NORTHWEST NATURAL GAS CO
Form 10-Q
August 07, 2013

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

Form 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2013

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ___________ to____________
Commission file number 1-15973

NORTHWEST NATURAL GAS COMPANY
(Exact name of registrant as specified in its charter)

Oregon	93-0256722
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

220 N.W. Second Avenue, Portland, Oregon 97209
(Address of principal executive offices) (Zip Code)
Registrant's telephone number, including area code: (503) 226-4211

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

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

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

Large Accelerated Filer [X]	Accelerated Filer [ ]
Non-accelerated Filer [ ] (Do not check if a Smaller Reporting Company)	Smaller Reporting Company [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes [ ] No [X]

At July 26, 2013, 26,975,108 shares of the registrant's Common Stock (the only class of Common Stock) were outstanding.

NORTHWEST NATURAL GAS COMPANY
For the Quarterly Period Ended June 30, 2013

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FORWARD-LOOKING STATEMENTS

This report contains “forward-looking statements” within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. Forward-looking statements can be identified by words such as “anticipates,” “intends,” “plans,” “seeks,” “believes,” “estimates,” “expects” and similar references to future periods. Examples of forward-looking statements include, but are not limited to, statements regarding the following:

- plans;
- objectives;
- goals;
- strategies;
- assumptions and estimates;
- future events or performance;
- trends;
- timing and cyclicality;
- earnings and dividends;
- growth;
- customer rates;
- commodity costs;
- gas reserves;
- operational performance and costs;
- efficacy of derivatives and hedges;
- liquidity and financial positions;
- project development and expansion;
- competition;
- procurement and development of gas supplies;
- estimated expenditures;
- costs of compliance;
- credit exposures;
- potential efficiencies;
- rate recovery and refunds;
- impacts of laws, rules and regulations;
- tax liabilities or refunds;
- outcomes and effects of litigation, regulatory actions, and other administrative matters;
- projected obligations under retirement plans;
- availability, adequacy, and shift in mix of gas supplies;
- approval and adequacy of regulatory deferrals; and
- environmental, regulatory, litigation and insurance costs and recoveries.

Forward-looking statements are based on our current expectations and assumptions regarding our business, the economy and other future conditions. Because forward-looking statements relate to the future, they are subject to inherent uncertainties, risks, and changes in circumstances that are difficult to predict. Our actual results may differ materially from those contemplated by the forward-looking statements. We therefore caution you against relying on any of these forward-looking statements. They are neither statements of historical fact nor guarantees or assurances of future performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements are discussed in our 2012 Annual Report on Form 10-K, Part I, Item 1A. “Risk Factors” and Part II, Item 7. and Item 7A., “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Quantitative and Qualitative Disclosures about Market Risk,” and in Part I, Items 2 and 3, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Quantitative and Qualitative

Disclosures About Market Risk," and Part II, Item 1A, "Risk Factors," herein.

Any forward-looking statement made by us in this report speaks only as of the date on which it is made. Factors or events that could cause our actual results to differ may emerge from time to time, and it is not possible for us to predict all of them. We undertake no obligation to publicly update any forward-looking statement, whether as a result of new information, future developments or otherwise, except as may be required by law.

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ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

In thousands, except per share data	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Operating revenues	$131,714	$103,991	$409,575	$413,630
Operating expenses:				
Cost of gas	59,142	34,498	201,501	204,253
Operations and maintenance	33,217	32,138	66,974	66,570
General taxes	7,342	7,417	16,074	16,253
Depreciation and amortization	18,930	18,099	37,737	36,049
Total operating expenses	118,631	92,152	322,286	323,125
Income from operations	13,083	11,839	87,289	90,505
Other income and expense, net	1,450	620	1,970	1,092
Interest expense, net	11,069	10,464	22,196	21,655
Income before income taxes	3,464	1,995	67,063	69,942
Income tax expense	1,338	768	27,298	28,431
Net income	2,126	1,227	39,765	41,511
Other comprehensive income:				
Amortization of non-qualified employee benefit plan liability, net of taxes of $151 and $109 for the three months and $302 and $217 for the six months ended June 30, 2013 and 2012, respectively	232	166	465	332
Comprehensive income	$2,358	$1,393	$40,230	$41,843
Average common shares outstanding:				
Basic	26,958	26,812	26,943	26,797
Diluted	26,999	26,896	26,991	26,879
Earnings per share of common stock:				
Basic	$0.08	$0.05	$1.48	$1.55
Diluted	0.08	0.05	1.47	1.54
Dividends declared per share of common stock	0.455	0.445	0.910	0.890

See Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	June 30, 2013	June 30, 2012	December 31, 2012
Assets:			
Current assets:			
Cash and cash equivalents	$12,214	$4,002	$8,923
Accounts receivable	39,061	13,459	61,229
Accrued unbilled revenue	14,692	12,921	56,955
Allowance for uncollectible accounts	(1,189)	(2,653)	(2,518)
Regulatory assets	25,952	65,297	52,448
Derivative instruments	623	2,142	1,950
Inventories	62,412	68,868	67,602
Gas reserves	15,324	11,021	14,966
Income taxes receivable	1,297	3,119	2,552
Other current assets	8,781	8,606	19,592
Total current assets	179,167	186,782	283,699
Non-current assets:			
Property, plant, and equipment	2,833,083	2,720,037	2,786,008
Less: Accumulated depreciation	833,851	791,021	812,396
Total property, plant, and equipment, net	1,999,232	1,929,016	1,973,612
Gas reserves	113,762	65,026	84,693
Regulatory assets	393,652	362,290	382,255
Derivative instruments	1,054	1,170	3,639
Other investments	67,410	68,230	67,667
Restricted cash	4,000	4,000	4,000
Other non-current assets	14,312	13,936	13,555
Total non-current assets	2,593,422	2,443,668	2,529,421
Total assets	$2,772,589	$2,630,450	$2,813,120

See Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	June 30, 2013	June 30, 2012	December 31, 2012
Liabilities and equity:			
Current liabilities:			
Short-term debt	$136,000	$113,200	$190,250
Accounts payable	63,466	48,361	85,613
Taxes accrued	6,798	5,205	9,588
Interest accrued	6,404	5,607	5,953
Regulatory liabilities	16,644	20,748	20,792
Derivative instruments	9,392	29,407	10,796
Other current liabilities	34,446	42,336	45,444
Total current liabilities	273,150	264,864	368,436
Long-term debt	691,700	641,700	691,700
Deferred credits and other non-current liabilities:			
Deferred tax liabilities	469,964	438,217	444,377
Regulatory liabilities	294,202	280,295	288,113
Pension and other postretirement benefit liabilities	214,125	185,844	215,792
Derivative instruments	1,754	2,130	578
Other non-current liabilities	79,145	82,665	74,497
Total deferred credits and other non-current liabilities	1,059,190	989,151	1,023,357
Commitments and contingencies (see Note 13)	—	—	—
Equity:			
Common stock - no par value; authorized 100,000 shares; issued and outstanding 26,972, 26,827, and 26,917 at June 30, 2013 and 2012 and December 31, 2012, respectively	359,772	352,955	356,571
Retained earnings	397,603	389,247	382,347
Accumulated other comprehensive loss	(8,826)	(7,467)	(9,291)
Total equity	748,549	734,735	729,627
Total liabilities and equity	$2,772,589	$2,630,450	$2,813,120

See Notes to Consolidated Financial Statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

In thousands	Six Months Ended June 30, 2013	2012
Operating activities:		
Net income	$39,765	$41,511
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	37,737	36,049
Deferred tax liabilities	28,401	28,346
Non-cash expenses related to qualified defined benefit pension plans	2,773	4,109
Contributions to qualified defined benefit pension plans	(4,200)	(18,400)
Deferred environmental expenditures, net of recoveries	(2,989)	(3,925)
Other	3,403	1,459
Changes in assets and liabilities:		
Receivables	63,102	114,117
Inventories	5,190	5,495
Taxes accrued	(1,535)	(1,616)
Accounts payable	(22,155)	(37,854)
Interest accrued	451	(250)
Deferred gas costs	(648)	(11,830)
Other, net	10,847	18,171
Cash provided by operating activities	160,142	175,382
Investing activities:		
Capital expenditures	(55,055)	(61,552)
Utility gas reserves	(34,397)	(27,060)
Proceeds from sale of assets	6,580	—
Other	1,743	61
Cash used in investing activities	(81,129)	(88,551)
Financing activities:		
Common stock issued, net	2,355	2,910
Long-term debt retired	—	(40,000)
Change in short-term debt	(54,250)	(28,400)
Cash dividend payments on common stock	(24,509)	(23,839)
Other	682	667
Cash used in financing activities	(75,722)	(88,662)
Increase (decrease) in cash and cash equivalents	3,291	(1,831)
Cash and cash equivalents, beginning of period	8,923	5,833
Cash and cash equivalents, end of period	$12,214	$4,002
Supplemental disclosure of cash flow information:		
Interest paid	$21,746	$21,652
Income taxes paid	—	2,648

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. ORGANIZATION AND PRINCIPLES OF CONSOLIDATION

The accompanying consolidated financial statements represent the consolidation of Northwest Natural Gas Company (NW Natural or the Company) and all companies that we directly or indirectly control, either through majority ownership or otherwise. Our direct and indirect wholly-owned subsidiaries include NW Natural Energy, LLC (NWN Energy), NW Natural Gas Storage, LLC (NWN Gas Storage), Gill Ranch Storage, LLC (Gill Ranch), NNG Financial Corporation (NNG Financial), Northwest Energy Corporation (Energy Corp), and NW Natural Gas Reserves, LLC (NWN Gas Reserves). Investments in corporate joint ventures and partnerships that we do not directly or indirectly control, and for which we are not the primary beneficiary, are accounted for under the equity method or the cost method, which includes NWN Energy’s investment in Palomar Gas Holdings, LLC (PGH) and NNG Financial's investment in Kelso-Beaver (KB) Pipeline. NW Natural and its affiliated companies are collectively referred to herein as NW Natural. The consolidated financial statements are presented after elimination of all significant intercompany balances and transactions, except for amounts required to be included under regulatory accounting standards to reflect the effect of such regulation. In this report, the term “utility” is used to describe our regulated gas distribution business, and the term “non-utility” is used to describe our gas storage business and other non-utility investments and business activities.

During the first quarter of 2013, we identified an error in the rate used to calculate interest on regulatory assets. We assessed the materiality of this error on prior period financial statements and concluded it was not material to any prior annual or interim periods; however, the cumulative impact would have been material to the interim period ending March 31, 2013, if corrected in 2013. As a result, in accordance with accounting standards, we have revised our prior period financial statements as shown in Note 14 to correct for this error.

Certain prior year balances in our consolidated financial statements and notes have been reclassified to conform with the current presentation. These changes had no material impact on our prior year’s consolidated results of operations, financial condition or cash flows.

Information presented in these interim consolidated financial statements is unaudited, but includes all material adjustments that management considers necessary for a fair statement of the results for each period reported including normal recurring accruals. These consolidated financial statements should be read in conjunction with the audited consolidated financial statements and related notes included in our 2012 Annual Report on Form 10-K (2012 Form 10-K). A significant part of our business is of a seasonal nature; therefore, results of operations for interim periods are not necessarily indicative of the results for a full year.

2. SIGNIFICANT ACCOUNTING POLICIES

Our significant accounting policies are described in Note 2 of the 2012 Form 10-K. There were no material changes to those accounting policies during the six months ended June 30, 2013. The following are current updates to certain critical accounting policy estimates and accounting standards in general.

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Regulatory Accounting

In applying regulatory accounting in accordance with generally accepted accounting principles in the United States of America (GAAP), we capitalize or defer certain costs and revenues as regulatory assets and liabilities. The amounts deferred as regulatory assets and liabilities were as follows:

	Regulatory Assets		
	June 30,		December 31,
In thousands	2013	2012	2012
Current:			
Unrealized loss on derivatives[1]	$9,392	$29,407	$10,796
Other[2]	16,560	35,890	41,652
Total current	$25,952	$65,297	$52,448
Non-current:			
Unrealized loss on derivatives[1]	$1,754	$2,130	$578
Pension balancing[3]	20,327	10,611	14,727
Income tax asset	53,065	63,452	55,879
Pension and other postretirement benefit liabilities[3]	191,312	162,767	182,688
Environmental costs[4]	120,224	113,369	121,144
Other[2]	6,970	9,961	7,239
Total non-current	$393,652	$362,290	$382,255

	Regulatory Liabilities		
	June 30,		December 31,
In thousands	2013	2012	2012
Current:			
Gas costs	$6,353	$12,980	$9,100
Unrealized gain on derivatives[1]	547	2,142	1,950
Other[2]	9,744	5,626	9,742
Total current	$16,644	$20,748	$20,792
Non-current:			
Gas costs	$481	$1,504	$—
Unrealized gain on derivatives[1]	1,054	1,170	3,639
Accrued asset removal costs	289,105	274,756	281,213
Other[2]	3,562	2,865	3,261
Total non-current	$294,202	$280,295	$288,113

(1) Unrealized gains or losses on derivatives are non-cash items and, therefore, do not earn a rate of return or a carrying charge. These amounts are recoverable through utility rates as part of the annual Purchased Gas Adjustment (PGA) mechanism when realized at settlement.

(2) Other primarily consists of several deferrals and amortizations under other approved regulatory mechanisms. The accounts being amortized typically earn a rate of return or carrying charge.

(3) Certain utility pension costs are approved for regulatory deferral, including amounts recorded to the pension balancing account, to mitigate the effects of higher and lower pension expenses. Pension costs that are deferred include an interest component when recognized in net periodic benefit costs. See Note 7.

(4) Environmental costs relate to specific sites approved for regulatory deferral by the Public Utility Commission of Oregon (OPUC) and Washington Utilities and Transportation Commission (WUTC). In Oregon, we earn a carrying charge on amounts paid, whereas amounts accrued but not yet paid do not earn a carrying charge until expended. In Washington, a carrying charge related to deferred amounts will be determined in a future proceeding. In the 2012 Oregon general rate case, the OPUC authorized a Site Remediation and Recovery Mechanism (SRRM) that allows the Company to recover prudently incurred environmental costs, subject to an earnings test. For further information on environmental matters, see Note 13 and Note 15.

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New Accounting Standards

Recent Accounting Pronouncements

OBLIGATIONS RESULTING FROM JOINT AND SEVERAL LIABILITY ARRANGEMENTS. In February 2013, the Financial Accounting Standards Board (FASB) issued guidance regarding the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. This new guidance does not apply to obligations previously addressed within existing guidance. Under the new guidance, an entity is required to measure those fixed obligations as the sum of the amount the reporting entity agreed to pay on the basis of its arrangement among its co-obligors and any additional amount the reporting entity expects to pay on behalf of its co-obligors. In addition, an entity must disclose the nature and amount of the obligation as well as other information about the obligations. The guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. We are currently assessing the impact, if any, of this guidance on our financial position, results of operations, and disclosures.

Subsequent Events

Two stipulated settlements were filed with the OPUC on July 11, 2013 with regards to the implementation of our new environmental recovery mechanism and the recovery of carrying costs on working gas inventory. See Note 15 for more information.

3. EARNINGS PER SHARE

Basic earnings per share are computed using net income and the weighted-average number of common shares outstanding for each period presented. Diluted earnings per share are computed in the same manner, except it uses the weighted-average number of common shares outstanding plus the effects of the assumed exercise of stock options, and payment of estimated stock awards from other stock-based compensation plans that are outstanding at the end of each period presented. Diluted earnings per share are calculated as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per share data	2013	2012	2013	2012
Net income	$2,126	$1,227	$39,765	$41,511
Average common shares outstanding - basic	26,958	26,812	26,943	26,797
Additional shares for stock-based compensation plans outstanding	41	84	48	82
Average common shares outstanding - diluted	26,999	26,896	26,991	26,879
Earnings per share of common stock - basic	$0.08	$0.05	$1.48	$1.55
Earnings per share of common stock - diluted	$0.08	$0.05	$1.47	$1.54
Additional information:				
Anti-dilutive shares excluded from net income per diluted common share calculation	43	1	28	1

4. SEGMENT INFORMATION

We operate in two primary reportable business segments, local gas distribution and gas storage. We also have other investments and business activities not specifically related to one of these two reporting segments, which we aggregate and report as “other.” We refer to our local gas distribution business as the “utility,” and our “gas storage” and “other” business segments as “non-utility.” Our utility segment also includes NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp, and the utility portion of our Mist underground storage facility in Oregon (Mist). Our gas storage segment includes NWN Gas Storage, which is a wholly-owned subsidiary of NWN Energy, Gill Ranch, which is a wholly-owned subsidiary of NWN Gas Storage, the non-utility portion of Mist, and all third-party asset management services. Our “other” segment includes NNG Financial and NWN Energy's equity investment in PGH, which is pursuing development of a cross-Cascades pipeline project. See Note 4 in our 2012 Form 10-K for further discussion of our segments.

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The following table presents summary financial information concerning the reportable segments. Inter-segment transactions are insignificant:

	Three Months Ended Three Months Ended June 30,			
In thousands	Utility	Gas Storage	Other	Total
2013				
Operating revenues	$123,943	$7,715	$56	$131,714
Depreciation and amortization	17,311	1,619	—	18,930
Income from operations	9,437	3,625	21	13,083
Net income	657	1,452	17	2,126
Capital expenditures	32,134	247	—	32,381
2012				
Operating revenues	$95,938	$7,996	$57	$103,991
Depreciation and amortization	16,478	1,621	—	18,099
Income from operations	8,547	3,264	28	11,839
Net income (loss)	130	1,124	(27)	1,227
Capital expenditures	40,786	319	—	41,105

	Three Months Ended Six Months Ended June 30,			
In thousands	Utility	Gas Storage	Other	Total
2013				
Operating revenues	$393,602	$15,861	$112	$409,575
Depreciation and amortization	34,499	3,238	—	37,737
Income from operations	79,665	7,582	42	87,289
Net income (loss)	36,688	3,088	(11)	39,765
Capital expenditures	54,522	533	—	55,055
Total assets at June 30, 2013	2,469,320	287,341	15,928	2,772,589
2012				
Operating revenues	$398,843	$14,675	$112	$413,630
Depreciation and amortization	32,816	3,233	—	36,049
Income from operations	84,511	5,943	51	90,505
Net income (loss)	39,598	1,930	(17)	41,511
Capital expenditures	60,442	1,110	—	61,552
Total assets at June 30, 2012	2,326,919	287,622	15,909	2,630,450
Total assets at December 31, 2012	2,505,655	291,568	15,897	2,813,120

Utility Margin

Utility margin is a financial measure consisting of utility operating revenues less revenue taxes and the associated cost of gas. By netting fluctuating costs of gas from utility operating revenues, utility margin provides a key metric used by our chief operating decision maker in assessing the performance of the utility segment. The following table presents additional segment information concerning utility margin. The gas storage and other segments emphasize growth in operating revenues and net income as opposed to margin because these segments do not incur commodity cost of sales like the utility and, therefore, use operating revenues and net income to assess performance.

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2013	2012	2013	2012
Utility margin calculation:				
Utility operating revenues	$123,943	$95,938	$393,602	$398,843
Less: Utility cost of gas	59,142	34,498	201,501	204,253
Utility margin	$64,801	$61,440	$192,101	$194,590

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5. STOCK-BASED COMPENSATION

Our stock-based compensation plans include a Long-Term Incentive Plan (LTIP) under which various types of equity awards may be granted, an Employee Stock Purchase Plan, and a Restated Stock Option Plan (Restated SOP). These plans are designed to promote stock ownership in NW Natural by employees and officers. For additional information on our stock-based compensation plans, see Note 6 in the 2012 Form 10-K and updates provided below.

Long-Term Incentive Plan

Performance-Based Stock Awards

LTIP performance shares incorporate market, performance, and service-based factors. On February 27, 2013, 37,300 performance-based shares were granted under the LTIP based on target-level awards and a weighted-average grant date fair value of $38.96 per share. Fair value was estimated as of the date of grant using a Monte-Carlo option pricing model based on the following assumptions:

Stock price on valuation date	$45.38	
Performance term (in years)	3.0	
Quarterly dividends paid per share	$0.455	
Expected dividend yield	3.9	%
Dividend discount factor	0.8943	

Performance-Based Restricted Stock Units (RSUs)

On February 27, 2013, 25,748 performance-based RSUs were granted under the LTIP with a grant date fair value of $45.38 per share. As of June 30, 2013, there was $1.9 million of unrecognized compensation cost from grants of RSUs, which is expected to be recognized over a period extending through 2017. The RSUs awarded include a performance-based threshold and a vesting period of four years from the grant date. An RSU obligates the Company upon vesting to issue the RSU holder one share of common stock plus a cash payment equal to the total amount of dividends paid per share between the grant date and vesting date of that portion of the RSU.

Restated Stock Option Plan

As of June 30, 2013, there was $0.3 million of unrecognized compensation cost from grants of stock options issued in prior years, which is expected to be recognized over a period extending through 2014. The Restated SOP was terminated for new option grants in 2012; however, options that had been granted before the Restated SOP was terminated will remain outstanding until the earlier of their expiration, forfeiture, or exercise. Any new grants of stock options would be made under the LTIP. No stock options were granted in the six months ended June 30, 2013.

6. DEBT

Short-Term Debt

At June 30, 2013, our short-term debt consisted of commercial paper notes payable with a maximum maturity of 57 days, an average maturity of 43 days, and an outstanding balance of $136.0 million. The carrying cost of our commercial paper approximates fair value using Level 2 inputs due to the short-term nature of the notes. See Note 2 in our 2012 Form 10-K for a description of the fair value hierarchy.

Long-Term Debt

At June 30, 2013, our utility's long-term debt consisted of $651.7 million of first mortgage bonds (FMBs) with maturity dates ranging from 2014 through 2042, interest rates ranging from 3.176% to 9.05%, and a weighted-average coupon rate of 5.71%. During the six months ended June 30, 2012, we did not issue or redeem any FMBs.

At June 30, 2013, our gas storage segment’s long-term debt consisted of $40 million of senior secured debt with a maturity date of November 30, 2016. This debt consists of $20 million of fixed rate debt with an interest rate of 7.75% and $20 million of variable interest rate debt, which currently has an interest rate of 7.00%. The debt is secured by all of the membership interests in Gill Ranch and is nonrecourse to NW Natural.

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As our outstanding debt does not trade in active markets, we estimate the fair value of our outstanding long-term debt using interest rates of other companies' outstanding debt issuances that actively trade in public markets and have similar credit ratings, terms, and remaining maturities to our debt. These valuations are based on Level 2 inputs as defined in the fair value hierarchy. See Note 2 in our 2012 Form 10-K.

The following table provides an estimate of the fair value of our long-term debt, including current maturities of long-term debt, using market prices in effect on the valuation date:

In thousands	June 30, 2013	2012	December 31, 2012
Carrying amount	$691,700	$641,700	$691,700
Estimated fair value	769,679	768,429	834,664

See Note 7 in our 2012 Form 10-K for more detail on our long-term debt.

7. PENSION AND OTHER POSTRETIREMENT BENEFIT COSTS

The following table provides the components of net periodic benefit cost for the Company's pension and other postretirement benefit plans:

	Three Months Ended Three Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
In thousands	2013	2012	2013	2012
Service cost	$2,341	$2,130	$179	$177
Interest cost	4,104	4,304	286	315
Expected return on plan assets	(4,678)	(4,639)	—	—
Amortization of net actuarial loss	4,421	3,844	169	103
Amortization of prior service costs	55	49	49	49
Amortization of transition obligations	—	—	—	103
Net periodic benefit cost	6,243	5,688	683	747
Amount allocated to construction	(1,801)	(1,428)	(211)	(215)
Amount deferred to regulatory balancing account[1]	(2,271)	(2,094)	—	—
Net amount charged to expense	$2,171	$2,166	$472	$532

	Three Months Ended Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
In thousands	2013	2012	2013	2012
Service cost	$4,682	$4,260	$358	$354
Interest cost	8,207	8,608	572	629
Expected return on plan assets	(9,356)	(9,277)	—	—
Amortization of net actuarial loss	8,842	7,687	338	206
Amortization of prior service costs	111	98	98	98
Amortization of transition obligations	—	—	—	206
Net periodic benefit cost	12,486	11,376	1,366	1,493
Amount allocated to construction	(3,656)	(2,846)	(430)	(429)
Amount deferred to regulatory balancing account[1]	(4,620)	(4,162)	—	—
Net amount charged to expense	$4,210	$4,368	$936	$1,064

[1] Effective January 1, 2011, the OPUC approved the deferral of certain pension expenses above or below the amount set in rates, with recovery of these deferred amounts through the implementation of a balancing account, which

includes the

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expectation of lower net periodic benefit costs in future years. Deferred pension expense balances accrue interest at the utility's actual cost of long-term debt. See Note 2.

The following table presents amounts recognized in accumulated other comprehensive loss (AOCL) and the changes in AOCL related to our non-qualified employee benefit plan:

In thousands	Three Months Ended June 30, 2013	Six Months Ended June 30, 2013
Beginning balance	$(9,058)	$(9,291)
Amounts reclassified into AOCL	—	—
Amounts reclassified from AOCL:		
Amortization of prior service costs	(2)	(4)
Amortization of actuarial losses	385	771
Total reclassifications before tax	383	767
Tax expense	(151)	(302)
Total reclassifications for the period	232	465
Ending balance	$(8,826)	$(8,826)

Employer Contributions to Company-Sponsored Defined Benefit Pension Plan

In the six months ended June 30, 2013, we made cash contributions totaling $4.2 million to our qualified defined benefit pension plan. In 2012, Congress passed the "Moving Ahead for Progress in the 21st Century Act" (MAP-21), which among other things, includes provisions that reduce the level of minimum required contributions in the near-term but generally increase contributions in the long-run as well as increase the operational costs of running a pension plan. Including the impacts of MAP-21, we expect to make approximately $8 million in additional pension contributions during 2013.

Multiemployer Pension Plan

In addition to the Company-sponsored defined benefit pension plan referred to above, we contribute to a multiemployer pension plan for our utility's union employees known as the Western States Office and Professional Employees International Union Pension Fund (Western States Plan) in accordance with our collective bargaining agreement. The employer identification number of the plan is 94-6076144. The cost of this plan, and corresponding future liabilities, are in addition to pension expense presented in the table above. Our contributions to the Western States Plan amounted to $0.2 million for the six months ended June 30, 2013 and 2012. Under the terms of our current collective bargaining agreement, we can withdraw from the Western States Plan at any time. However, if the plan is underfunded at the time we withdraw, we would be assessed a withdrawal liability. In accordance with accounting rules for multiemployer plans, we have not recognized these potential withdrawal liabilities on the balance sheet. Currently, we have made no decision to withdraw from the plan. We continue to monitor the financial condition of the plan and consider options with respect to this plan.

Defined Contribution Plan

The Retirement K Savings Plan provided to our employees is a qualified defined contribution plan under Internal Revenue Code Section 401(k). Our contributions to this plan totaled $1.6 million and $1.2 million for the six months ended June 30, 2013 and 2012, respectively.

See Note 8 in the 2012 Form 10-K for more information about these retirement and other postretirement benefit plans.

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8. INCOME TAX

The effective income tax rate varied from the combined federal and state statutory tax rates principally due to the following:

	June 30, 2013	2012
Federal statutory tax rate	35.0 %	35.0 %
Increase (decrease):		
Current state income tax, net of federal tax benefit	4.6	4.8
Amortization of investment and energy tax credits	(0.3)	(0.3)
Differences required to be flowed-through by regulatory commissions	2.3	1.5
Gains on company and trust-owned life insurance	(0.8)	(0.7)
Other, net	(0.1)	0.3
Effective income tax rate	40.7 %	40.6 %

See Note 9 in the 2012 Form 10-K for more detail on income taxes and effective tax rates.

9. PROPERTY, PLANT, AND EQUIPMENT

The following table sets forth the major classifications of our property, plant, and equipment and related accumulated depreciation:

In thousands	June 30, 2013	2012	December 31, 2012
Utility plant in service	$2,468,853	$2,363,061	$2,435,886
Utility construction work in progress	61,283	54,039	46,831
Less: Accumulated depreciation	807,652	770,825	789,201
Utility plant, net	1,722,484	1,646,275	1,693,516
Non-utility plant in service	296,167	296,619	296,781
Non-utility construction work in progress	6,780	6,318	6,510
Less: Accumulated depreciation	26,199	20,196	23,195
Non-utility plant, net	276,748	282,741	280,096
Total property, plant, and equipment	$1,999,232	$1,929,016	$1,973,612

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10. GAS RESERVES

We have agreements with Encana Oil & Gas (USA) Inc. (Encana) to develop physical gas reserves. These agreements are intended to provide long-term gas price protection for our utility customers rather than serving as a source of gas supply. Encana began drilling in 2011 under these agreements, and gas which is currently being produced from our working interests in these gas fields is sold by Encana at then prevailing market prices, with revenues from such sales, net of associated production costs, credited to our cost of gas. The cost of gas, including a carrying cost for the net rate base investment, is part of our annual Oregon PGA filing, which allows us to recover our costs through customer rates in a manner previously approved by the OPUC. This transaction acted to hedge the cost of gas for approximately 6% and 3% of our gas supplies for the six months ended June 30, 2013 and 2012, respectively. Our utility gas reserves are stated at cost, net of regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet. The following table outlines our net investment in gas reserves:

	June 30,		December 31,
In thousands	2013	2012	2012
Gas reserves, current	$15,324	$11,021	$14,966
Gas reserves, non-current	126,215	69,097	92,179
Less: Accumulated amortization	12,453	4,071	7,486
Total gas reserves	129,086	76,047	99,659
Less: Deferred tax liabilities on gas reserves	39,963	26,839	28,329
Net investment in gas reserves	$89,123	$49,208	$71,330

11. INVESTMENTS

Equity Method Investments

Palomar, a wholly-owned subsidiary of PGH, is pursuing the development of a new gas transmission pipeline that would provide an interconnection with our utility distribution system. PGH is owned 50% by NWN Energy and 50% by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation. PGH is a development stage VIE and Palomar is reported under equity method accounting based on the determination that we are not the primary beneficiary of PGH’s activities, as defined by the authoritative guidance related to consolidations, due to the fact that we have a 50% share and there are no stipulations that allow disproportionate influence over the entity. Our investment in PGH and Palomar are included in other investments on our balance sheet. Our maximum loss exposure related to PGH is limited to our equity investment balance, less our share of any cash or other assets available to us as a 50% owner. See Note 12 in our 2012 Form 10-K for more detail.

Other Investments

Other investments include financial investments in life insurance policies, which are accounted for at fair value. See Note 12 in the 2012 Form 10-K for more detail on other investments.

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12. DERIVATIVE INSTRUMENTS

We enter into swap, option, and combinations of option contracts for the purpose of hedging natural gas. We primarily use these derivative financial instruments to manage commodity price variability related to our natural gas purchase requirements. A small portion of our derivative hedging strategy involves foreign currency exchange transactions related to purchases of natural gas from Canadian suppliers.

In the normal course of business, we enter into indexed-price physical forward natural gas commodity purchase (gas supply) contracts to meet the requirements of utility customers. We also enter into financial derivatives, up to prescribed limits, to hedge price variability related to these physical gas supply contracts as well as to hedge spot purchases of natural gas. The following table presents the absolute notional amounts related to open positions on financial derivative instruments:

	June 30,		December 31,
Dollars in thousands	2013	2012	2012
Open position absolute notional amount:			
Natural gas (millions of therms)	35.9	35.1	39.5
Foreign exchange	$17,171	$13,725	$13,231

Derivatives entered into by the utility for the procurement or hedging of natural gas for future gas years and prior to our annual PGA filing receive regulatory deferred accounting treatment. Derivative contracts entered into after the annual PGA rate is set for the current gas contract year are subject to our PGA incentive sharing mechanism, which provides for either an 80% or 90% deferral of any gains and losses as regulatory assets or liabilities, with the remaining 10% or 20% recognized in current income. All of our commodity hedging for the 2012-13 gas year was completed prior to the start of the gas year, and these hedge prices were included in the Company's PGA filing.

The following table reflects the income statement presentation for the unrealized gains and losses from our derivative instruments. Outstanding derivative instruments related to regulated utility operations are deferred in accordance with regulatory accounting standards. We also enter into exchange contracts related to the optimization of our gas portfolio, which are derivatives but do not qualify for hedge accounting or regulatory deferral, and are subject to our regulatory sharing agreement.

	Three Months Ended			
	June 30, 2013		June 30, 2012	
In thousands	Natural gas commodity	Foreign currency	Natural gas commodity	Foreign currency
Cost of sales increase (decrease)	$(16,139)	$—	$27,780	$—
Other comprehensive loss	—	(274)	—	(237)
Less:				
Amounts deferred to regulatory accounts	16,069	274	(27,780)	237
Total loss in pre-tax earnings	$(70)	$—	$—	$—

	Six Months Ended			
	June 30, 2013		June 30, 2012	
In thousands	Natural gas commodity	Foreign currency	Natural gas commodity	Foreign currency
Cost of sales increase (decrease)	$(8,956)	$—	$(28,114)	$—
Other comprehensive loss	—	(513)	—	(111)
Less:				
Amounts deferred to regulatory accounts	9,032	513	28,114	111
Total gain in pre-tax earnings	$76	$—	$—	$—

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No collateral was posted with or by our counterparties as of June 30, 2013 or 2012. We attempt to minimize the potential exposure to collateral calls by counterparties to manage our liquidity risk. Counterparties generally allow a certain credit limit threshold before requiring us to post collateral against loss positions. Given our counterparty credit limits and portfolio diversification, we have not been subject to collateral calls in 2012 or 2013. Our collateral call exposure is set forth under credit support agreements, which generally contain credit limits. We could also be subject to collateral call exposure where we have agreed to provide adequate assurance, which is not specific as to the amount of credit limit allowed, but could potentially require additional collateral in the event of a material adverse change. Based upon current financial derivative contracts outstanding, which reflect unrealized losses of $8.8 million at June 30, 2013, we have estimated the level of collateral demands, with and without potential adequate assurance calls, using current gas prices and various credit downgrade rating scenarios for NW Natural as follows:

		Credit Rating Downgrade Scenarios			
In thousands	(Current Ratings) A+/A3	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative
With Adequate Assurance Calls	$—	$—	$—	$—	$6,337
Without Adequate Assurance Calls	—	—	—	—	6,180

Our derivative financial instruments are subject to master netting arrangements; however, they are presented on a gross basis on the face of our statement of financial position. The Company and its counterparties have the ability to set-off their obligations to each other under specified circumstances. Generally set-off of any early termination amount payable to one party by the other party, in circumstances where there is a defaulting party or where there is one affected party in the case where either a credit event upon merger has occurred, the occurrence of an event of default or any other termination event, will, at the option of the non-defaulting party be reduced by or set-off against any other amounts payable. If netted by counterparty, our derivative position would result in an asset of $0.2 million and $0.9 million and a liability of $9.7 million and $29.1 million as of June 30, 2013 and June 30, 2012, respectively.

In the three and six months ended June 30, 2013, we realized a net gain of $1.4 million and a net loss of $4.0 million, respectively, from the settlement of natural gas hedge contracts at maturity, which were recorded as decreases and increases to the cost of gas, compared to net losses of $21.3 million and $50.7 million, respectively, for the three and six months ended June 30, 2012. The currency exchange rate in all foreign currency forward purchase contracts is included in our purchased cost of gas at settlement; therefore, no gain or loss is recorded from the settlement of those contracts.

We are exposed to derivative credit and liquidity risk primarily through securing fixed price natural gas commodity swaps to hedge the risk of price increases for our natural gas purchases made on behalf of customers. See Note 13 in our 2012 Form 10-K for more information on our derivative instruments.

Fair Value

In accordance with fair value accounting, we include nonperformance risk in calculating fair value adjustments. This includes a credit risk adjustment based on the credit spreads of our counterparties when we are in an unrealized gain position, or on our own credit spread when we are in an unrealized loss position. The inputs in our valuation techniques include natural gas futures, volatility, credit default swap spreads and interest rates. Additionally, our assessment of non-performance risk is generally derived from the credit default swap market and from bond market credit spreads. The impact of the credit risk adjustments for all outstanding derivatives was immaterial to the fair value calculation at June 30, 2013. As of June 30, 2013 and 2012 and December 31, 2012, the fair value was a liability of $9.5 million, $28.2 million, and $5.8 million, respectively, using significant other observable, or Level 2, inputs. We have used no Level 3 inputs in our derivative valuations. We did not have any transfers between Level 1 or Level 2 during the six months ended June 30, 2013 and 2012.

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13. ENVIRONMENTAL MATTERS

We own, or previously owned, properties that may require environmental remediation or action. We estimate the range of loss for environmental liabilities based on current remediation technology, enacted laws and regulations, industry experience gained at similar sites and an assessment of the probable level of involvement and financial condition of other potentially responsible parties. Due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases, we have disclosed the nature of the possible loss and the fact that the high end of the range cannot be reasonably estimated. Unless there is an estimate within a range of possible losses that is more likely than other cost estimates within that range, we record the liability at the low end of this range. It is likely that changes in these estimates and ranges will occur throughout the remediation process for each of these sites due to our continued evaluation and clarification concerning our responsibility, the complexity of environmental laws and regulations and the determination by regulators of remediation alternatives.

Environmental site remediation costs are deferred under regulatory approval from the OPUC and WUTC. In addition, the OPUC authorized a mechanism (SRRM) that allows the Company to recover prudently incurred environmental site remediation costs, subject to an earnings test. Actual cost recovery under SRRM depends upon future insurance recoveries, future expenditures, annual prudence reviews, and the impacts of an earnings test. Cost recovery and carrying charges on amounts deferred for costs associated with services provided to Washington customers will be determined in a future proceeding. We annually review all regulatory assets for recoverability and more often if circumstances warrant. If we should determine that all or a portion of these regulatory assets no longer meet the criteria for continued application of regulatory accounting, then we would be required to write off the net unrecoverable balances against earnings in the period such determination is made. See Note 15 for information on the settlement agreement filed with the OPUC to resolve implementation issues for SRRM.

In December 2010, NW Natural commenced litigation against certain of its historical liability insurers in Multnomah County Circuit Court, State of Oregon (see Item 3. Legal Proceedings). In the complaint, NW Natural sought damages in excess of the $50 million in losses it had incurred through the date of the complaint, as well as declaratory relief for additional losses it expected to incur in the future.

The following table summarizes information regarding liabilities related to environmental sites, which are recorded in other current liabilities and other non-current liabilities on the balance sheet:

	Current Liabilities			Non-Current Liabilities		
	June 30,		December 31,	June 30,		December 31,
In thousands	2013	2012	2012	2013	2012	2012
Portland Harbor site:						
Gasco/Siltronic Sediments	$427	$2,340	$2,207	$38,058	$43,066	$36,087
Other Portland Harbor	1,729	1,286	1,767	2,598	3,409	3,160
Gasco Uplands site	11,354	12,606	18,722	8,230	10,769	5,028
Siltronic Uplands site	496	467	637	392	620	379
Central Service Center site	100	100	140	338	436	396
Front Street site	475	866	993	178	646	—
Oregon Steel Mills	—	—	—	179	117	185
Total	$14,581	$17,665	$24,466	$49,973	$59,063	$45,235

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The following table presents information regarding the total amount of cash paid for environmental sites and the total regulatory asset deferred:

In thousands	June 30, 2013	2012	December 31, 2012
Cash paid	$83,936	$62,468	$71,124
Total regulatory asset deferral[1]	120,224	113,369	121,144

[1] Total regulatory asset deferral includes cash paid, remaining liability, and interest, net of insurance reimbursement.

PORTLAND HARBOR SITE. The Portland Harbor is an EPA listed Superfund site that is approximately 11 miles long on the Willamette River and is adjacent to NW Natural's Gasco uplands and Siltronic uplands sites. We have been notified that we are a potentially responsible party to the Superfund site and we have joined with other potentially responsible parties (the Lower Willamette Group or LWG) to develop a Portland Harbor Remedial Investigation/Feasibility Study (RI/FS). The LWG submitted a draft Feasibility Study (FS) to EPA in March 2012 that provides a range of remedial costs for the entire Portland Harbor Superfund Site, which includes the Gasco/Siltronic Sediment site, discussed below. The range of costs estimated for various remedial alternatives for the entire Portland Harbor, as provided in the draft FS, is $169 million to $1.8 billion. NW Natural's potential liability is a portion of the costs of the remedy EPA will select for the entire Portland Harbor Superfund site. The cost of that remedy is expected to be allocated among more than 100 potentially responsible parties. NW Natural is participating in a non-binding allocation process in an effort to settle this potential liability. We manage our liability related to the Superfund site as two distinct remediation projects, the Gasco/Siltronic Sediments and Other Portland Harbor projects.

Gasco/Siltronic Sediments. In 2009, NW Natural and Siltronic Corporation entered into a separate Administrative Order on Consent with EPA to evaluate and design specific remedies for sediments adjacent to the Gasco uplands and Siltronic uplands sites. NW Natural submitted a draft Engineering Evaluation/Cost Analysis (EE/CA) to the EPA in May 2012 to provide the estimated cost of potential remedial alternatives for this site. At this time, the estimated costs for the various sediment remedy alternatives in the draft EE/CA range from $38.5 million to $350 million. We have recorded a liability of $34.0 million for the sediment clean-up, which reflects the low end of the EE/CA range. We have recorded an additional liability of $4.5 million for the additional studies and design work needed before the clean-up can occur, and for regulatory oversight throughout the clean-up. At this time, we believe sediments at this site represent the largest portion of our liability related to the Portland Harbor site, discussed above.

Other Portland Harbor. NW Natural incurs costs related to its membership in the LWG which is performing the RI/FS for EPA. NW Natural may also incur costs related to natural resource damages. In 2008, the Portland Harbor Natural Resource Trustee Council advised a number of potentially responsible parties that it intended to pursue natural resource damage claims at the Portland Harbor Superfund site. The Company and other parties have signed a cooperative agreement with the Natural Resource Trustees to participate in a phased natural resource damage assessment to estimate liabilities to support an early restoration-based settlement of natural resource damage claims. We have accrued a liability for these claims which is at the low end of the range of the potential liability. This liability is not included in the range of costs provided in the draft FS for the Portland Harbor.

GASCO UPLANDS SITE. NW Natural owns a former gas manufacturing plant that was closed in 1956 (Gasco site) and is adjacent to the Portland Harbor site described above. The Gasco site has been under investigation by us for environmental contamination under the Oregon Department of Environmental Quality (ODEQ) Voluntary Clean-Up Program. It is not included in the range of remedial costs for the Portland Harbor site. We manage the Gasco site in two parts, the uplands portion and the groundwater source control action.

In May 2007, we completed a revised Remedial Investigation Report for the uplands portion and submitted it to ODEQ for review. We have recognized a liability for this portion of the site remediation which is at the low end of the range of potential liability.

In 2012, ODEQ approved our final design remediation plan for a groundwater source control system on which we began construction in October 2012. Based on the information currently available for groundwater source control at the Gasco site and our current assumptions regarding the effectiveness of the source control system, we have estimated a range of liability between $10.7 million and $25 million, for which we have recorded an accrued liability

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which is at the low end of the range of the potential liability. This range has uncertainty due to potential additional ODEQ requirements and actions needed to meet those requirements, including uncertainty about how to meet the agreed standards set by ODEQ subsequent to the initial testing of the system and as part of the final remedy for the uplands portion of the Gasco site.

OTHER SITES. In addition to those sites above, we have environmental exposures at four other sites, Siltronic, Central Service Center, Front Street, and Oregon Steel Mills. Due to the uncertainty of the design of remediation, regulation, timing of the liabilities, and in the case of the Oregon Steel Mills site, pending litigation, liabilities for each of these sites has been recognized at their respective low end of the range of potential liability and the high end of the range cannot be reasonably estimated. See "Legal Proceedings" below.

Legal Proceedings

NW Natural is subject to claims and litigation arising in the ordinary course of business. Although the final outcome of any of these legal proceedings cannot be predicted with certainty, including the matter described below, NW Natural does not expect that the ultimate disposition of any of these matters will have a material effect on our financial condition, results of operations or cash flows. See also Part II, Item 1, "Legal Proceedings."

OREGON STEEL MILLS SITE. In 2004, NW Natural was served with a third-party complaint by the Port of Portland (the Port) in a Multnomah County Circuit Court case, Oregon Steel Mills, Inc. v. The Port of Portland. The Port alleges that in the 1940s and 1950s petroleum wastes generated by our predecessor, Portland Gas & Coke Company, and 10 other third-party defendants, were disposed of in a waste oil disposal facility operated by the United States or Shaver Transportation Company on property then owned by the Port and now owned by Oregon Steel Mills. The complaint seeks contribution for unspecified past remedial action costs incurred by the Port regarding the former waste oil disposal facility as well as a declaratory judgment allocating liability for future remedial action costs. No date has been set for trial. Although the final outcome of this proceeding cannot be predicted with certainty, we do not expect that the ultimate disposition of this matter will have a material effect on our financial condition, results of operations or cash flows.

14. REVISION OF PRIOR PERIOD FINANCIAL STATEMENTS

During the first quarter of 2013, we identified an error in the rate used to calculate interest on certain regulatory assets. Accounting standards allow for the capitalization of all or part of an incurred cost that would otherwise be charged to expense if the regulator provides orders that create probable recovery of past costs through future revenues. Historically we had accrued interest as specified by regulatory order on certain regulatory balances at our authorized rate of return (ROR). This ROR includes both a debt and equity component, which we are allowed to recover from customers in the form of a carrying cost on regulatory deferred account balances. As the equity component of our ROR is not an incurred cost that would otherwise be charged to expense, this portion of the carrying cost should not have been capitalized for financial reporting purposes.

We assessed the materiality of this error on prior period financial statements and concluded it was not material to any prior annual or interim periods; however, the cumulative impact would have been material to the interim period ending March 31, 2013, if corrected in 2013. As a result, in accordance with accounting standards, we revised our prior period financial statements as described below to correct for this error. The revision had no effect on reported cash flows.

The adjustment impacted years 2003 through 2012 with a cumulative pre-tax decrease over that period of $5.6 million to regulatory assets and other income and expense. The revision decreased net income by $1.1 million, $0.9 million and $0.7 million for the years ended December 31, 2012, 2011 and 2010, respectively. The cumulative decrease to January 1, 2010 retained earnings was $0.7 million as a result of the revision.

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The following table presents the income statement impacts of this revision for the years ended December 31:

	2012			2011			2010		
In thousands, except per share data	Reported Balance	Adjust-ment	Adjusted Balance	Reported Balance	Adjust-ment	Adjusted Balance	Reported Balance	Adjust-ment	Adjusted Balance
Other income and expense, net	$4,936	$(1,777)	$3,159	$4,523	$(1,411)	$3,112	$7,102	$(1,083)	$6,019
Income before income taxes	103,959	(1,777)	102,182	107,280	(1,411)	105,869	122,129	(1,083)	121,046
Income tax expense	44,104	(701)	43,403	43,382	(557)	42,825	49,462	(429)	49,033
Net Income	59,855	(1,076)	58,779	63,898	(854)	63,044	72,667	(654)	72,013
Comprehensive income	58,364	(1,076)	57,288	62,702	(854)	61,848	72,031	(654)	71,377
Basic EPS	2.23	(0.04)	2.19	2.39	(0.03)	2.36	2.73	(0.02)	2.71
Diluted EPS	2.22	(0.04)	2.18	2.39	(0.03)	2.36	2.73	(0.03)	2.70

The following table presents the balance sheet impacts of this revision as of December 31:

	2012			2011		
In thousands	Reported Balance	Adjustment	Adjusted Balance	Reported Balance	Adjustment	Adjusted Balance
Non-current assets:						
Regulatory assets	$387,888	$(5,633)	$382,255	$371,392	$(3,856)	$367,536
Total non-current assets	2,535,054	(5,633)	2,529,421	2,397,885	(3,856)	2,394,029
Total assets	2,818,753	(5,633)	2,813,120	2,746,574	(3,856)	2,742,718
Liabilities and equity:						
Deferred credits and other non-current liabilities:						
Deferred tax liabilities	$446,604	$(2,227)	$444,377	$413,209	$(1,526)	$411,683
Total deferred credits and other non-current liabilities	1,025,584	(2,227)	1,023,357	975,922	(1,526)	974,396
Equity:						
Retained earnings	385,753	(3,406)	382,347	373,905	(2,330)	371,575
Total equity	733,033	(3,406)	729,627	714,488	(2,330)	712,158
Total liabilities and equity	2,818,753	(5,633)	2,813,120	2,746,574	(3,856)	2,742,718

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The following tables present the income statement and balance sheet corrections for the following quarters:

	2012							
	First Quarter		Second Quarter		Third Quarter		Fourth Quarter	
In thousands, except per share data	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance
Other income and expense, net	$1,005	$472	$921	$620	$1,710	$1,180	$1,300	$887
Income (loss) before income taxes	68,480	67,947	2,296	1,995	(13,594)	(14,124)	46,777	46,364
Income tax expense (benefit)	27,873	27,663	887	768	(3,036)	(3,245)	18,380	18,217
Net income (loss)	40,607	40,284	1,409	1,227	(10,558)	(10,879)	28,397	28,147
Comprehensive income (loss)	40,773	40,450	1,575	1,393	(10,391)	(10,712)	26,407	26,157
Basic EPS	1.52	1.50	0.05	0.05	(0.39)	(0.41)	1.06	1.05
Diluted EPS	1.51	1.50	0.05	0.05	(0.39)	(0.41)	1.05	1.04
Non-current assets:								
Regulatory assets	$368,521	$364,132	$366,981	$362,290	$367,692	$362,472	$387,888	$382,255
Total non-current assets	2,416,372	2,411,983	2,448,359	2,443,668	2,492,467	2,487,247	2,535,054	2,529,421
Total assets	2,727,262	2,722,873	2,635,141	2,630,450	2,690,368	2,685,148	2,818,753	2,813,120
Liabilities and equity:								
Deferred credits and other non-current liabilities:								
Deferred tax liabilities	$438,486	$436,750	$440,073	$438,217	$430,885	$428,821	$446,604	$444,377
Total deferred credits and other non-current liabilities	999,028	997,292	991,007	989,151	985,729	983,665	1,025,584	1,023,357
Equity:								
Retained earnings	402,599	399,946	392,082	389,247	369,584	366,428	385,753	382,347
Total equity	745,971	743,318	737,570	734,735	717,559	714,403	733,033	729,627
Total liabilities and equity	2,727,262	2,722,873	2,635,141	2,630,450	2,690,368	2,685,148	2,818,753	2,813,120

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	2011							
	First Quarter		Second Quarter		Third Quarter		Fourth Quarter	
In thousands, except per share data	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance
Other income and expense, net	$1,214	$1,291	$1,122	$779	$1,781	$1,426	$406	$(384)
Income (loss) before income taxes	68,627	68,704	3,509	3,166	(14,012)	(14,367)	49,156	48,366
Income tax expense (benefit)	27,854	27,884	1,316	1,181	(5,700)	(5,840)	19,912	19,600
Net income (loss)	40,773	40,820	2,193	1,985	(8,312)	(8,527)	29,244	28,766
Comprehensive income (loss)	40,919	40,966	2,339	2,131	(8,166)	(8,381)	27,610	27,132
Basic EPS	1.53	1.53	0.08	0.07	(0.31)	(0.32)	1.09	1.08
Diluted EPS	1.53	1.53	0.08	0.07	(0.31)	(0.32)	1.09	1.07
Non-current assets:								
Regulatory assets	$345,452	$343,085	$326,081	$323,371	$328,757	$325,692	$371,392	$367,536
Total non-current assets	2,290,848	2,288,481	2,294,100	2,291,390	2,317,293	2,314,228	2,397,885	2,394,029
Total assets	2,571,553	2,569,186	2,521,994	2,519,284	2,567,840	2,564,775	2,746,574	2,742,718
Liabilities and equity:								
Deferred credits and other non-current liabilities:								
Deferred tax liabilities	$396,357	$395,419	$398,825	$397,751	$394,217	$393,003	$413,209	$411,683
Total deferred credits and other non-current liabilities	873,714	872,776	874,842	873,768	866,927	865,713	975,922	974,396
Equity:								
Retained earnings	385,899	384,470	376,489	374,853	356,574	354,723	373,905	371,575
Total equity	723,228	721,799	714,628	712,992	696,605	694,754	714,488	712,158
Total liabilities and equity	2,571,553	2,569,186	2,521,994	2,519,284	2,567,840	2,564,775	2,746,574	2,742,718

	Six months ended June 30, 2012		Nine months ended September 30, 2012	
In thousands, except per share data	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance
Other income and expense, net	$1,926	$1,092	$3,636	$2,272
Income before income taxes	70,776	69,942	57,182	55,818
Income tax expense	28,760	28,431	25,724	25,186
Net Income	42,016	41,511	31,458	30,632
Comprehensive income	42,348	41,843	31,957	31,131
Basic EPS	1.57	1.55	1.17	1.14
Diluted EPS	1.56	1.54	1.17	1.14

15. SUBSEQUENT EVENTS

Regulatory Settlements

On July 11, 2013, NW Natural filed stipulated settlement agreements in two dockets that resulted from certain decisions deferred by the OPUC from our 2012 general rate case. One settlement addresses implementation issues related to the new environmental recovery mechanism (SRRM), and the second settlement relates to the recovery of carrying costs on working gas inventory. The settlement agreements are subject to Commission review and approval. The Company anticipates Commission review during the third quarter.

Environmental Cost (SRRM) Settlement

If approved, the settlement addresses SRRM implementation issues including a review of the prudence of past deferred expenses, as well as the creation and application of an earnings test to determine the amount of environmental costs that would be collected from customers based on the Company's past and future earnings.

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Under the settlement agreement, approximately $97.6 million of environmental remediation expenses and associated carrying costs incurred by NW Natural through December 31, 2012 were deemed prudently incurred. The parties also agreed that insurance settlements finalized through 2012 (approximately $40.7 million) were prudently executed, with these recoveries applied against deferred expenses to reduce amounts to be amortized under the SRRM. As part of the settlement, NW Natural has agreed not to seek recovery of $7.0 million of its $97.6 million in deferred expenses and associated carrying costs incurred through December 31, 2012. Upon Commission approval, this disallowance and other related adjustments will result in a one-time, net after-tax charge of $3.4 million.

The settlement also provides that environmental remediation expenditures deferred on or after January 1, 2013 will be reviewed annually for prudency, and an earnings test will be applied annually as follows:

- If NW Natural's Oregon utility results of operations (ROO) for a given year show that NW Natural's earnings were more than 75 basis points below its authorized return on equity in that year (Authorized ROE), NW Natural will be allowed to collect all of the prudently incurred environmental remediation expenses deferred in that year.
- If NW Natural's ROO for a given year shows that its earnings are between 75 basis points below Authorized ROE and Authorized ROE (or at Authorized ROE), NW Natural will reduce the balance of the SRRM account up to the net amount deferred for the current year, including offsetting insurance proceeds and other third-party recoveries allocated to that year (Net Amount Deferred), by 10% of its earnings between 75 basis points below Authorized ROE and Authorized ROE.
- If NW Natural's ROO for a given year shows that its earnings are above Authorized ROE but less than or equal to 50 basis points above Authorized ROE, NW Natural will reduce the balance of the SRRM account, up to the Net Amount Deferred for the current year, including offsetting insurance proceeds and other third-party recoveries allocated to that year, by: (1) 80% of NW Natural's earnings between Authorized ROE and 50 basis points above Authorized ROE; and (2) 10% of its earnings between 75 basis points below Authorized ROE and Authorized ROE.
- If NW Natural's ROO for a given year shows that its earnings are more than 50 basis points above Authorized ROE, NW Natural will reduce the balance of the SRRM account, up to the Net Amount Deferred for the current year, including offsetting insurance proceeds and other third-party recoveries allocated to that year, by: (1) 95% of its earnings above 50 basis points above Authorized ROE; (2) 80% of its earnings between Authorized ROE and 50 basis points above Authorized ROE; and (3) 10% of its earnings between 75 basis points below Authorized ROE and Authorized ROE.

Any insurance proceeds recovered after December 31, 2012 will be applied against expenses approved for amortization in the SRRM in equal amounts over the 10-year period following receipt of the funds.

The settlement also provides for recovery of the Company's costs associated with the construction of a water treatment station at NW Natural's Gasco site in Portland, Oregon. The station is currently under construction and is expected to be completed in the third quarter of 2013 with a cost estimate between $20 million and $25 million. Under the settlement agreement, NW Natural can file for rate recovery upon completion and after a prudency review. After these steps, the approved capital costs will be rolled into customer rates as part of rate base at the time of the subsequent PGA.

Working Gas Inventory Settlement

The working gas inventory carrying costs settlement, if approved, would allow the Company to collect $4.5 million, before interest, for deferred carrying costs on working gas inventory balances for the period of November 1, 2012 through October 31, 2013. Upon approval, this amount will be included in the 2013-2014 PGA rates. Prior to the settlement, the Company had been accruing $4.0 million annually for these carrying costs.

In addition, beginning November 1, 2013, approximately $39.5 million in working gas inventory will be included in rate base at NW Natural's authorized utility rate of return. This equates to an annual revenue requirement increase of approximately $4.5 million.

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is management’s assessment of Northwest Natural Gas Company’s (NW Natural or the Company) financial condition, including the principal factors that affect results of operations. The disclosures contained in this report refer to our consolidated activities for the three and six months ended June 30, 2013 and 2012. Unless otherwise indicated, references below to “Notes” are to the Notes to Consolidated Financial Statements in this report. A significant portion of our business results are seasonal in nature, and as such the results of operations for these three and six month periods are not necessarily indicative of expected fiscal year results. Therefore, this discussion should be read in conjunction with our 2012 Annual Report on Form 10-K (2012 Form 10-K).

The consolidated financial statements include NW Natural, the parent company, and its direct and indirect wholly-owned subsidiaries, including and organized as follows:

We operate in two primary reportable business segments, local gas distribution and gas storage. We also have other investments and business activities not specifically related to one of these two reporting segments, which we aggregate and report as “other.” We refer to our local gas distribution business as the “utility,” and our “gas storage” and “other” business segments as “non-utility.” Our utility segment includes our NW Natural local gas distribution business, NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp, and the utility portion of our Mist underground storage facility in Oregon (Mist). Our gas storage segment includes NWN Gas Storage, which is a wholly-owned subsidiary of NWN Energy, Gill Ranch, which is a wholly-owned subsidiary of NWN Gas Storage, the non-utility portion of Mist, and all third-party asset management services. Our “other” segment includes NWN Energy's equity investment in Palomar Gas Holdings, LLC (PGH), which is pursuing the development of a proposed natural gas pipeline through its wholly-owned subsidiary, Palomar Gas Transmission, LLC (Palomar), and NNG Financial's equity investment in Kelso-Beaver Pipeline (KB Pipeline). For a further discussion of our business segments, see Note 4.

In addition to presenting results of operations and earnings amounts in total, certain financial measures are expressed in cents per share, which is a non-GAAP financial measure. These amounts reflect factors that directly impact earnings. In calculating these financial disclosures, we allocate income tax expense based on the effective tax rate, where applicable. All references in this section to earnings per share (EPS) are on the basis of diluted shares (see Part II, Item 8., Note 3, “Earnings Per Share,” in our 2012 Form 10-K). We use such non-GAAP measures in analyzing our financial performance because we believe they provide useful information to our investors and creditors in evaluating our financial condition and results of operations.

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EXECUTIVE SUMMARY

Key financial highlights include:

	Three Months Ended June 30,		
In thousands, except per share data	2013	2012	Change
Consolidated net income	$2,126	$1,227	$899
Consolidated EPS	0.08	0.05	0.03
Utility margin	64,801	61,440	3,361

THREE MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The primary factors contributing to results were as follows:

- an increase in consolidated net income and EPS primarily due to higher utility margin, partially offset by higher operations and maintenance expenses, and depreciation expense.
- an increase in utility margin primarily related to revenue timing impacts, customer growth, and increased contributions from our gas reserve investment. Partially offsetting this margin increase were lower gains from gas cost savings.

In addition to our financial results for the second quarter of 2013, we also continue to make progress on several key initiatives including:

- signing settlement agreements for both our Site Remediation and Recovery Mechanism (SRRM) and Working Gas Inventory dockets, which, if approved, will resolve two of the open items from our 2012 Oregon general rate case. See "Regulatory Matters—General Rate Cases—Settlements" below for more detail;
- planning continues for the next gas storage expansion at our Mist facility and is expected to include the development of gas storage wells, a compressor station, and additional pipeline facilities; and
- developing new utility service opportunities such as the Company owning and servicing CNG fueling stations at customer locations.

Our progress on, and commitment to, these initiatives are a part of our core business objectives and long-term strategic plan. See Part II, Item 7, “2013 Outlook” in our 2012 Form 10-K and "Strategic Opportunities" below.

Issues, Challenges and Performance Measures

ECONOMY. The local, national, and global economies continued to show some signs of growth during the second quarter of 2013; however, the economy remains delicate and the recovery slow. Our utility’s annual customer growth rate was 1.0% at June 30, 2013, compared to 0.9% at June 30, 2012. The unemployment rates in our region have declined to under 8% from over 11% in 2009, and new housing permits in Oregon have increased. We will continue to monitor the economy but believe our utility business is well positioned to continue adding customers and to serve increasing energy demand as the economy recovers because of low, stable natural gas prices, our relatively low market penetration, and our ongoing focus on converting homes and commercial businesses to natural gas, as well as industrial customers switching to natural gas due to its price advantage over oil, propane, and other fuels. In addition, government and regulatory policies that favor lower carbon emissions and lower cost energy alternatives such as natural gas could increase demand for our services in the future.

GAS PRICES AND SUPPLIES. Our gas acquisition strategy is to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge gas prices so we can effectively manage costs, reduce price volatility, and maintain a competitive advantage. With recent developments in drilling technologies and substantial access to supplies around the U.S. and in Canada, the current outlook for North American natural gas supply is strong and is projected to remain this way well into the future. The continuation of low and stable gas prices in the future depends on a combination of supply outlook and demand factors as well as a regulatory environment that continues to support hydraulic fracturing and other drilling technologies.

Our utility's annual PGA mechanisms in Oregon and Washington, combined with our gas price hedging strategies, enable us to reduce earnings exposure for the Company and secure low, stable gas costs for our customers. See "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment" below. We typically hedge gas prices for approximately 75% of our utility's annual sales requirement based on average weather, including both physical and financial hedges. We entered the 2012-13 gas year (November 1, 2012 – October 31, 2013) hedged at 75% of our forecasted sales volumes, including 47% in financial swaps and option contracts and 28% in physical gas supplies.

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The physical hedges consisted of a combination of gas inventories in storage, local production from the Mist area, and supply region production from utility gas reserve investment. For further discussion of gas reserves, see “Strategic Opportunities—Gas Reserves” below.

In addition to the amount hedged for the current gas contract year, we were also hedged at approximately 59% as of June 30, 2013 for the upcoming 2013-14 gas year and between 8% and 25% hedged for annual requirements over the following five gas years. Our hedge levels are subject to change based on actual load volumes, which depend to a certain extent on weather and economic conditions. Also, our storage inventory levels may increase or decrease based on storage expansion, storage contracts with third parties, or storage recall by the utility.

Although less expensive and more stable gas prices provide opportunities to manage costs for our utility customers, they also present challenges for our gas storage businesses by lowering the price of, and reducing the demand for, storage services. Consequently, our ability to sign storage contracts with customers at favorable prices affects our financial results. However, if there is an increase in demand for natural gas or a decrease in drilling activity, there may be upward pressure on gas prices or an increase in gas price volatility, which may result in increased demand or prices for storage services. In the short-term, we strive to find opportunities for increasing revenues, lowering costs, and developing enhanced services for storage customers.

ENVIRONMENTAL COSTS. We accrue all environmental loss contingencies related to environmental sites for which we are responsible. Due to numerous uncertainties surrounding the nature of environmental investigations and the development of remediation solutions approved by regulatory agencies, actual costs could vary significantly from our loss estimates. As a regulated utility, we are allowed to defer certain costs pursuant to regulatory orders. In our most recent general rate case, the Public Utility Commission of Oregon (OPUC) approved the recovery of environmental costs from investigation and site remediation subject to certain conditions as noted in "Results of Operations—Regulatory Matters—Rate Mechanisms" below.

We also recover some of our environmental costs from insurance policies and only seek recovery from customers for amounts not covered by insurance. Ultimate recovery of environmental costs from regulated utility rates will depend on our ability to effectively manage these costs, demonstrate that costs were prudently incurred, and the impact of cost sharing, if any, under the new earnings test. See "Regulatory Matters—General Rate Cases—Settlements" below for more detail on the stipulated settlement filed with the OPUC, which outlines implementation issues regarding the SRRM's earnings test. Environmental cost recovery and carrying charges on amounts charged to Washington customers will be determined in a future proceeding.

See Part II, Item 7, “Issues, Challenges, and Performance Measures” in our 2012 Form 10-K for a discussion of our performance metrics.

Strategic Opportunities

SAFETY, RELIABILITY, AND SERVICE. We are committed to customer and employee safety, operational effectiveness, and service quality, as each is a means of leveraging our competitive position. We have several ongoing initiatives designed to improve the quality, effectiveness, and integrity of our utility and non-utility business operations. To this end, we have upgraded several facilities to enhance business continuity, employee training, safety, productivity, and energy efficiency. Our initiatives in 2013 will further enhance our commitment to safety. For example, the Company has increased staffing levels in the areas of pipeline safety, emergency response, regulatory compliance, field training, and customer service to respond to new federal pipeline safety legislation and system integrity requirements including the accelerated completion of bare steel replacement, as well as customer expectations for service responsiveness.

GAS STORAGE. We own and operate two underground gas storage facilities—the Mist facility in Oregon and the Gill Ranch facility near Fresno, California. Storage operations benefit from seasonal swings in commodity pricing and market volatility. Our storage facilities position us to capitalize on rising demand for natural gas, higher gas prices, or increased market volatility. Currently natural gas prices remain relatively low and stable; however, if there is an increase in demand for natural gas, a decrease in drilling activity, or other factors, including weather, there may be upward pressure on gas prices or price volatility may return. We have the ability to expand both facilities beyond their current capacities.

The Pacific Northwest storage market has been impacted by lower gas prices and lack of gas price volatility, although less than in California due to greater seasonal price differentials. In addition, new flexible gas-fired

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generation is needed in the Pacific Northwest region to integrate intermittent wind resources into the power system, thereby increasing the associated need for gas storage. As a result, we are in the early planning stage of a new expansion at Mist. This expansion is anchored by an agreement to provide gas storage services to Portland General Electric (PGE) for gas-fired generation facilities at Port Westward, Oregon. Our Mist expansion project is subject to several conditions, including, but not limited to, PGE's approval of projected costs and timelines and its notice to proceed with the project, and NW Natural's filing and approval by the OPUC of a new rate schedule for this service, as well as NW Natural receiving required permits and regulatory approvals for the project. The expansion would likely include the development of new storage wells, a compressor station, and additional pipeline facilities that would also enable more storage expansions in the future. If the project proceeds as currently planned, the earliest timeframe for completing the next expansion would be 2016.

In addition, we currently estimate that the Gill Ranch storage facility could support an additional 25 Bcf of storage capacity, bringing the total storage capacity to approximately 45 Bcf, of which our current rights would give us up to an additional 7.5 Bcf or ownership of a total of approximately 22.5 Bcf. An expansion at the Gill Ranch storage facility would require certain infrastructure investments, but no further expansion of our gas transmission pipeline.

PIPELINE DIVERSIFICATION. Currently, our utility operations and gas storage operations at Mist depend on a single bi-directional interstate transmission pipeline to ship gas supplies to customers. We continue to work with regulators and utilities in the Pacific Northwest to advance a new integrated, regional cross-Cascades pipeline through our Palomar investment, to reduce this risk, and create regional diversity and increased reliability for our system.

The Federal Energy Regulatory Commission (FERC) will regulate the proposed pipeline. Palomar intends to file an application with FERC for a pipeline delivering gas from the GTN pipeline near Madras in central Oregon to a NW Natural hub near Molalla, Oregon. The application will be filed after NW Natural has received OPUC and Washington Utilities and Transportation Commission (WUTC) acknowledgment of its filed resource plans and after Palomar has conducted a new open season to obtain adequate commercial support for the pipeline. The approval and timing of potential construction of the pipeline will depend on the project being competitive with alternative Pacific Northwest pipeline projects, as well as being able to obtain regulatory permits and the necessary commercial support from shippers. See Note 11 for further discussion.

GAS RESERVES. In addition to hedging gas prices with commodity-based financial derivative contracts, we entered into an agreement with Encana Oil & Gas (USA) Inc. (Encana) in 2011 to hedge a portion of our Oregon utility customers’ cost of gas over an estimated 30 years. Under this agreement, we have invested in working interests in certain gas leases in a field located in Sublette County, Wyoming. During the first 10 years of the contract, we forecast the volumes of gas to be produced under the gas reserves agreement sufficient to hedge approximately 8% to 10% of our average annual utility gas supply requirements. We receive certain federal tax deductions for drilling costs incurred under our gas reserves agreements. The timing of when we realize these federal tax benefits has been affected by net operating losses (NOLs) for tax purposes, which will be carried forward to reduce our current tax liability in future years. We continue to evaluate additional investments in gas reserves as part of our gas hedging strategy. See Part II, Item 7, "Results of Operations—Regulatory Matters—Rate Mechanisms—Gas Reserves" in our 2012 Form 10-K.

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CONSOLIDATED EARNINGS AND DIVIDENDS

Consolidated Earnings

Consolidated highlights include:

In thousands, except per share data	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	QTR Change	YTD Change
Consolidated operating revenues	$131,714	$103,991	$409,575	$413,630	$27,723	$(4,055)
Consolidated operating expenses	118,631	92,152	322,286	323,125	26,479	(839)
Consolidated interest expense, net	11,069	10,464	22,196	21,655	605	541
Consolidated net income	2,126	1,227	39,765	41,511	899	(1,746)
Consolidated EPS	0.08	0.05	1.47	1.54	0.03	(0.07)

THREE MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The primary factors contributing to increased consolidated net income were as follows:

- a $3.4 million increase in utility margin primarily due to:
  - revenue timing impact from changes in fixed monthly charges and the decoupling baseline in rates from our 2012 Oregon general rate case;
  - an increase in utility margin from customer growth; and
  - an increase in utility margin contribution from our gas reserves investment.

  Partially offsetting these increases was a revenue reduction due in part to a lower authorized return on equity resulting from our 2012 Oregon general rate case noted above; and
  - a lower contribution to utility margin from our gas cost incentive sharing mechanism.

- Partially offsetting the utility margin increase was:
  - a $1.1 million increase in operations and maintenance expense due to increased utility payroll and system maintenance and safety costs;
  - a $0.8 million increase in depreciation and amortization expense primarily due to a higher level of investment in utility property, plant, and equipment; and
  - a $0.6 million increase in income tax expense due to higher pre-tax income.

SIX MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The primary factors contributing to decreased consolidated net income were as follows:

- a $2.5 million decrease in utility margin primarily due to:
  - revenue timing impact from changes in fixed monthly charges and the decoupling baseline in rates from our 2012 Oregon general rate case;
  - an overall revenue reduction due in part to a lower authorized return on equity also from our 2012 Oregon general rate case mentioned above; and
  - a lower contribution to utility margin from our gas cost incentive sharing mechanism.

  Partially offsetting these losses was an increase in utility margin from customer growth and an increase in utility margin contribution from our gas reserves investment.
- a $1.7 million increase in depreciation and amortization expense primarily due to a higher level of investment in utility property, plant, and equipment; and
- a $0.4 million increase in operations and maintenance expense due to increases in utility payroll expenses and system maintenance and safety costs, partially offset by a decrease in bad debt expense.

Partially offsetting the decrease in margin and increase in depreciation and operations and maintenance expenses was:

- a $1.2 million increase in gas storage operating revenues;
- a $1.1 million decrease in income tax expense due to lower pre-tax income; and
- an increase in other income.

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Dividends

Dividend highlights include:

	Three Months Ended June 30,		
Per common share	2013	2012	Change
Dividends paid	$0.455	$0.445	$0.01

The Board of Directors declared a quarterly dividend on our common stock of 45.5 cents per share, payable on August 15, 2013, to shareholders of record on July 31, 2013, currently reflecting an indicated annual dividend rate of $1.82 per share.

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RESULTS OF OPERATIONS

Regulatory Matters

Regulation and Rates

UTILITY. Our utility business is subject to regulation with respect to, among other matters, rates, and terms of service set by the OPUC, WUTC, and FERC. The OPUC and WUTC also regulate our systems of accounts and the issuance of securities by our utility. In 2012, approximately 90% of our utility gas volumes and revenues were derived from Oregon customers, with the remaining 10% from Washington customers. Earnings and cash flows from utility operations are largely determined by rates set in general rate cases and other regulatory proceedings in Oregon and Washington, but will also be affected by the economies in Oregon and Washington, by the pace of customer growth in the residential and commercial markets, and by our ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery of our utility-related costs, including operating expenses and investment costs in utility plant and other regulatory assets. See "General Rate Cases" below.

GAS STORAGE. Our gas storage business is subject to regulation with respect to, among other matters, rates and terms of service set by the OPUC, California Public Utilities Commission (CPUC), and FERC. The OPUC and CPUC also regulate the issuance of securities and our system of accounts. The OPUC and FERC regulate intrastate and interstate storage services, respectively, under a cost of service model which allows for storage prices to be set at or below the cost of service as approved by each agency in the last regulatory filing. The CPUC regulates Gill Ranch under a market-based rate model which allows for the price of storage services to be set by the marketplace.

See Part II, Item 7, “Results of Operations—Regulatory Matters,” in the 2012 Form 10-K.

General Rate Cases

OREGON. Our most recent general rate case in Oregon was completed in 2012, in which the OPUC authorized rates to customers based on an ROE of 9.5%, an overall rate of return of 7.78%, and a capital structure of 50% common equity and 50% long-term debt. These customer rates went into effect on November 1, 2012.

DEFERRED DOCKETS. The following items were deferred for decision by the Commission to separate dockets:

- Prepaid Pension Assets - the Company requested to include prepaid pension assets in rate base and allow a return on and recovery of the asset; a new docket was ordered by the OPUC to review the treatment of pensions on a general, non-utility-specific basis. That docket is currently open. Until a conclusion is reached, the OPUC has authorized us to continue to collect and defer pension costs based on its previous 2003 rate case recovery amounts;
- Interstate Storage Sharing - a docket has been opened to review the sharing arrangement whereby we allocate a portion of the net revenues generated from non-utility Mist storage services and third-party asset management services;
- Working Gas Inventory - the Company filed a settlement agreement with the OPUC in July 2013 to resolve this docket. See detail on agreement below in "Settlements"; and
- Site Remediation and Recovery Mechanism (SRRM) - the Company also filed a settlement agreement with the OPUC in July 2013 to address how to apply the mechanism. See "Settlements" and "Environmental Costs" below.

We anticipate Commission review of the working gas inventory and SRRM settlements before year end and expect decisions on the prepaid pension assets and interstate storage sharing open dockets during 2013 or 2014.

SETTLEMENTS. As noted above, on July 11, 2013, NW Natural filed stipulated settlements with all parties to resolve two open dockets from the 2012 Oregon general rate case. The settlements are subject to OPUC review and approval, which the Company expects to be completed during the third quarter.

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SRRM Settlement. If approved, the SRRM settlement agreement resolves all remaining implementation issues, including a review of the prudence of past deferred expenses, as well as the creation and application of an earnings test to determine the amount of costs that would be collected from customers based on the Company's past and future earnings.

Under the settlement agreement, approximately $97.6 million of environmental remediation expenses and associated carrying costs incurred by NW Natural through December 31, 2012 were deemed prudently incurred, with $33,400 disallowed. The parties also agreed that insurance settlements finalized through 2012 (approximately $40.7 million) were entered into prudently, with these recoveries applied against deferred environmental costs to reduce amounts to be amortized under the SRRM. As part of the settlement, NW Natural has agreed not to seek recovery of $7.0 million of its $97.6 million in deferred expenditures and associated carrying costs incurred through December 31, 2012. Upon OPUC approval, this amount and other related adjustments will result in a one-time, net after-tax charge of $3.4 million.

The settlement agreement also provides that environmental remediation expenditures deferred on or after January 1, 2013 will be reviewed annually for prudency, and an earnings test applied as follows:

- If NW Natural's Oregon utility results of operations (ROO) for a given year show that NW Natural's earnings were more than 75 basis points below its authorized return on equity in that year (Authorized ROE), NW Natural will be allowed to collect all of the prudently incurred environmental remediation expenses deferred in that year.
- If NW Natural's ROO for a given year shows that its earnings are between 75 basis points below Authorized ROE and Authorized ROE (or at Authorized ROE), NW Natural will reduce the balance of the SRRM account up to the net amount deferred for the current year, including offsetting insurance proceeds and other third-party recoveries allocated to that year (Net Amount Deferred), by 10% of its earnings between 75 basis points below Authorized ROE and Authorized ROE.
- If NW Natural's ROO for a given year shows that its earnings are above Authorized ROE but less than or equal to 50 basis points above Authorized ROE, NW Natural will reduce the balance of the SRRM account, up to the Net Amount Deferred, including offsetting insurance proceeds and other third-party recoveries allocated to that year for the current year, by: (1) 80% of NW Natural's earnings between Authorized ROE and 50 basis points above Authorized ROE; and (2) 10% of its earnings between 75 basis points below Authorized ROE and Authorized ROE.
- If NW Natural's ROO for a given year shows that its earnings are more than 50 basis points above Authorized ROE, NW Natural will reduce the balance of the SRRM account, up to the Net Amount Deferred for the current year, including offsetting insurance proceeds and other third-party recoveries allocated to that year for the current year, by: (1) 95% of its earnings above 50 basis points above Authorized ROE; (2) 80% of its earnings between Authorized ROE and 50 basis points above Authorized ROE; and (3) 10% of its earnings between 75 basis points below Authorized ROE and Authorized ROE.

For example, assuming that the amount of NW Natural's current Oregon rate base remains unchanged and that NW Natural had earned its Authorized ROE (currently 9.5%) when the earning test was applied, NW Natural would not recover approximately the first $0.6 million of its net environmental remediation expenditures for that year.

Any insurance proceeds recovered after December 31, 2012 will be applied against expenses approved for amortization in the SRRM in equal amounts over the 10-year period following receipt of the funds.

This settlement agreement also provides for recovery of NW Natural's costs associated with the construction of a water treatment station at the Gasco site in Portland, Oregon. The station is currently under construction and is expected to be completed in the third quarter of 2013 with a cost estimate between $20 million and $25 million. Under the settlement agreement, NW Natural will request rate recovery in the upcoming annual PGA filing upon completion of the project. After these steps and prudency review, the approved environmental costs will be rolled into customer rates as part of rate base.

Working Gas Inventory Settlement. The working gas inventory carrying costs settlement, if approved, would allow the Company to collect $4.5 million, before interest, for deferred carrying costs on working gas inventory balances for the period of November 1, 2012 through October 31, 2013. Upon approval, this amount will be included in the PGA rates that become effective November 1, 2013.

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In addition, approximately $39.5 million in working gas inventory will be included in rate base at NW Natural's authorized utility rate of return and be included in PGA rates that become effective November 1, 2013. This equates to an annual revenue requirement increase of approximately $4.5 million.

Rate Mechanisms

PURCHASED GAS ADJUSTMENT. Rate changes are established for the utility each year under PGA mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases. This includes gas prices under spot purchases as well as contract supplies, gas prices hedged with financial derivatives, gas prices from the withdrawal of storage inventories, the production of gas reserves, interstate pipeline demand costs, the application of temporary rate adjustments, which amortize balances of deferred regulatory accounts, and the removal of temporary rate adjustments effective for the previous year.

Under the current PGA mechanism in Oregon, there is an incentive sharing provision whereby we are required to select each year either an 80% deferral or a 90% deferral of higher or lower actual gas costs compared to estimated PGA prices, such that the impact on current earnings from the incentive sharing is either 20% or 10% of the difference between actual and estimated gas costs, respectively. For the 2012-2013 PGA year, we selected the 90% deferral option. Under the Washington PGA mechanism, we defer 100% of the higher or lower actual gas costs, and those gas cost differences are normally passed on to customers through the annual PGA rate adjustment.

SYSTEM INTEGRITY PROGRAM (SIP). The OPUC has approved specific accounting treatment and cost recovery for our transmission pipeline integrity management program and the related rules adopted by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) and provided a two-year extension of our capital expenditure tracking mechanism to recover capital costs related to SIP. We record the costs related to the integrity management program as either capital expenditures or regulatory assets, accumulate the costs over each 12-month period, and recover the revenue requirement associated with these costs, subject to audit, through rate changes effective with the Oregon annual PGA. As such, our SIP costs are tracked into rates with the annual PGA filing, except that the first $4 million of capital costs, and an annual cap on expenditures of $12 million, are not included in the amounts tracked into rates. During the second quarter of 2013, the Commission approved an additional $13.7 million of expenditures over the next two years to be tracked into rates. With the increased cap, we plan to be substantially complete with our bare steel replacement by the end of 2015, and as a result this stipulation precludes us from tracking any additional bare steel replacement costs into rates after 2015.

ENVIRONMENTAL COSTS. The OPUC has authorized us to defer environmental costs associated with certain named sites and to accrue a carrying cost on amounts deferred, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. Through a series of extensions, the authorized cost deferral and accrual of carrying costs was extended through January 2012. In January 2013, we filed a request with the OPUC to continue our deferral of these environmental costs, and we are awaiting an order from the OPUC.

The new SRRM allows the Company to recover prudently incurred environmental site remediation costs, net of insurance recoveries. The SRRM allows recovery of one-fifth of the Company's currently deferred environmental expenses and future expenses as incurred each year in rates on a rolling basis until all such expenses are recovered, subject to an annual prudence review. Recovery of these incurred costs will also be subject to an earnings test, which has been defined in the settlement mentioned above and is awaiting OPUC approval. This test compares earnings in a year to our Authorized ROE with certain levels of sharing of environmental expenditures from that year at graduated levels above and below our Authorized ROE. For more detail on the test, see "General Rate Cases--Settlements" above.

The WUTC has also authorized the deferral of environmental costs that are allocated to Washington customers. This order was effective January 26, 2011 with cost recovery and a carrying charge to be determined in a future proceeding. Based on the Washington proceeding and our filed settlement in Oregon noted above, recovery may vary significantly from amounts currently recorded as regulatory assets, and amounts not recovered would be required to be charged to income in the period they were deemed to be unrecoverable. The settlement also addresses allocation of costs to Oregon, but the Washington allocation has not been determined. For detail on the Oregon environmental settlement, see "General Rate Cases--Settlements" above and Note 15. See Note 13 for further discussion of our regulatory and insurance recovery of environmental costs.

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PENSION DEFERRAL. Effective January 1, 2011, the OPUC approved our request to defer annual pension expenses above the amount set in rates, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of higher and lower pension expenses in future years. Our recovery of these deferred balances includes accrued interest on the account balance at the utility's actual cost of long-term debt. However, upon collection of these deferred balances, we also receive and recognize the equity portion of our weighted average cost of capital as specified by the OPUC. The deferral from operations and maintenance expense in 2012 was $7.9 million. Future years' deferrals will depend on changes in plan assets and projected benefit liabilities based on a number of key assumptions, and our pension contributions. We estimate pension expense deferrals totaling $8 million to $9 million in 2013, with $2.3 million and $4.6 million being deferred for the three and six months ended June 30, 2013, respectively.

As noted above, the Company continues to seek rate treatment in Oregon for amounts invested in prepaid pension assets in a docket which is currently open. The timing of a decision on this docket is uncertain and may continue into 2014.

CUSTOMER CREDITS FOR GAS STORAGE SHARING. In the second quarter of 2013, the Company received regulatory approval to provide its Oregon utility customers with an $8.8 million interstate storage credit, in their June bills, from our regulatory incentive sharing mechanism related to related to non-utility Mist storage services and asset management services. Last year, the OPUC approved a $9.2 million credit to Oregon customers in their June 2012 bills.

For a discussion of other rate mechanisms, see Part II, Item 7, "Results of Operations—Regulatory Matters—Rate Mechanisms" in our 2012 Form 10-K.

Business Segments - Local Gas Distribution "Utility" Operations

Our utility margin results are largely affected by customer growth and, to a certain extent, by changes in volume due to weather, and customers' gas usage patterns because a significant portion of our utility margin is derived from natural gas sales to residential and commercial customers. In Oregon, we have a conservation tariff (also called the decoupling mechanism), which adjusts utility margin up or down each month through a deferred accounting adjustment to offset changes resulting from increases or decreases in average use by residential and commercial customers. We also have a weather normalization tariff in Oregon, which adjusts customer bills up or down to offset changes in utility margin resulting from above- or below-average temperatures during the winter heating season. Both mechanisms are designed to reduce the volatility of our utility's earnings and customer charges. See "Results of Operations—Regulatory Matters—Rate Mechanisms" in our 2012 Form 10-K for more information on our decoupling and weather normalization mechanisms.

Utility segment highlights include:

In thousands, except per share data	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	QTR Change	YTD Change
Utility net income	$657	$130	$36,688	$39,598	$527	$(2,910)
EPS - utility segment	$0.02	$0.01	$1.36	$1.47	$0.01	$(0.11)
Gas sold and delivered (in therms)	212,097	219,017	612,287	627,176	(6,920)	(14,889)
Utility margin[1]	$64,801	$61,440	$192,101	$194,590	$3,361	$(2,489)

[1] See Utility Margin Table below for additional detail.

THREE MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The primary factors contributing to the increase in net income were as follows:

- a $3.4 million increase in utility margin primarily due to:
  - a $3.0 million increase related to timing impacts of changes in fixed monthly charges and decoupling baselines in the 2012 Oregon general rate case; and
  - a $1.4 million increase related to customer growth and the rate-base return on our gas reserve investment.

  Partially offsetting these increases was a $0.4 million decrease related to the general rate decrease primarily due to our lower Oregon authorized ROE of 9.5% and a $0.9 million decrease in gains from gas cost incentive sharing.

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- Partially offsetting the above margin factors were:
  - a $1.6 million increase in operations and maintenance expense due to increases in utility payroll and expenses related to system maintenance and safety costs;
  - a $0.8 million increase in depreciation and amortization expense primarily due to a higher level of investment in utility property, plant, and equipment; and
  - a $0.5 million increase in income taxes due to higher pre-tax utility income.

Total utility volumes sold and delivered decreased 3% over last year primarily due to the impact of 14% warmer weather on residential and commercial use. As the second quarter is a non-heating quarter, weather does not significantly impact volumes or margin.

SIX MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The primary factors contributing to the decrease in net income were as follows:

- a $2.5 million decrease in utility margin primarily due to:
  - a $2.2 million decrease related to the timing impacts of changes in fixed monthly charges and decoupling baselines in the 2012 rate case;
  - a $1.1 million decrease related to the general rate decrease primarily reflecting the lower Oregon authorized ROE of 9.5%; and
  - a $3.0 million decrease in gains from gas cost incentive sharing due to actual gas prices that were roughly equivalent to estimated PGA prices for the current year as compared to actual gas prices that were lower than estimated PGA prices for the prior year.

  Partially offsetting these decreases was a $3.2 million increase related to customer growth and the rate-base return on our gas reserve investment.
- a $1.7 million increase in depreciation and amortization expenses primarily due to a higher level of investment in utility property, plant, and equipment.
- Partially offsetting the above factors was a $1.6 million decrease in income taxes due to lower pre-tax utility income.

Total utility volumes sold and delivered decreased 2% over last year primarily due to the impact of warmer weather on residential and commercial use.

TIMING IMPACTS. As a result of changes to the utility's baseline for average use per customer included in the 2012 Oregon general rate case, the decoupling mechanism's results this year will not be comparable to last year. Also, customers' fixed monthly charges were increased in the rate case, which allows the Company to recover more of its costs through a higher fixed charge, rather than through the previous volumetric charge, which was more seasonal in nature.

In addition, our weather normalization mechanism was extended through the end of May instead of May 15. This aligns the period covered by our weather normalization mechanism with our decoupling mechanism and further reduces the effect of weather on earnings during this quarter.

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UTILITY MARGIN TABLE. The following table summarizes the composition of utility gas volumes, revenues, and costs of sales. Certain prior year amounts in the following table have been reclassified to conform with the current year’s presentation. These reclassifications reflect miscellaneous revenue amounts allocated to residential, commercial, and industrial categories where such amounts were specifically attributable to that customer category. Utility volumes and margin in total were not affected by these reclassifications.

In thousands, except degree day and customer data	Three Months Ended Three Months Ended Three Months Ended June 30, 2013 e="TEXT-ALIGN: left">%		Six Months Ended Three Months Ended June 30,		Favorable/(Unfavorable)			
Natural gas equivalent (per Mcfe)								
Rocky Mountain Region	5.84	3.73	56.6	%	6.34	3.68	72.3	%
Appalachian Basin	4.31	3.65	18.1	%	4.95	4.35	13.8	%
Other	5.77	4.36	32.3	%	8.67	8.78	-1.3	%
Weighted average price	5.74	3.73	53.9	%	6.25	3.75	66.7	%

*Percentage change not meaningful or greater than 250%

Despite decreases in production for the three and six months ended 2010, natural gas and oil sales revenue for these periods, excluding the provision for underpayment of gas sales in 2009, increased $9 million and $26.9 million, compared to the three and six months ended 2009, respectively. Approximately $17.3 million and $43.4 million of the increase in natural gas and oil sales revenue for the three and six months ended 2010, respectively, was due to pricing, offset in part by decreased production, which reduced natural gas and oil sales by $8.3 million and $16.5 million, respectively.

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PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)

Natural Gas and Oil Pricing. Our results of operations depend upon many factors, particularly the price of natural gas and oil and our ability to market our production effectively. Natural gas and oil prices are among the most volatile of all commodity prices. These price variations have a material impact on our financial results. Natural gas prices vary by region and locality, depending upon the distance to markets, the supply and demand relationships in that region or locality and the availability of sufficient pipeline capacity. 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 local market oversupply situations from time to time. Like most producers in the region, we rely on major interstate pipeline companies to construct these pipelines to increase capacity, rendering the timing and availability of these facilities beyond our control. Oil pricing, unlike natural gas pricing, is driven predominantly by global supply and demand relationships.

The price we receive for our natural gas produced in the Rocky Mountain Region is based on a market basket of prices, which generally includes natural gas sold at Colorado Interstate Gas ("CIG") prices as well as Mid-Continent or other nearby regional 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 New York Mercantile Exchange ("NYMEX") -based. This negative differential has narrowed in the last year and is lower than historical variances. This negative differential between NYMEX and CIG averaged $1.13 and $1.38 for the three and six months ended 2009, respectively, and narrowed to an average of $0.48 and $0.32 for the three and six months ended 2010, respectively.

The table below identifies the market for our natural gas and oil sales based on production for the three months ended 2010. The pricing basis is the index that most closely relates to the price under which our natural gas and oil was sold.

Energy Market Exposure
For the Three Months Ended June 30, 2010

Area	Market	Commodity	Percent of Production
Rocky Mountain Region			
Piceance/Wattenberg	Colorado Interstate Gas	Gas	42%
Wattenberg/Piceance/North Dakota	NYMEX	Oil	23%
Piceance	San Juan Basin/Southern California	Gas	14%
NECO	Mid Continent (Panhandle Eastern)	Gas	10%
Wattenberg	Colorado Liquids	Gas	4%
Total Rocky Mountain Region			93%
Appalachian Basin	NYMEX	Gas	6%
Other	Other	Gas/Oil	1%
			100%

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)			
Lease operating expenses	$ 10,641	$ 6,936	$ 19,695	$ 16,875
Production taxes	2,503	2,753	4,855	4,596
Costs of well operations and pipeline income	1,914	1,657	3,804	3,262
Overhead and other production expenses	1,327	2,331	3,178	4,804
Total natural gas and oil production and well operations costs	$ 16,385	$ 13,677	$ 31,532	$ 29,537

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Lease operating expenses. Lifting costs per Mcfe increased to $1.24 per Mcfe for the three months ended 2010 from $0.64 per Mcfe for the same period in 2009, and increased to $1.14 per Mcfe for the six months ended 2010, from $0.78 per Mcfe for the same period in 2009. The increases in per Mcfe cost were due to decreases in production volumes of 20.6% and 20.3% for the three and six month periods ended 2010, respectively, which results in the fixed cost portion of our lease operating expenses being absorbed by a reduced number of units. Also contributing to the increases for the three and six months ended 2010 compared to the same 2009 periods were related to well workovers, which include tubing and casing repairs of $1.2 million and $1.5 million, and environmental remediation charges of $1.3 million and $1.5 million, respectively.

Production taxes. Production taxes for the three months ended 2010 decreased $0.3 million compared to the three months ended 2009. The decrease was primarily related to a reduction of ad valorem tax rates for certain counties and an increase in the number of wells exempt from severance taxes, due to their re-characterization as stripper wells, offset in part by an increase in overall sales prices. For the six months ended 2010, production taxes increased by $0.3 million compared to the six months ended 2009. The increase was primarily related to increase in overall sales prices, offset in part by a reduction of ad valorem tax rates for certain counties and an increase in the number of stripper wells.

Costs of well operations and pipeline income. The increases of $0.3 million and $0.5 million in cost of well operations and pipeline income for the three and six months ended 2010, respectively, compared to same 2009 periods were the result of increased costs related to pipeline maintenance and compressor expenses.

Overhead and other production expenses. The decreases in overhead and other production expenses for the three and six months ended 2010 compared to the same 2009 periods were the result of the reduction in expenses related to the deconsolidation of PDCM along with various other decreases.

Commodity Price Risk Management, Net

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

The following table presents the realized and unrealized derivative gains and losses included in commodity price risk management, net.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)			
Commodity price risk management gain (loss), net:				
Realized gains:				
Natural gas	$ 5,854	$ 19,477	$ 26,733	$ 48,809
Oil	2,039	4,818	4,084	12,112

Total realized gain, net	7,893	24,295	30,817	60,921
Unrealized gains (losses):				
Reclassification of realized gains included in prior periods unrealized	(7,503)	(25,699)	(21,604)	(47,587)
Unrealized gains (losses) for the period	11,867	(21,880)	46,266	(12,935)
Total unrealized gain (loss), net	4,364	(47,579)	24,662	(60,522)
Total commodity price risk management gain (loss), net	$ 12,257	$ (23,284)	$ 55,479	$ 399

The realized derivative gains for the three and six months ended 2010 were primarily a result of lower natural gas and oil spot prices at settlement compared to the respective strike price, offset in part by the basis differential between NYMEX and CIG being narrower than the strike price of the derivative position. For the three month period, realized gains related to natural gas derivatives were $11.4 million and realized losses on our CIG basis swaps were $5.6 million. For the six month period, realized gains related to natural gas and oil derivatives were $32.3 million and $4.1 million, respectively, and realized losses on our CIG basis swaps were $5.6 million.

For the three month period, the unrealized gains were primarily related to our oil positions, as the forward strip price shifted downward during the quarter, and the widening of the NYMEX-CIG basis differential. Unrealized gains on our oil positions and our CIG basis swaps for the three months ended 2010 were $8 million and $4 million, respectively. For the six month period, the unrealized gains were primarily a downward shift in the natural gas and oil forward curves. For the six months ended 2010, unrealized gains on our natural gas and oil positions were $37.3 million and $9.2 million, respectively.

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For the three and six months ended 2009, we realized significant gains as a result of lower natural gas and oil prices at settlement compared to the respective derivative strike prices. Unrealized losses for the periods were primarily related to oil swaps as the forward strip price of oil rebounded during the periods and the CIG basis swaps as the forward basis differential between NYMEX and CIG continuing to narrow during the periods from the strike price of the derivative position.

Natural Gas and Oil Sales Derivative Instruments. We use various derivative instruments to manage fluctuations in natural gas and oil prices. We have in place a variety of floors, collars, fixed-price swaps and basis swaps on a portion of our estimated natural gas and oil production. See Note 4, Derivative Financial Instruments, to Consolidated Financial Statements in our 2009 Form 10-K for an additional discussion of how each derivative type impacts our cash flows.

The following table presents our derivative positions (including our proportionate share of both the derivative positions held by PDCM and those designated to our affiliated partnerships) in effect as of June 30, 2010, related to natural gas and oil production by area.

Commodity/Operating Area/Index/ Maturity Period	Floors		Collars			Fixed-Price Swaps		CIG Basis Protection Swaps		Fa Val June 3 (1 (i thous
	Quantity (Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMBtu Oil-Bbls)	Weighted Average Contract Price Floors	Weighted Average Contract Price Ceilings	Quantity (Gas-MMBtu Oil-Bbls)	Weighted Average Contract Price	Quantity (MMBtu)	Weighted Average Contract Price	
Natural gas										
Rocky Mountain Region										
CIG										
07/01 - 09/30/2010	-	$-	-	$-	$-	392,505	$5.05	-	$-	$41
10/01 - 12/31/2010	-	-	680,411	4.75	9.45	234,319	5.05	-	-	57
01/01 - 03/31/2011	-	-	1,020,617	4.75	9.45	187,211	5.81	-	-	66
04/01 - 06/30/2011	-	-	-	-	-	330,752	5.81	-	-	39
07/01 - 12/31/2011	-	-	-	-	-	441,780	5.81	-	-	40
PEPL										
07/01 - 09/30/2010	-	-	300,000	5.00	8.90	526,993	5.93	-	-	1,0
10/01 - 12/31/2010	-	-	360,000	5.55	9.38	427,624	5.95	-	-	1,0
01/01 - 03/31/2011	-	-	390,000	5.76	9.56	271,628	6.18	-	-	74
04/01 - 06/30/2011	-	-	-	-	-	636,998	6.18	-	-	88
07/01 - 12/31/2011	-	-	-	-	-	1,208,798	6.18	-	-	1,2
2012-2013	-	-	-	-	-	2,346,224	6.18	-	-	1,7
NYMEX										
07/01 - 09/30/2010	-	-	152,202	5.85	10.15	2,969,035	6.02	2,542,131	(1.88)	1,2
10/01 - 12/31/2010	-	-	569,044	5.94	9.15	1,758,300	6.66	1,794,323	(1.88)	1,5

01/01 - 03/31/2011	-	-	724,551	5.96	9.10	930,958	7.47	1,200,677	(1.88)	994
04/01 - 06/30/2011	-	-	-	-	-	2,317,139	6.90	2,215,694	(1.88)	1,2
07/01 - 12/31/2011	-	-	-	-	-	4,456,746	6.89	4,253,857	(1.88)	898
2012-2013	-	-	8,785,211	6.05	8.43	7,410,257	7.08	14,614,306	(1.88)	(2,0
Appalachia										
NYMEX										
07/01 - 09/30/2010	-	-	7,160	5.85	10.15	385,779	5.35	-	-	271
10/01 - 12/31/2010	-	-	7,235	6.45	11.48	378,662	5.36	-	-	151
01/01 - 03/31/2011	-	-	8,434	6.61	11.60	361,093	6.38	-	-	369
04/01 - 06/30/2011	-	-	-	-	-	358,275	6.38	-	-	448
07/01 - 12/31/2011	-	-	-	-	-	690,193	6.37	-	-	633
2012-2013	-	-	-	-	-	72,007	7.23	-	-	101
Other										
NYMEX										
07/01 - 09/30/2010	-	-	73,305	5.85	10.15	181,093	6.73	-	-	461
10/01 - 12/31/2010	-	-	73,224	6.45	11.47	169,930	6.80	-	-	425
01/01 - 03/31/2011	-	-	83,823	6.62	11.64	72,184	8.85	-	-	378
04/01 - 06/30/2011	-	-	-	-	-	208,959	7.43	-	-	476
07/01 - 12/31/2011	-	-	-	-	-	407,712	7.44	-	-	801
2012-2013	-	-	427,363	6.05	8.43	1,076,642	7.17	-	-	1,7
Total natural gas	-		13,662,580			31,209,796		26,620,988		19,
Oil										
Rocky Mountain Region										
NYMEX										
07/01 - 09/30/2010	21,000	65.38	-	-	-	155,196	91.42	-	-	2,1
10/01 - 12/31/2010	21,000	65.38	-	-	-	142,070	92.30	-	-	1,9
01/01 - 03/31/2011	21,000	65.38	67,814	73.00	99.80	92,610	74.29	-	-	(13
04/01 - 06/30/2011	21,000	65.38	60,691	73.00	99.80	90,000	74.01	-	-	(23
07/01 - 12/31/2011	41,000	65.38	102,947	73.00	99.80	173,293	73.62	-	-	(67
2012-2013	36,000	65.38	686,148	75.00	102.63	-	-	-	-	2,4
Total oil	161,000		917,600			653,169		-		5,5
Total natural gas and oil										$25,

(1) Approximately 43.7% of the fair value of our derivative assets and 100% of our derivative liabilities were measured using significant unobservable inputs (Level 3); see Note 3, Fair Value Measurements, to the accompanying financial statements.

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Natural Gas Marketing

Sales from Natural Gas Marketing. The $1.3 million increase in sales from natural gas marketing for the three months ended 2010 compared to the three months ended 2009 is primarily due to an increase in commodity prices, offset in part by an increase in unrealized losses on derivatives. For the three months ended 2010, prices on sales were 18% higher on average than in the three months ended 2009, resulting in a $2 million increase in sales. Unrealized derivative losses for the three months ended 2010 increased $0.6 million from $2 million for the three months ended 2009 to unrealized losses of $2.6 million for the three months ended 2010. Sales from natural gas marketing for the six months ended 2010 increased $3.2 million to $35.3 million from $32.1 million for the six months ended 2009. The increase is primarily due to an 11% increase in commodity prices, which contributed $3.1 million to the increase. The increase in unrealized derivative gains of $2.1 million for the six months ended 2010 compared to the same 2009 period were predominantly offset by a comparable decrease in realized gains.

Cost of Natural Gas Marketing. Cost of natural gas marketing increased $1.3 million for the three months ended 2010 compared to the three months ended 2009. This increase was primarily due to a 22% increase in prices, contributing $2.3 million to the increase, offset in part by a $0.7 million decrease in realized derivative losses and a $0.4 million increase in unrealized gains on derivatives. The $3.3 million increase in cost of natural gas marketing for the six months ended 2010 compared to the six months ended 2009 is primarily due to a 15.3% increase in commodity prices, contributing $4 million to the increase, and an increase in unrealized derivative losses of $1.8 million, offset in part by a decrease in realized derivative losses of $2.5 million.

Natural Gas Marketing Derivative Instruments. Our derivative instruments related to natural gas marketing 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.

The following table presents our derivative positions in effect as of June 30, 2010, related to natural gas marketing.

	Collars			Fixed-Price Swaps		NYMEX Basis Protection Swaps		
Commodity/Derivative Instrument/ Maturity Period	Quantity (MMBtu)	Weighted Average Contract Price Floors	Ceilings	Quantity (MMBtu)	Weighted Average Contract Price	Quantity (MMBtu)	Weighted Average Contract Price	Fair Value June 30, 2010 (1) (in thousands)
Natural gas								
Physical sales								
07/01 - 09/30/2010	-	$-	$-	42,415	$6.80	13,429	$0.65	$ 81
10/01 - 12/31/2010	-	-	-	49,573	6.16	72,930	0.45	59
01/01 - 03/31/2011	-	-	-	-	-	126,045	0.36	20
04/01 - 06/30/2011	-	-	-	-	-	7,535	0.89	6
07/01 - 12/31/2011	-	-	-	-	-	7,015	0.90	5
01/01 - 04/30/2012	-	-	-	-	-	3,150	1.40	3

Financial purchases								
07/01 - 09/30/2010	-	-	-	41,938	5.44	-	-	(31)
10/01 - 12/31/2010	-	-	-	49,374	5.25	60,000	0.20	(9)
01/01 - 03/31/2011	-	-	-	-	-	90,000	0.20	2
Financial sales								
07/01 - 09/30/2010	52,500	4.53	7.16	698,100	6.53	-	-	1,303
10/01 - 12/31/2010	52,500	4.53	7.16	606,100	6.62	-	-	1,005
01/01 - 03/31/2011	52,500	4.53	7.16	454,200	6.42	-	-	468
04/01 - 06/30/2011	-	-	-	189,000	6.28	-	-	219
07/01 - 12/31/2011	-	-	-	255,000	6.45	-	-	257
Physical purchases								
07/01 - 09/30/2010	52,500	4.53	7.14	698,550	6.49	-	-	(1,138)
10/01 - 12/31/2010	52,500	4.53	7.14	606,250	6.59	-	-	(863)
01/01 - 03/31/2011	52,500	4.53	7.14	454,200	6.37	-	-	(338)
04/01 - 06/30/2011	-	-	-	189,000	6.27	-	-	(185)
07/01 - 12/31/2011	-	-	-	255,000	6.47	-	-	(215)
Total natural gas	315,000			4,588,700		380,104		$ 649

(1) Approximately 7.1% of the fair value of our derivative assets and 98.2% of our derivative liabilities were measured using significant unobservable inputs (Level 3); see Note 3, Fair Value Measurements, to the accompanying financial statements.

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Costs, Expenses and Other

Exploration Expense

The following table presents the major components of exploration expense.

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(in thousands)			
Amortization/impairment of unproved properties	$ 556	$ 518	$ 1,156	$ 1,132
Exploratory dry hole costs	650	106	3,552	937
Geological and geophysical costs	823	214	1,870	467
Operating, personnel and other	1,801	2,296	3,670	6,241
Total exploration expense	$ 3,830	$ 3,134	$ 10,248	$ 8,777

For the three months ended 2010, exploratory dry hole costs includes an oil test well in our Northeastern Colorado ("NECO") area and additional expenses on Piceance tests performed in the first quarter of 2010. The $0.6 million increase in geological and geophysical costs for the three months ended 2010 period compared to the same prior year period was primarily related to seismic work in the Marcellus Shale. Operating, personnel and other decreased $0.5 million for the period compared to the same prior year period primarily due to costs associated with 2009's rig demobilization in the Piceance Basin.

Exploratory dry hole costs for the six months ended 2010 includes the fracturing and testing of several exploratory zones on a well drilled in a prior year located in the Piceance Basin and an oil test well drilled in the NECO area. Additional fracturing and testing of different exploratory zones for these wells are planned for the second half of 2010. The increase in geological and geophysical costs for the period six months ended 2010 compared to the six months ended 2009 was primarily related to geological and seismic work in the Marcellus Shale as we have intensified our efforts in this area. Operating, personnel and other decreased for the six months ended 2010 compared to the six months ended 2009 primarily due to the demobilization of drilling rigs in the Piceance Basin of $1.2 million and an inventory impairment of $0.7 million in 2009.

General and Administrative Expense

General and administrative expense decreased from $14.8 million and $26.9 million for the three and six months ended 2009 to $9.9 million and $20.5 million for the three and six months ended 2010, a decrease of $4.9 million and $6.4 million, respectively. The three month decrease was primarily related to a charge of $2.9 million related to a separation agreement with a former executive vice president and $1 million related to corporate relocation costs recorded in the three months ended 2009. In addition to the previously mentioned charges, the six month decrease was also related to the expensing of previously capitalized 2008 acquisition costs of $1.5 million during the three months ended March 31, 2009, pursuant to the adoption of a new accounting standard.

Depreciation, Depletion and Amortization

Natural gas and oil properties. The reduction in DD&A expense related to natural gas and oil properties for the three and six months ended 2010 compared to the three and six months ended 2009 was directly related to the decrease in production volumes as the weighted average DD&A rate for the three and six months ended 2010 was relatively unchanged at \$2.94 per Mcfe and \$2.95 per Mcfe, respectively, compared to \$2.89 per Mcfe and \$2.91 per Mcfe for the three and six months ended 2009, respectively.

The following table presents our DD&A rate for natural gas and oil properties by area.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
	(per Mcfe)					
Rocky Mountain Region:						
Wattenberg Field (1)	$ 3.54	$ 3.90	-9.2 %	$ 3.60	$ 3.99	-9.8 %
Piceance Basin	2.47	2.36	4.7 %	2.46	2.36	4.2 %
NECO	2.00	1.79	11.7 %	2.01	1.80	11.7 %
Weighted average	2.94	3.00	-2.0 %	2.95	3.02	-2.3 %
Appalachian Basin	2.71	1.81	49.7 %	2.67	1.84	45.1 %

(1) Although the Wattenberg Field development costs and DD&A rates are higher than the other fields, the relative value of its oil production currently more than offsets this cost difference.

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Non-natural gas and oil properties. Depreciation expense for non-natural gas and oil properties was $1.8 million and $3.7 million for the three and six months ended 2010, compared to $2 million and $3.9 million for the three and six months ended 2009, respectively.

Interest Expense

The decrease in interest expense for the three and six months ended 2010 compared to the same 2009 periods was primarily due to lower outstanding balances on our credit facility, offset in part by higher debt amortization costs due to our second quarter 2009 refinancing.

Provision/Benefit for Income Taxes

The effective income tax rate for continuing operations ("rate") for the three and six months ended 2010 was 36.8% (benefit on a loss) and 37.6% (provision on income) compared to 38.3% (benefit on a loss) and 38.8% (benefit on a loss) in the three and six months ended 2009. The rates for each period presented reflect a tax benefit from our statutory percentage depletion deduction. Discrete items did not have a material impact on the rates for the periods presented.

Beginning with our 2010 tax year, we have been accepted into and have agreed to participate in the IRS Compliance Assurance Process Program. As part of our entrance into this program, we have agreed to an accelerated timeline for the IRS examination of our 2007, 2008 and 2009 tax years. This examination commenced in May 2010.

Pursuant to our election to carry-back our 2009 net operating loss ("NOL"), we filed for and received our requested $25.9 million federal tax refund during the three months ended 2010. Our 2009 NOL was carried forward for state tax purposes and the net $2.6 million future state tax benefit is recorded as a deferred tax asset and netted against deferred tax liabilities on our balance sheet.

Discontinued Operations

Michigan Divestiture. In May 2010, we entered into an agreement to divest our Michigan assets. On July 30, 2010, the sale was completed. The sale involved our Michigan asset group. We will not have any significant continuing involvement in the operations of or cash flows from this asset group. Accordingly, the results of operations related to the Michigan assets have been separately reported as discontinued operations for all periods presented. During the three months ended 2010, in conjunction with our decision to divest our Michigan assets we recorded a pre-tax impairment charge of $4.5 million. The impairment charge was the primary cause for the decreases in discontinued operations for the three and six months ended 2010 compared to the same 2009 periods. See Note 3, Fair Value Measurements, and Note 12, Assets Held for Sale and Discontinued Operations, for additional information regarding the divestiture of our Michigan assets.

Natural Gas and Oil Well Drilling Operations. We have not had significant revenue from our well drilling activities since 2007. In January 2008, we announced that we had no plans to sponsor new drilling partnerships. As of June 30, 2009, we had concluded all partnership drilling and completion activities and reported our natural gas and oil well drilling activities as discontinued operations. Prior period financial statements have been reclassified to present the activities of our natural gas and oil well drilling operations as discontinued operations.

Net Income (Loss) from Continuing Operations/Adjusted Net Income (Loss) from Continuing Operations

Net income (loss) from continuing operations for the three and six months ended 2010 was a net loss of $0.3 million and net income of $22.9 million compared to net losses of $33.3 million and $39.6 million for the three and six months ended 2009, respectively. Adjusted net income (loss) from continuing operations, a non-GAAP financial measure, for the three and six months ended 2010 was a net loss of $3 million and net income of $7.4 million compared to a net loss of $3.9 million and a net loss of $0.8 million for the three and six months ended 2009. The factors driving changes in the metric net income (loss) from continuing operations are discussed above. These same factors similarly impact the metric adjusted net income (loss) from continuing operations, with the exception of the unrealized derivative gains and losses on derivatives and provision for underpayment of gas sales, adjusted for taxes. See Reconciliation of Non-GAAP Financial Measures, below, for a more detailed discussion of this non-GAAP financial measure.

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Financial Condition

Capital Resources and Liquidity

Our primary sources of cash for the six months ended 2010 were from funds generated from the sale of natural gas and oil production, funds received from the federal government for our 2009 NOL carry-back and the realized gains from our derivative positions. These sources of cash were primarily used to fund our operating costs, general and administrative activities and our capital expenditures, including both our developmental and exploratory activities. Additionally, we were able to improve our liquidity position by reducing borrowings outstanding under the credit facility. Our primary sources of cash from operations are sales of natural gas and oil. Fluctuations in our operating cash flow are substantially driven by changes in commodity prices and production volumes. Commodity prices have historically been volatile and we manage this volatility through our derivative program. Therefore, the primary sources of our cash flow from operations become the net activity between our natural gas and oil sales and realized derivative gains and losses. However, we do not hold economic hedges for more than 80% of our expected future production from producing wells, nor do we engage in speculative positions. Consequently, we may still have significant fluctuations in our cash flows from operations, which may result in an increase or decrease in our expected developmental and exploratory activities in the future. As of June 30, 2010, we had natural gas and oil derivative positions in place covering 64.3% of our expected natural gas production and 58.2% of our expected oil production for the remainder of 2010, at an average price of $5.05 per Mcf and $88.56 per Bbl, respectively. See Results of Operations for further discussion of the impact of prices and volumes on sales from operations and the impact of derivative activities on our revenues.

From time to time, our working capital will reflect a surplus, while at other times it will reflect a deficit. The primary factors affecting our working capital are our current unrealized derivative position, the timing of our payments to reduce our borrowings on our credit facility and the other variables discussed above. Our working capital was reduced by $49.8 million from a surplus of $32.9 million at December 31, 2009, to a deficit of $16.9 million at June 30, 2010. The majority of this decrease is due to the decrease in cash and cash equivalents of $12.5 million, accounts receivable of $11.6 million and income tax receivable of $27.7 million and the corresponding use of these amounts to reduce debt.

We ended June 2010 with cash and cash equivalents of $19.4 million and availability under our credit facility of $249.3 million for a total liquidity position of $268.7 million compared to $238.2 million at December 31, 2009. Our operating cash flows of $95.4 million for the six months ended 2010 provided us with ample capital to reduce our borrowings under our credit facility by $43 million, net of borrowings, and consequently contribute to the $30.5 million or 12.8% increase in our liquidity position. With our current liquidity position and expected cash flow from operations, we believe that we have sufficient capital for operations and our planned uses of capital through 2011. On July 30, 2010, as a result of closing our acquisition of producing assets located in the Wolfberry oil trend and divesting our Michigan assets, we used approximately $50 million of our June 30, 2010, available liquidity.

Cash flows from operations are impacted by commodity prices, production volumes, realized gains and losses from our derivative positions, operating costs and general and administrative expenses. The increase in cash provided by operating activities was primarily due to the increase in natural gas and oil sales of $29.5 million and the income tax refund of $25.9 million from our 2009 NOL carry-back filed and received during the three months ended 2010, offset by a decrease in realized derivative gains of $29.6 million. The remaining change in our operating cash flow was primarily due to changes in our assets and liabilities related to the timing of cash payments and receipts. The key components for the changes in our cash flows from operations are described in more detail in our Results of Operations above.

Adjusted cash flows from operations remained relatively unchanged from $78.2 million for the six months ended 2010 compared to $77.4 million for the six months ended 2009. Adjusted EBITDA was $82.1 million for the six months ended 2010 compared to $81 million for the six months ended 2009. These changes were primarily due to the same factors mentioned above for changes in cash provided by operating activities without regard to timing of cash payments and receipts of our assets and liabilities, which includes the receipt of our income tax refund. See Reconciliation of Non-GAAP Financial Measures, below, for a more detailed discussion of these non-GAAP financial measures.

Cash flows used for investing activities, primarily drilling capital expenditures, decreased $23.4 million, or 22.5%, from $104 million for the six months ended 2009 to $80.6 million for the six months ended 2010. The decrease in cash flows was due primarily to the carryover to the six months ended 2009 of approximately $42 million of accounts payable related to our 2008 drilling program. The capital spent in the six months ended 2009 unrelated to 2008 carryover capital was approximately $62 million. Therefore, when comparing our 2010 capital program to our 2009 capital program, the 2010 program has increased $18.6 million or 30%. We've projected our 2010 developmental capital program to be $141 million versus $79 million for 2009. We currently have one rig operating in the Piceance Basin and two rigs operating in the oil and liquids-rich sections of the Wattenberg Field.

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We used cash of $27.3 million for financing activities for the first six months of 2010; whereas, the first six months of 2009 provided a source of cash in the amount of $14.3 million. The majority of the change was due to the shift from net borrowings of $23.5 million for the six months ended 2009 period to a net payment on borrowings of $43 million for the six months ended 2010. Additionally, our PDCM joint venture partner contributed $28 million to PDCM, which is included in cash flows from financing activities in our six months ended 2010 statement of cash flows at $16.2 million, thereby reflecting our decreased ownership interest in PDCM from 67.4% to 57.8%.

Our revised planned 2010 capital expenditures of $232 million, excluding joint venture related projects and including our July 2010 Wolfberry oil trend acquisition and our anticipated partnership purchases, represent an approximate 113% increase from our 2009 capital expenditures. We believe, based on the current commodity price environment, our cash flows from operations will fund the majority of our organic 2010 capital spending program and borrowings from our credit facility will fund the acquisitions. In order to grow our production, we would need to commit greater amounts of capital in 2011 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. Because natural gas and oil produced from our existing properties declines rapidly in the first few years of production, we cannot maintain our current level of natural gas and oil production and cash flows from operations if capital markets and commodity prices return to their 2009 depressed state for a prolonged period of time, which could have a material negative impact on our operations in the future.

We considered the possibility of reduced available liquidity in planning our 2010 drilling program and believe we will have adequate cash flows from operations during the year to execute our planned capital expenditures. Currently, we operate approximately 95% of our properties, allowing us to direct the pace of substantially all of our planned capital expenditures. Consequently, we may elect to defer a substantial portion of our planned capital expenditures for 2010 and beyond if market conditions worsen.

We have experienced no impediments in our ability to access borrowings under our current bank credit facility or the capital markets, as demonstrated by our August 2009 sale of equity. We continue to monitor market events and circumstances and their potential impacts on each of the twelve lenders that comprise our bank credit facility. Our $305 million bank credit facility's borrowing base is subject to size redeterminations each May and November 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. On May 5, 2010, based on our December 31, 2009, reserves, our borrowing base was reaffirmed at $305 million. While we will continue to add producing reserves through our drilling operations, we believe a significant decrease in commodity prices could have a negative impact on our future borrowing base redeterminations.

We are subject to quarterly financial debt covenants on our bank credit facility. The indenture governing our senior notes contains customary representations and warranties as well as typical restrictive and incurrence covenants. Our debt covenants are described in Note 8, Long-Term Debt, to Consolidated Financial Statements in our 2009 Form 10-K and updated, as necessary, in this Form 10-Q. We were in compliance with all debt covenants as of June 30, 2010. We believe we have sufficient liquidity and capital resources to remain compliant with our debt covenants throughout the next year based upon our 2010 cash flow projections, anticipated capital requirements, the discretionary nature of our capital expenditures and available capacity under our bank credit facility. However, we cannot predict with any certainty the impact to our future business of any continued uncertainty or further deterioration in the financial or commodity 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.

We have a shelf registration statement on Form S-3 filed with the SEC on November 26, 2008, declared effective on January 30, 2009. The shelf provides for an aggregate of $500 million, through the potential 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 us to be proactive in our efforts to raise capital should the need arise, and to have the flexibility to raise such funds in one or more offerings should we perceive the market conditions to be favorable. We have available $448.2 million of our shelf from which we may utilize to raise capital.

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

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Contractual Obligations, Commitments and Contingencies

The table below presents our contractual obligations, commitments and contingencies.

	Payments due by period				
As of June 30, 2010	Total	Less than 1 year	1-3 years (in thousands)	3-5 years	More than 5 years
Long-term liabilities reflected on the balance sheet (1)					
Long-term debt (2)	$ 240,000	$ -	$ 37,000	$ -	$ 203,000
Derivative contracts (3)	54,251	16,213	31,785	6,253	-
Derivative contracts - affiliated partnerships (4)	17,057	3,695	11,095	2,267	-
Production tax liability	25,346	15,008	10,338	-	-
Other liabilities (5)	9,736	272	3,509	604	5,351
Asset retirement obligations (6)	24,716	250	394	789	23,283
	371,106	35,438	94,121	9,913	231,634
Commitments, contingencies and other arrangements (7)					
Interest on long-term debt (8)	190,919	27,091	51,163	48,720	63,945
Operating leases	6,258	1,750	2,499	1,776	233
Drilling commitment	1,040	-	-	-	1,040
Firm transportation and processing agreements (9)	170,705	18,179	40,753	39,227	72,546
Other	625	125	250	250	-
	369,547	47,145	94,665	89,973	137,764
Total	$ 740,653	$ 82,583	$ 188,786	$ 99,886	$ 369,398

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(1) Table does not include deferred income tax liability to taxing authorities of $184.6 million, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.

(2) Amount presented does not agree with the balance sheet in that it does not include $2.2 million in unamortized notes discount.

(3) 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 $18.2 million.

(4) Represents our affiliated partnerships' designated portion of the fair value of our gross derivative assets.

(5) Includes funds held from revenue distribution to third party investors for plugging liabilities related to wells we operate and deferred officer compensation.

(6) Includes $0.8 million related to assets held for sale.

(7) Table does not include maximum annual repurchase obligations to investing partners of $11.4 million, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.

(8) 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 $185.7 million payable to the holders of our 12% senior notes and $5.2 million related to our outstanding balance of $37 million on our credit facility, including interest of $0.5 million related to our letter of credit, based on an imputed interest rate of 4.9%.

(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 interest. See Note 9, Commitments and Contingencies – Firm Transportation Agreements, to our accompanying financial statements.

As managing general partner of 33 partnerships, we have liability for 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 9, Commitments and Contingencies – Litigation, to our accompanying 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.

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Drilling Activity

The following table summarizes our development and exploratory drilling activity. 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.
As of June 30, 2010, a total of 38 productive wells, all of which were drilled in 2010, were waiting to be fractured and/or for gas pipeline connection.

	Three Months Ended June 30,				Six Months Ended June 30,			
	2010		2009		2010		2009	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells:								
Productive								
Rocky Mountain Region	53	42.4	24	19.7	96	80.7	46	40.0
Appalachian Basin	-	-	-	-	-	-	1	1.0
Total productive	53	42.4	24	19.7	96	80.7	47	41.0
Dry								
Rocky Mountain Region	-	-	-	-	-	-	1	0.5
Total dry	-	-	-	-	-	-	1	0.5
Total development	53	42.4	24	19.7	96	80.7	48	41.5
Exploratory Wells:								
Productive								
Rocky Mountain Region	-	-	-	-	-	-	2	1.0
Appalachian Basin	3	1.7	-	-	4	2.3	2	2.0
Total productive	3	1.7	-	-	4	2.3	4	3.0
Total exploratory	3	1.7	-	-	4	2.3	4	3.0
Total drilling activity	56	44.1	24	19.7	100	83.0	52	44.5
Recompletions/refractures	5	4.2	3	2.9	16	14.7	3	2.9

As of June 30, 2010, a total of 38 productive wells, all of which were drilled in 2010, were waiting to be fractured and/or for gas pipeline connection.

Commitments and Contingencies

See Note 9, Commitments and Contingencies, to the accompanying financial statements included in this report.

Recent Accounting Standards

See Note 2, Recent Accounting Standards, to the accompanying financial statements included in this report.

Critical Accounting Polices and Estimates

The preparation of the accompanying financial statements in conformity with U.S. GAAP 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.

With the exception of the following, there have been no other significant changes to our critical accounting policies and estimates 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 2009 Form 10-K, such policies include revenue recognition, derivatives instruments, natural gas and oil properties, deferred income tax asset valuation and purchase accounting.

Consolidation and Accounting for Variable Interest Entities

Under applicable accounting guidance, a variable interest entity ("VIE") is consolidated by the entity's primary beneficiary. The primary beneficiary of a VIE has both the following characteristics: (1) the power to direct the activities of the VIE that most significantly impact the entity's economic performance and (2) the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

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In determining whether we are the primary beneficiary of the VIE, we consider a number of factors, including our ability to direct the activities that most significantly affect the entity's economic success and our contractual rights and responsibilities under the arrangement. These considerations impact the way we account for our existing joint venture relationship. Further, as certain events occur, we reconsider whether those events have caused us to become the primary beneficiary. The consolidation status of our VIE may change as a result of a change in the composition of the board of managers or we enter into new or modified contractual arrangements. A reconsideration event may also occur when we acquire new or additional interests in a VIE.

Reconciliation of Non-GAAP Financial Measures

Adjusted cash flow from operations. We define adjusted cash flow from operations as the cash flow earned or incurred from operating activities without regard to the collection or payment of associated receivables or payables. We believe it is important to consider adjusted cash flow from operations as well as cash flow from operations, as we believe it often provides more transparency into what drives the changes in our operating trends, such as production, prices, operating costs, and related operational factors, without regard to whether the earned or incurred item was collected or paid during the period. We also use this measure because the collection of our receivables or payment of our obligations has not been a significant issue for our business, but merely a timing issue from one period to the next, with fluctuations generally caused by significant changes in commodity prices.

Adjusted net income (loss) from continuing operations. We define adjusted net income (loss) from continuing operations as net income (loss) from continuing operations plus unrealized derivative losses and provisions for underpayment of gas sales minus unrealized derivative gains, each adjusted for tax effect. We believe it is important to consider adjusted net income (loss) from continuing operations as well as net income (loss) from continuing operations. We believe it often provides more transparency into the trends of our ongoing operations, such as production, prices, operating costs, realized gains and losses from derivatives and related factors, without regard to changes in our net income (loss) from continuing operations from our mark-to-market adjustments resulting from unrealized gains and losses from derivatives. Additionally, other items, such as the provision for underpayment of gas sales, which are not indicative of future results, may be excluded to clearly identify trends in our continuing operations.

Adjusted EBITDA. We define adjusted EBITDA as net income (loss) from continuing operations plus unrealized derivative losses, interest expense, net of interest income, income taxes, and depreciation, depletion and amortization for the period minus unrealized derivative gains. We believe adjusted EBITDA is relevant because it is a measure of cash available to fund our capital expenditures and service our debt and is a widely used industry metric which allows comparability of our results with our peers.

The following table presents a reconciliation of each of our non-GAAP financial measures to its nearest U.S. GAAP measure.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)			
Adjusted cash flow from operations:				

Adjusted cash flow from operations	$	28,850		$	37,665		$	78,179		$	77,406
Changes in assets and liabilities		15,176			(12,885	)		17,192			(16,747	)
Net cash provided by operating activities	$	44,026		$	24,780		$	95,371		$	60,659
Adjusted net income (loss) from continuing operations:											
Adjusted net income (loss) from continuing operations	$	(2,974	)	$	(3,947	)	$	7,421		$	(836	)
Unrealized gain (loss) on derivatives, net		4,211			(47,574	)		24,701			(60,762	)
Provision for underpayment of gas sales		-			-			-			(2,581	)
Tax effect of above adjustments		(1,567	)		18,223			(9,271	)		24,578
Net income (loss) from continuing operations	$	(330	)	$	(33,298	)	$	22,851		$	(39,601	)
Adjusted EBITDA:											
Adjusted EBITDA	$	30,022		$	36,280		$	82,122		$	80,989
Unrealized gain (loss) on derivatives, net		4,211			(47,574	)		24,701			(60,762	)
Interest expense, net		(7,638	)		(9,408	)		(15,433	)		(17,771	)
Income tax benefit (expense)		192			20,663			(13,766	)		25,088
Depreciation, depletion and amortization		(27,117	)		(33,259	)		(54,773	)		(67,145	)
Net income (loss) from continuing operations	$	(330	)	$	(33,298	)	$	22,851		$	(39,601	)

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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, restricted cash (current and non-current) 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. As of June 30, 2010, we held interest-bearing deposits totaling $34.5 million earning an average interest rate of 0.6% per annum. The $34.5 million represents our aggregate bank balances, which includes outstanding checks issued. Based on a sensitivity analysis of the credit facility borrowings as of June 30, 2010, it was estimated that if market interest rates were to increase or decrease by 1%, our 2010 interest expense would correspondingly change by $0.4 million.

Commodity Price Risk

We are exposed to the effect of market fluctuations in the prices of natural gas and oil. Price risk represents the potential risk of loss from adverse changes in the market price of natural gas and oil commodities. We utilize commodity based derivative instruments to manage a portion of our exposure to price volatility with regard to our natural gas and oil sales and natural gas marketing. We utilize both financial and physical instruments. The financial instruments generally consist of collars, swaps and basis swaps and are NYMEX-traded and CIG and PEPL-based contracts. We may utilize derivatives based on other indices or markets where appropriate. Our policies prohibit the use of commodity derivatives for speculative purposes and permit utilization of derivatives only if there is an underlying physical position. We manage price risk on only a portion of our anticipated production, so the remaining portion of our production is subject to the full fluctuation of market pricing. As of June 30, 2010, we had natural gas and oil derivative positions in place covering 64.3% of our expected natural gas production and 58.2% of our expected oil production for the remainder of 2010, at an average price of $5.05 per Mcf and $88.56 per Bbl, respectively.

Derivative Strategies. Our derivative strategies with regard to natural gas and oil sales and natural gas marketing are discussed below. We believe our derivative instruments continue to be effective in achieving the risk management objectives for which they were intended.

- For our natural gas and oil sales, we enter into, for our own and affiliated partnerships' production, derivative contracts to protect against price declines in future periods. The contracts economically provide price stability for anticipated natural gas and oil sales, generally forecasted to occur within the next four-year period. While we structure these derivatives 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 increases in the physical market.

- For our natural gas marketing, we enter into fixed-price physical purchase and sale agreements that qualify as derivative contracts. The contracts economically provide price stability for committed and anticipated natural gas and oil purchases and sales, generally forecasted to occur within the next two-year period. In order to offset the fixed-price physical derivatives in our natural gas marketing, 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.

Based on a sensitivity analysis as of June 30, 2010, it was estimated that a 10% increase in natural gas and oil prices, inclusive of basis, over the entire period for which we have derivatives then in place would result in a decrease in fair value of $38.6 million; whereas, a 10% decrease in prices would result in an increase in fair value of $39.1 million. See Note 4, Derivative Financial Instruments, to the accompanying financial statements included in this report for additional disclosure regarding our derivative financial instruments including, but not limited to, a summary of our open derivative positions as of June 30, 2010.

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The following table presents monthly average NYMEX and CIG closing prices for natural gas and oil for the periods presented, as well as the average sales prices we realized for the respective commodities.

	Six Months Ended June 30, 2010	Year Ended December 31, 2009
Average Index Closing Price		
Natural gas (per MMBtu)		
CIG	$ 4.38	$ 3.07
NYMEX	4.70	3.99
Oil (per Bbl)		
NYMEX	77.16	58.36
Average Sales Price Realized		
Excluding realized derivative gains/(losses)		
Natural gas (per MMbtu)	4.61	3.12
Oil (per Bbl)	72.91	55.03
Including realized derivative gains/(losses)		
Natural gas (per MMbtu)	6.58	5.63
Oil (per Bbl)	79.44	68.87

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. 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. We primarily use 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, the impact of the nonperformance of our counterparties on the fair value of our derivative instruments was not significant.

Disruptions in the credit market may have 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 of a financial institution.

Disclosure of Limitations

Because the information above includes only those exposures that existed at June 30, 2010, 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 June 30, 2010, 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 Exchange Act Rules 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 June 30, 2010.

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 the quarter ended June 30, 2010, 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 9, Commitments and Contingencies, to our accompanying 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 2009 Form 10-K . 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 2009 Form 10-K, except for the following:

Possible additional regulation could have an adverse effect on our operations.

The BP oil spill in the Gulf of Mexico and other anti-industry sentiment may result in new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. Although we have no operations in the Gulf of Mexico, this incident could result in regulatory initiatives in other areas as well that could limit our ability to drill wells and increase our costs of exploration and production. Furthermore, the U.S. Environmental Protection Agency has recently focused on citizen concerns about the risk of water contamination and public health problems from drilling and hydraulic fracturing activities, including public meetings around the country on this issue which have been well publicized and well attended. This renewed focus could lead to additional federal and state laws and regulations affecting our drilling, fracturing and operations. Additional laws, regulations or other changes could significantly reduce our future growth, increase our costs of operations, and reduce our cash flow, in addition to undermining the demand for the natural gas and oil we produce.

New derivatives legislation and regulation could adversely affect our ability to hedge natural gas and oil prices, and increase our costs.

On July 21, 2010, U. S. President Barack Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"). The Dodd-Frank Act regulates derivative transactions, including our natural gas and oil hedging swaps (swaps are broadly defined to include most of our hedging instruments). The new law requires the issuance of new regulations and administrative procedures related to derivatives within one year. The effect of such future regulations on our business is currently uncertain. In particular, note the following:

- The Dodd-Frank Act may decrease our ability to enter into hedging transactions which would expose us to additional risks related to commodity price volatility; commodity price decreases would then have an immediate significant adverse affect on our profitability and revenues. Reduced hedging may also impair our ability to have certainty with respect to a portion of our cash flow, which could lead to decreases in capital spending and, therefore, decreases in future production and reserves.

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- We expect that the cost to hedge will increase as a result of fewer counterparties in the market and the pass-through of increased counterparty costs. Our derivatives counterparties may be subject to significant new capital, margin and business conduct requirements imposed as a result of the new legislation.

- The Dodd-Frank Act contemplates that most swaps will be required to be cleared through a registered clearing facility and traded on a designated exchange or swap execution facility. There are some exceptions to these requirements for entities that use swaps to hedge or mitigate commercial risk. While we may ultimately be eligible for such exceptions, the scope of these exceptions currently is somewhat uncertain, pending further definition through rulemaking proceedings.

- The above factors could also affect the pricing of derivatives, and make it more difficult for us to enter into hedging transactions on favorable terms.

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

Purchases of Equity Securities by the Issuer and Affiliated Purchasers.

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
April 1-30, 2010	120	$ 23.36	-	-
May 1-31, 2010	2,480	21.22	-	-
June 1-30, 2010	1,688	21.74	-	-
	4,288	21.49		

(1) Purchases during the quarter represent shares purchased pursuant to our stock-based compensation plans for payment of tax liabilities related to the vesting of securities.

Item 3. Defaults Upon Senior Securities - None

Item 4. [Removed and Reserved]

Item 5. Other Information – None

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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*	Non-Employee Director Deferred Compensation Plan.	S-8	333-118222	99.1	8/13/2004	
10.2*	2004 Long-Term Equity Compensation Plan amended and restated as of March 8, 2008.	10-K	000-07246	10.26	2/27/2009	
10.3*	2010 Short-Term Incentive Compensation Performance Metrics for Executive Officers.	8-K	000-07246		3/18/2010	
10.4*	Non-Employee Director Compensation for the 2010-2011 Term.	8-K	000-07246		4/23/2010	
10.5*	Executive Compensation and Short-Term Incentive Targets for 2010.	8-K	000-07246		4/23/2010	
10.6*	Employment Agreement with Richard W. McCullough, Chief Executive Officer, dated as of April 19, 2010.	8-K	000-07246	10.1	4/23/2010	
10.7*	Employment Agreement with Gysle R. Shellum, Chief Financial Officer, dated as of April 19, 2010.	8-K	000-07246	10.2	4/23/2010	
10.8*	Employment Agreement with Daniel W. Amidon, General Counsel and Corporate Secretary, dated as of April 19, 2010.	8-K	000-07246	10.3	4/23/2010	
10.9*	Employment Agreement with Lance A. Lauck, Senior Vice President of Business Development, dated as of April	8-K	000-07246	10.4	4/23/2010	

	19, 2010.					
10.10*	Employment Agreement with Barton R. Brookman, Jr., Senior Vice President of Exploration and Production, dated as of April 19, 2010.	8-K	000-07246	10.5	4/23/2010	
10.11*	2010 Long-Term Equity Compensation Plan.	S-8	333-167945	99.1	7/1/2010	
12.1	Computation of Ratio of Earnings to Fixed Charges.					X
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: August 9, 2010

/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