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Total	11,153,565	8,479,534	31.5%

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	Three Months Ended March 31,		
	2009	2008	Change
Average Sales Price (excluding realized derivative gains/losses)			
Oil (per Bbl)			
Rocky Mountain Region	$37.78	$81.08	-53.4%
Appalachian Basin	37.06	88.71	-58.2%
Michigan Basin	36.90	96.03	-61.6%
Weighted average price	37.77	81.14	-53.5%
Natural gas (per Mcf)			
Rocky Mountain Region	$2.95	$7.13	-58.6%
Appalachian Basin	5.04	8.41	-40.1%
Michigan Basin	4.24	7.63	-44.4%
Weighted average price	3.23	7.33	-55.9%
Natural gas equivalent (per Mcfe)			
Rocky Mountain Region	$3.65	$8.49	-57.0%
Appalachian Basin	5.04	8.45	-40.4%
Michigan Basin	4.26	7.74	-45.0%
Weighted average price	3.79	8.45	-55.1%

While our production increased to 11.2 Bcfe for first quarter 2009 from 8.5 Bcfe for first quarter 2008, our oil and gas sales revenue decreased $31.9 million quarter-to-quarter, primarily due to the dramatic decline in commodity prices, partially offset by increased volumes. Approximately $39.5 million of the decrease in revenue was due to pricing, offset in part by increased production, which contributed $10.1 million. The decrease in oil and gas sales revenue was offset by realized derivative gains for first quarter 2009 of $36.6 million, see Oil and Gas Price Risk Management, Net discussion below.

Oil and Natural Gas Pricing. Financial results depend upon many factors, particularly the price of oil and natural gas and our ability to market our production effectively. Oil and natural gas prices have been among the most volatile of all commodity prices. These price variations have a material impact on our financial results. Oil and natural gas prices also vary by region and locality, depending upon the distance to markets, and the supply and demand relationships in that region or locality. This can be especially true in the Rocky Mountain Region. The combination of increased drilling activity and the lack of local markets have resulted in a local market oversupply situation from time to time. Like most producers in the region, we rely on major interstate pipeline companies to construct these facilities to increase pipeline capacity, rendering the timing and availability of these facilities beyond our control. Oil pricing is also driven strongly by supply and demand relationships.

The price we receive for a large portion of the natural gas produced in the Rocky Mountain Region is based on a market basket of prices, which generally includes gas sold at CIG prices as well as gas sold at Mid-Continent or other nearby region prices. The CIG Index, and other indices for production delivered to other Rocky Mountain pipelines, has historically been less than the price received for natural gas produced in the eastern regions, which is NYMEX based.

Although 86.1% of our natural gas production for first quarter 2009 is produced in the Rocky Mountain Region, much of our Rocky Mountain natural gas pricing is based upon other indices in addition to CIG. The table below identifies the pricing basis of our oil and natural gas sales based on production for first quarter 2009. The pricing basis is the index that most closely relates to the price under which our oil and natural gas is sold.

Energy Market Exposure
For the Three Months Ended March 31, 2009

Area	Pricing Basis	Commodity	Percent of Production
Piceance/Wattenberg	Colorado Interstate Gas (CIG)	Gas	37%
Colorado/North Dakota	NYMEX	Oil	18%
Piceance	San Juan Basin/Southern California	Gas	16%
NECO	Mid Continent (Panhandle Eastern)	Gas	12%
Appalachian	NYMEX	Gas	9%
Wattenberg	Colorado Liquids	Gas	4%
Michigan	Mich-Con/NYMEX	Gas	3%
Other	Other	Gas/Oil	1%
			100%

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Oil and Gas Production and Well Operations Costs. Oil and gas production and well operations cost includes our lifting cost, production taxes, the cost to operate wells and pipelines for our affiliated partnerships and other third parties (whose income is included in well operations and pipeline income) and certain production and engineering staff related overhead costs.

	Three Months Ended March 31,	
	2009	2008
	(in thousands)	
Lifting cost, excluding production taxes	$ 10,321	$ 9,610
Production taxes	1,913	5,015
Costs for well operations segment	1,643	1,362
Overhead and other production expenses	2,339	2,145
Total oil and gas production and well operations cost	$ 16,216	$ 18,132

Lifting Costs. Lifting costs per Mcfe, excluding production taxes which fluctuate with oil and natural gas prices, decreased 17.7% to $0.93 per Mcfe for first quarter 2009 from $1.13 per Mcfe for first quarter 2008. The decrease is primarily due to a 31.5% increase in production, which allows us to spread the fixed portion of our production costs over an increased volume, thereby lowering the per unit cost. Additionally, lower oil and natural gas prices have also put pressure on oil and gas service providers to reduce their rates, for which we have started seeing the benefits. We expect a downward trend to continue until commodity prices rebound.

Production Taxes. Production taxes decreased $3.1 million or 61.9% to $1.9 million. This decrease is primarily related to the 40.9% decrease in oil and gas sales along with a decrease of $1.1 million in our estimated 2008 taxes.

Oil and Gas Price Risk Management, Net

	Three Months Ended March 31,	
	2009	2008
	(in thousands)	
Oil and gas price risk management, net:		
Realized gain (loss)		
Oil	$ 7,294	$ (1,306)
Natural gas	29,332	(1,105)
Total realized gain, net	36,626	(2,411)
Reclassification of realized (gains) losses included in prior periods unrealized	(30,193)	351
Unrealized gains (losses) for the period	17,250	(40,250)
	$ 23,683	$ (42,310)

The net unrealized gain for first quarter 2009 of $17.3 million was primarily due to a $33 million net unrealized gain from our commodity derivatives offset in part by a decrease in fair value of our CIG basis protection swaps of $15.7 million. The net unrealized gain from commodity derivatives resulted from the continued decline in commodity prices during the first quarter. The unrealized loss from our CIG basis protection swaps resulted from a more significant decline in NYMEX pricing compared to CIG pricing. The realized gains from commodity derivatives resulted from the current realized prices being below our swaps and floor contract prices.

Oil and gas price risk management, net includes realized gains and losses and unrealized changes in the fair value of derivative instruments related to our oil and natural gas production. Oil and gas price risk management, net does not include derivative transactions related to natural gas marketing activities, which are included in sales from and cost of natural gas marketing activities. See Note 3, Fair Value Measurements, and Note 4, Derivative Financial Instruments, to the accompanying condensed consolidated financial statements for additional details of our derivative financial instruments.

Oil and Gas Derivative Activities. We use various derivative instruments to manage fluctuations in oil and natural gas prices. We have in place a series of collars, fixed price swaps and basis swaps on a portion of our oil and natural gas production. Under the collar arrangements, if the applicable index rises above the ceiling price or swap, we pay the counterparty; however, if the index drops below the floor or swap, the counterparty pays us.

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The following table identifies our derivative positions (excluding the derivative positions allocated to our affiliated partnerships) related to oil and gas sales activities in effect as of March 31, 2009, on our production by area. Our production volumes for first quarter 2009 were 343,884 Bbls of oil and 9.1 Bcf of natural gas. No new positions have been entered into subsequent to March 31, 2009, through the date of this filing.

	Floors		Ceilings		Swaps (Fixed Prices)		Basis Protection Contracts		Fai Valu
Commodity/ Index/ Operating Area	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	At Marc 31, 2009 (in thousa
Natural Gas									
Rocky Mountain Region									
CIG									
2Q 2009	3,641,103	$5.75	3,641,103	$8.90	-	$-	-	$-	$11,9
3Q 2009	3,641,103	5.75	3,641,103	8.90	-	-	-	-	10,4
4Q 2009	2,656,180	6.70	2,656,180	10.26	1,008,939	9.20	-	-	14,2
2010	2,845,497	6.84	2,845,497	10.93	1,513,408	9.20	6,957,835	1.88	9,66
2011	1,022,667	4.75	1,022,667	9.45	-	-	7,651,364	1.88	(4,7
2012	-	-	-	-	-	-	7,687,672	1.88	(5,6
2013	-	-	-	-	-	-	6,888,618	1.88	(4,3
PEPL									
2Q 2009	720,000	6.14	720,000	10.81	-	-	-	-	2,42
3Q 2009	720,000	6.14	720,000	10.81	-	-	-	-	1,95
4Q 2009	580,000	7.81	580,000	12.68	240,000	10.91	-	-	3,90
2010	1,470,000	6.52	1,470,000	10.79	1,060,000	7.99	-	-	5,85
2011	390,000	5.76	390,000	9.56	-	-	-	-	218
NYMEX									
2010	417,447	5.75	417,447	8.30	6,016,290	5.60	-	-	(1,12
2011	551,618	5.75	551,618	8.30	-	-	-	-	(84
Appalachian and Michigan Basins									
NYMEX									
2Q 2009	903,434	7.13	903,434	12.85	429,430	9.09	-	-	5,30
3Q 2009	903,434	7.13	903,434	12.85	429,430	9.09	-	-	4,84
4Q 2009	866,452	9.00	866,452	15.66	429,138	9.09	-	-	5,34
2010	1,543,551	8.22	1,543,551	14.19	1,879,614	8.78	-	-	9,50
2011	264,504	6.62	264,504	11.64	797,515	9.60	-	-	2,41
2012	-	-	-	-	154,379	9.89	-	-	378
Total Natural Gas									72,5

Oil									
Rocky Mountain Region									
NYMEX									
2Q 2009	-	-	-	-	155,891	90.52	-	-	6,03
3Q 2009	-	-	-	-	157,603	90.52	-	-	5,53
4Q 2009	-	-	-	-	157,603	90.52	-	-	5,07
2010	-	-	-	-	529,624	92.96	-	-	15,6
Total Oil									32,3
Total Natural Gas and Oil									$ 104,

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Natural Gas Marketing Activities

The decreases in sales from and cost of natural gas marketing activities for first quarter 2009 compared to first quarter 2008 is primarily due to a decrease in prices of approximately 40%, partially offset by increases in realized and unrealized derivative gains.

Our natural gas marketing segment specializes in the purchase, aggregation and sale of natural gas production in our eastern operating areas. Through our natural gas marketing segment, we market the natural gas we produce as well as our purchases of natural gas from other producers in the Appalachian Basin, including our affiliated partnerships. Our derivative activities related to natural gas marketing activities include both physical and cash-settled derivatives. We offer fixed-price derivative contracts for the purchase or sale of physical gas and enter into cash-settled derivative positions with counterparties in order to offset those same physical positions. We do not take speculative positions on commodity prices.

Natural Gas Marketing Derivative Activities. The following table identifies our derivative positions related to our gas marketing activities in effect as of March 31, 2009.

	Swaps (Fixed Prices)		Basis Swaps		Fair Value
Commodity/ Derivative Instrument	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	At March 31, 2009 (in thousands)
Natural Gas					
Physical Sales					
2Q 2009	73,132	$ 7.76	84,644	$ 0.32	$ 261
3Q 2009	61,320	7.66	77,631	0.32	205
4Q 2009	19,293	6.98	115,026	0.35	38
2010	15,610	8.45	137,632	0.38	31
Financial Purchases					
2Q 2009	73,132	6.86	-	-	(226)
3Q 2009	61,191	6.80	-	-	(163)
4Q 2009	39,293	9.32	61,000	0.17	(175)
2010	45,610	10.86	90,000	0.17	(235)
Financial Sales					
2Q 2009	322,500	9.27	211,272	0.32	1,794
3Q 2009	250,500	9.39	141,250	0.32	1,336
4Q 2009	248,500	8.90	166,050	0.32	1,001
2010	695,000	8.71	-	-	1,904
2011	150,000	8.44	-	-	237
Physical Purchases					
2Q 2009	322,995	9.44	46,874	0.32	(1,770)
3Q 2009	250,995	9.56	46,752	0.32	(1,338)

4Q 2009	228,665	9.60	15,584	0.32		(1,035)
2010	665,000	9.14	-	-		(2,024)
2011	150,000	8.61	-	-		(251)
Total Natural Gas					$	(410)

Oil and Gas Well Drilling

Oil and gas well drilling operations revenue was $0.2 million for first quarter 2009 compared to $3.1 million for first quarter 2008. The decrease is due to our decision, as announced in January 2008, not to sponsor a drilling partnership in 2008. In August 2007, we completed our only sponsored drilling partnership offering in 2007. Drilling for the partnership commenced during the third quarter of 2007, with the majority of the revenue being recognized in 2008. Currently, we do not plan to sponsor a drilling partnership in 2009 or in the foreseeable future.

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Other Costs and Expenses

Exploration Expense.

The following table sets forth the major components of exploration expense.

	Three Months Ended March 31,	
	2009	2008
	(in thousands)	
Amortization and impairment of unproved properties	$ 614	$ 442
Exploratory dry holes	832	1,100
Geological and geophysical costs	253	846
Operating and other (1)	3,944	1,895
Total exploration expense	$ 5,643	$ 4,283

(1) 2009 includes $0.7 million related to tubular inventory impairments and $0.9 million for demobilization of drilling rigs in the Piceance Basin.

General and Administrative Expense.

General and administrative expense increased to $12.1 million for first quarter 2009 from $9.8 million for first quarter 2008. However, on a per Mcfe basis, general and administrative expenses declined to $1.08 per Mcfe for first quarter 2009 from $1.16 per Mcfe for first quarter 2008. The increase for first quarter 2009 is primarily related to increased staffing and related payroll benefits of $2 million, the expensing of previously capitalized acquisitions costs of $1.5 million pursuant to the adoption of a new accounting standard, increased stock-based compensation costs of $1 million and increased office space and related rent of $0.4 million. General and administrative expense for first quarter 2008 includes $3.2 million in payroll and payroll related expenses, including $1.1 million in acceleration of stock-based compensation expense, relating to a separation agreement with our former president. See Note 2, Recent Accounting Standards, to the accompanying condensed consolidated financial statements.

Depreciation, Depletion, and Amortization.

DD&A expense includes depreciation and amortization expense related to non-oil and natural gas properties as well as oil and natural gas properties. DD&A expense for non-oil and natural gas properties was $2 million for first quarter 2009 compared to $1.4 million for first quarter 2008. DD&A expense related to oil and natural gas properties is directly related to reserves and production volumes. DD&A expense is primarily based upon year-end proved developed producing oil and gas reserves. These reserves are priced at the price of oil and natural gas as of December 31 each year. If prices increase, the corresponding volume of oil and gas reserves will increase, resulting in decreases in the rate of DD&A per unit of production. If prices decrease, as they did from 2008 to 2009, volumes of oil and gas reserves will decrease resulting in increases in the rate of DD&A per unit of production. The cost to acquire acreage, drill, complete and equip new wells has risen significantly over the past five years and is a major contributing factor, as well as our 2008 reduction in proved developed reserves, for the increased DD&A rate in the table below:

	Three Months Ended March 31,	
	2009	2008
	(per Mcfe)	
Rocky Mountain Region:		
Wattenberg Field	$ 4.08	$ 3.37
Piceance Basin	2.36	1.81
NECO	1.81	1.29
Appalachian Basin	1.86	1.47
Michigan Basin	1.49	1.30

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Non-Operating Income/Expense

Interest Income. The decrease in our interest income for first quarter 2009 compared to first quarter 2008 was the result of lower interest bearing cash balances and lower interest rates.

Interest Expense. The increase in our interest expense for first quarter 2009 was primarily due to significantly higher average outstanding balances of our credit facility and our 12% senior notes offset in part by lower average interest rates on our bank credit facility. Interest expense is net of capitalized interest. Interest costs capitalized in first quarter 2009 were unchanged from $0.6 million for first quarter 2008. We have historically utilized our daily cash balances to reduce our line of credit borrowings, thereby lowering our interest costs.

Provision for Income Taxes

The effective income tax rate, including the effect of discrete items and applicable $1.6 million tax benefit limitation, for first quarter 2009 was 41.3% compared to 37.1% for first quarter 2008. The current period rate is reflective of the tax benefit from our percentage depletion deduction adding to the limited tax benefit of our current period net operating loss recorded at our statutory tax rate.

Liquidity and Capital Resources

Cash flows from operations and our bank credit facility are the primary sources of liquidity for us to satisfy our operating expenses and fund our capital expenditures. We had $152.5 million of available borrowing capacity under our $375 million bank credit facility as of March 31, 2009. Cash provided by operating activities was $35.9 million for first quarter 2009 compared to $48.8 million for first quarter 2008. The $12.9 million decrease in first quarter 2009 was primarily due to the timing of the payment of accounts payable obligations and capital spending. Changes in cash flows from operations are largely due to the same factors that affect our net income, excluding non-cash items which are primarily depreciation, depletion and amortization and unrealized gains and losses on derivative transactions. See the discussion under Results of Operations above. Cash flows used in investing activities, primarily drilling capital expenditures, increased $9.5 million, or 14.8%, from $64.1 million for first quarter 2008 to $73.6 million in first quarter 2009. Cash flows provided from financing activities increased $71.1 million from a $43.2 million use of cash to $27.9 million source of cash for first quarter 2009 and 2008, respectively. This increase was primarily due to increased net borrowing to fund operating activities and capital expenditures.

Changes in market prices for oil and natural gas, our ability to increase production, the impact of realized gains and losses on our oil and natural gas derivative instruments and changes in costs are the principal determinants of the level of our cash flows from operations. Oil and natural gas sales for first quarter 2009 were approximately 44.5% lower than first quarter 2008, resulting from a 55.1% decrease in average oil and natural gas prices offset in part by a 31.5% increase in oil and natural gas production. While a decline in oil and natural gas prices would affect the amount of cash from operations that would be generated, we have oil and natural gas derivative positions in place, as of the date of this filing, covering 57.5% of our expected oil production and 62.2% of our expected natural gas production for the remainder of 2009, at average prices of $90.52 per Bbl and $6.83 per Mcf, respectively. These contracts reduce the impact of price changes for a substantial portion of our 2009 cash from operations.

Our primary use of funds is for capital expenditures. As a result of the current unstable conditions in the commodity and financial markets, we have significantly reduced our planned 2009 capital expenditures to a range of $108 million to $120 million which represents an approximate 65% decrease from our 2008 capital expenditures. With this reduction, we estimate our 2009 production will increase by approximately 10% to 14% over 2008 in part due to increased production from wells drilled in the latter part of 2008. We believe, based on the current commodity price environment, our cash flows from operations will fund our reduced 2009 capital spending program. We expect to manage capital expenditures within our cash flows from operations for the foreseeable future until commodity prices and capital markets are more favorable. In order to continue to maintain or grow our production, we would need to commit greater amounts of capital in 2010 and beyond. If capital is not available or is constrained in the future, we will be limited to our cash flows from operations and liquidity under our credit facility as the sources of funding for our capital expenditures. Oil and gas produced from our existing properties declines rapidly in the first two years of production. We could not maintain our current level of oil and gas production and cash flows from operations if capital markets and commodity prices remain in their current depressed state for a prolonged period beyond 2009, which would have a material negative impact on our operations in 2010 and beyond.

We considered the possibility of reduced available liquidity in planning our 2009 drilling program and believe we will have adequate cash flows from operations during the year to execute our planned capital expenditures without drawing additional funds from our credit facility. Currently, we operate approximately 95% of our properties, allowing us to control the pace of substantially all of our planned capital expenditures. Consequently, a substantial portion of our planned capital expenditures for 2009 and beyond could be deferred if market conditions worsen.

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In addition to deferring capital expenditures to reduce borrowings under our credit facility, other sources of liquidity include the fair value of our oil and natural gas derivative positions, excluding the derivative positions allocated to our affiliated partnerships, of $104.5 million as well as our available cash balance which was $41.1 million as of March 31, 2009.

We have experienced no impediments in our ability to access borrowings under our current bank credit facility. We continue to monitor market events and circumstances and their potential impacts on each of the thirteen lenders that comprise our bank credit facility. Our $375 million bank credit facility borrowing base is subject to size redeterminations each April and October based upon a quantification of our proved reserves at each December 31st and June 30th, respectively. A commodity price deck reflective of the current and future commodity pricing environment is utilized by our lenders to quantify our reserve reports and determine the underlying borrowing base.

We increased our borrowing base in July 2008, and again in November 2008, to $300 million and $375 million respectively. The increases were driven primarily by increases in proved producing reserves from drilling operations. While we have continued to add producing reserves since our November 2008 redetermination, we believe the significant decrease in commodity prices and turmoil in the credit markets could have a negative impact on our April borrowing base redetermination, which will be sized based upon a quantification of our reserves as of December 31, 2008. In April 2009, we commenced the biannual redetermination of our borrowing base. Additionally, as our credit facility matures in November 2010 and with the intent to renew our credit facility prior to November 2009, we have requested an extension and renewal of the credit facility for a three year term and have requested certain adjustments to the terms and conditions of the facility. We currently expect to complete the facility renewal and extension in second quarter 2009. Further, costs of capital have increased since we last amended our credit facility and we expect interest and commitment fees under a new facility to be higher than in our current credit facility. See Note 6, Long Term Debt, to the accompanying condensed consolidated financial statements. At March 31, 2009, we had $152.5 million available for borrowing under our $375 million credit facility. While we expect our borrowing base to be reduced as a result of the significant decrease in year end 2008 commodity prices and our pending semi-annual redetermination, we believe that producing reserves added since our last redetermination and our oil and natural gas derivative positions in place could mitigate the risk of a significant decrease in our borrowing base in 2009. We also believe that while costs of capital have increased for credit facilities like ours, the impact of an increase in interest and commitment fees on our outstanding balance and commitments will not have a material adverse effect on our liquidity for the next year. If economic conditions deteriorate further in 2009 and 2010, our ability to renew our credit facility and provide adequate liquidity to continue our drilling programs could be negatively impacted in 2010 and beyond. There is no assurance that we will successfully renew our credit facility as expected, if at all, or that all of the lenders in our credit facility will participate in the renewal; further, there is no assurance that our borrowing base will not be reduced from its current level as a result of the renewal. Furthermore, if we fail to extend our credit facility term by November 1, 2009, our then outstanding borrowings would be reclassified as a current liability.

We are subject to quarterly financial debt covenants on our bank credit facility. Our key credit facility debt covenants require that we maintain: 1) total debt of less than 3.75 times earnings before interest, taxes, depreciation, amortization and capital expenditures (“EBITDAX”) and 2) an adjusted working capital ratio of at least 1.0 to 1.0. Our adjusted working capital ratio is calculated by reducing our current assets and liabilities by any impact of recording the fair value of our oil and gas derivative instruments and adding our available borrowings on our bank credit facilities to our current assets. In addition, the impact of any current portion of our debt is eliminated from the current liabilities. Therefore, any change in our available borrowings under our credit facility impacts our working capital ratio. We were in compliance with all debt covenants at March 31, 2009.

We believe we have sufficient liquidity and capital resources to conduct our business and remain compliant with our debt covenants throughout the next year based upon our 2009 and 2010 cash flow projections, anticipated capital requirements, the discretionary nature of our capital expenditures and available capacity under our bank credit facility. While current conditions in the financial markets are extremely difficult and illiquid, we have no current plans or requirements to raise capital through these markets. However, we cannot predict with any certainty the impact to our future business of any continued uncertainty or further deterioration in the financial markets. We will continue to closely monitor our liquidity and the credit markets and may choose to access them opportunistically should conditions and capital market liquidity improve.

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We filed a shelf registration statement on Form S-3 with the SEC on November 26, 2008. The shelf provides for an aggregate of $500 million, through the sale of debt securities, common stock or preferred stock, either separately or represented by depository shares, warrants and purchase contracts, as well as units that may include any of these securities or securities of other entities. The shelf registration statement is intended to allow the Company to be proactive in its ability to raise capital should the need arise, and to have the flexibility to raise such funds in one or more offerings, subject to market conditions. This shelf registration statement was declared effective by the SEC on January 30, 2009. There are no immediate plans to raise any funds and there is no assurance that we will be able to secure any such funds should the need arise.

See Part I, Item 3, Quantitative and Qualitative Disclosure about Market Risk, for our discussion of credit risk.

2009 Outlook

We currently estimate that our 2009 production will be approximately 42.5 Bcfe to 44 Bcfe or a 10% to 14% increase over our 2008 production of 38.7 Bcfe. Our 2009 capital budget of $108 million to $120 million represents an approximate 65% decrease compared to 2008. We selected this level of spending with the goal of remaining debt neutral to help maintain adequate liquidity during 2009. We realize that oil and gas prices may vary considerably from our projections. We use oil and natural gas derivatives contracts in order to reduce the effects of volatile commodity prices. As of March 31, 2009, we had oil and natural gas hedges in place covering 57.5% of our expected oil production and 62.2% of our expected natural gas production for the remainder of 2009.

Our current 2009 drilling plans continue to be focused primarily in the Rocky Mountain Region. We plan to drill approximately 105 gross wells to 155 gross wells in the Rocky Mountain Region and the Appalachian Basin. Exclusive of exploratory wells, through March 31, 2009, we have drilled 24 gross wells compared to 92 gross wells for the same period last year. We are currently evaluating the exploration potential of the Marcellus Formation in the Appalachian Basin. Through a combination of lease, farmout and wellbore ownership, we operate over 2,100 wells within the Marcellus "Fairway" area. As of March 31, 2009, we have drilled four Marcellus wells, two of which are in line, and five additional vertical tests are planned in 2009.

Due to the continued decline in natural gas prices, in early 2009, we temporarily ceased all of our drilling operations in the Piceance Basin, resulting in the demobilization of the three contracted drilling rigs in this area. Should natural gas prices change materially from the projected levels, we will reevaluate our drilling options.

Contractual Obligations and Contingent Commitments

The table below sets forth our contractual obligations and contingent commitments as of March 31, 2009:

		Payments due by period			
ontractual Obligations and Contingent Commitments	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(in thousands)		
ong term liabilities reflected on the condensed consolidated balance sheet (1)					
ong-Term Debt	$422,939	$-	$222,500	$-	$200,43
sset retirement obligations	23,962	50	100	100	23,712
erivative contracts (2)	33,839	1,976	19,069	12,794	-
erivative contracts - Partnerships (3)	7,465	2,024	5,441	-	-

oduction tax liability	44,692	17,830	26,862	-	-
ther liabilities (4)	7,478	239	990	990	5,259
	540,375	22,119	274,962	13,884	229,41
ommitments, contingencies and other arrangements (5)					
terest on long-term debt(6)	232,224	34,413	54,696	48,720	94,395
perating leases	8,519	1,963	3,371	1,726	1,459
g commitments (7)	12,238	10,254	1,984	-	-
rilling commitments(8)	1,800	-	-	-	1,800
rm transportation and processing agreements (9)	204,184	4,549	37,311	70,793	91,531
ther	750	125	250	250	125
	459,715	51,304	97,612	121,489	189,31
otal	$1,000,090	$73,423	$372,574	$135,373	$418,72

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(1)Table does not include deferred income tax obligations to taxing authorities of $155 million as of March 31, 2009, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.
(2)Represents our gross liability related to the fair value of derivative positions, including the fair value of derivative contracts we entered into on behalf of our affiliated partnerships as the managing general partner. We have a related receivable from the partnerships of $10.6 million as of March 31, 2009.
(3)Represents our affiliated partnerships' allocated portion of the fair value of our gross derivative assets as of March 31, 2009.
(4)Includes funds held from revenue distribution to third party investors for plugging liabilities related to wells we operate and deferred officer compensation.
(5)Table does not include maximum annual repurchase obligations to investing partners of $15.7 million as of March 31, 2009, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.
(6)Amounts presented for long term debt consist of amounts related to our 12% senior notes and our outstanding credit facility. The interest on long term debt includes $216.2 million payable to the holders of our 12% senior notes and $16 million related to our outstanding balance of $222.5 million on our credit facility as of March 31, 2009, based on an imputed interest rate of 4.5%.
(7)Drilling rig commitments in the above table reflect our maximum obligation for the services of two drilling rigs and does not include potential future increases to daily rates as provided for in the agreements as such increases are not predictable and are only included in the above obligation table upon notification to us by the contractor of an increase in the rate. Further, this commitment includes $3.2 million related to a rig sublet to a third party and remains our obligation should the third party default on terms of the sublet agreement.
(8)See Note 8, Commitments and Contingencies – Drilling and Development Agreements, to our accompanying condensed consolidated financial statements.
(9)Represents our gross commitment, including amounts for volumes transported or sold on behalf of our affiliated partnerships and other working interest owners. We will recognize in our financial statements our proportionate share based on our working and net revenue interest.

As managing general partner of 33 partnerships, we have liability for any potential casualty losses in excess of the partnership assets and insurance. We believe that the casualty insurance coverage we and our subcontractors carry is adequate to meet this potential liability.

For information regarding our legal proceedings, see Note −8, Commitments and Contingencies – Litigation, to our accompanying condensed consolidated financial statements included in this report. From time to time we are a party to various other legal proceedings in the ordinary course of business. We are not currently a party to any litigation that we believe would have a materially adverse affect on our business, financial condition, results of operations, or liquidity.

Drilling Activity

The following table summarizes our development and exploratory drilling activity for first quarter 2009 and 2008. There is no correlation between the number of productive wells completed during any period and the aggregate reserves attributable to those wells. Productive wells consist of producing wells and wells capable of commercial production.

Drilling Activity Three Months Ended March 31,			
2009		2008	
Gross	Net	Gross	Net

Development				
Productive (1)	23.0	21.4	92.0	58.8
Dry	1.0	0.5	-	-
Total development	24.0	21.9	92.0	58.8
Exploratory				
Productive (1)	-	-	-	-
Dry	-	-	2.0	2.0
Pending determination	4.0	3.0	7.0	7.0
Total exploratory	4.0	3.0	9.0	9.0
Total Drilling Activity	28.0	24.9	101.0	67.8

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(1) As of March 31, 2009, a total of 51 productive wells, 18 drilled in 2009 and 33 drilled in 2008, were waiting to be fractured and/or for gas pipeline connection.

The following table sets forth the wells we drilled by operating area during the periods indicated.

	Three Months Ended March 31,			
	2009		2008	
	Gross	Net	Gross	Net
Rocky Mountain Region:				
Wattenberg	18.0	17.9	45.0	21.7
Piceance	1.0	1.0	21.0	13.4
NECO	5.0	2.5	29.0	26.6
North Dakota	1.0	0.5	-	-
Total Rocky Mountain Region	25.0	21.9	95.0	61.8
Appalachian Basin	3.0	3.0	5.0	5.0
Fort Worth Basin	-	-	1.0	1.0
Total	28.0	24.9	101.0	67.8

Commitments and Contingencies

See Note 8, Commitments and Contingencies, to the accompanying condensed consolidated financial statements.

Recent Accounting Standards

See Note 2, Recent Accounting Standards, to the accompanying condensed consolidated financial statements.

Critical Accounting Polices and Estimates

The preparation of the accompanying condensed consolidated financial statements in conformity with accounting principles generally accepted in the U.S. requires management to use judgment in making estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities and the reported amounts of revenue and expenses.

We believe that our accounting policies for revenue recognition, derivatives instruments, oil and gas properties, deferred income tax asset valuation and purchase accounting are based on, among other things, judgments and assumptions made by management that include inherent risks and uncertainties. There have been no significant changes to these policies or in the underlying accounting assumptions and estimates used in these critical accounting policies from those disclosed in the consolidated financial statements and accompanying notes contained in our annual report on Form 10-K for the fiscal year ended December 31, 2008, filed with the SEC on February 27, 2009.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Market-Sensitive Instruments and Risk Management

We are exposed to market risks associated with interest rates, commodity prices and credit exposure. Management has established risk management processes to monitor and manage these market risks.

Interest Rate Risk

We are exposed to risk resulting from changes in interest rates primarily as it relates to interest we earn on our deposit accounts, including cash, cash equivalents and designated cash, current and noncurrent, and interest we pay on borrowings under our revolving credit facility. Our interest-bearing deposit accounts include money market accounts, certificates of deposit and checking and savings accounts with various banks. The amount of our interest-bearing cash and cash equivalents as of March 31, 2009, is $59.3 million with an average interest rate of 1.5%.

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Commodity Price Risk

See Note 4, Derivative Financial Instruments, to the accompanying condensed consolidated financial statements included in this report for additional disclosure regarding our derivative financial instruments including, but not limited to, the accounting for our derivative financial instruments and a summary of our open derivative positions as of March 31, 2009.

We are exposed to the effect of market fluctuations in the prices of oil and natural gas as they relate to our oil and natural gas sales and natural gas marketing segments. Price risk represents the potential risk of loss from adverse changes in the market price of oil and natural gas commodities. We employ established policies and procedures to manage the risks associated with these market fluctuations using derivative instruments. Our policy prohibits the use of oil and natural gas derivative instruments for speculative purposes.

Validation of a contract's fair value is performed internally and while we use common industry practices to develop our valuation techniques, changes in our pricing methodologies or the underlying assumptions could result in significantly different fair values. While we believe these valuation methods are appropriate and consistent with those used by other market participants, the use of different methodologies, or assumptions, to determine the fair value of certain financial instruments could result in a different estimate of fair value.

Economic Hedging Strategies. Our results of operations and operating cash flows are affected by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative contracts. As of March 31, 2009, our derivative instruments consisted of natural gas collars and swaps, oil swaps and basis protection swaps.

- For swap instruments, if the market price is below the fixed contract price, we receive the market price from the purchaser and receive the difference between the market price and the fixed contract price from the counterparty. If the market price is above the fixed contract price, we receive the market price from the purchaser and pay the difference between the market price and the fixed contract price to the counterparty.

- Basis protection swaps are arrangements that guarantee a price differential for natural gas from a specified delivery point. For CIG basis protection swaps, which have negative differentials to NYMEX, we receive a payment from the counterparty if the price differential is greater than the stated terms of the contract and pay the counterparty if the price differential is less than the stated terms of the contract.

- Collars contain a fixed floor price (put) and ceiling price (call). If the market price falls below the fixed put strike price, we receive the market price from the purchaser and receive the difference between the put strike price and market price from the counterparty. If the market price exceeds the fixed call strike price, we receive the market price from the purchaser and pay the difference between the call strike price and market price to the counterparty. If the market price is between the put and call strike price, no payments are due to or from the counterparty.

For our oil and gas sales activities, we set collars and swaps for our own and affiliated partnerships' production to protect against price declines in future periods. For our natural gas marketing activities, we enter into fixed-price physical purchase and sale agreements that are derivative contracts. In order to offset these fixed-price physical derivatives, we enter into financial derivative instruments that have the effect of locking in the prices we will receive or pay for the same volumes and period, offsetting the physical derivative. While these derivatives are structured to reduce our exposure to changes in price associated with the derivative commodity, they also limit the benefit we might otherwise have received from price changes in the physical market. We believe our derivative instruments continue to be effective in achieving the risk management objectives for which they were intended.

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The following table presents monthly average NYMEX and CIG closing prices for oil and natural gas for first quarter 2009, and the year ended December 31, 2008, as well as average sales prices we realized for the respective commodity.

	Three Months Ended March 31, 2009	Year Ended December 31, 2008
Average Index Closing Prices		
Natural Gas (per MMbtu)		
CIG	$ 3.27	$ 6.22
NYMEX	4.89	9.04
Oil (per Barrel)		
NYMEX	37.18	104.42
Average Sales Price		
Natural Gas	3.23	6.98
Oil	37.77	89.77

Based on a sensitivity analysis as of March 31, 2009, it was estimated that a 10% increase in oil and natural gas prices, inclusive of basis, over the entire period for which we have derivatives then in place would have resulted in an decrease in fair value of $38.3 million and a 10% decrease in oil and natural gas prices would have resulted in an increase in fair value of $39 million.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. We attempt to reduce credit risk by diversifying our counterparty exposure and entering into transactions with high-quality counterparties. When exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis. We have had no counterparty default losses.

Our receivables are from a diverse group of companies, including major energy companies, both upstream and mid-stream, financial institutions and end-users in various industries related to our gas marketing group. We monitor their creditworthiness through credit reports and rating agency reports.

Our derivative financial instruments expose us to the credit risk of nonperformance by the counterparty to the contracts. These contracts consist of fixed price swaps, basis swaps and collars. We primarily use three financial institutions, who are also major lenders in our credit facility agreement, as counterparties to our derivative contracts. We have evaluated the credit risk of the counterparties holding our derivative assets using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the impact of the nonperformance of our counterparties on the fair value of our derivative instruments is insignificant. As of March 31, 2009, no valuation allowance was recorded.

The recent disruption in the credit market has had a significant adverse impact on a number of financial institutions. We monitor the creditworthiness of the financial institutions with which we transact, giving consideration to the reports of credit agencies and their related ratings. While we believe that our monitoring procedures are sufficient and customary, no amount of analysis can guarantee performance in these uncertain times.

Disclosure of Limitations

Because the information above included only those exposures that exist at March 31, 2009, it does not consider those exposures or positions which could arise after that date. As a result, our ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, our hedging strategies at the time, and interest rates and commodity prices at the time.

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of March 31, 2009, we carried out an evaluation under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Securities Exchange Act Rule 13a-15(e) and 15d-15(e). This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the SEC reports that we file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified by the SEC’s rules and forms, and that such information is accumulated and communicated to our management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely discussion regarding required financial disclosure.

Based on the results of this evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures were effective as of March 31, 2009.

Changes in Internal Control over Financial Reporting

We made no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934) during first quarter 2009, that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings

Information regarding our legal proceedings can be found in Note 8, Commitments and Contingencies, to our accompanying condensed consolidated financial statements included in this report.

Item 1A. Risk Factors

We face many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock are described under Item 1A, Risk Factors, of our annual report on Form 10-K for the year ended December 31, 2008, as filed with the SEC on February 27, 2009. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC. There have been no material changes from the risk factors previously disclosed in our 2008 Form 10-K.

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Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Purchases of Equity Securities by the Issuer and Affiliated Purchasers.

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
January 1 - 31, 2009	2,241	$ 24.07	-	-
February 1 - 28, 2009	768	13.20	-	-
March 1 - 31, 2009	1,056	10.40	-	-
	4,065	18.47		

(1) Pursuant to our stock-based compensation plans, shares purchased during the quarter represent purchases from our executives and employees for their payment of tax liabilities related to the vesting of securities.

Items 3, 4 and 5 have been omitted as there is nothing to report.

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Item 6. Exhibits Index

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
10.1*	2009 Base Salary and Short-Term Incentive Compensation Terms for Executive Officers.	8-K	000-07246		03/05/2009	
10.2*	2009 Long-Term Incentive Program for Executive Officers.	8-K	000-07246	10.1	03/05/2009	
10.3*	Non-Employee Director Compensation for the 2009-2010 Term.	8-K	000-07246		03/05/2009	
10.4*	2009 Short-Term Incentive Compensation Terms for Executive Officers.	8-K	000-07246		04/06/2009	
31.1	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1	Certifications by Chief Executive Officer and Chief Financial Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.					X

*Management contract or compensatory plan or arrangement.

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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 thereunto duly authorized.

Petroleum Development Corporation
(Registrant)

Date: May 8, 2009

/s/ Richard W. McCullough
Richard W. McCullough
Chairman and Chief Executive Officer

/s/ Gysle R. Shellum
Gysle R. Shellum
Chief Financial Officer

/s/ R. Scott Meyers
R. Scott Meyers
Chief Accounting Officer