times during the year when circumstances indicate there has been a significant change in reserves or costs. We adopted the new SEC accounting and disclosure regulations for oil and gas companies effective December 31, 2009. Accounting Standards Codification (ASC) 2010-3 clarified that the effect of the change in price encompassed in the new SEC rules was a change in accounting principle inseparable from a change in estimate for 2009 and was accounted for prospectively. For 2009, we estimated the effect of this change in estimate increased depletion, depreciation and amortization expense by approximately $3.4 million ($2.2 million after tax) primarily due to lower prices reflected in our estimated reserves.

Our natural gas and oil producing properties are reviewed for impairment periodically as events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. These assets are reviewed for potential impairments at the lowest levels for which there are identifiable cash flows that are largely independent of other groups of assets. The review is done by determining if the historical cost of proved properties less the applicable accumulated depreciation, depletion and amortization is less than the estimated expected undiscounted future net cash flows. The expected future net cash flows are estimated based on our plans to produce and develop reserves. Expected future net cash inflow from the sale of produced reserves is calculated based on estimated future prices and estimated operating and development costs. We estimate prices based upon market related information including published futures prices. The estimated future level of production is based on assumptions surrounding future levels of prices and costs, field decline rates, market demand and supply, and the economic and regulatory climates. In certain circumstances, we also consider potential sales of properties to third parties in our estimates of cash flows. When the carrying value exceeds the sum of future net cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future net cash flows using a discount rate similar to that used by market participants) and the carrying value of the asset. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future natural gas and oil prices, an estimate of the ultimate amount of recoverable natural gas and oil reserves that will be produced from a field, the timing of future production, future production costs, future abandonment costs and future inflation. We cannot predict whether impairment charges may be required in the future. For additional information regarding 2010 and 2009 proved property impairments, see Note 12.

Proceeds from the disposal of natural gas and oil producing properties that are part of an entire amortization group are credited to the net book value of their amortization group with no immediate effect on income. However, gain or loss is recognized if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base.

We evaluate our unproved property investment periodically for impairment. The majority of these costs generally relate to the acquisition of leasehold costs. The costs are capitalized and evaluated (at least quarterly) as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. Impairment of a significant portion of our unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. Impairment of individually significant unproved property is assessed on a property-by-property basis considering a combination of time, geologic and engineering factors. Unproved properties had a net book value of $648.1 million in 2010 compared to $572.5 million in 2009. Assets of discontinued operations include unproved properties of $163.7 million at December 31, 2010 and $202.0 million at December 31, 2009. We have recorded abandonment and impairment expense related to unproved properties from continuing operations of $49.7 million in 2010 compared to $36.9 million in 2009 and to $15.3 million in 2008.

Transportation and Field Assets

Our gas transportation and gathering systems are generally located in proximity to certain of our principal fields. Depreciation on these pipeline systems is provided on the straight-line method based on estimated useful lives of 10 to 15 years. We receive third-party income for providing field service and certain transportation services, which is recognized as earned. Depreciation on the associated assets is calculated on the straight-line method based on estimated useful lives ranging from five to seven years. Buildings are depreciated over 10 to 15 years. Depreciation expense from continuing operations was $16.1 million in 2010 compared to $31.6 million in 2009 and $13.6 million in 2008. The fourth quarter 2009 includes accelerated depreciation expense of $10.3 million related to an interim processing plant in our Appalachian region that was dismantled in first quarter 2010 and replaced with permanent facilities.

Other Assets

The expenses of issuing debt are capitalized and included in other assets in the accompanying consolidated balance sheets. These costs are amortized over the expected life of the related instruments. When a security is retired before maturity or modifications significantly change the cash flows, related unamortized costs are expensed. Other assets at December 31, 2010 include $27.9 million of unamortized debt issuance costs, $47.8 million of marketable securities held in our deferred compensation plans and $9.3 million of other investments.

Accounts Payable

Included in accounts payable at December 31, 2010 and 2009, are liabilities of approximately $97.2 million and $33.1 million representing the amount by which checks issued, but not presented to our banks for collection, exceeded balances in our applicable bank accounts.

Stock-based Compensation Arrangements

The fair value of stock options and stock-settled SARs is estimated on the date of grant using the Black-Scholes-Merton option-pricing model. The model employs various assumptions, based on management's best estimates at the time of the grant, which impact the fair value calculated and ultimately, the expense that is recognized over the life of the award. We have utilized historical data and analyzed current information to reasonably support these assumptions. The fair value of restricted stock awards is determined based on the fair market value of our common stock on the date of grant.

We recognize stock-based compensation expense on a straight-line basis over the requisite service period for the entire award. The expense we recognize is net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant. Restricted stock awards are classified as a liability and are remeasured at fair value each reporting period.

Derivative Financial Instruments and Hedging

All of our derivative instruments are issued to manage the price risk attributable to our expected natural gas and oil production. While there is risk that the financial benefit of rising natural gas and oil prices may not be captured, we believe the benefits of stable and predictable cash flow are more important. Among these benefits are more efficient utilization of existing personnel and planning for future staff additions, the flexibility to enter into long-term projects requiring substantial committed capital, smoother and more efficient execution of our ongoing development drilling and production enhancement programs, more consistent returns on invested capital and better access to bank and other capital markets. Every unsettled derivative instrument is recorded on the accompanying consolidated balance sheets as either an asset or a liability measured at its fair value. Changes in a derivative's fair value are recognized in earnings unless specific hedge accounting criteria are met. Cash flows from natural gas and oil derivative contract settlements are reflected in operating activities in the accompanying consolidated statements of cash flows.

Through December 2010, we have elected to designate our commodity derivative instruments that qualify for hedge accounting as cash flow hedges. To designate a derivative as a cash flow hedge, we document at the hedge's inception our assessment that the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. This assessment, which is updated at least quarterly, is generally based on the most recent relevant historical correlation between the derivative and the item hedged. The ineffective portion of the hedge is calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged. If, during the derivative's term, we determine the hedge is no longer highly effective, hedge accounting is prospectively discontinued and any remaining unrealized gains or losses, based on the effective portion of the derivative at that date, are reclassified to earnings as natural gas, NGL and oil sales when the underlying transaction occurs. If it is determined that the designated hedged transaction is probable to not occur, any unrealized gains or losses is recognized immediately in derivative fair value income in the accompanying consolidated statements of operations. During 2010, we recognized a pre-tax gain of $11.6 million compared to a pre-tax gain of $5.4 million in 2009 and a pre-tax loss of $583,000 in 2008 as a result of the discontinuance of hedge accounting treatment for certain of our derivatives.

We apply hedge accounting to qualifying derivatives (or "hedge derivatives") used to manage price risk associated with our natural gas and oil production. Accordingly, we record changes in the fair value of our collar and call option contracts, including changes associated with time value, in accumulated other comprehensive income ("AOCI") in the stockholders' equity section of the accompanying consolidated balance sheets. Gains or losses on these collar and call options contracts are reclassified out of AOCI and into natural gas, NGL and oil sales when the underlying physical transaction occurs and the hedging contract is settled. Any hedge ineffectiveness associated with a contract qualifying and designated as a cash flow hedge (which represents the amount by which the change in the fair value of the derivative differs from the change in the cash flows of the forecasted sale of production) is reported currently each period in derivative fair value income on the accompanying consolidated statement of operations. Ineffectiveness can be associated with open positions (unrealized) or can be associated with closed contracts (realized).

Realized and unrealized gains and losses on derivatives that are not designated as hedges (or "non-hedge derivatives") are accounted for using the mark-to-market accounting method. We recognize all unrealized and realized gains and losses related to these contracts in each period in derivative fair value income in the accompanying consolidated statements of operations. We also enter into basis swap agreements which do not qualify for hedge accounting and are marked to market. The price we receive for our gas production can be more or less than the NYMEX price because of adjustments for delivery location ("basis"), relative quality and other factors; therefore, we have entered into basis swap agreement that effectively fix our basis adjustments.

Asset Retirement Obligations

The fair value of asset retirement obligations is recognized in the period they are incurred, if a reasonable estimate of fair value can be made. Asset retirement obligations primarily relate to the abandonment of natural gas and oil producing facilities and include costs to dismantle and relocate or dispose of production platforms, gathering systems, wells and related structures. Estimates are based on historical experience of plugging and abandoning wells, estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future and federal and state regulatory requirements. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. The depreciation will generally be determined on a units-of-production basis while accretion to be recognized will escalate over the life of the producing assets.

Deferred Taxes

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. Deferred tax assets are recorded when it is more likely than not that they will be realized. The realization of deferred tax assets is assessed periodically based on several interrelated factors. These factors include our expectation to generate sufficient taxable income including tax credits and operating loss carryforwards.

Accumulated Other Comprehensive Income (Loss)

The following details the components of AOCI and related tax effects for the three years ended December 31, 2010. Amounts included in AOCI relate to our derivative activity.

	Gross	Tax Effect	Net of Tax
Accumulated other comprehensive loss at December 31, 2007	$ (41,352)	$ 15,614	$ (25,738)
Contract settlements reclassified to income	63,574	(24,158)	39,416
Change in unrealized deferred hedging gains	98,008	(35,453)	62,555
Adoption of fair value accounting for trading securities	2,022	(748)	1,274
Accumulated other comprehensive income at December 31, 2008	122,252	(44,745)	77,507
Contract settlements reclassified to income	(203,119)	75,154	(127,965)
Change in unrealized deferred hedging gains	91,059	(34,180)	56,879
Accumulated other comprehensive income at December 31, 2009	10,192	(3,771)	6,421
Contract settlements reclassified to income	(64,772)	24,841	(39,931)
Change in unrealized deferred hedging gains	165,642	(64,662)	100,980
Accumulated other comprehensive income at December 31, 2010	$ 111,062	$ (43,592)	$ 67,470

Accounting Pronouncements Implemented

Recently Adopted

Accounting standards for variable interest entities were amended by the Financial Accounting Standards Board (the "FASB") in September 2009. The new accounting standards replace the existing quantitative-based risks and rewards calculation for determining which enterprise has a controlling financial interest in a variable interest entity with an approach focused on identifying which enterprise has the power to direct the activities of a variable interest entity. In addition, the concept of qualifying special-purpose entities has been eliminated. Ongoing assessments of whether an enterprise is the primary beneficiary of a variable interest entity are also required. The amended accounting standard for variable interest entities requires reconsideration for determining whether an entity is a variable entity when changes in facts and circumstances occur such that the holders of the equity investment at risk, as a group, lack the power from voting rights or similar rights to direct the activities of the entity. Enhanced disclosures are required for any enterprise that holds a variable interest in a variable interest entity. The adoption of this guidance did not have an impact on our consolidated results of operations, financial position or cash flows.

A standard to improve disclosures about fair value measurements was issued by the FASB in January 2010. The additional disclosures required include: (a) the different classes of assets and liabilities measured at fair value, (b) the significant inputs and techniques used to measure Level 2 and Level 3 assets and liabilities for both recurring and nonrecurring fair value measurements, (c) the gross presentation of purchases, sales, issuances and settlements for the roll forward of Level 3 activity, and (d) the transfers in and out of Levels 1 and 2. We adopted all aspects of this standard in first quarter 2010. This adoption did not have a significant impact on our consolidated results of operations, financial position or cash flows. See Note 12 for our disclosures about fair value measurements.

In February 2010, the FASB amended guidance on subsequent events to alleviate potential conflicts between FASB guidance and SEC requirements. Under this amended guidance, SEC filers are no longer required to disclose the date through which subsequent events have been evaluated in originally issued and revised financial statements. This guidance was effective immediately and we adopted these new requirements in first quarter 2010. The adoption of this guidance did not have an impact on our financial statements.

Accounting Pronouncements Not Yet Adopted

In December 2010, the FASB issued ASU No. 2010-29, which updates the guidance in ASC Topic 805, *Business Combinations.* The objective of ASU 2010-29 is to address diversity in practice about the interpretation of the pro forma revenue and earnings disclosure requirements for business combinations. The amendments in ASU 2010-29 specify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The amendments also expand the supplemental pro forma disclosures to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The amendments affect any public entity as defined by ASC 805 that enters into business combinations that are material on an individual or aggregate basis. This guidance will become effective for us for acquisitions occurring on or after the beginning of our 2012 fiscal year. We do not expect the adoption of this guidance will have a material impact upon our financial position or results of operations.

(3) DISPOSITIONS AND ACQUISITIONS

Dispositions

In February 2010, we entered into an agreement to sell our tight gas sand properties in Ohio. We closed approximately 90% of the sale in March 2010 and closed the remainder in June 2010. The total proceeds we received were approximately $323.0 million and we recorded a gain of $77.6 million. The agreement had an effective date of January 1, 2010, and consequently operating net revenue after January 1, 2010 was a downward adjustment to the selling price. The proceeds we received were placed in a like-kind exchange account and in June 2010, we used a portion of the proceeds to purchase proved and unproved natural gas properties in Virginia. In September 2010, the like-kind exchange account was closed and the balance of these proceeds ($135.0 million) was used to repay amounts outstanding under our credit facility.

In second quarter 2009, we sold certain oil properties located in West Texas for proceeds of $181.8 million. In fourth quarter 2009, we sold natural gas properties in New York for proceeds of $36.3 million. The proceeds from the sale of these properties were credited to natural gas and oil properties, with no gain or loss recognized, as the dispositions did not materially impact the depletion rate of the remaining properties in the amortization base. Additionally, in fourth quarter 2009, we sold Marcellus Shale acreage for $11.2 million and we recognized a gain of $10.4 million. In first quarter 2008, we sold East Texas properties for proceeds of $64.0 million and recorded a gain of $20.2 million.

In October 2010, we announced our plan to offer for sale our Barnett Shale properties in North Central Texas. The properties included approximately 360 producing wells and 700 proved and unproved drilling locations. The data room opened in December 2010 and on February 28, 2011, we announced that we signed a definitive agreement to sell these assets along with certain derivative contracts for a price of $900.0 million, subject to normal closing adjustments. On April 29, 2011, we sold substantially all of the Barnett Shale properties, including the assumption of certain derivatives, for proceeds of $900.0 million before normal closing adjustments (see also Note 4 and Note 12).

Acquisitions

Acquisitions are accounted for as purchases and, accordingly, the results of operations are included in the accompanying statements of operations from the closing date of the acquisition. Purchase prices are allocated to acquired assets and assumed liabilities based on their estimated fair value at the time of the acquisition. In the past, acquisitions have been funded with internal cash flow, bank borrowings and the issuance of debt and equity securities.

In June 2010, we purchased proved and unproved natural gas properties in Virginia for approximately $134.5 million. After recording asset retirement obligations, the purchase price allocated $131.3 million to proved property and $3.7 million to unproved property. We used proceeds from our like-kind exchange account to fund this acquisition (see Dispositions above). No pro forma information has been provided as the acquisition was not considered significant.

In 2009, we completed no material acquisitions. In 2008, we completed several acquisitions of Barnett Shale producing and unproved properties for $331.2 million. After recording asset retirement obligations and transactions costs of $827,000, the purchase price allocated to proved properties was $232.9 million and unproved properties was $99.4 million.

(4) DISCONTINUED OPERATIONS

In October 2010, we announced our plan to offer for sale our Barnett Shale properties in North Central Texas. On February 28, 2011, we announced that we signed a definitive agreement to sell these assets along with certain derivative contracts for a price of $900.0 million subject to normal post-closing adjustments. On April 29, 2011, we sold substantially all of the Barnett Shale properties including the assumption of certain derivatives for proceeds of $900.0 million before normal closing adjustments. The sale had an effective date of February 1, 2011 and therefore, operating net revenues after that date is a downward adjustment to the selling price. The derivatives being assumed as part of the sale transaction are not classified as a component of assets of discontinued operations and, at December 31, 2010, their fair value of $44.5 million was included as a component of unrealized derivative gain in the accompanying balance sheet. Accordingly, assets, liabilities and historical results of operations of our Barnett Shale assets have been classified as discontinued operations herein.

The following table represents the components of discontinued operations for the years ended December 31, 2010, 2009 and 2008 (in thousands).

	Year Ended December 31,		
	2010	2009	2008
Revenues and other income:			
Natural gas, NGL and oil sales	$ 149,154	$ 125,357	$ 237,253
Transportation and gathering	35	—	—
Gain on the sale of assets	955	—	—
Other	32	3	—
	150,176	125,360	237,253
Costs and expenses:			
Direct operating	35,328	34,960	29,404
Production and ad valorem taxes	7,545	6,633	5,801
Exploration	581	2,209	10,734
Abandonment and impairment of unproved properties	20,233	76,603	32,063
Interest expense (a)	40,527	42,106	35,785
Depletion, depreciation and amortization	88,269	106,354	88,868
Impairment of proved properties	463,244	—	—
Total costs and expenses	655,727	268,865	202,655
(Loss) income before income taxes	(505,551)	(143,505)	34,598
Income tax (benefit) expense			
Current	—	—	—
Deferred	(177,597)	(50,655)	12,651
	(177,597)	(50,655)	12,651
Net (loss) income from discontinued operations	$(327,954)	$ (92,850)	$ 21,947

(a) Interest expense is allocated to discontinued operations based on the ratio of net assets of discontinued operations to our consolidated net assets plus long-term debt.

The carrying values of our Barnett operations were included in discontinued operations in the accompanying consolidated balance sheets, which is comprised of the following (in thousands):

	December 31, 2010	December 31, 2009
Composition of assets of discontinued operations:		
Natural gas properties and oil properties, net	$ 838,044	$ —
Transportation and field assets, net	684	—
Accounts receivable	29,300	42,928
Unrealized derivative gain	8,195	1
Inventory and other	81	552
Total current assets of discontinued operations	$ 876,304	$ 43,481
Natural gas and oil properties, net	$ —	$ 1,347,184
Transportation and field assets, net	—	795
Total long-term assets of discontinued operations	$ —	$ 1,347,979
Composition of liabilities of discontinued operations:		
Accounts payable	$ 23,366	$ 23,193
Accrued liabilities	9,596	9,747
Asset retirement obligations	—	445
Total current liabilities of discontinued operations	$ 32,962	$ 33,385
Asset retirement obligations	$ 1,980	$ 1,779
Other liabilities	1,921	2,785
Total long-term liabilities of discontinued operations	$ 3,901	$ 4,564

(5) INCOME TAXES

Our income tax expense from continuing operations was $50.9 million for the year ended December 31, 2010 compared to $45.8 million in 2009 and $181.2 million in 2008. Reconciliation between the statutory federal income tax rate and our effective income tax rate is as follows:

	Year Ended December 31, 2010	2009	2008
Federal statutory tax rate	35.0%	35.0%	35.0%
State	(0.3)	20.6	1.9
Valuation allowance	1.4	(1.9)	(0.2)
Other	0.4	0.3	(1.2)
Consolidated effective tax rate	36.5%	54.0%	35.5%

Table of Contents

Income tax provision attributable to income from continuing operations before income taxes consists of the following:

	Year Ended December 31, 2010	2009 (in thousands)	2008
Current:			
U.S. federal	$ —	$ (1,000)	$ 1,000
U.S. state and local	(836)	364	3,268
	$ (836)	$ (636)	$ 4,268
Deferred:			
U.S. federal	$ 51,280	$ 29,085	$ 174,329
U.S. state and local	466	17,344	2,583
	$ 51,746	$ 46,429	$ 176,912
Total tax provision	$ 50,910	$ 45,793	$ 181,180

Significant components of deferred tax assets and liabilities are as follows:

	December 31, 2010	2009
	(in thousands)	
Deferred tax assets:		
Current		
Deferred compensation	$ 5,857	$ 3,337
Current portion of asset retirement obligation	1,579	952
Other	4,106	6,207
Current portion of net operating loss carryforward	17,586	—
Total current	29,128	10,496
Non-current		
Net operating loss carryforward	85,120	72,131
Deferred compensation	49,933	53,869
AMT credits and other credits	3,211	3,815
Non-current portion of asset retirement obligation	23,127	29,642
Cumulative unrealized mark-to-market loss	9,826	8,625
Other	23,481	20,311
Valuation allowance	(4,841)	(2,555)
Total non-current	189,857	185,838
Deferred tax liabilities:		
Current		
Net unrealized gain in AOCI	(40,976)	(2,443)
Total current	(40,976)	(2,443)
Non-current		
Depreciation, depletion and investments	(858,502)	(959,931)
Net unrealized gain in AOCI	(2,616)	(1,328)
Other	(780)	(1,543)
Total non-current	(861,898)	(962,802)
Net deferred tax liability	$ (683,889)	$ (768,911)

At December 31, 2010, deferred tax liabilities exceeded deferred tax assets by $683.9 million, with $43.6 million of deferred tax liability related to net deferred hedging gains included in AOCI. As of December 31, 2010, we have a $4.8 million valuation allowance on the deferred tax asset related to our deferred compensation plan for planned future distributions to top executives to the extent that their estimated future compensation plus distribution amounts would exceed the $1.0 million deductible limit provided under I.R.C. Section 162(m). As of December 31, 2009, we had a valuation allowance of $600,000 recorded against our capital loss carryover and a $2.0 million valuation allowance on the deferred tax asset related to our deferred compensation plan.

At December 31, 2010, we had regular net operating loss (“NOL”) carryforwards of $413.2 million and alternative minimum tax (“AMT”) NOL carryforwards of $363.9 million that expire between 2012 and 2030. Our deferred tax asset related to regular NOL carryforwards at December 31, 2010 was $102.7 million, which is net of the ASC 718 Stock Compensation reduction for unrealized benefits. Regular NOLs generally offset taxable income and to such extent, no income tax payments are required. At December 31, 2010, we have AMT credit carryforwards of $665,000 that are not subject to limitation or expiration.

We file consolidated tax returns in the United States federal jurisdiction. We file separate company state income tax returns in Louisiana, Mississippi, Ohio, Pennsylvania and Virginia and file consolidated or unitary state income tax returns in New Mexico, Oklahoma, Texas and West Virginia. We are subject to U.S. Federal income tax examinations for the years after 2006 and we are subject to various state tax examinations for years after 2005. We have not extended the statute of limitation period in any tax jurisdiction. Our continuing policy is to recognize interest related to income tax expense in interest expense and penalties in general and administrative expense. We do not have any accrued interest or penalties related to tax amounts as of December 31, 2010. Throughout 2010, our unrecognized tax benefits were not material.

(6) INCOME FROM CONTINUING OPERATIONS PER COMMON SHARE

Basic income from continuing operations per share attributable to common shareholders is computed as (i) income from continuing operations (ii) less income allocable to participating securities (iii) divided by weighted average basic shares outstanding. Diluted income per share attributable to common shareholders is computed as (i) basic income from continuing operations attributable to common shareholders (ii) plus diluted adjustments to income allocable to participating securities divided by weighted average diluted shares outstanding. The following table sets forth a reconciliation of income from continuing operations to basic income from continuing operations attributable to common shareholders and to diluted income from continuing operations attributable to common shareholders and a reconciliation of basic weighted average common shares outstanding to diluted weighted average common shares outstanding (in thousands except per share amounts):

	Year Ended December 31,		
	2010	2009	2008
Numerator:			
Income from continuing operations	$ 88,698	$ 38,980	$ 329,093
Less: Basic income allocable to participating securities (a)	(1,574)	—	—
Basic income from continuing operations attributable to common shareholders	87,124	38,980	329,093
Diluted adjustments to income allocable to participating securities (a)	11	—	—
Diluted income from continuing operations attributable to common shareholders	$ 87,135	$ 38,980	$ 329,093
Denominator:			
Weighted average common shares outstanding — basic	156,874	154,514	151,116
Effect of dilutive securities:			
Employee stock options, SARs and stock held in the deferred compensation plan	1,554	4,264	4,876
Treasury shares	—	—	(49)
Weighted average common shares outstanding — diluted	158,428	158,778	155,943
Income from continuing operations per common share:			
Basic — income	$ 0.56	$ 0.25	$ 2.18
Diluted — income	$ 0.55	$ 0.24	$ 2.11

(a) Restricted stock awards represent participating securities because they participate in nonforfeitable dividends or distributions with common equity owners. Income allocable to participating securities represents the distributed and undistributed earnings attributable to the participating securities. Restricted stock awards do not participate in undistributed net losses.

Weighted average common shares — basic excludes 2.8 million shares at December 31, 2010, 2.6 million shares at December 31, 2009 and 2.3 million shares at December 31, 2008 of restricted stock held in our deferred compensation plans (although all restricted stock is issued and outstanding upon grant). Stock appreciation rights ("SARs") of 2.1 million, 1.1 million and 880,000 shares for the years ended December 31, 2010, 2009 and 2008 were outstanding but not included in the computations of diluted net income per share because the grant prices of the SARs were greater than the average market price of the common shares and would be anti-dilutive to the computations.

(7) SUSPENDED EXPLORATORY WELL COSTS

We capitalize exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. Capitalized exploratory well costs are presented in natural gas and oil properties in the accompanying consolidated balance sheets. If an exploratory well is determined to be impaired, the well costs are charged to expense. The following table reflects the changes in capitalized exploratory well costs for the year ended December 31, 2010, 2009 and 2008 (in thousands):

	2010	2009	2008
Balance at beginning of period	$ 19,052	$ 47,623	$ 15,053
Additions to capitalized exploratory well costs pending the determination of proved reserves	28,897	26,216	43,968
Reclassifications to wells, facilities and equipment based on determination of proved reserves	(24,041)	(52,849)	(3,847)
Capitalized exploratory well costs charged to expense	—	(1,938)	(7,551)
Balance at end of period	23,908	19,052	47,623
Less exploratory well costs that have been capitalized for a period of one year or less	(13,181)	(10,778)	(41,681)
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$ 10,727	$ 8,274	$ 5,942
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	4	6	3

As of December 31, 2010, the $10.7 million of capitalized exploratory well costs that have been capitalized for more than one year relates primarily to wells waiting on pipelines, with three of these wells in our Marcellus Shale area. The following table provides an aging of capitalized exploratory well costs that have been suspended for more than one year as of December 31, 2010 (in thousands):

	Total	2010	2009	2008
Capitalized exploratory well costs that have been capitalized for more than one year	$ 10,727	$ 4,546	$ 4,602	$ 1,579

(8) INDEBTEDNESS

We had the following debt outstanding as of the dates shown below (bank debt interest rate at December 31, 2010 is shown parenthetically). No interest was capitalized during 2010, 2009, and 2008 (in thousands):

	December 31,	
	2010	2009
Bank debt (2.7%)	$ 274,000	$ 324,000
Senior subordinated notes:		
7.375% senior subordinated notes due 2013, net of $1,638 discount in 2009	—	198,362
6.375% senior subordinated notes due 2015	150,000	150,000
7.5% senior subordinated notes due 2016, net of $317 and $363 discount, respectively	249,683	249,637
7.5% senior subordinated notes due 2017	250,000	250,000
7.25% senior subordinated notes due 2018	250,000	250,000
8.0% senior subordinated notes due 2019, net of $13,147 and $14,166 discount, respectively	286,853	285,834
6.75% senior subordinated notes due 2020	500,000	—
Total debt	$ 1,960,536	$ 1,707,833

Bank Debt

In October 2006, we entered into an amended and restated revolving bank facility, which we refer to as our bank debt or our bank credit facility, which is secured by substantially all of our assets. The bank credit facility provides for an initial commitment equal to the lesser of the facility amount or the borrowing base. On December 31, 2010, the facility amount was $1.25 billion and the borrowing base was $1.5 billion. The bank credit facility provides for a borrowing base subject to redeterminations semi-annually and for event-driven unscheduled redeterminations. Our current bank group is comprised of twenty-six commercial banks; with no one bank holding more than 5% of the total facility. The facility amount may be increased to the borrowing base amount with twenty days notice, subject to payment of a mutually acceptable commitment fee to those banks agreeing to participate in the facility increase. As of December 31, 2010, the outstanding balance under the bank credit facility was $274.0 million as well as $5.4 million of undrawn letters of credit leaving $970.1 million of borrowing capacity available under the facility amount. The loan matures on October 25, 2012. Borrowings under the bank facility can either be at the Alternate Base Rate (as defined) plus a spread ranging from 0.875% to 1.625% or LIBOR borrowings at the Adjusted LIBO Rate (as defined) plus a spread ranging from 1.75% to 2.5%. The applicable spread is dependent upon borrowings relative to the borrowing base. We may elect, from time to time, to convert all or any part of our LIBOR loans to base rate loans or to convert all or any of the base rate loans to LIBOR loans. The weighted average interest rate was 2.2% for the year ended December 31, 2010 compared to 2.4% for the year ended December 31, 2009 and 4.4% for the year ended December 31, 2008. A commitment fee is paid on the undrawn balance based on an annual rate of 0.375% to 0.50%. At December 31, 2010, the commitment fee was 0.375% and the interest rate margin was 1.75% on our LIBOR loans and 0.875% on our base rate loans.

Subsequent Development

On February 18, 2011, we entered into an amended and restated revolving bank facility, which replaced our previous bank credit facility. The new facility, secured by substantially all of our assets, provides for an initial commitment equal to the lesser of the facility amount or the borrowing base. At closing, the facility amount was $1.5 billion, the borrowing base was $2.0 billion and there was $1.0 billion of borrowing capacity available under the facility amount. The new bank credit facility provides for a borrowing base subject to redetermination semi-annually each April and October and for event-driven unscheduled redeterminations. The new bank group is comprised of twenty seven commercial banks, with no one bank holding more than 7% of the total facility. The facility amount may be increased to the borrowing base amount with twenty days notice, subject to payment of a mutually acceptable commitment fee to those banks agreeing to participate in the facility increase. As of February 25, 2011, the outstanding balance under the bank credit facility was $440.0 million and of undrawn letters of credit leaving $1.1 billion of borrowing capacity available under the facility amount. The loan matures on February 18, 2016. Borrowings under the bank facility can either be at the Alternate Base Rate (as defined) plus a spread ranging from 0.50% to 1.50% or LIBOR borrowings at the Adjusted LIBO Rate (as defined) plus a spread ranging from 1.50% to 2.5%. The applicable spread is dependent upon borrowings relative to the borrowing base. We may elect, from time to time, to convert all or any part of our LIBOR loans to base rate loans or to convert all or any of the base rate loans to LIBOR loans. A commitment fee is paid on the undrawn balance based on an annual rate of 0.375% to 0.50%. At closing, the commitment fee was 0.375% and the interest rate margin was 1.50% on our LIBOR loans and 0.50% on our base rate loans.

Senior Subordinated Notes

In August 2010, we issued $500.0 million aggregate principal amount of 6.75% senior subordinated notes due 2020 ("6.75% Notes") for net proceeds after underwriting discounts and commissions of $491.3 million. The 6.75% Notes were issued at par. Interest on the 6.75% Notes is payable semi-annually in February and August and is guaranteed by substantially all of our subsidiaries. We may redeem the 6.75% Notes, in whole or in part, at any time on or after August 1, 2015, at redemption prices of 103.375% of the principal amount as of August 1, 2015 declining to 100.0% on August 1, 2018 and thereafter. Before August 1, 2013, we may redeem up to 35% of the original aggregate principal amount of the 6.75% Notes at a redemption price equal to 106.75% of the principal amount thereof, plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings, provided that at least 65% of the original aggregate principal amount of the 6.75% Notes remain outstanding immediately after the occurrence of such redemption and also provided such redemption shall occur within 60 days of the date of the closing of the equity offering. We used $287.1 million of the proceeds to repay outstanding borrowings under our credit facility and $204.2 million to redeem our 7.375% senior subordinated notes due 2013.

If we experience a change of control, there will be a requirement to repurchase all or a portion of all of our senior subordinated notes at 101% of the principal amount plus accrued and unpaid interest, if any. All of the senior subordinated notes and the guarantees by our subsidiary guarantors are general, unsecured obligations and are subordinated to our bank debt and will be subordinated to future senior debt that we or our subsidiary guarantors are permitted to incur under the bank credit facility and the indentures governing the subordinated notes.

Early Extinguishment of Debt

In August 2010, we redeemed our 7.375% senior subordinated notes due 2013 at a redemption price equal to 101.229%. We recorded a loss on extinguishment of debt of $5.4 million including the transaction call premium costs as well as the expensing of related deferred financing cost on the repurchased debt.

Guarantees

Range Resources Corporation is a holding company which owns no operating assets and has no significant operations independent of its subsidiaries. The guarantees by our subsidiaries of our senior subordinated notes are full and unconditional and joint and several; any subsidiaries other than the subsidiary guarantors are minor subsidiaries.

Debt Covenants and Maturity

Our bank credit facility contains negative covenants that limit our ability, among other things, to pay cash dividends, incur additional indebtedness, sell assets, enter into certain hedging contracts, change the nature of our business or operations, merge, consolidate, or make investments. In addition, we are required to maintain a ratio of debt to EBITDAX (as defined in the credit agreement) of no greater than 4.0 to 1.0 and a current ratio (as defined in the credit agreement) of no less than 1.0 to 1.0. We were in compliance with our covenants under the bank credit facility at December 31, 2010.

Following is the principal maturity schedule for the long-term debt outstanding as of December 31, 2010 (in thousands):

	Year Ended December 31,
2011	$ —
2012	274,000
2013	—
2014	—
2015	150,000
2016	249,682
Thereafter	1,286,854
	$ 1,960,536

The indentures governing our senior subordinated notes contain various restrictive covenants that are substantially identical to each other and may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, enter into transactions with affiliates, or change the nature of our business. At December 31, 2010, we were in compliance with these covenants.

(9) ASSET RETIREMENT OBLIGATIONS

Our asset retirement obligations primarily represent the estimated present value of the amounts we will incur to plug, abandon and remediate our producing properties at the end of their productive lives. Significant inputs used in determining such obligations include estimates of plugging and abandonment costs, estimated future inflation rates and well life. The inputs are calculated based on historical data as well as current estimated costs. A reconciliation of our liability for plugging and abandonment costs for the years ended December 31, 2010 and 2009 is as follows (in thousands):

	2010	2009
Beginning of period — continuing operations	$ 76,589	$ 82,380
Liabilities incurred	1,495	1,368
Acquisitions-continuing operations	556	—
Liabilities settled	(2,331)	(556)
Disposition of wells	(12,891)	(15,946)
Accretion expense-continuing operations	5,137	5,720
Change in estimate	(7,862)	3,623
End of period — continuing operations	60,693	76,589
Less current portion	(4,020)	(2,001)
Long-term asset retirement obligations — continuing operations	$ 56,673	$ 74,588
Asset retirement obligations-discontinued operations	$ 1,980	$ 2,224

Accretion expense is recognized as a component of depreciation, depletion and amortization expense in the accompanying statements of operations.

(10) CAPITAL STOCK

We have authorized capital stock of 485.0 million shares which includes 475.0 million shares of common stock and 10.0 million shares of preferred stock. The following is a schedule of changes in the number of common shares outstanding since the beginning of 2008:

	Year Ended December 31,		
	2010	2009	2008
Beginning balance	158,118,937	155,375,487	149,511,997
Public offerings	—	—	4,435,300
Shares issued in lieu of cash bonuses	—	184,926	—
Stock options/SARs exercised	991,988	1,384,861	1,339,536
Restricted stock grants	405,127	413,353	167,054
Issued for acreage purchases	380,229	743,737	—
Treasury shares	12,771	16,573	(78,400)
Ending balance	159,909,052	158,118,937	155,375,487

Treasury Stock

In 2008, the Board of Directors approved up to $10.0 million of repurchases of common stock based on market conditions and opportunities. During 2008, we repurchased 78,400 shares of common stock an average price of $41.11 for a total of $3.2 million. As of December 31, 2010, we have $6.8 million remaining authorization to repurchase shares.

Shelf Registration Statement

In June 2009, we filed a shelf registration statement with the Securities and Exchange Commission to potentially offer securities which include debt securities or common stock. The securities will be offered at prices and on terms to be determined at the time of sale. Net proceeds from the sale of such securities will be used for general corporate purposes, including a reduction of bank debt. Also in June 2009, we issued a $200.0 million registration statement where we may, from time to time, sell shares of our common stock in connection with an acquisition or business combination. As of December 31, 2010, we have $156.4 million remaining under this registration statement.

Common Stock Dividends

The Board of Directors declared quarterly dividends of $0.04 per common share for each of the four quarters of 2010, 2009 and 2008. The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of the Board of Directors and will depend on our financial condition, earnings and cash flow from operations, level of capital expenditures, our future business prospects and other matters our Board of Directors deem relevant. Our bank credit facility and our senior subordinated notes allow for the payment of common dividends, with certain limitations. Dividends are limited to our legally available funds.

(11) DERIVATIVE ACTIVITIES

We use commodity-based derivative contracts to manage exposure to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. We do not utilize complex derivatives such as swaptions, knockouts or extendable swaps. We typically utilize commodity swap and collar contracts to (1) reduce the effect of price volatility of the commodities we produce and sell and (2) support our annual capital budget and expenditure plans. In third quarter 2010, we also entered into call option derivative contracts under which we sold call options on crude oil in exchange for a cash premium received from the counterparty. At the time of settlement of these monthly call options, if the market price exceeds the fixed price of the call option, we will pay 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. At December 31, 2010, we had collars covering 192.8 Bcf of gas at weighted average floor and cap prices of $5.54 to $6.43 per mcf and 0.7 million barrels of oil at weighted average floor and cap prices of $70.00 to $80.00 per barrel. We also had sold call options for 3.7 million barrels of oil at a weighted average price of $82.31. Their fair value, represented by the estimated amount that would be realized upon termination, based on a comparison of the contract price and a reference price, generally NYMEX, approximated a net unrealized pre-tax gain of $118.0 million (including $8.2 million related to discontinued operations) at December 31, 2010. These contracts expire monthly through December 2012. We currently have not entered into any NGL derivative contracts. The following table sets forth the derivative volumes by year as of December 31, 2010. Included in the table below for 2011 natural gas collars is 22,797 Mmbtu/day related to discontinued operations.

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price
Natural Gas			
2011	Collars	408,200 Mmbtu/day	$ 5.56—$6.48
2012	Collars	119,641 Mmbtu/day	$ 5.50—$6.25
Crude Oil			
2012	Collars	2,000 bbls/day	$ 70.00—$80.00
2011	Call options	5,500 bbls/day	$ 80.00
2012	Call options	4,700 bbls/day	$ 85.00

Every derivative instrument is required to be recorded on the balance sheet as either an asset or a liability measured at its fair value. Fair value is determined based on the difference between the fixed contract price and the underlying market price at the determination date. Changes in the fair value of our derivatives that qualify for hedge accounting are recorded as a component of AOCI in the stockholders' equity section of the accompanying consolidated balance sheets, which is later transferred to natural gas, NGL and oil sales when the underlying physical transaction occurs and the hedging contract is settled. As of December 31, 2010, an unrealized pre-tax derivative gain of $111.1 million was recorded in AOCI. This gain will be reclassified into earnings as a gain of $104.3 million in 2011 and a gain of $6.8 million in 2012 as the contracts settle. The actual reclassification to earnings will be based on market prices at the contract settlement date. If the derivative does not qualify as a hedge or is not designated as a hedge, changes in fair value of these non-hedge derivatives are recognized in earnings in derivative fair value income.

For those derivative instruments that qualify for hedge accounting, settled transaction gains and losses are determined monthly, and are included as increases or decreases to natural gas, NGL and oil sales in the period the hedged production is sold. Natural gas, NGL and oil sales include $64.8 million of gains in 2010 compared to gains of $202.9 million in 2009 and losses of $62.4 million in 2008 related to settled hedging transactions. Any ineffectiveness associated with these hedge derivatives are reflected in derivative fair value income in the accompanying statements of operations. The ineffective portion is calculated as the difference between the changes in fair value of the derivative and the estimated change in future cash flows from the item hedged. Derivative fair value income for the year ended December 31, 2010 includes ineffective gains (unrealized and realized) of $2.0 million compared to $3.1 million in 2009 and $3.1 million in 2008.

In addition to the collars above, we have entered into basis swap agreements which do not qualify for hedge accounting and are marked to market. The price we receive for our natural gas production can be more or less than the NYMEX price because of adjustments for delivery location, relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix our basis adjustments. The fair value of the basis swaps was a net unrealized pre-tax loss of $352,000 at December 31, 2010.

Derivative fair value income

The following table presents information about the components of derivative fair value income in the three-year period ended December 31, 2010 (in thousands):

	2010	2009	2008
Change in fair value of derivatives that do not qualify for hedge accounting (a) (c)	$ (2,086)	$ (115,909)	$ 85,594
Realized gain (loss) on settlement-natural gas (a) (b)	35,988	171,998	(1,383)
Realized gain (loss) on settlement-oil (a)(b)	—	7,304	(15,431)
Realized gain on early settlement of oil derivatives (c)	15,697	—	—
Hedge ineffectiveness-realized	(352)	4,749	1,386
-unrealized (c)	2,387	(1,696)	1,695
Derivative fair value income	$ 51,634	$ 66,446	$ 71,861

(a) Derivatives that do not qualify for hedge accounting.

(b) These amounts represent the realized gains and losses on settled derivatives that do not qualify for hedge accounting, which before settlement are included in the category above called the change in fair value of derivatives that do not qualify for hedge accounting.

(c) Not included in realized prices.

Derivative assets and liabilities

The combined fair value of derivatives included in the accompanying consolidated balance sheets as of December 31, 2010 and 2009 is summarized below (in thousands). As of December 31, 2010, we are conducting derivative activities with nine financial institutions, all of which are secured lenders in our bank credit facility. We believe all of these institutions are acceptable credit risks. At times, such risks may be concentrated with certain counterparties. The credit worthiness of our counterparties is subject to periodic review. The assets and liabilities are netted where derivatives with both gain and loss positions are held by a single counterparty.

	December 31, 2010	December 31, 2009
Derivative assets:		
Natural gas-collars	$ 155,159	$ 26,649
-collars - discontinued operations	8,195	—
-basis swaps	—	(1,063)
Crude oil-collars	—	66
-call options	(31,904)	—
	$ 131,450	$ 25,652
Derivative liabilities:		
Natural gas-collars	$ 27,032	$ 2,020
-basis swaps	(352)	(16,779)
Crude oil-collars	(12,051)	—
-call options	(28,393)	—
	$ (13,764)	$ (14,759)

The table below provides data about the fair value of our derivative contracts. Derivative assets and liabilities shown below are presented as gross assets and liabilities, without regard to master netting arrangements, which are considered in the presentation of derivative assets and liabilities in the accompanying consolidated balance sheets (in thousands):

	December 31, 2010			December 31, 2009		
	Assets Carrying Value	(Liabilities) Carrying Value	Net Carrying Value	Assets Carrying Value	(Liabilities) Carrying Value	Net Carrying Value
Derivatives that qualify for cash flow hedge accounting :						
Collars (a)	$ 164,933	$ —	$ 164,933	$ 22,062	$ —	$ 22,062
Collars — discontinued operations	8,195	—	8,195	—	—	—
	$ 173,128	$ —	$ 173,128	$ 22,062	$ —	$ 22,062
Derivatives that do not qualify for hedge accounting :						
Collars (a)	$ 17,259	$ (12,052)	$ 5,207	$ 6,673	$ —	$ 6,673
Call options (a)	—	(60,297)	(60,297)	—	—	—
Basis swaps (a)	—	(352)	(352)	65	(17,907)	(17,842)
	$ 17,259	$ (72,701)	$ (55,442)	$ 6,738	$ (17,907)	$ (11,169)

(a) Included in unrealized derivative gain or loss in the accompanying consolidated balance sheets.

The effects of our cash flow hedges (or those derivatives that qualify for hedge accounting) on accumulated other comprehensive income in the accompanying consolidated balance sheets are summarized below:

	Year Ended December 31,			
	Change in Hedge Derivative Fair Value		Realized Gain Reclassified from OCI into Revenue (a)	
	2010	2009	2010	2009
Collars	$ 157,447	$ 91,209	$ 64,772	$ 202,930
Collars — discontinued operations	8,195	(150)	—	189
Income taxes	(64,662)	(34,180)	(24,841)	(75,154)
	$ 100,980	$ 56,879	$ 39,931	$ 127,965

(a) For realized gains upon contract settlement, the reduction in AOCI is offset by an increase in natural gas, NGL and oil sales. For realized losses upon contract settlement, the increase in AOCI is offset by a decrease in natural gas, NGL and oil sales.

The effects of our non-hedge derivatives (or those derivatives that do not qualify for hedge accounting) and the ineffective portion of our hedge derivatives on our consolidated statement of operations is summarized below:

	Year Ended December 31,								
	Gain (Loss) Recognized in Income (Non-hedge Derivatives)			Gain (Loss) Recognized in Income (Ineffective Portion)			Derivative Fair Value Income		
	2010	2009	2008	2010	2009	2008	2010	2009	2008
Swaps	$ —	$ 63,755	$ 14,395	$ —	$ —	$ (438)	$ —	$ 63,755	$ 13,957
Collars	65,996	33,859	33,119	2,035	3,053	3,519	68,031	36,912	36,638
Call options	(15,895)	—	—	—	—	—	(15,895)	—	—
Basis swaps	(502)	(34,221)	21,266	—	—	—	(502)	(34,221)	21,266
Total	$ 49,599	$ 63,393	$ 68,780	$ 2,035	$ 3,053	$ 3,081	$ 51,634	$ 66,446	$ 71,861

(12) FAIR VALUE MEASUREMENTS

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. There are three approaches for measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value amount using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset. This is often referred to as current replacement cost. The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

The fair value accounting standards do not prescribe which valuation technique should be used when measuring fair value and does not prioritize among the techniques. These standards establish a fair value hierarchy that prioritizes the inputs used in applying the various valuation techniques. Inputs broadly refer to the assumptions that market participants use to make pricing decisions, including assumptions about risk. Level 1 inputs are given the highest priority in the fair value hierarchy while Level 3 inputs are given the lowest priority. The three levels of the fair value hierarchy are as follows.

- Level 1 — Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 — Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.
- Level 3 — Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significantly to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy.

Fair Values-Recurring

We use a market approach for our recurring fair value measurements and endeavor to use the best information available. Accordingly, valuation techniques that maximize the use of observable impacts are favored. The following tables present the fair value hierarchy table for assets and liabilities measured at fair value, on a recurring basis (in thousands):

	Fair Value Measurements at December 31, 2010 Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of December 31, 2010
Trading securities held in the deferred compensation plans	$ 47,794	$ —	$ —	$ 47,794
Derivatives—collars	—	170,140	—	170,140
-collars — discontinued operations	—	8,195	—	8,195
-call options	—	(60,297)	—	(60,297)
-basis swaps	—	(352)	—	(352)

	Fair Value Measurements at December 31, 2009 Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of December 31, 2009
Trading securities held in the deferred compensation plans	$ 43,554	$ —	$ —	$ 43,554
Derivatives—collars	—	28,735	—	28,735
-basis swaps	—	(17,842)	—	(17,842)

Our trading securities in Level 1 are exchange-traded and measured at fair value with a market approach using December 31, 2010 market value. Derivatives in Level 2 are measured at fair value with a market approach using third-party pricing services, which have been corroborated with data from active markets or broker quotes.

Our trading securities held in the deferred compensation plan are accounted for using the mark-to-market accounting method and are included in other assets in the accompanying consolidated balance sheets. We elected to adopt the fair value option to simplify our accounting for the investments in our deferred compensation plan. Interest, dividends, and mark-to-market gains/losses are included in deferred compensation plan expense in the accompanying statement of operations. For the year ended December 31, 2010, interest and dividends were $864,000 and mark-to-market was a gain of $11.5 million. For the year ended December 31, 2009, interest and dividends were $487,000 and the mark-to-market was a gain of $10.4 million. For the year ended December 31, 2008, interest and dividends were $1.5 million and the mark-to-market was a loss of $19.4 million.

Fair Values-Non recurring

We review our long-lived assets to be held and used, including proved natural gas and oil properties, whenever events or circumstances indicate the carrying value of those assets may not be recoverable. Several long-lived assets held for use were evaluated for impairment during 2010 and 2009 due to reductions in estimated reserves and natural gas prices. Additionally, while our Barnett properties did not meet held for sale criteria as of December 31, 2010, our analysis reflected undiscounted cash flows for these properties that were less than their carrying value. We therefore compared the carrying value of the Barnett properties to the estimated fair value of the properties and recognized an impairment charge of $463.2 million in the fourth quarter of 2010, which is reflected in discontinued operations. The fair value of our Barnett properties considered the potential sale of these properties in addition to using an income approach with internal estimates which included reserve quantities, forward natural gas prices, anticipated drilling and operating costs and discount rates, which are Level 3 inputs. The fair value of our onshore Gulf Coast assets in 2010 and our Michigan assets in 2009 was measured using an income approach based upon internal estimates of future production levels, prices, drilling and operating costs and discount rates, which are Level 3 inputs. Our projected undiscounted cash flows associated with these assets was less than their carrying value and therefore, we recorded an impairment of $6.5 million in 2010 related to our onshore Gulf Coast proved properties and an impairment of $930,000 in 2009 on our Michigan proved properties.

In 2009, our investment in Whipstock Natural gas Services, LLC was evaluated for impairment due to reductions in business activity and continued losses. The fair value of this investment was measured using an income approach based upon internal estimates of business activity, prices and discount rates, which are Level 3 inputs. Based on this analysis, we determined our equity investment was not recoverable and an impairment of $9.0 million was recorded.

The following table presents the value of these assets measured at fair value on a nonrecurring basis (in thousands):

	Year Ended December 31,			
	2010		2009	
	Fair Value	Impairment	Fair Value	Impairment
Natural gas and oil properties—continuing operations	$ 16,075	$ 6,505	$ 1,244	$ 930
Natural gas and oil properties—discontinued operations	835,913	463,244	—	—
Equity investments	—	—	2,895	8,950

On February 28, 2011, we announced that we entered into a definitive agreement to sell our Barnett properties and certain derivative contracts, for a price of $900.0 million, subject to typical post-closing adjustments. The basis of the asset group, which excludes the derivative contracts being sold, was approximately $835.9 million, net of the $463.2 million impairment charge noted above. These assets are included in assets of discontinued operations at December 31, 2010 and 2009. On April 29, 2011, we sold substantially all of these assets.

Fair Values — Reported

The following table presents the carrying amounts and the fair values of our financial instruments as of December 31, 2010 and 2009 (in thousands):

	December 31, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:				
Commodity swaps, collars and call options	$ 123,255	$ 123,255	$ 25,652	$ 25,652
Commodity collars—discontinued operations	8,195	8,195	—	—
Marketable securities [(a)]	47,794	47,794	43,554	43,554
Liabilities:				
Commodity swaps, collars and call options	(13,764)	(13,764)	(14,759)	(14,759)
Long-term debt [(b)]	(1,960,536)	(2,055,813)	(1,707,833)	(1,842,625)

(a) Marketable securities are held in our deferred compensation plans.

(b) The book value of our bank debt approximates fair value because of its floating rate structure. The fair value of our senior subordinated notes is based on end of period market quotes.

Our current assets and liabilities contain financial instruments, the most significant of which are trade accounts receivables and payables. We believe the carrying values of our current assets and liabilities approximate fair value. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments and (2) our historical incurrence of and expected future insignificance of bad debt expense.

Concentration of Credit Risk

As of December 31, 2010, our primary concentrations of credit risk are the risks of collecting accounts receivable and the risk of counterparty failure to perform under derivative obligations. Most of our receivables are from a diverse group of companies, including major energy companies, pipeline companies, local distribution companies, financial institutions and end-users in various industries. Letters of credit or other appropriate security are obtained as necessary to limit risk of loss. Our allowance for uncollectible receivables was $5.0 million at December 31, 2010 and $2.2 million at December 31, 2009. As of December 31, 2010, our derivative contracts consist of collars and call options. Our exposure is diversified primarily among major investment grade financial institutions, the majority of which we have master netting agreements with that provide for offsetting payables against receivables from separate derivative contracts. Currently our derivative counterparties include nine financial institutions, all of which are secured lenders in our bank credit facility. None of our derivative contracts have margin requirements or collateral provisions that would require funding prior to the scheduled cash settlement date.

(13) STOCK-BASED COMPENSATION PLANS

Description of the Plans

The 2005 Equity Based Compensation Plan (the “2005 Plan”) authorizes the Compensation Committee of the Board of Directors to grant, among other things, stock options, stock appreciation rights and restricted stock awards to employees and directors. The 2004 Non-Employee Director Stock Option Plan (the “Director Plan”) allows such grants to our non-employee directors of our Board of Directors. The 2005 Plan was approved by stockholders in May 2005 and replaced our 1999 Stock Option Plan. No new grants have been made from the 1999 Stock Option Plan. The number of shares that may be issued under the 2005 Plan is equal to (i) 5.6 million shares (15.0 million less the 2.2 million shares issued under the 1999 Stock Option Plan before May 18, 2005, the effective date of the 2005 Plan and less the 7.2 million shares issuable pursuant to awards under the 1999 Stock Option Plan outstanding as of the effective date of the 2005 Plan) plus (ii) the number of shares subject to 1999 Stock Option Plan awards outstanding at May 18, 2005 that subsequently lapse or terminate without the underlying shares being issued plus (iii) subsequent shares approved by the shareholders. The Director Plan was approved by stockholders in May 2004 and no more than 450,000 shares of common stock may be issued under the Plan.

Stock-based awards under the Plans

Stock options represent the right to purchase shares of stock in the future at the fair value of the stock on the date of grant. Most stock options granted under our stock option plans vest over a three-year period and expire five years from the date they are granted. Beginning in 2005, we began granting stock appreciation rights ("SARs") to reduce the dilutive impact of our equity plans. Similar to stock options, SARs represent the right to receive a payment equal to the excess of the fair market value of shares of common stock on the date the right is exercised over the value of the stock on the date of grant. All SARs granted under the 2005 Plan will be settled in shares of stock, vest over a three-year period and have a maximum term of five years from the date they are granted.

The Compensation Committee grants restricted stock to certain employees and non-employee directors of the Board of Directors as part of their compensation. Compensation expense is recognized over the balance of the vesting period, which is typically three years for employee grants and immediate vesting for non-employee directors. All restricted stock awards are issued at prevailing market prices at the time of the grant and the vesting is based upon an employee's continued employment with us. Prior to vesting, all restricted stock awards have the right to vote such stock and receive dividends thereon. All restricted shares that are granted are placed in our deferred compensation plan and employees are allowed to take withdrawals either in cash or in stock. Restricted stock awards are classified as a liability award and are remeasured at fair value each reporting period. This mark-to-market is reported in deferred compensation plan expense in the accompanying consolidated statements of operations. Historically, we have used unissued shares of stock when restricted stock is issued. However, we also utilize treasury shares when available.

In 2009, as part of the closure of our Houston office, unvested SARs and restricted stock grants were modified and fully vested effective with the closing of the office on November 1, 2009. The incremental compensation cost of this modification was $332,000. As part of the sale of our Ohio properties in 2010, unvested SARs and restricted stock grants were modified and fully vested effective with the date of the sale. The incremental compensation cost of this modification was $2.8 million. These modification costs are reported in termination costs in the accompanying consolidated statements of operations.

Total Stock-Based Compensation Expense

Stock-based compensation represents amortization of restricted stock grants and SARs expense. In 2010, stock-based compensation was allocated to operating expense ($2.0 million), exploration expense ($4.2 million), general and administrative expense ($34.2 million) and termination costs ($2.8 million) for a total of $44.4 million. In 2009, stock-based compensation was allocated to operating expense ($2.5 million), exploration expense ($4.7 million) general administrative expense ($33.3 million) and termination costs ($332,000) for a total of $41.6 million. In 2008, stock-based compensation was allocated to direct operating expense ($2.7 million), exploration expense ($4.1 million) and general and administrative expense ($23.8 million) for a total of $31.1 million. Unlike the other forms of stock-based compensation mentioned above, the mark-to-market of the liability related to the vested restricted stock held in our deferred compensation plans is directly tied to the change in our stock price and not directly related to the functional expenses and therefore, is not allocated to the functional categories. For the year ended December 31, 2010, cash received upon exercise of stock options/SARs awards was $5.9 million. Due to the net operating loss carryforward for tax purposes, tax benefits realized for deductions that were in excess of the stock-based compensation expense were not recognized.

Stock and Option Plans

We have two active equity-based stock plans, the 2005 Plan and the Director Plan. Under these plans, incentive and non-qualified stock options, stock appreciation rights, restricted stock, phantom stock and various other awards may be issued to directors and employees pursuant to decisions of the Compensation Committee, which is made up of non-employee, independent directors from the Board of Directors. All awards granted under these plans have been issued at prevailing market prices at the time of the grant. Since the middle of 2005, only SARs have been granted under the plans to limit the dilutive impact of our equity plans. Of the 6.5 million grants outstanding at December 31, 2010, 785,000 of the grants relate to stock options with the remainder of 5.7 million grants relating to SARs. Information with respect to stock option and SARs activities is summarized below:

	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2007	7,772,325	$ 17.95
Granted	1,159,649	63.18
Exercised	(1,590,390)	12.24
Expired/forfeited	(92,918)	40.82
Outstanding at December 31, 2008	7,248,666	26.15
Granted	1,714,165	36.90
Exercised	(1,717,584)	14.31
Expired/forfeited	(90,535)	40.73
Outstanding at December 31, 2009	7,154,712	31.38
Granted	1,394,136	46.09
Exercised	(1,883,091)	20.49
Expired/forfeited	(203,918)	48.18
Outstanding at December 31, 2010	6,461,839	$ 37.20

The following table shows information with respect to stock options and SARs outstanding and exercisable at December 31, 2010:

	Outstanding			Exercisable	
Range of Exercise Prices	Shares	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Shares	Weighted Average Exercise Price
$1.29 - $9.99	770,056	1.10	$ 3.55	770,056	$ 3.55
10.00 - 19.99	15,435	4.73	19.63	15,435	19.63
20.00 - 29.99	780,219	0.26	24.32	780,219	24.32
30.00 - 39.99	1,958,221	1.94	34.49	1,373,383	34.60
40.00 - 49.99	1,938,906	3.90	44.69	293,309	42.36
50.00 - 59.99	634,837	1.94	58.32	404,805	58.53
60.00 - 69.99	18,927	2.42	65.56	11,356	65.56
70.00 - 75.00	345,238	2.29	75.00	224,285	75.00
Total	6,461,839	2.25	$ 37.20	3,872,848	$ 31.82

Stock Appreciation Right Awards

During 2010, 2009 and 2008, we granted SARs to officers, non-officer employees and directors. The weighted average grant date fair value of these SARs, based on our Black-Scholes-Merton assumptions, is shown below:

	2010	2009	2008
Weighted average exercise price per share	$ 46.09	$ 36.90	$ 63.18
Expected annual dividends per share	0.35%	0.44%	0.26%
Expected life in years	3.6	3.5	3.5
Expected volatility	49%	58%	41%
Risk-free interest rate	1.6%	1.5%	2.4%
Weighted average grant date fair value of SARs granted	$ 17.01	$ 15.42	$ 20.58

The dividend yield is based on the current annual dividend at the time of grant. The expected term was based on the historical exercise activity. The volatility factors are based on a combination of both the historical volatilities of the stock and implied volatility of traded options on our common stock. The risk-free interest rate is based on the U.S. Treasury yield curve in effect at the time of grant for periods commensurate with the expected terms of the options.

The total intrinsic value (the difference in value between exercise and market price) of stock options and SARs exercised during the years ended December 31, 2010 was $50.6 million compared to $50.9 million in 2009 and $67.9 million in 2008. As of December 31, 2010, the aggregate intrinsic value of the awards outstanding was $71.0 million. The aggregate intrinsic value and weighted average remaining contractual life of stock option/SARs awards currently exercisable was $63.5 million and 1.3 years. As of December 31, 2010, the number of fully vested awards and awards expected to vest was 6.3 million. The weighted average exercise price and weighted average remaining contractual life of these awards were $36.91 and 2.2 years and the aggregate intrinsic value was $70.4 million. As of December 31, 2010, unrecognized compensation cost related to the awards was $25.5 million, which is expected to be recognized over a weighted average period of 1.8 years.

Restricted Stock Awards

In 2010, we granted 413,000 shares of restricted stock grants as compensation to directors and employees at an average price of $45.83. The restricted stock grants included 21,000 issued to directors which vest immediately and 392,000 to employees with vesting generally over a three-year period. In 2009, we granted 686,000 shares of restricted stock grants as compensation to directors and employees at an average price of $39.99. The restricted stock grants included 22,700 issued to directors, which vest immediately and 663,300 to employees with vesting generally over a three-year period. In 2008, we issued 362,000 shares of restricted stock grants as compensation to directors and employees at an average price of $63.00. The restricted stock grants included 14,400 issued to directors, which vest immediately and 347,600 to employees with vesting generally over a three-year period. We recorded compensation expense for restricted stock grants of $20.5 million in the year ended December 31, 2010 compared to $19.7 million in 2009 and $14.7 million in 2008. As of December 31, 2010, there was $23.3 million of unrecognized compensation related to restricted stock awards expected to be recognized over a weighted average period of 1.8 years. All of our restricted stock grants are held in our deferred compensation plan. All restricted stock awards are classified as liability award and are remeasured at fair value each reporting period. This mark-to-market is reported in the deferred compensation expense in our consolidated statement of operations (see additional discussion below). The proceeds received from the sale of stock held in our deferred compensation plan was $5.2 million in 2010.

A summary of the status of our non-vested restricted stock outstanding at December 31, 2010 is summarized below:

	Shares	Weighted Average Grant Date Fair Value
Non-vested shares outstanding at December 31, 2007	563,660	$ 30.42
Granted	362,313	63.00
Vested	(438,058)	37.54
Forfeited	(14,368)	38.87
Non-vested shares outstanding at December 31, 2008	473,547	48.50
Granted	685,578	39.99
Vested	(521,536)	40.91
Forfeited	(10,400)	40.83
Non-vested shares outstanding at December 31, 2009	627,189	45.64
Granted	413,422	45.83
Vested	(439,361)	46.90
Forfeited	(18,499)	46.04
Non-vested shares outstanding at December 31, 2010	582,751	$ 44.81

401(k) Plan

We maintain a 401(k) benefit plan that allows employees to contribute up to 75% of their salary (subject to Internal Revenue Service limitations) on a pretax basis. Prior to 2008, we made discretionary contributions of our common stock to the 401(k) Plan annually. Beginning in 2008, we began matching up to 6% of salary in cash. All our contributions become fully vested after the individual employee has two years of service with us. In 2010, we contributed $3.1 million to the plan compared to $3.2 million in 2009 and $2.7 million in 2008. Employees have a variety of investment options in the 401(k) benefit plan.

Deferred Compensation Plan

Our deferred compensation plan gives directors, officers and key employees the ability to defer all or a portion of their salaries and bonuses and invest in Range common stock or make other investments at the individual's discretion. Range provides a partial matching contribution which vests over three years. The assets of all of the plans are held in a grantor trust, which we refer to as the Rabbi Trust, and are therefore available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Our stock held in the Rabbi Trust is treated as a liability award as employees are allowed to take withdrawals from the Rabbi Trust either in cash or in Range stock. The liability for the vested portion of the stock held in the Rabbi Trust is reflected in the deferred compensation liability in the accompanying consolidated balance sheets and is adjusted to fair value each reporting period by a charge or credit to deferred compensation plan expense on our consolidated statements of operations. The assets of the Rabbi Trust, other than our common stock, are invested in marketable securities and reported at their market value in other assets in the accompanying consolidated balance sheets. The deferred compensation liability reflects the vested market value of the marketable securities and Range stock held in the Rabbi Trust. Changes in the market value of the marketable securities and changes in the fair value of the deferred compensation plan liability are charged or credited to deferred compensation plan expense each quarter. We recorded mark-to-market income of $10.2 million in 2010 compared to mark-to-market loss of $31.1 million in 2009 and mark-to-market income of $24.7 million in 2008. The Rabbi Trust held 2.9 million shares (2.3 million of vested shares) of Range stock at December 31, 2010 compared to 2.7 million shares (2.1 million of vested shares) at December 31, 2009.

(14) SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31,		
	2010	2009	2008
		(in thousands)	
Net cash provided from operating activities included:			
Income taxes (refunded from) paid to taxing authorities	$ (1,359)	$ 170	$ 4,298
Interest paid	116,766	108,685	93,954
Non-cash investing and financing activities included:			
Asset retirement costs (removed) capitalized, net	(6,370)	4,985	4,007
Unproved property purchased with stock	20,000	33,726	—
Shares issued in lieu of bonuses	—	6,312	—

(15) COMMITMENTS AND CONTINGENCIES

Litigation

We are the subject of, or party to, a number of pending or threatened legal actions and claims arising in the ordinary course of our business. While many of these matters involve inherent uncertainty, we believe that the amount of the liability, if any, ultimately incurred with respect to proceedings or claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future annual results of operations. We will continue to evaluate our litigation on a quarter-by-quarter basis and will establish and adjust any litigation reserves as appropriate to reflect our assessment of the then current status of litigation.

Lease Commitments

We lease certain office space, office equipment, production facilities, compressors and transportation equipment under cancelable and non-cancelable leases. Rent expense under operating leases (including renewable monthly leases and amounts related to discontinued operations) totaled $18.5 million in 2010 compared to $18.8 million in 2009 and $15.4 million in 2008. Commitments related to these lease payments are not recorded in the accompanying consolidated balance sheets. Future minimum rental commitments under non-cancelable leases having remaining lease terms in excess of one year are as follows (in thousands):

	Operating Lease Obligations
2011	$ 9,913
2012	10,054
2013	7,067
2014	6,395
2015	6,368
Thereafter	27,833
Sublease rentals	(615)
	$ 67,015

Transportation Contracts

We have entered firm transportation contracts with various pipelines. Under these contracts, we are obligated to transport minimum daily natural gas volumes, or pay for any deficiencies at a specified reservation fee rate. In most cases, our production committed to these pipelines is expected to exceed the minimum daily volumes provided in the contracts. As of December 31, 2010, future minimum transportation fees under our gas transportation commitments are as follows (in thousands):

	Transportation Commitments
2011	$ 61,925
2012	61,937
2013	61,404
2014	60,988
2015	59,852
Discontinued operations	14,320
Thereafter	381,697
	$ 702,123

In addition to the amounts included in the above table, we have contracted with several pipeline companies through 2030 to deliver natural gas production volumes in Appalachia from certain Marcellus Shale wells. The agreements call for total incremental increases of 683,000 Mmbtu per day over the 284,905 Mmbtu per day at December 31, 2010. These increases, which are contingent on certain pipeline modifications, are for 350,000 Mmbtu per day in February 2011, 150,000 Mmbtu per day in September 2011, 108,000 Mmbtu per day in November 2012 and 75,000 Mmbtu per day in November 2013.

Drilling Contracts

As of December 31, 2010, we have contracts with drilling contractors to use eight drilling rigs with terms of up to three years and minimum future commitments of $72.9 million in 2011, $53.7 million in 2012, $14.7 million in 2013 and $896,000 in 2014. Six rigs were custom built for our Marcellus Shale program. Early termination of these contracts at December 31, 2010 would have required us to pay maximum penalties of $93.4 million. We do not expect to pay any early termination penalties related to these contracts.

Delivery Commitments — Discontinued Operations

Under a sales agreement, we have an obligation to deliver 30,000 Mmbtu per day of volume at various delivery points within the Barnett Shale in the Fort Worth Basin. The contract, which began in 2008, extends for five years ending March 2013. As of December 31, 2010, remaining volumes to be delivered under this commitment are approximately 24.6 Bcf.

Other

We have agreements in place to purchase seismic data. These agreements total $11.8 million in 2011, $6.0 million in 2012 and $645,000 in 2013. We also have a two-year agreement to lease equipment, material and labor for hydraulic fracturing services for $48.0 million in 2011 and $40.0 million in 2012. We have lease acreage that is generally subject to lease expiration if initial wells are not drilled within a specified period, generally between three to five years. We do not expect to lose significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, we have allowed acreage to expire and will allow additional acreage to expire in the future. To date, our expenditures to comply with environmental or safety regulations have not been significant and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

(16) MAJOR CUSTOMERS

We market our production on a competitive basis. Natural gas is sold under various types of contracts including month-to-month, and one to five-year contracts. Pricing on the month-to-month and short-term contracts is based largely on NYMEX, with fixed or floating basis. For one to five-year contracts, we sell our natural gas on NYMEX pricing, published regional index pricing or percentage of proceeds sales based on local indices. We sell our oil under contracts ranging in terms from month-to-month, up to as long as one year. The price for oil is generally equal to a posted price set by major purchasers in the area or is based on NYMEX pricing or fixed pricing, adjusted for quality and transportation differentials. We sell to natural gas and oil purchasers on the basis of price, credit quality and service reliability. Our NGL production is primarily sold to natural gas processors. For the year ended December 31, 2010, we had no customers that accounted for 10% or more of total oil and gas revenues. For the year ended December 31, 2009, we had no customers that accounted for 10% or more of total oil and gas revenues. For the year ended December 31, 2008, one customer accounted for 10% or more of total oil and gas revenues. We believe that the loss of any one customer would not have a material adverse effect on our results.

(17) EQUITY METHOD INVESTMENTS

We account for our investments in entities over which we have significant influence, but not control, using the equity method of accounting. Under the equity method of accounting, we record our proportionate share of net earnings, declared dividends and partnership distributions based on the most recently available financial statements of the investee. We also evaluate our equity method investments for potential impairment whenever events or changes in circumstances indicate that there is an other than temporary decline in value of the investment. Such events may include sustained operating losses by the investee or long-term negative changes in the investee's industry. For our investment in Whipstock, these indicators were present during the year ended December 31, 2009 and as a result, we recognized impairment charges of $9.0 million related to our equity method investment in 2009.

Investment in Whipstock Natural Gas Services, LLC

In 2006, we acquired a 50% interest in Whipstock Natural Gas Services, LLC ("Whipstock"), an unconsolidated investee in the business of providing oil and gas drilling equipment, well servicing rigs and equipment, and other well services in Appalachia. On the acquisition date, we contributed cash of $11.7 million representing the fair value of 50% of the membership interest in Whipstock.

Whipstock follows a calendar year basis of financial reporting consistent with us and our equity in Whipstock's earnings from the acquisition date is included in other revenue in the accompanying statements of operations for 2010, 2009 and 2008. During the year ended December 31, 2009, we received $301,000 in cash distributions from Whipstock. During the year ended December 31, 2008, we received cash distributions from Whipstock of $1.8 million. In determining our proportionate share of the net earnings of Whipstock, certain adjustments are required to be made to Whipstock's reported results to eliminate the profits recognized by Whipstock for services provided to us. For the year ended December 31, 2010, our equity in the losses of Whipstock totaled $2.2 million compared to losses of $13.1 million in 2009 and losses of $479,000 in 2008. In 2010, equity in the losses of Whipstock was reduced by $1.1 million to eliminate the profit on services provided to us compared to $422,000 in 2009 and $1.8 million in 2008. In addition, equity in 2009 losses of Whipstock reflected a $9.0 million impairment charge due to an other than temporary decline in the fair value of our investment. Our fair value determination was based on a discounted cash flow analysis which qualifies as a level 3 fair value measurement in the fair value hierarchy table. Our net book value in this equity investment was $1.7 million at December 31, 2010. Range and Whipstock have entered into an agreement whereby

Whipstock will provide us with the right of first refusal such that we will have the opportunity to secure services from Whipstock in preference to and in advance of Whipstock entering into additional commitments for services with other customers. All services provided to us are based on Whipstock's usual and customary terms.

Investment in Nora Gathering, LLC

In May 2007, we completed the initial closing of a joint development arrangement with EQT Corporation ("EQT"). Pursuant to the terms of the arrangement, Range and EQT ("the parties") agreed to, among other things, form a new pipeline and natural gas gathering operations entity, Nora Gathering, LLC ("NGLLC"). NGLLC is an unconsolidated investee created by the parties for the purpose of conducting pipeline, natural gas gathering, and transportation operations associated with the parties' collective interests in properties in the Nora Field. In connection with the acquisition, we contributed cash of $94.7 million for a 50% membership interest in NGLLC. During 2010, Range and EQT made no additional contributions to fund the expansion of the Nora Field gathering system infrastructure compared to $6.4 million of additional capital in 2009.

NGLLC follows a calendar year basis of financial reporting consistent with Range and our equity in NGLLC earnings from the acquisition date is included in other revenue in the accompanying statements of operations for 2010, 2009 and 2008. There were no dividends or partnership distributions received from NGLLC during the years ended December 31, 2010 or December 31, 2009. In determining our proportionate share of the net earnings of NGLLC, certain adjustments are required to be made to NGLLC's reported results to eliminate the profits recognized by NGLLC included in the gathering and transportation fees charged to us on production in the Nora field. For the year ended December 31, 2010, our equity in the earnings of NGLLC of $684,000 reflects a reduction of $8.8 million to eliminate the profit on the gathering and transportation fees charged to us. For the year ended December 31, 2009, our equity in the losses of NGLLC of $629,600 reflects a reduction of $7.0 million to eliminate the profit on gathering and transportation fees charged to us. For the year ended December 31, 2008, our equity in the earnings of NGLLC of $261,000 reflects a reduction of $4.8 million to eliminate the profit on gathering and transportation fees charged to us. Our net book value in this equity investment was $153.4 million at December 31, 2010.

(18) OFFICE CLOSING AND EXIT ACTIVITIES

In February 2010, we entered into an agreement to sell our tight gas sand properties in Ohio. The first quarter 2010 includes $5.1 million accrued severance costs, which is reflected in termination costs in the accompanying consolidated statements of operations. As part of their severance agreement, our Ohio employees' vesting of SARs and restricted stock grants was accelerated, increasing termination costs for stock compensation expense by approximately $2.8 million.

In third quarter 2009, we announced the closing of our Gulf Coast area administrative and operations office in Houston, Texas. The properties are now operated from our Southwest area office in Fort Worth. The year ended December 31, 2009 includes $1.3 million of accrued severance, lease termination and accelerated vesting of SARs and restricted stock grants costs. Expenses related to lease termination and severance costs are included in termination costs in the accompanying consolidated statements of operations.

In fourth quarter 2009 we sold our natural gas properties in New York. We accrued $635,000 of severance costs related to this divestiture and the cost is included in termination costs in the accompanying consolidated statements of operations. The following table details our exit activities (in thousands):

	2010	2009
Beginning balance	$ 1,568	$ —
Accrued one-time termination costs	5,138	1,895
Office lease	514	252
Payments	(6,128)	(579)
Ending balance	$ 1,092	$ 1,568

(19) SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following tables set forth unaudited financial information on a quarterly basis for each of the last two years and our Barnett Shale operations have been classified as discontinued operations (in thousands).

	2010				
	March	June	September	December	Total
Revenues and other income:					
Natural gas, NGL and oil sales	$ 187,673	$ 173,153	$ 187,757	$ 211,870	$ 760,453
Transportation and gathering	2,081	663	(1,640)	(71)	1,033
Derivative fair value income (loss)	42,333	6,546	9,981	(7,226)	51,634
Gain (loss) on the sale of assets	67,913	10,176	67	(1,514)	76,642
Other	(1,575)	637	(1,010)	985	(963)
Total revenue and other income	298,425	191,175	195,155	204,044	888,799
Costs and expenses:					
Direct operating	21,836	21,171	25,535	27,732	96,274
Production and ad valorem taxes	6,542	5,663	6,903	6,999	26,107
Exploration	14,139	14,420	15,225	16,722	60,506
Abandonment and impairment of unproved properties	6,551	9,727	14,435	19,025	49,738
General and administrative	28,170	35,836	36,523	40,042	140,571
Termination costs	7,938	—	—	514	8,452
Deferred compensation plan	(5,712)	(14,135)	(5,347)	14,978	(10,216)
Interest expense	20,931	21,271	23,363	25,100	90,665
Loss on early extinguishment of debt	—	—	5,351	—	5,351
Depletion, depreciation and amortization	64,807	67,813	69,730	72,888	275,238
Impairment of proved properties	6,505	—	—	—	6,505
Total costs and expenses	171,707	161,766	191,718	224,000	749,191
Income (loss) from continuing operations before income taxes	126,718	29,409	3,437	(19,956)	139,608
Income tax expense (benefit)					
Current	—	—	(10)	(826)	(836)
Deferred	49,012	11,763	794	(9,823)	51,746
	49,012	11,763	784	(10,649)	50,910
Income (loss) from continuing operations	77,706	17,646	2,653	(9,307)	88,698
Discontinued operations, net of taxes	(127)	(8,594)	(10,821)	(308,412)	(327,954)
Net income (loss)	$ 77,579	$ 9,052	$ (8,168)	$ (317,719)	$ (239,256)
Income (loss) per common share:					
Basic-income (loss) from continuing operations	$ 0.49	$ 0.11	$ 0.02	$ (0.06)	$ 0.56
-discontinued operations	—	(0.05)	(0.07)	(1.96)	(2.09)
-net income (loss)	$ 0.49	$ 0.06	$ (0.05)	$ (2.02)	$ (1.53)
Diluted-income (loss) from continuing operations	$ 0.48	$ 0.11	$ 0.02	$ (0.06)	$ 0.55
-discontinued operations	—	(0.05)	(0.07)	(1.96)	(2.07)
-net income (loss)	$ 0.48	$ 0.06	$ (0.05)	$ (2.02)	$ (1.52)

Table of Contents

	2009				
	March	June	September	December	Total
Revenues and other income:					
Natural gas, NGL and oil sales	$171,579	$168,297	$170,513	$204,175	$714,564
Transportation and gathering	(505)	2,152	2,444	(3,605)	486
Derivative fair value income (loss)	75,547	(9,856)	(482)	1,237	66,446
Gain on the sale of assets	36	(29)	32	10,374	10,413
Other	(1,830)	(4,358)	(475)	(3,265)	(9,928)
Total revenue and other income	244,827	156,206	172,032	208,916	781,981
Costs and expenses:					
Direct operating	26,212	25,891	22,472	23,676	98,251
Production and ad valorem taxes	6,330	6,163	5,948	7,095	25,536
Exploration	12,681	10,896	10,433	10,266	44,276
Abandonment and impairment of unproved properties	6,317	11,406	8,355	10,857	36,935
General and administrative	24,910	29,103	29,925	31,381	115,319
Termination costs	—	—	842	1,637	2,479
Deferred compensation plan	12,434	756	16,445	1,438	31,073
Interest expense	17,076	18,952	19,643	19,590	75,261
Depletion, depreciation and amortization	58,641	61,461	69,213	77,833	267,148
Impairment of proved properties	—	—	—	930	930
Total costs and expenses	164,601	164,628	183,276	184,703	697,208
Income (loss) from continuing operations before income taxes	80,226	(8,422)	(11,244)	24,213	84,773
Income tax expense (benefit)					
Current	—	619	(695)	(560)	(636)
Deferred	29,363	(3,388)	(2,184)	22,638	46,429
	29,363	(2,769)	(2,879)	22,078	45,793
Income (loss) from continuing operations	$ 50,863	$ (5,653)	$ (8,365)	$ 2,135	$ 38,980
Discontinued operations, net of taxes	(18,255)	(34,230)	(21,453)	(18,912)	(92,850)
Net income (loss)	$ 32,608	$ (39,883)	$ (29,818)	$ (16,777)	$ (53,870)
Income (loss) per common share:					
Basic-income (loss) from continuing operations	$ 0.33	$ (0.04)	$ (0.05)	$ 0.01	$ 0.25
-discontinued operations	(0.12)	(0.22)	(0.14)	(0.12)	(0.60)
-net income (loss)	$ 0.21	$ (0.26)	$ (0.19)	$ (0.11)	$ (0.35)
Diluted-income (loss) from continuing operations	$ 0.33	$ (0.04)	$ (0.05)	$ 0.01	$ 0.24
-discontinued operations	(0.12)	(0.22)	(0.14)	(0.12)	(0.58)
-net income (loss)	$ 0.21	$ (0.26)	$ (0.19)	$ (0.11)	$ (0.34)

Principal Unconsolidated Investees (unaudited)

Company	December 31, 2010 Ownership	Activity
Whipstock Natural Gas Services, LLC	50 %	Drilling services
Nora Gathering, LLC	50%	Gas gathering and transportation

Table of Contents

(20) SUPPLEMENTAL INFORMATION ON NATURAL GAS AND OIL EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED)

Our gas natural and oil producing activities are conducted onshore within the continental United States and all of our proved reserves are located within the United States.

Capitalized Costs and Accumulated Depreciation, Depletion and Amortization (a)

	December 31, 2010	2009 (in thousands)	2008
Natural gas and oil properties:			
Properties subject to depletion	$ 4,742,248	$ 4,144,007	$ 4,018,224
Unproved properties	648,143	572,471	485,935
Total	5,390,391	4,716,478	4,504,159
Accumulated depreciation, depletion and amortization	(1,306,378)	(1,164,843)	(1,038,131)
Net capitalized costs	$ 4,084,013	$ 3,551,635	$ 3,466,028

(a) Includes capitalized asset retirement costs and the associated accumulated amortization.

Costs Incurred for Property Acquisition, Exploration and Development (a)

	Year Ended December 31, 2010	2009 (in thousands)	2008
Acquisitions:			
Unproved leasehold	$ 3,697	$ —	$ —
Proved oil and gas properties	130,767	—	320
Asset retirement obligations	556	—	—
Acreage purchases (b)	151,572	162,172	453,792
Development	727,720	374,970	472,946
Exploration:			
Drilling	50,433	49,029	110,023
Expense	56,298	39,873	52,826
Stock-based compensation expense	4,209	4,817	4,130
Gas gathering facilities:			
Development	19,627	27,937	39,472
Subtotal	1,144,879	658,798	1,133,509
Asset retirement obligations	(6,370)	4,985	4,007
Total – continuing operations	1,138,509	663,783	1,137,516
Discontinued operations	73,369	150,461	689,770
Total costs incurred	$ 1,211,878	$ 814,244	$ 1,827,286

(a) Includes cost incurred whether capitalized or expensed.

(b) 2009 includes $20.0 million accrued for acreage purchases for which 380,229 shares were issued in January 2010. 2008 includes a single transaction to acquire Marcellus Shale acreage for $223.9 million.

Estimated Quantities of Proved Oil and Gas Reserves (Unaudited)

Reserves of natural gas, natural gas liquids, crude oil and condensate are estimated by our engineers and are adjusted to reflect contractual arrangements and royalty rates in effect at the end of each year. Many assumptions and judgmental decisions are required to estimate reserves. Reported quantities are subject to future revisions, some of which may be substantial, as additional information becomes available from reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors.

Recent SEC and FASB Rule-Making Activity

In December 2008, the SEC announced that it had approved revisions designed to modernize the natural gas and oil company reserves reporting requirements. We adopted the rules effective December 31, 2009 and the rule changes, including those related to pricing and technology, are included in our reserves estimates for 2010 and 2009.

Reserve Estimation

At year-end 2010, the following independent petroleum consultants conducted a process review of our reserves: DeGolyer and MacNaughton (Southwest), H.J. Gruy and Associates, Inc. (Southwest) and Wright and Company, Inc. (Appalachia). These engineers were selected for their geographic expertise and their historical experience in engineering certain properties. At December 31, 2010, these consultants collectively reviewed approximately 90% of our proved reserves. A copy of the summary reserve report of each of these independent petroleum consultants is included as an exhibit to this Annual Report on Form 10-K. The technical person at each independent petroleum consulting firm responsible for reviewing the reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent petroleum consultants to ensure the integrity, accuracy and timeliness of data furnished to independent petroleum consultants for their reserves review process. Throughout the year, our technical team meets regularly with representatives of each of our independent petroleum consultants to review properties and discuss methods and assumptions. While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, our senior management reviews and approves any internally estimated significant changes to our proved reserves. We provide historical information to our consultants for our largest producing properties such as ownership interest; natural gas and oil production; well test data; commodity prices and operating and development costs. The consultants perform an independent analysis and differences are reviewed with our Senior Vice President of Reservoir Engineering. In some cases, additional meetings are held to review additional reserve work performed by the technical teams related to any identified reserve differences.

Historical variances between our reserve estimates and the aggregate estimates of our consultants have been less than 5%. The reserves included in this Annual Report on Form 10-K are those reserves estimated by our employees. All of our reserve estimates are reviewed and approved by our Senior Vice President of Reservoir Engineering, who reports directly to our President and Chief Operating Officer. Mr. Alan Farquharson, our Senior Vice President of Reservoir Engineering, holds a Bachelor of Science degree in Electrical Engineering from the Pennsylvania State University. Before joining Range, he held various technical and managerial positions with Amoco, Hunt Oil and Union Pacific Resources. During the year, our reserves group may also perform separate, detailed technical reviews of reserve estimates for significant acquisitions or for properties with problematic indicators such as excessively long lives, sudden changes in performance or changes in economic or operating conditions.

The SEC defines proved reserves as those volumes of natural gas, natural gas liquids, crude oil and condensate that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves, which can be expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped reserves are volumes 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 drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Proved undeveloped reserves can only be assigned to acreage for which improved recovery technology is contemplated when such techniques have been proven effective by actual tests in the area and in the same reservoir. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating they are scheduled to be drilled within five years, unless specific circumstances, justify a longer time.

Production quantities shown are net volumes withdrawn from reservoirs. These may differ from sales quantities due to inventory changes, and, especially in the case of natural gas, volumes consumed for fuel and/or shrinkage from extraction of natural gas liquids.

The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future net cash flows because prices, costs and governmental policies do not remain static, appropriate discount rates may vary, and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts.

Table of Contents

The average realized prices used at December 31, 2010 to estimate reserve information were $72.51 per barrel of oil, $39.14 per barrel for natural gas liquids and $3.70 per mcf for gas, using benchmark prices (NYMEX) of $79.81 per barrel and $4.38 per Mmbtu. The average realized prices used at December 31, 2009 to estimate reserve information were $54.65 per barrel of oil, $34.05 per barrel for natural gas liquids and $3.19 per mcf for gas, using benchmark prices (NYMEX) of $60.85 per barrel and $3.87 per Mmbtu. The average realized prices used at December 31, 2008 to estimate reserve information were $42.76 per barrel of oil, $25.00 per barrel for natural gas liquids and $5.23 per mcf for gas, using benchmark prices (NYMEX) of $44.60 per barrel and $5.71 per Mmbtu.

	Natural Gas (Mmcf)	NGLs (Mbbls)	Crude Oil (Mbbls)	Natural Gas Equivalents (a) (Mmcfe)
Proved developed and undeveloped reserves:				
Balance, December 31, 2007	1,832,797	17,748	48,912	2,232,762
Revisions	(23,397)	1,791	(4,946)	(42,333)
Extensions, discoveries and additions	423,354	5,643	10,198	518,404
Purchases	95,262	53	—	95,578
Property sales	(147)	—	(1,592)	(9,701)
Production	(114,323)	(1,386)	(3,085)	(141,145)
Balance, December 31, 2008	2,213,546	23,849	49,487	2,653,565
Revisions	(37,497)	8,434	(1,536)	3,890
Extensions, discoveries and additions	620,114	21,492	3,479	769,939
Purchases	—	—	—	—
Property sales	(50,797)	—	(14,791)	(139,543)
Production	(130,649)	(2,187)	(2,557)	(159,112)
Balance, December 31, 2009	2,614,717	51,588	34,082	3,128,739
Revisions	3,599	26,832	(2,672)	148,558
Extensions, discoveries and additions	1,089,632	48,792	4,663	1,410,359
Purchases	124,981	—	—	124,981
Property sales	(124,369)	—	(10,865)	(189,558)
Production	(142,034)	(4,490)	(1,969)	(180,789)
Balance, December 31, 2010 (b)	3,566,526	122,722	23,239	4,442,290
Proved developed reserves:				
December 31, 2008	1,337,978	16,398	32,611	1,632,032
December 31, 2009	1,445,705	26,205	20,626	1,726,696
December 31, 2010	1,762,766	53,071	17,050	2,183,488
Proved undeveloped reserves:				
December 31, 2008	875,567	7,451	16,876	1,021,531
December 31, 2009	1,169,012	25,382	13,457	1,402,043
December 31, 2010	1,803,760	69,651	6,189	2,258,802

(a) Oil and NGLs are converted to mcfe at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil to natural gas, which is not necessarily indicative of the relationship of oil and natural gas prices.

(b) Total proved reserves at December 31, 2010 includes 906,371 Mmcfe related to discontinued operations of which 408,710 Mmcfe is proved undeveloped.

The following details the changes in proved undeveloped reserves for 2010 (Mmcfe):

Beginning proved undeveloped reserves-2009	1,402,043
Undeveloped reserves transferred to developed	(191,220)
Revisions	(75,685)
Purchases/sales	(25,643)
Extension and discoveries	1,149,307
Ending proved undeveloped reserves-2010	2,258,802

During 2010, various exploration and development drilling evaluations were completed. Approximately $192.0 million was spent during 2010 related to undeveloped reserves that were transferred to developed reserves. Estimated future development costs relating to the development of proved undeveloped reserves are projected to be approximately $476.9 million in 2011, $830.8 million in 2012 and $924.8 million in 2013. Included in proved undeveloped reserves at December 31, 2010 are approximately 2,388 Mmcfe of reserves (less than 1% of total proved undeveloped reserves) that have been reported for five or more years. All proved undeveloped drilling locations are scheduled to be drilled prior to the end of 2015.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited)

The following summarizes the policies we used in the preparation of the accompanying natural gas and oil reserve disclosures, standardized measures of discounted future net cash flows from proved natural gas and oil reserves and the reconciliations of standardized measures from year to year. The information disclosed is an attempt to present the information in a manner comparable with industry peers.

The information is based on estimates of proved reserves attributable to our interest in natural gas and oil properties as of December 31 of the years presented. These estimates were prepared by our petroleum engineering staff. Proved reserves are estimated quantities of natural gas, NGLs and crude oil, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

1. Estimates are made of quantities of proved reserves and future amounts expected to be produced based on current year-end economic conditions.
2. Prior to 2009, estimated future cash inflows were calculated by applying current year-end prices of natural gas and oil relating to our proved reserves to the quantities of those reserves produced in each future year. For 2009 and 2010, estimated future cash inflows are calculated by applying a twelve-month average price of natural gas and oil relating to our proved reserves to the quantities of those reserves produced in each future year.
3. Future cash flows are reduced by estimated production costs, administrative costs, costs to develop and produce the proved reserves and abandonment costs, all based on current year-end economic conditions. Future income tax expenses are based on current year-end statutory tax rates giving effect to the remaining tax basis in the natural gas and oil properties, other deductions, credits and allowances relating to our proved natural gas and oil reserves.
4. The resulting future net cash flows are discounted to present value by applying a discount rate of 10%.

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of our natural gas and oil reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves, which includes reserves associated with discontinued operations, is as follows and excludes cash flows associated with hedges outstanding at each of the respective reporting dates.

	As of December 31, 2010	2009
	(in thousands)	
Future cash inflows	$19,676,630	$11,969,906
Future costs:		
Production	(4,305,292)	(3,371,762)
Development	(2,855,407)	(1,877,330)
Future net cash flows before income taxes	12,515,931	6,720,814
Future income tax expense	(3,923,264)	(1,767,965)
Total future net cash flows before 10% discount	8,592,667	4,952,849
10% annual discount	(5,113,541)	(2,861,760)
Standardized measure of discounted future net cash flows	$ 3,479,126	$ 2,091,089

The following table summarizes changes in the standardized measure of discounted future net cash flows.

	As of December 31, 2010	2009	2008
		(in thousands)	
Beginning of period	$2,091,089	$2,581,380	$ 3,666,363
Revisions of previous estimates:			
Changes in prices	957,994	(992,809)	(1,675,703)
Revisions in quantities	190,874	4,124	(65,931)
Changes in future development costs	(474,058)	(375,344)	(688,259)
Accretion of discount	259,280	340,025	520,482
Net change in income taxes	(666,517)	317,158	719,595
Purchases of reserves in place	160,580	—	148,857
Additions to proved reserves from extensions, discoveries and improved recovery	1,812,077	816,278	807,386
Production	(744,354)	(673,907)	(1,029,001)
Development costs incurred during the period	298,624	316,523	333,979
Sales of natural gas and oil	(243,551)	(147,942)	(15,109)
Timing and other	(162,912)	(94,397)	(141,279)
End of period	$3,479,126	$2,091,089	$ 2,581,380

Table of Contents

SIGNATURES

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

RANGE RESOURCES CORPORATION

By: /s/ *Roger S. Manny*
Roger S. Manny
Chief Financial Officer

Date: May 6, 2011

Table of Contents

RANGE RESOURCES CORPORATION

INDEX TO EXHIBITS

Exhibit Number	Exhibit Description
23.1*	Consent of Independent Registered Public Accounting Firm
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith.

** Furnished herewith.

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-150474, 333-161314, 333-159112, 333-158930, 333-160169 and 333-168371) on Form S-4 (Nos. 333-78231, 333-108516, 333-117834, 333-123534 and 333-160170) and on Form S-8 (Nos. 333-151818, 333-125665, 333-90760, 333-63764, 333-40380, 333-30534, 333-88657, 333-69905, 333-62439, 333-44821, 333-10719, 333-105895, 333-116320, 333-135196, 333-135198, 333-143875, 333-159951 and 333-167199) of Range Resources Corporation and in the related Prospectuses of our report dated March 1, 2011, except Note 4, as to which the date is May 6, 2011, with respect to the consolidated financial statements of Range Resources Corporation as of December 31, 2010 and 2009 and for each of the three years ended December 31, 2010 included in this Current Report on Form 8-K.

/s/ Ernst & Young LLP

Fort Worth, Texas
May 6, 2011