BEARINGPOINT INC
Form 10-Q
January 17, 2007

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 10-Q

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2005.**

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number 001-31451

BEARINGPOINT, INC.
(Exact name of Registrant as specified in its charter)

DELAWARE	**22-3680505**
(State or other jurisdiction of incorporation or organization)	**(IRS Employer Identification No.)**
1676 International Drive, McLean, VA	**22102**
(Address of principal executive offices)	**(Zip Code)**

(703) 747-3000
(Registrant s telephone number, including area code)

(Former name, former address and former fiscal year, if changed since last report)

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 o No þ

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

The number of shares of common stock of the Registrant outstanding as of January 3, 2007 was 201,593,999.

BEARINGPOINT, INC.
QUARTERLY REPORT ON FORM 10-Q
FOR THE QUARTER ENDED JUNE 30, 2005
EXPLANATORY NOTE

As a result of significant delays in completing our Consolidated Financial Statements for the year ended December 31, 2004 (fiscal 2004), we were unable to timely file with the Securities and Exchange Commission (the SEC) this Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 and our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2005 and September 30, 2005. In addition, we were unable to timely file with the SEC our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2006, June 30, 2006 and September 30, 2006. We filed our Annual Report on Form 10-K for fiscal 2004 on January 31, 2006 and our Annual Report on Form 10-K for the fiscal year ended December 31, 2005 (fiscal 2005) on November 22, 2006.

Due to the delay of the filing of this Quarterly Report on Form 10-Q and the significant changes to our business in the interim, certain information presented herein relates to events that occurred subsequent to June 30, 2005. For additional information regarding the Company, our business, operations, risks and results, please refer to our Annual Report on Form 10-K for the fiscal year ended December 31, 2005, filed with the SEC on November 22, 2006, and Current Reports on Form 8-K and other documents filed with SEC subsequent to November 22, 2006.

Contemporaneous with the filing with the SEC of this Quarterly Report on Form 10-Q for the quarter ended June 30, 2005, we are filing our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2005 and September 30, 2005.

BEARINGPOINT, INC.
QUARTERLY REPORT ON FORM 10-Q
FOR THE QUARTER ENDED JUNE 30, 2005
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PART I, ITEM 1. FINANCIAL STATEMENTS (UNAUDITED)

BEARINGPOINT, INC.
CONSOLIDATED CONDENSED STATEMENTS OF OPERATIONS
(in thousands, except share and per share amounts)
(unaudited)

	Three Months Ended June 30, 2005	Three Months Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
Revenue	$ 895,245	$ 875,387	$ 1,766,578	$ 1,763,990
Costs of service:				
Professional compensation	406,344	371,746	882,918	750,186
Other direct contract expenses	247,139	254,737	530,981	548,979
Lease and facilities restructuring charge		8,364	19,605	11,699
Other costs of service	64,459	55,080	130,821	124,812
Total costs of service	717,942	689,927	1,564,325	1,435,676
Gross profit	177,303	185,460	202,253	328,314
Amortization of purchased intangible assets	566	1,003	1,132	2,098
Selling, general and administrative expenses	164,360	167,853	327,801	318,490
Operating income (loss)	12,377	16,604	(126,680)	7,726
Interest income	1,682	87	3,033	292
Interest expense	(8,834)	(4,033)	(16,890)	(8,442)
Other expense, net	(5,270)	(2,392)	(10,353)	(4,418)
Income (loss) before taxes	(45)	10,266	(150,890)	(4,842)
Income tax expense	4,841	32,684	86,554	34,586
Net loss	$ (4,886)	$ (22,418)	$ (237,444)	$ (39,428)
Loss per share basic and diluted	$ (0.02)	$ (0.11)	$ (1.18)	$ (0.20)
Weighted average shares basic	201,235,807	196,016,196	200,799,624	195,633,359
Weighted average shares diluted	201,235,807	196,016,196	200,799,624	195,633,359

The accompanying Notes are an integral part of these Consolidated Condensed Financial Statements.

BEARINGPOINT, INC.
CONSOLIDATED CONDENSED BALANCE SHEETS
(in thousands, except share amounts)
(unaudited)

	June 30, 2005	December 31, 2004
ASSETS		
Current assets:		
Cash and cash equivalents	$ 278,362	$ 244,810
Restricted cash	113,891	21,053
Accounts receivable, net of allowances of $6,402 at June 30, 2005 and $11,296 at December 31, 2004	413,386	400,285
Unbilled revenue	437,679	381,681
Income tax receivable	25,822	50,518
Deferred income taxes	19,930	59,566
Prepaid expenses	48,885	31,196
Other current assets	25,045	33,038
Total current assets	1,363,000	1,222,147
Property and equipment, net	181,879	203,403
Goodwill	604,865	656,877
Other intangible assets, net	2,678	3,810
Deferred income taxes, less current portion	12,952	20,522
Other assets	82,236	75,948
Total assets	$ 2,247,610	$ 2,182,707
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Current portion of notes payable	$ 17,182	$ 17,558
Accounts payable	264,325	306,325
Accrued payroll and employee benefits	265,022	269,876
Deferred revenue	119,392	107,308
Income tax payable	18,682	33,927
Current portion of accrued lease and facilities charge	14,727	22,956
Deferred income taxes	12,170	16,750
Other current liabilities	279,550	134,744
Total current liabilities	991,050	909,444
Notes payable, less current portion	651,619	405,668
Accrued employee benefits	79,981	84,631
Accrued lease and facilities charge, less current portion	35,543	27,386
Deferred income taxes, less current portion	25,518	6,810
Other liabilities	102,693	124,070

Total liabilities	1,886,404	1,558,009
Commitments and contingencies (note 10)		
Stockholders equity:		
Preferred stock, $.01 par value 10,000,000 shares authorized		
Common stock, $.01 par value 1,000,000,000 shares authorized, 205,346,543 shares issued and 201,534,293 shares outstanding on June 30, 2005 and 203,132,716 shares issued and 199,320,466 shares outstanding on December 31, 2004	2,044	2,022
Additional paid-in capital	1,163,583	1,143,059
Accumulated deficit	(1,000,000)	(762,556)
Notes receivable from stockholders	(7,576)	(8,055)
Accumulated other comprehensive income	238,882	285,955
Treasury stock, at cost (3,812,250 shares)	(35,727)	(35,727)
Total stockholders equity	361,206	624,698
Total liabilities and stockholders equity	$ 2,247,610	$ 2,182,707

The accompanying Notes are an integral part of these Consolidated Condensed Financial Statements.

BEARINGPOINT, INC.
CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
(in thousands)
(unaudited)

	Six Months Ended June 30,	
	2005	**2004**
Cash flows from operating activities:		
Net loss	$ (237,444)	$ (39,428)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Deferred income taxes	60,938	(21,641)
Provision for doubtful accounts	174	3,358
Stock-based compensation	5,134	4,962
Depreciation and amortization of property and equipment	35,808	40,679
Amortization of purchased intangible assets	1,133	2,098
Lease and facilities restructuring charge	19,605	11,699
Amortization of debt issuance costs	8,604	826
Other	8,895	2,596
Changes in assets and liabilities:		
Accounts receivable	(26,919)	22,303
Unbilled revenue	(61,546)	(187,782)
Income tax receivable, prepaid expenses and other current assets	14,112	(11,301)
Other assets	(8,270)	(10,534)
Accrued payroll and employee benefits	896	10,361
Accounts payable and other current liabilities	103,906	192,123
Other liabilities	(23,618)	3,631
Net cash provided by (used in) operating activities	(98,592)	23,950
Cash flows from investing activities:		
Purchases of property and equipment	(18,411)	(37,133)
Increase in restricted cash	(92,838)	
Net cash used in investing activities	(111,249)	(37,133)
Cash flows from financing activities:		
Proceeds from issuance of common stock	14,897	13,365
Proceeds from issuance of notes payable	244,253	352,680
Repayment of notes payable	(5,765)	(323,255)
Decrease in book overdrafts	(1,479)	(13,964)
Payments on notes receivable from stockholders		102
Net cash provided by financing activities	251,906	28,928
Effect of exchange rate changes on cash and cash equivalents	(8,513)	(2,105)
Net increase in cash and cash equivalents	33,552	13,640

Cash and cash equivalents beginning of period	244,810	122,475
Cash and cash equivalents end of period	$ 278,362	$ 136,115

The accompanying Notes are an integral part of these Consolidated Condensed Financial Statements.

BearingPoint, Inc.
Notes to Consolidated Condensed Financial Statements
(in thousands, except share and per share amounts)
(unaudited)

Note 1. Basis of Presentation and Liquidity

Basis of Presentation

The accompanying unaudited interim Consolidated Condensed Financial Statements of BearingPoint, Inc. (the Company) have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. These statements do not include all of the information and Note disclosures required by accounting principles generally accepted in the United States of America, and should be read in conjunction with the Company s Consolidated Financial Statements and Notes thereto for the year ended December 31, 2005, included in the Company s Annual Report on Form 10-K and filed with the SEC on November 22, 2006 (the 2005 Form 10-K). The accompanying Consolidated Condensed Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America and reflect adjustments (consisting solely of normal, recurring adjustments, except as noted below) which are, in the opinion of management, necessary for a fair presentation of results for these interim periods. The results of operations for the three and six months ended June 30, 2005 are not necessarily indicative of the results that may be expected for any other interim period or the entire fiscal year.

The interim Consolidated Condensed Financial Statements reflect the operations of the Company and all of its majority-owned subsidiaries. Upon consolidation, all significant intercompany accounts and transactions are eliminated. Prior to 2004, certain of the Company s consolidated foreign subsidiaries within the Europe, Middle East and Africa (EMEA), Asia Pacific and Latin America regions reported their results on a one-month lag, which allowed additional time to compile results. During the first quarter of 2004, the Company recorded a change in accounting principle resulting from certain Asia Pacific and EMEA regions now reporting on a current period basis. The purpose of the change is to have these certain foreign subsidiaries report on a basis that is consistent with the Company s fiscal reporting period. As a result, net loss for the three months ended March 31, 2004 includes a cumulative effect of a change in accounting principle of $529, which represents the December 2003 loss for these entities. This amount is included in other income (expense), net in the interim Consolidated Condensed Statement of Operations for the six months ended June 30, 2004 due to the immateriality of the effect of the change in accounting principle to consolidated net loss. Certain of the Company s consolidated foreign subsidiaries within EMEA continue to report their results of operations on a one-month lag.

During 2005, the Company identified certain errors in its previously reported financial statements. Because these changes are not material to the Company s financial statements for the periods prior to 2005 or to 2005 taken as a whole, the Company corrected these errors in the first quarter of 2005. These adjustments included entries to correct errors in accounting for revenue, certain foreign tax withholdings, income taxes, and other miscellaneous items. Had these errors been recorded in the proper periods, the impact of the adjustments on the first quarter of 2005 and the six months ended June 30, 2005 would have been an increase to revenue and gross profit of $726 and $4,927, respectively, and a decrease to net loss of $15,445.

Liquidity

The interim Consolidated Condensed Financial Statements of the Company are prepared on a going concern basis, which assumes that the Company will continue its operations for the foreseeable future and will realize its assets and discharge its liabilities in the ordinary course of business. The Company has recently experienced a number of factors that have negatively impacted its liquidity, including the following:

- The Company has experienced significant recurring net losses. At June 30, 2005, the Company had an accumulated deficit of $1,000,000.

- The Company s business has not generated positive cash from operating activities in some recent periods during fiscal 2005 and 2004.

Due to the material weaknesses in its internal controls, the Company continues to experience significant delays in completing its consolidated financial statements and filing periodic reports with the SEC on a timely basis. Accordingly, the Company continues to devote substantial additional internal and external resources, and experience higher than expected fees for audit services.

BearingPoint, Inc.
Notes to Consolidated Condensed Financial Statements (Continued)
(in thousands, except share and per share amounts)
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In the first quarter of 2005, the Company incurred losses of $113,257 under a significant contract with Hawaiian Telcom Communications, Inc., which consequently will result in significantly less cash from operating activities in future years.

The Company currently is a party to a number of disputes which involve or may involve litigation or other legal or regulatory proceedings. See Note 10, Commitments and Contingencies.

The Company is currently engaged in a number of activities, intended to further improve its cash balances and their accessibility, if current internal estimates for cash uses for fiscal 2007 prove incorrect. These activities include: increased focus on reducing its days sales outstanding; review and reconsideration of proposed capital expenditure budgets; reviewing its offshore capabilities and operations to increase efficiency and to reduce redundancies in its workforce; and extensive reviews of its borrowing base calculations to ascertain whether the Company is receiving full credit for all available cash and receivables. Furthermore, in fiscal 2007, the Company expects the significant investments it has made, or will make, in fiscal years 2006 and 2007 with respect to its financial reporting and processes, to begin to significantly reduce the cash required to operate its financial reporting and processes.

Based on the foregoing and its current state of knowledge of the outlook for its business, the Company currently believes that cash provided from operations, existing cash balances and available borrowings under its 2005 Credit Facility will be sufficient to meet its working capital needs through the end of fiscal 2007. The Company also believes that it will continue to have sufficient access to the capital markets to make up any deficiencies if cash provided from operations and existing cash balances are insufficient during this period of time. However, actual results may differ from current expectations for many reasons, including losses of business that could result from the Company s continuing failure to timely file periodic reports with the SEC, the Company s lenders under the senior credit facility ceasing to grant extensions to file periodic reports, possible delisting from the New York Stock Exchange, further downgrades of its credit ratings or unexpected demands on its current cash resources (e.g., to settle lawsuits).

Note 2. Stock-Based Compensation and Employee Stock Purchase Plan

The Company has several stock-based employee compensation plans. Statement of Financial Accounting Standards (SFAS) No. 123, Accounting for Stock-Based Compensation (SFAS 123), defined a fair value method of accounting for stock options and other equity instruments. As provided for in SFAS 123, the Company accounts for stock-based compensation awards issued to employees by applying the intrinsic value method prescribed in Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees (APB 25), whereby the difference between the quoted market price as of the date of grant and the contractual purchase price of the award is charged to operations over the vesting period. The Company granted both service-based and performance-based restricted stock units (RSUs) and stock options during 2005. For the service-based RSUs and stock options, the fair value is fixed on the date of grant based on the number of RSUs or stock options issued and the fair value of the Company s stock on the date of grant. For the performance-based RSUs and stock options, the fair value is estimated on the date the performance conditions are established based on the fair value of the Company s stock and the Company s estimate of the number of RSUs or stock options that will ultimately be issued. The performance-based RSUs and stock options are marked to market from the date it is probable that the performance conditions will be achieved. With respect to RSUs, stock options granted where the exercise price is below the market price on the date of grant, and other awards granted prior to December 31, 2005, compensation expense is measured based on the intrinsic value of such awards and charged to expense using the straight-line method over the period of restriction or vesting period.

Pro forma information regarding net loss and loss per share is required assuming the Company had accounted for its stock-based awards issued to employees under the fair value recognition provisions of SFAS 123, whereby stock options and other awards are valued at the grant date using an option pricing model, and compensation is amortized as a charge to earnings over the awards vesting period. The weighted average fair value of stock options granted during the three months ended June 30, 2005 and 2004 were $3.94 and $5.81, respectively. The weighted average fair value of stock options granted during the six months ended June 30, 2005 and 2004 were $4.73 and $6.24 respectively. The fair value of options granted was estimated using the Black-Scholes option-pricing model with the following weighted average assumptions:

BearingPoint, Inc.
Notes to Consolidated Condensed Financial Statements (Continued)
(in thousands, except share and per share amounts)
(unaudited)

	Stock Price Expected Volatility	Risk-Free Interest Rate	Expected Life	Expected Dividend Yield
Three months ended June 30, 2005	50.70%	3.93%	6	
Three months ended June 30, 2004	64.27%	3.95%	6	
Six months ended June 30, 2005	51.27%	3.96%	6	
Six months ended June 30, 2004	65.29%	3.61%	6	

The fair value of the Company s common stock purchased under the Employee Stock Purchase Plan, as amended (the ESPP) was estimated for the three and six months ended June 30, 2005 and 2004 using the Black-Scholes option-pricing model and an expected volatility ranging between 30.4% and 70.0%, risk-free interest rates ranging from 1.03% to 3.29%, an expected life ranging from 6 to 24 months and an expected dividend yield of zero. The weighted average fair value of share purchase rights under the ESPP was $3.84 for the three months ended June 30, 2004. The weighted average fair value of share purchase rights under the ESPP was $3.21 and $3.59 for the six months ended June 30, 2005 and 2004, respectively.

The following table illustrates the effect on net loss and loss per share if the Company had applied the fair value method for the three and six months ended June 30, 2005 and 2004:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Net loss	$ (4,886)	$ (22,418)	$ (237,444)	$ (39,428)
Add back:				
Total stock-based compensation expense recorded under intrinsic value method for all stock awards, net of tax effects	3,414	945	5,134	2,935
Deduct:				
Total stock-based compensation expense recorded under fair value method for all stock awards, net of tax effects	(26,029)	(22,718)	(51,144)	(47,876)
Pro forma net loss	$ (27,501)	$ (44,191)	$ (283,454)	$ (84,369)
Loss per share:				
Basic and diluted as reported	$ (0.02)	$ (0.11)	$ (1.18)	$ (0.20)
Basic and diluted pro forma	$ (0.14)	$ (0.23)	$ (1.41)	$ (0.43)

In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123 (revised 2004), Share-Based Payment (SFAS 123R), which replaces SFAS 123 and supersedes APB 25. SFAS 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values beginning with the first reporting period following the fiscal year that begins on or after June 15, 2005. The pro forma disclosures previously permitted under SFAS 123 no longer will be an alternative to financial statement recognition. The Company is required to adopt SFAS 123R in the first quarter of fiscal 2006, beginning January 1, 2006. Under SFAS 123R, the Company must determine the appropriate fair value model to be used for valuing share-based payments, the amortization method for compensation cost and the transition method to be used at date of adoption. The transition methods include modified prospective and modified retroactive adoption options. Under the modified retroactive option, prior periods may be restated either as of the beginning of the year of adoption or for all periods presented. The modified prospective method requires that compensation expense be recorded for all unvested stock options and restricted stock at the beginning of the first quarter of adoption of SFAS 123R, while the modified retroactive method would record compensation expense for all unvested stock options and restricted stock beginning with the first period restated. In March 2005, Staff Accounting Bulletin (SAB) No. 107, Share-Based Payment, (SAB 107), was issued regarding the SEC s interpretation of SFAS 123R and the valuation of share-based payments for public companies. The Company currently utilizes the Black-Scholes option pricing model to estimate fair value for the above pro forma calculations and will continue

BearingPoint, Inc.
Notes to Consolidated Condensed Financial Statements (Continued)
(in thousands, except share and per share amounts)
(unaudited)

using the same methodology in the foreseeable future. The Company will use the modified prospective method for adoption of SFAS 123R, and management believes that the incremental compensation cost to be recognized as a result of the adoption of SFAS 123R and SAB 107 for fiscal 2006 will range from $22,000 to $28,000.

On March 25, 2005, the Compensation Committee of the Company s Board of Directors approved the issuance of up to an aggregate of $165,000 in RSUs under the Long-Term Incentive Plan (the LTIP) to the Company s current managing directors (MDs) and a limited number of key employees, and delegated to the Company s officers the authority to grant these awards. Certain RSU awards under this authorization were made in three tranches of grants representing 30%, 30%, and 40% of the total RSU award for each employee. Additional awards were also made at various grant dates as determined by the Company s Chief Executive Officer. During the three and six months ended June 30, 2005, the Company granted RSU awards of 4,375,565 and 5,125,565, respectively, with grant date weighted average fair values of $7.27 and $7.49, respectively. Total compensation expense recorded as a result of these awards during the three and six months ended June 30, 2005 was $1,465 and $1,491, respectively. As of June 30, 2005, the Company had 5,107,417 RSUs outstanding, net of forfeitures, with a grant date weighted average fair value of $7.49 and remaining deferred compensation of $36,764, which will be amortized in accordance with the respective employees vesting schedule, subject to the application of SFAS 123R in 2006.

On December 14, 2006, the Company amended its LTIP, including the elimination of the current formula used to determine the number of shares available for issuance under the LTIP, along with an increase to the number of shares available for issuance under the LTIP by 25 million additional shares. Previously, the number of shares of common stock authorized for issuance under the LTIP was determined by a formula. The formula provided that the number of shares of common stock authorized for issuance under the LTIP is equal to the greater of (i) 35,084,158 shares of common stock and (ii) 25% of the sum of (x) the number of issued and outstanding shares of the Company s common stock and (y) the authorized shares. The amendment to the LTIP eliminated this formulaic determination of the number of shares of common stock authorized for issuance under the LTIP and replaced this formula with the specified number of authorized shares of 92,179,333, an aggregate increase of 25 million shares available for awards under the Plan (measured as of November 1, 2006).

In connection with the acquisition of various Andersen Business Consulting practices, the Company committed to the issuance of approximately 3,000,000 shares of common stock (net of forfeitures) to former partners of those practices as a retentive measure. The stock awards have no purchase price and are issued as to one-third of the shares on the first three anniversaries of the acquisition of the relevant consulting practice, so long as the recipient remains employed by the Company. Compensation expense was recorded ratably over the three-year service period beginning in July 2002. Compensation expense was $1,796 and $2,276 for the three months ended June 30, 2005 and 2004, respectively. Compensation expense was $3,482 and $4,263 for the six months ended June 30, 2005 and 2004, respectively. As of June 30, 2005, 2,100,998 shares of common stock have been issued. During the third quarter of 2005, $4,929 was paid in cash in lieu of the third and final installment of the stock award in fulfillment of the Company s obligations under this commitment, which was recorded as a reduction of additional paid in capital.

The Company s ESPP was adopted on October 12, 2000 and allows eligible employees to purchase shares of the Company s common stock at a discount, through accumulated payroll deductions of 1% to 15% of their compensation, up to a maximum of $25. Under the ESPP, shares of the Company s common stock are purchased at 85% of the lesser of the fair market value at the beginning of the 24-month offering period, or the fair market value at the end of each 6-month purchase period ending on July 31 and January 31, respectively. The ESPP became effective on February 8, 2001. In 2005, the Board of Directors also approved the removal of the 24-month look-back, resulting in straight 6-month offering periods, where the purchase price will be 15% off the closing price on the last day of the 6-month purchase period. Current participants are grandfathered (protected) from this change through January 31, 2007, provided they maintain continued enrollment. These Plan changes will be effective for all new enrollees beginning with the next open enrollment cycle. During the six months ended June 30, 2005, the Company s employees purchased an aggregate of 2,053,154 shares for an aggregate amount of $13,769.

Because the Company is not current in its SEC filings, it is unable to issue freely tradable shares of its common stock. Consequently, the Company has not issued shares under the ESPP since January 2005 and significant features of many of the Company s employee equity plans remain suspended. If the Company is unable to become current in its SEC filings by April 30, 2007, the purchase price discount the Company will be able to offer pursuant to applicable provisions of the U.S. Internal Revenue Code could be substantially reduced. If the purchase price of the Company s common stock purchased under the ESPP changes to 85% of the fair market value of the common stock on the date of purchase, increases in the Company s stock price above current levels could result in increased withdrawal rates to levels higher than those the Company has historically experienced. The Company currently does not anticipate becoming current in its SEC filings by

BearingPoint, Inc.
Notes to Consolidated Condensed Financial Statements (Continued)
(in thousands, except share and per share amounts)
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April 30, 2007. Employee contributions to the ESPP held by the Company were approximately $10,146 at June 30, 2005. These amounts are included in cash and cash equivalents and are repayable on demand.

Note 3. Notes Payable

Notes payable consists of the following:

	June 30, 2005	December 31, 2004
Current portion:		
Yen-denominated term loan (January 31, 2003)	$ 5,994	$ 6,509
Yen-denominated term loan (June 30, 2003)	2,997	3,254
Yen-denominated line of credit	7,221	7,795
Other	970	
Total current portion	17,182	17,558
Long-term portion:		
Series A and Series B Convertible Debentures	450,000	400,000
April 2005 Convertible Debentures	200,000	
Yen-denominated term loan (January 31, 2003)		3,215
Yen-denominated term loan (June 30, 2003)		1,609
Other	1,619	844
Total long-term portion	651,619	405,668
Total notes payable	$ 668,801	$ 423,226

Series A and Series B Convertible Subordinated Debentures

On December 22, 2004, the Company completed a $400,000 offering of Convertible Subordinated Debentures. The offering consisted of $225,000 aggregate principal amount of 2.50% Series A Convertible Subordinated Debentures due December 15, 2024 (the Series A Debentures) and $175,000 aggregate principal amount of 2.75% Series B Convertible Subordinated Debentures due December 15, 2024 (the Series B Debentures and together with the Series A Debentures, the Subordinated Debentures). On January 5, 2005, the Company issued an additional $25,000 aggregate principal amount of its Series A Debentures and an additional $25,000 aggregate principal amount of its Series B Debentures upon the exercise in full of the option granted to the initial purchasers. Interest is payable on the Subordinated Debentures on June 15 and December 15 of each year, beginning June 15, 2005. The Subordinated Debentures are unsecured and are subordinated to the Company s existing and future senior debt. Due to the delay in the completion of the Company s audited financial statements for the fiscal year ended December 31, 2004, the Company was unable to file a timely registration statement with the SEC to register for resale its Subordinated Debentures and underlying common stock. Accordingly, pursuant to the terms of these securities, the applicable interest rate on each series of Subordinated Debentures increased by 0.25% beginning on March 23, 2005 and increased another 0.25% beginning on June 22, 2005. These changes together increased the interest rate on the Series A Debentures and the Series B Debentures to 3.00% and 3.25%, respectively, and such increased interest rates will be the applicable interest rates until the date the registration statement is declared effective.

The net proceeds from the sale of the Subordinated Debentures were approximately $435,600, after deducting offering expenses and the initial purchasers commissions of $11,400 and other fees and expenses of approximately $3,000. The Company used approximately $240,590 of the net proceeds from the sale of the Subordinated Debentures to repay its outstanding $220,000 Senior Notes and approximately $135,000 to repay amounts outstanding under its then existing revolving credit facility. The Company also used the proceeds to pay fees and expenses in connection with entering into the $400,000 Interim Senior Secured Credit Facility, as defined below.

The Subordinated Debentures are initially convertible, under certain circumstances, into shares of the Company s common stock at a conversion rate of 95.2408 shares for each $1 principal amount of the Subordinated Debentures, subject to anti-dilution and adjustments but not to exceed 129.0 shares, equal to an initial conversion price of approximately $10.50 per share. Holders of the Subordinated Debentures may exercise the right to convert the Subordinated Debentures prior to their maturity only under certain circumstances, including when the Company s stock price reaches a specified level for a

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specified period of time, upon notice of redemption, and upon specified corporate transactions. Upon conversion of the Subordinated Debentures, the Company will have the right to deliver, in lieu of shares of common stock, cash or a combination of cash and shares of common stock. The Subordinated Debentures will be entitled to an increase in the conversion rate upon the occurrence of certain change of control transactions or, in lieu of the increase, at the Company s election, in certain circumstances, to an adjustment in the conversion rate and related conversion obligation so that the Subordinated Debentures are convertible into shares of the acquiring or surviving company. The Company will also increase the conversion rate upon occurrence of certain transactions. As of June 30, 2005, none of the circumstances under which the Subordinated Debentures are convertible existed.

On December 15, 2011, December 15, 2014 and December 15, 2019, holders of Series A Debentures, at their option, have the right to require the Company to repurchase any outstanding Series A Debentures. On December 15, 2014 and December 15, 2019, holders of Series B Debentures, at their option, have the right to require the Company to repurchase any outstanding Series B Debentures. In each case, the Company will pay a repurchase price in cash equal to 100% of the principal amount of the Subordinated Debentures, plus accrued and unpaid interest, including liquidated damages, if any, to the repurchase date. In addition, holders of the Subordinated Debentures may require the Company to repurchase all or a portion of the Subordinated Debentures on the occurrence of a designated event, at a repurchase price equal to 100% of the principal amount of the Subordinated Debentures, plus any accrued but unpaid interest and liquidated damages, if any, to, but not including, the repurchase date. A designated event includes certain change of control transactions and a termination of trading, occurring if the Company s common stock is no longer listed for trading on a U.S. national securities exchange.

The Company may redeem some or all of the Series A Debentures beginning on December 23, 2011 and, beginning on December 23, 2014, may redeem the Series B Debentures, in each case at a redemption price in cash equal to 100% of the principal amount of the Subordinated Debentures plus accrued and unpaid interest and liquidated damages, if any, on the Subordinated Debentures to, but not including, the redemption date.

Upon a continuing event of default, the trustee or the holders of at least 25% in aggregate principal amount of the Subordinated Debentures may declare the applicable series of Debentures immediately due and payable, which could lead to cross-defaults and possible acceleration of unpaid principal and accrued interest of the April 2005 Senior Debentures, July 2005 Senior Debentures and the 2005 Credit Facility, all defined below.

On September 8, 2005, certain holders of the Series B Debentures provided a purported Notice of Default to the Company based upon its failure to timely file its Annual Report on Form 10-K for the year ended December 31, 2004 and Quarterly Reports on Form 10-Q for the periods ended March 31, 2005 and June 30, 2005. On or about November 17, 2005, the Company received a notice from these holders of the Series B Debentures, asserting that an event of default had occurred and was continuing under the indenture for the Series B Debentures and, as a result, the principal amount of the Series B Debentures, accrued and unpaid interest and unpaid damages were due and payable immediately.

Based on the foregoing, the indenture trustee for the Series B Debentures brought suit against the Company and, on September 19, 2006, the Supreme Court of New York ruled that the Company was in default under the indenture for the Series B Debentures and ordered that the amount of damages to be determined subsequently at trial. The Company believed the ruling to be in error and on September 25, 2006, appealed the court s ruling and moved for summary judgment on the matter of determination of damages.

After further negotiations, on November 7, 2006, the Company and the relevant holders of its Series B Debentures filed a stipulation to discontinue the lawsuit. Concurrent with the agreement to discontinue the lawsuit, the Company entered into a First Supplemental Indenture (the First Supplemental Indenture) with The Bank of New York, as trustee, which amends the subordinated indenture governing the Series A Debentures and the Series B Debentures. The First Supplemental Indenture includes a waiver of the Company s SEC reporting requirements under the subordinated indenture through October 31, 2008. Pursuant to the terms of the First Supplemental Indenture, effective as of November 7, 2006: (i) the interest rate payable on the Series A Debentures will increase from 3.00% per annum to 3.10% per annum (inclusive of any liquidated damages relating to the failure to file a registration statement for the Series A Debentures that may be payable) until December 23, 2011, and (ii) the interest rate payable on the Series B Debentures will increase from 3.25% per annum to 4.10% per annum (inclusive of any liquidated damages relating to the failure to file a registration statement for the Series B Debentures that may be payable) until December 23, 2014. The increased interest rates apply to all Series A Debentures and Series B Debentures outstanding.

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April 2005 Convertible Senior Subordinated Debentures

On April 27, 2005, the Company issued $200,000 aggregate principal amount of its 5.00% Convertible Senior Subordinated Debentures due April 15, 2025 (the April 2005 Senior Debentures). Interest is payable on the April 2005 Senior Debentures on April 15 and October 15 of each year, beginning October 15, 2005. The April 2005 Senior Debentures are unsecured and are subordinated to the Company s existing and future senior debt. The April 2005 Senior Debentures are senior to the Subordinated Debentures. Since the Company failed to file a registration statement with the SEC to register for resale of its April 2005 Senior Debentures and the underlying common stock by December 31, 2005, the interest rate on the April 2005 Senior Debentures increased by 0.25% to 5.25% beginning on January 1, 2006 and will continue to be the applicable interest rate through the date the registration statement is filed.

The net proceeds from the sale of the April 2005 Senior Debentures, after deducting offering expenses and the placement agents commissions and other fees and expenses, were approximately $192,800. The Company used the net proceeds from the offering to replace the working capital that was at the time used to cash collateralize letters of credit under the 2004 Interim Credit Facility (see below).

The April 2005 Senior Debentures are initially convertible into shares of the Company s common stock at a conversion rate of 151.5151 shares for each $1 principal amount of the April 2005 Senior Debentures, subject to anti-dilution and adjustments, equal to an initial conversion price of $6.60 per share at any time prior to the stated maturity. Upon conversion of the April 2005 Senior Debentures, the Company will have the right to deliver, in lieu of shares of common stock, cash or a combination of cash and shares of common stock. The April 2005 Senior Debentures will be entitled to an increase in the conversion rate upon the occurrence of certain change of control transactions or, in lieu of the increase, at the Company s election, in certain circumstances, to an adjustment in the conversion rate and related conversion obligation so that the April 2005 Senior Debentures are convertible into shares of the acquiring or surviving company.

The holders of the April 2005 Senior Debentures have the right, at their option, to require the Company to repurchase all or some of their debentures on April 15, 2009, 2013, 2015 and 2020. In each case, the Company will pay a repurchase price in cash equal to 100% of the principal amount of the April 2005 Senior Debentures, plus any accrued but unpaid interest, including additional interest, if any, to the repurchase date. In addition, holders of the April 2005 Senior Debentures may require the Company to repurchase all or a portion of the April 2005 Senior Debentures on the occurrence of a designated event, at a repurchase price equal to 100% of the principal amount of the April 2005 Senior Debentures, plus any accrued but unpaid interest and additional interest, if any, to, but not including, the repurchase date. A designated event includes certain change of control transactions and a termination of trading, occurring if the Company s common stock is no longer listed for trading on a U.S. national securities exchange.

The April 2005 Senior Debentures will be redeemable at the Company s option on or after April 15, 2009 at a redemption price in cash equal to 100% of the principal amount of the April 2005 Senior Debentures plus accrued and unpaid interest and additional interest, if any, on the April 2005 Senior Debentures to, but not including, the redemption date.

Upon a continuing event of default, the trustee or the holders of at least 25% in aggregate principal amount of the April 2005 Senior Debentures may declare the applicable series of Debentures immediately due and payable, which could lead to cross-defaults and possible acceleration of unpaid principal and accrued interest of the Subordinated Debentures, July 2005 Senior Debentures (defined below) and the 2005 Credit Facility (defined below).

In connection with the Series B lawsuit described above, on November 2, 2006, the Company entered into a First Supplemental Indenture with The Bank of New York, as trustee, which amends the indenture governing the April 2005 Senior Debentures. The supplemental indenture includes a waiver of the Company s SEC reporting requirements through October 31, 2007, and provides for further extension through October 31, 2008 upon the Company s payment of an additional fee of 0.25% of the principal amount of the debentures. The Company paid to certain consenting holders of April 2005 Senior Debentures, who provided their consents prior to the expiration of the consent solicitation, a consent fee equal to 1.00% of the outstanding principal amount of the April 2005 Senior Debentures.

July 2005 Convertible Senior Debentures

On July 15, 2005, the Company issued $40,000 aggregate principal amount of its 0.50% Convertible Senior Subordinated Debentures due July 2010 (the July 2005 Senior Debentures) and common stock warrants (the July 2005 Warrants) to purchase up to 3,500,000 shares of the Company s common stock. The July 2005 Senior Debentures bear interest at a rate of 0.50% per year and will mature on July 15, 2010. Interest is payable on the July 2005 Senior Debentures on January 15 and July 15 of each year, beginning January 15, 2006. The July 2005 Senior Debentures are pari passu to the

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April 2005 Senior Debentures and senior to the Subordinated Debentures. Since the Company failed to file a registration statement with the SEC to register for resale its July 2005 Senior Debentures and the underlying common stock by December 31, 2005, the interest rate on the July 2005 Senior Debentures increased by 0.25% to 0.75% beginning on January 1, 2006 and will continue to be the applicable interest rate through the date the registration statement is filed.

The net proceeds from the sale of the July 2005 Senior Debentures and July 2005 Warrants, after deducting offering expenses and other fees and expenses, were approximately $38,900.

In accordance with the terms of the purchase agreement, the holders of the July 2005 Senior Debentures appointed a designated director to the Company s Board of Directors (with a term that expires in 2007) effective July 15, 2005. If the designated director ceases to be affiliated with the holders of the July 2005 Senior Debentures or ceases to serve on the Company s Board of Directors, so long as the holders together hold at least 40% of the original principal amount of the July 2005 Senior Debentures, the holders or their designees have the right to designate a replacement director to the Company s Board of Directors.

The July 2005 Senior Debentures are initially convertible on or after July 15, 2006 into shares of the Company s common stock at a conversion price of $6.75 per share, subject to anti-dilution and other adjustments. Upon conversion of the July 2005 Senior Debentures, the Company will have the right to deliver, in lieu of shares of common stock, cash or a combination of both. The July 2005 Senior Debentures will be entitled, in certain change of control transactions, to an adjustment in the conversion obligation so that the July 2005 Senior Debentures are convertible into shares of stock, other securities or other property or assets receivable upon the occurrence of such transaction by a holder of shares of the Company s common stock in such transaction.

The holders of the July 2005 Senior Debentures may require the Company to repurchase all or a portion of the July 2005 Senior Debentures on the occurrence of a designated event, at a repurchase price equal to 100% of the principal amount of the July 2005 Senior Debentures, plus any accrued but unpaid interest and additional interest, if any, to, but not including, the repurchase date. The list of designated events includes certain change of control transactions and a termination of trading occurring if the Company s common stock is no longer listed for trading on a U.S. national securities exchange.

The July 2005 Warrants may be exercised on or after July 15, 2006 and have a five-year term. The initial number of shares issuable upon exercise of the July 2005 Warrants is 3,500,000 shares of common stock, and the initial exercise price per share of common stock is $8.00. The number of shares and exercise price are subject to certain customary anti-dilution protections and other customary terms. These terms include, in certain change of control transactions, an adjustment in the conversion obligation so that the July 2005 Warrants, upon exercise, will entitle the July 2005 Warrant holders to receive shares of stock, other securities or other property or assets, receivable upon the occurrence of such transaction by a holder of shares of the Company s common stock in such transaction.

Upon a continuing event of default, the holders of at least 25% in aggregate principal amount of the July 2005 Senior Debentures may declare the July 2005 Senior Debentures immediately due and payable, which could lead to cross-defaults and possible acceleration of unpaid principal and accrued interest of the Subordinated Debentures, April 2005 Senior Debentures and the 2005 Credit Facility (defined below).

In connection with the Series B lawsuit described above, on November 9, 2006, the Company entered into an agreement with the holders of the July 2005 Debentures, pursuant to which the Company paid a consent fee equal to 1.00% of the outstanding principal amount of the July 2005 Debentures, in accordance with the terms of the purchase agreement governing the issuance of the July 2005 Debentures.

In accordance with the provisions of Emerging Issues Task Force (EITF) Issue 98-5, Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios, and EITF 00-27, Application of Issue No. 98-5 to Certain Convertible Instruments the Company allocated the proceeds received from the July 2005 Senior Debentures to the elements of the debt instrument based on their relative fair values. The

Company allocated fair value to the July 2005 Warrants and conversion option utilizing the Black-Scholes option pricing model, which was consistent with the Company s historical valuation methods. The following assumptions and estimates were used in the Black-Scholes model: volatility of 48.5%; an average risk-free interest rate of 3.98%; dividend yield of 0%; and an expected life of 5 years. The fair value of debt component of the July 2005 Debentures was based on the net present value of the underlying cash flows discounted at a rate derived from the Company s then publicly traded debt, which was 11.4%. Once the relative fair values were established the Company allocated the proceeds to each component of the contract. Because the conversion price was lower than the then current fair market value of the Company s common stock, the Company determined that a beneficial conversion feature (BCF) existed which required separate accounting.

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The accounting conversion value of the BCF calculated was $14,288 and the fair value allocated to the July 2005 Warrants was $8,073. The fair value allocated to the warrants and the accounting conversion value of the BCF amounting to $22,361 were recorded as credits to additional paid in capital. Additionally, $1,000 paid to the holders in connection with this transaction was recorded as a reduction of the net proceeds. The offsetting $23,361 was treated as a discount to the $40,000 principal amount of the July 2005 Senior Debentures. Using the effective interest method with an imputed interest rate of 17.9%, the discount will be accreted as interest expense over the term of the debt contract to bring the value of the debt to its face amount at the time the principal payment is due in July 2010.

2005 Credit Facility

On July 19, 2005, the Company entered into a $150,000 Senior Secured Credit Facility (the 2005 Credit Facility), which was amended on December 21, 2005, March 30, 2006, July 19, 2006, September 29, 2006, and October 31, 2006. The 2005 Credit Facility, as amended, provides for up to $150,000 in revolving credit and advances, all of which can be available for issuance of letters of credit, and includes up to $15,000 in a swingline subfacility, which allows for same day borrowing. Advances under the revolving credit line are limited by the available borrowing base, which is based upon a percentage of eligible accounts receivable and unbilled receivables.

The Company may not have access to the entire $150,000 because, among other things: (i) certain accounts receivable for government contracts cannot be included in the calculation of the borrowing base without obtaining certain consents (this restriction was removed by amendment on March 30, 2006); and (ii) delays in the Company s ability to provide month-end account receivables reports negatively impact its ability to include such account receivables as part of the borrowing base, which determines the amount the Company may borrow under the 2005 Credit Facility. Borrowings available under the 2005 Credit Facility will be used for general corporate purposes.

In addition, prior to the March 30, 2006 amendment, the Company was required to cash collateralize 105% of its borrowings, including any outstanding letters of credit, under the 2005 Credit Facility and any accrued and unpaid interest and fees thereon. The Company is charged an annual rate of 2.75% for the credit spread and other fees for its outstanding letters of credit. The Company fulfilled its obligation to cash collateralize using cash on hand. The requirement to deposit and maintain cash collateral terminated as part of the March 30, 2006 amendment to the 2005 Credit Facility, and such cash collateral was released to the Company.

Interest on loans (other than swingline loans) under the 2005 Credit Facility are calculated, at the Company s option, at a rate equal to LIBOR, or, for dollar-denominated loans, at a rate equal to the higher of the bank s corporate base rate or the Federal funds rate plus 50 basis points (Base Rate Loans). No matter which rate the Company chooses, an applicable margin is added that varies depending upon availability under the revolver. For Base Rate Loans, the applicable margin ranges from 0.25% (when availability is greater than $100,000) to 1.25% (when availability is less than or equal to $25,000); provided that until the Company is current in its SEC filings, the applicable margin shall be 1.00%. For LIBOR loans, the applicable margin ranges from 1.25% (when availability is greater than $100,000) to 2.25% (when availability is less than or equal to $25,000); provided that until the Company is current in its SEC filings, the applicable margin shall be 2.00%. Interest on swingline loans under the 2005 Credit Facility are calculated at a rate equal to the higher of the bank s corporate base rate or the Federal funds rate plus 50 basis points plus the applicable margin for Base Rate Loans. A facility fee on the unused portion of the commitments of the lenders under the 2005 Credit Facility will be due at a rate of 0.50% per annum. In the event of a default, the interest rate increases by 2.0%.

The 2005 Credit Facility matures on July 15, 2010, unless on or before December 15, 2008, the April 2005 Senior Debentures shall have not been (i) fully converted into common stock of the Company or (ii) refinanced or replaced with securities that do not require the Company to make any principal payments (including, without limitation, by way of a put option) on or prior to July 15, 2010, in which case the 2005 Credit Facility matures on December 15, 2008.

The 2005 Credit Facility contains affirmative, financial and negative covenants.

The financial covenants include: (i) a minimum U.S. cash collections requirement of $125,000 monthly and $420,000 by the Company on a rolling three-month basis, (ii) a minimum trailing twelve-month EBITDA covenant which increases quarterly from $107,600 (for the quarter ending September 30, 2005) to $333,800 (for the quarter ending March 31, 2009 and thereafter) as of the end of the applicable quarter, (iii) a maximum leverage ratio which decreases from 7.7 to 1 (for the quarter ending September 30, 2005) to 2.4 to 1 (for the quarter ending March 31, 2009 and thereafter) as of the end of the applicable quarter and (iv) a maximum trailing twelve-month capital expenditures covenant which starts at $111,300 for the quarter ending September 30, 2005

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and fluctuates thereafter, including reducing to $89,700 a year thereafter and ultimately remaining fixed at $94,100, starting with the quarter ending December 31, 2006.

The EBITDA and maximum leverage ratio will not be tested for a quarterly test period if (i) at all times during the test period that the borrowing base was less than $120,000, borrowing availability was greater than $15,000, (ii) at all times during the test period that the borrowing base was greater than or equal to $120,000 and less than $130,000, borrowing availability was greater than $20,000, or (iii) at all times during the test period that the borrowing base was greater than or equal to $130,000, borrowing availability was greater than $25,000. The Company intends to maintain, and the Company s management believes that it has maintained through November 30, 2006, the minimum borrowing availability in sufficient amounts so as not to trigger the minimum EBITDA and maximum leverage ratio covenants, and, the Company is permitted to post cash collateral, which amount will count toward the borrowing availability, so that these covenants are not tested. If the Company does not maintain the required minimum borrowing availability and the Company is unable to post sufficient cash collateral to rectify a borrowing availability shortfall and these financial covenants are tested, the Company would likely not be in compliance with these covenants, resulting in a default under the 2005 Credit Facility.

The affirmative covenants include:

(i) becoming current in the Company s SEC filings according to the following schedule:

- the Company s 2005 Form 10-K by November 30, 2006, which was filed on November 22, 2006;
- the Forms 10-Q for the quarters ended March 31, June 30, and September 30, 2005 by the earlier of two months after the date the Company files the 2005 Form 10-K and January 31, 2007, which were filed on the date hereof;
- the Forms 10-Q for the quarters ended March 31 and June 30, 2006 by February 28, 2007; and
- the Form 10-Q for the quarter ended September 30, 2006 by March 31, 2007; and

(ii) the Company must have repatriated at least $65,000 of cash from foreign subsidiaries (in December 2005, the Company repatriated $66,600 of cash from its foreign subsidiaries); and

(iii) the Company must provide weekly reports with respect to its cash position until the Company becomes current in its SEC filings and has satisfactory collateral systems, as defined by its lender (i.e., internal controls and accounting systems with respect to accounts receivable, cash and accounts payable), at which time the Company must provide monthly reports. The Company must also provide monthly reports with respect to its utilization and bookings data through November 2006, including divisional profit and loss statements and operating data for the months of April through November 2006.

The negative covenants restrict certain of the Company s corporate activities, including, among other things, its ability to make acquisitions or investments, make capital expenditures, repay other indebtedness, merge or consolidate with other entities, dispose of assets, incur additional indebtedness, pay dividends, create liens, make investments (including limitations on loans to its foreign subsidiaries) settle litigation and engage in certain transactions with affiliates.

The events of default include, among others, defaults based on: certain bankruptcy and insolvency events; nonpayment; cross-defaults to other debt; payments in respect of judgments against the Company in excess of $18,000; breach of specified covenants; change of control; termination of trading of Company stock; material inaccuracy of representations and warranties; failure to timely deliver audited financial statements; inaccuracy of the borrowing base; the prohibition or restraint on the Company or any loan party from conducting its business in any manner that has or could reasonably be expected to result in a material adverse effect because of any ruling, decision or order of a court or governmental authority; an indictment, conviction or the commencement of criminal proceedings of or against the Company or any subsidiary pursuant to which (a) either damages or penalties could be in excess of $5,000 or (b) such indictment could reasonably be expected to result in a material adverse effect.

Upon an event of default under the 2005 Credit Facility, the lenders may require the Company to post cash collateral in an amount equal to 105% of the principal amount of the outstanding letters of credit. In addition, lenders may declare all borrowings outstanding under the 2005 Credit Facility, together with accrued interest and other fees, immediately due and payable. Any default under the 2005 Credit Facility or agreements governing the Company s other significant indebtedness could lead to an acceleration of debt under the 2005 Credit Facility or other debt instruments that contain cross-default provisions.

The Company s obligations under the 2005 Credit Facility are secured by liens and security interests in substantially all of its present and future tangible and intangible assets and those of certain of its domestic subsidiaries, as guarantors of such obligations (including 65.0% of the stock of its foreign subsidiaries), subject to certain exceptions.

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In addition, in connection with the Series B lawsuit described above, the lenders of the 2005 Credit Facility granted the Company waivers for any default under the 2005 Credit Facility resulting from the Series B debenture lawsuit and the defaults alleged therein, and also consented to the Company s payment of consent fees to the holders of each series of debentures as well as increases in the interest rates payable on all of the debentures.

Yen-Denominated Term Loans and Line of Credit

On January 31, 2003, the Company s Japanese subsidiary entered into a 2.0 billion yen-denominated unsecured term loan. Scheduled principal payments are every six months through July 31, 2005 in the amount of 334.0 million yen and include a final payment of 330.0 million yen on January 31, 2006, which has been paid.

On June 30, 2003, the Company s Japanese subsidiary entered into a 1.0 billion yen-denominated unsecured term loan. Scheduled principal payments are every six months through December 31, 2005 in the amount of 167.0 million yen and include a final payment of 165.0 million yen on June 30, 2006, which has been paid. Borrowings under the term loan accrue interest of the TIBOR plus 1.40%.

On August 30, 2004, the Company s Japanese subsidiary extended its yen-denominated revolving line of credit facility and overdraft line of credit facility dated December 16, 2002. The renewed agreement includes a yen-denominated revolving line of credit facility with an aggregate principal balance not to exceed 1.85 billion yen (approximately $18,026 as of December 31, 2004) and an overdraft line of credit facility with an aggregate principal balance not to exceed 0.5 billion yen (approximately $4,872 as of December 31, 2004). Borrowings under the revolving line of credit agreement accrue interest of TIBOR plus 0.70% and borrowings under the overdraft line of credit facility accrue interest of Short Term Prime Rate plus 0.125%. These facilities, which were scheduled to mature on August 31, 2005 (and were extended to, and paid in full on, December 16, 2005) are unsecured, do not contain financial covenants, and are not guaranteed by the Company.

Discontinued Credit Facilities

On May 29, 2002, the Company entered into a credit agreement with a commercial lender, for a revolving credit facility with a maximum aggregate principal balance of $250,000. The funds available under the credit arrangement were used for general corporate purposes, for working capital, and for acquisitions subject to certain restrictions. The credit agreement provided for the issuance of letters of credit, in the aggregate amount not to exceed $30,000, with a maximum maturity of twelve months from the date of issuance. Interest on borrowings under the credit agreement was determined, at the Company s option, based on the prime rate, the LIBOR rate plus a margin ranging from 0.875% to 1.625% or the Libo (as defined therein) plus a margin ranging from 0.875% to 1.625%. There were commitment fees ranging from 0.20% to 0.275% for the revolving credit. The interest rate margins and the commitment fees varied based on the Company s leverage ratio at quarter-end. The revolving credit facility expired on May 29, 2005.

On December 17, 2004, the Company entered into a $400,000 Interim Senior Secured Credit Agreement (the 2004 Interim Credit Facility), which provided for up to $400,000 in revolving credit, all of which was to be available for issuance of letters of credit (subject to restrictions), and included up to $20,000 in a swingline subfacility. The amount of available borrowings was limited due to the Company s failure to timely file its Annual Report on Form 10-K for the fiscal year ended December 31, 2004. Based on preliminary information available during the first quarter of 2005, management anticipated that the Company may not have met one or more of the covenants contained within the 2004 Interim Credit Facility. In order to avoid any potential events of default from occurring under the 2004 Interim Credit Facility, the Company obtained amendments on March 17, 2005 and on March 24, 2005, which provided relief from certain covenant compliance requirements. The 2004 Interim Credit Facility was terminated by the Company on April 26, 2005.

The 2004 Interim Credit Facility was replaced by the 2005 Credit Facility on July 19, 2005 (see above). Immediately prior to termination of the 2004 Interim Credit Facility, there were no outstanding loans under the 2004 Interim Credit Facility; however, there were outstanding letters of credit of approximately $87,700, which were issued primarily to meet the Company s obligations to collateralize certain surety bonds issued to support client engagements, mainly in its state and local government business. The $87,700 in letters of credit remained outstanding after the termination of the 2004 Interim Credit Facility. In order to support the letters of credit that remained outstanding, the Company provided the lenders under the 2004 Interim Credit Facility with the following collateral: (i) $94,300 of cash which was sourced from cash on hand; and (ii) a security interest in the Company s domestic accounts receivable. Upon entering the 2005 Credit Facility, the lenders under the 2004 Interim Credit Facility: (i) released all but $5,000 of the cash collateral (remaining $5,000, net of expenses, was returned to the Company on April 4, 2006); (ii) released its security interest in the domestic accounts receivable; and (iii) received an $85,400 letter of credit issued by the lenders under the 2005 Credit Facility.

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Early Extinguishment of Senior Notes

On November 26, 2002, the Company completed a private placement of $220,000 in aggregate principal of Senior Notes. The offering consisted of $29,000 of 5.95% Series A Notes due November 2005, $46,000 of 6.43% Series B Senior Notes due November 2006 and $145,000 of 6.71% Series C Senior Notes due November 2007. The Senior Notes restricted the Company s ability to incur additional indebtedness and required the Company to maintain certain levels of fixed charge coverage and net worth, while limiting its leverage ratio to certain levels. The proceeds from the sale of these Senior Notes were used to repay a $220,000 short-term revolving credit facility entered into for the purpose of funding a portion of the acquisition cost of BE Germany. In December 2004, the entire $220,000 of Senior Notes was prepaid, using proceeds from the Company s sale of its Subordinated Debentures (see above). Due to the prepayment, the Company recorded in 2004, a loss on the early extinguishment of debt of $22,617, which represented the make whole premium, unamortized debt issuance costs and fees.

Note 4. Earnings (Loss) Per Share

Basic earnings (loss) per share is computed based on the weighted average number of common shares outstanding during the period. Diluted earnings (loss) per share is computed using the weighted average number of common shares outstanding during the period plus the dilutive effect of potential future issues of common stock relating to the Company s stock option program, restricted stock units, convertible debt and other potentially dilutive securities. In calculating diluted earnings (loss) per share, the dilutive effect of stock options is computed using the average market price for the period in accordance with the treasury stock method. The effect of convertible securities on the calculation of diluted net loss per share is calculated using the if converted method. The convertible debt was excluded from the calculation of the diluted earnings per share for all periods due to its anti-dilutive effect. During the three months ended June 30, 2005 and 2004, 119,394,228 and 59,567,675 shares, respectively, were not included in the computation of diluted EPS because to do so would have been anti-dilutive. During the six months ended June 30, 2005 and 2004, 106,508,079 and 59,008,841 shares, respectively, were not included in the computation of diluted EPS because to do so would have been anti-dilutive.

The following table sets forth the computation of basic and diluted earnings (loss) per share:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Net loss	$ (4,886)	$ (22,418)	$ (237,444)	$ (39,428)
Weighted average shares outstanding basic and diluted	201,235,807	196,016,196	200,799,624	195,633,359
Loss per share basic and diluted	$ (0.02)	$ (0.11)	$ (1.18)	$ (0.20)

Note 5. Comprehensive Loss

The components of comprehensive loss are as follows:

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Net loss	$ (4,886)	$ (22,418)	$ (237,444)	$ (39,428)
Foreign currency translation adjustment, net of tax (a)	(26,392)	(13,976)	(47,073)	(30,883)
Minimum pension liability adjustment				(63)
Unrealized loss of derivative instruments, net of tax		(39)		(78)
Comprehensive loss	$ (31,278)	$ (36,433)	$ (284,517)	$ (70,452)

(a) Movement in the foreign currency translation adjustment is primarily due to exchange-rate fluctuations of the Euro and Japanese Yen against the U.S. dollar.

Note 6. Segment Reporting

The Company s segment information has been prepared in accordance with SFAS No. 131, Disclosures about Segments of an Enterprise and Related Information. Operating segments are defined as components of an enterprise engaging in business activities about which separate financial information is available that is evaluated regularly by the Company s chief operating decision-maker, the Chief Executive Officer, in deciding how to allocate resources and assess performance. The Company s reportable segments consist of its three North America industry groups (Public Services, Financial Services and Commercial Services), its three international regions (EMEA, Asia Pacific and Latin America) and the Corporate/Other category (which consists primarily of infrastructure costs). Accounting policies of the segments are the same as those described in Note 2, Summary of Significant Accounting Policies, of the Company s 2005 Form 10-K. Upon consolidation, all intercompany accounts and transactions are eliminated. Inter-segment revenue is not included in the measure of profit or loss. Performance of the segments is evaluated on operating income excluding the costs of infrastructure functions (such as facilities, information systems, finance and accounting, human resources, legal and marketing). Beginning in fiscal 2005, the Company combined its Communications, Content and Utilities and Consumer, Industrial and Technology industry groups to form the Commercial Services industry group.

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	Three Months Ended June 30,			
	2005		2004	
	Revenue	Operating Income (Loss)	Revenue	Operating Income (Loss)
Public Services	$ 346,337	$ 70,327	$ 356,403	$ 87,623
Commercial Services	177,177	23,878	171,310	26,097
Financial Services	87,818	21,459	75,172	19,272
EMEA	181,031	26,596	163,047	26,542
Asia Pacific	80,264	12,693	84,765	7,398
Latin America	22,145	3,273	20,701	4,019
Corporate/Other (1)	473	(145,849)	3,989	(154,347)
Total	$ 895,245	$ 12,377	$ 875,387	$ 16,604

	Six Months Ended June 30,			
	2005		2004	
	Revenue	Operating Income (Loss)	Revenue	Operating Income (Loss)
Public Services	$ 678,438	$ 139,095	$ 735,290	$ 173,723
Commercial Services	349,964	(64,619)	349,077	48,825
Financial Services	178,517	41,779	142,604	29,130
EMEA	352,571	47,291	316,981	37,942
Asia Pacific	163,975	24,923	172,320	17,281
Latin America	42,178	7,085	41,516	6,610
Corporate/Other (1)	935	(322,234)	6,202	(305,785)
Total	$ 1,766,578	$ (126,680)	$ 1,763,990	$ 7,726

(1) Corporate/Other operating loss is principally due to infrastructure and shared services costs, such as facilities, information systems, finance

and accounting,
human
resources, legal,
and marketing.

Note 7. Transactions with KPMG LLP

During 2004, KPMG LLP, the Company s former parent, reduced its holdings in Company common stock to less than 5%, and in February 2005, the transaction services agreement (described below) between the Company and KPMG LLP expired. For these reasons, along with certain other factors, KPMG LLP is no longer considered a related party to the Company. There were various arrangements that remained in place during 2005 between the Company and KPMG LLP for infrastructure services (discussed below) and indemnification agreements (see Note 10, Commitments and Contingencies).

Infrastructure Services. Effective January 31, 2000, the Company and KPMG LLP entered into an outsourcing agreement whereby the Company received and was charged for services performed by KPMG LLP, which was amended and restated effective July 1, 2000 to eliminate the services related costs that were not required. On February 13, 2001, the Company and KPMG LLP entered into a transition services agreement whereby the Company received and was charged for infrastructure services on substantially the same basis as the amended and restated outsourcing agreement. The allocation of costs to the Company for such services was based on actual costs incurred by KPMG LLP and were allocated among KPMG LLP s assurance and tax businesses and the Company primarily on the basis of full-time equivalent personnel and actual

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usage (specific identification). With regard to facilities costs, the Company and KPMG LLP have entered into arrangements pursuant to which the Company subleases from KPMG LLP office space that was formally allocated to the Company under the outsourcing agreement. The terms of the arrangements are substantially equivalent to those under the original outsourcing agreement, and will extend over the remaining period covered by the lease agreement between KPMG LLP and the lessor.

Effective October 1, 2002, the Company and KPMG LLP entered into an outsourcing services agreement under which KPMG LLP provides the Company certain services relating to office space. These services covered by the outsourcing services agreement had previously been provided under the transition services agreement. The services will be provided for three years at a cost that is less than the cost for comparable services under the transition services agreement.

The transition services agreement and outsourcing services agreement expired on February 13, 2005 and October 1, 2005, respectively. The Company continues to sublease office space from KPMG LLP after the expiration of the transition services agreement under operating lease agreements.

Total expenses allocated to the Company under the transition services agreement and outsourcing services agreement with regard to occupancy costs and other infrastructure services were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Occupancy costs	$ 5	$ 5,919	$ 2,749	$ 12,086
Other infrastructure service costs	116	13,446	3,809	27,357
Total	$ 121	$ 19,365	$ 6,558	$ 39,443
Amounts included in:				
Other costs of service	$ 5	$ 5,919	$ 2,749	$ 12,086
Selling, general and administrative expenses	116	13,446	3,809	27,357
Total	$ 121	$ 19,365	$ 6,558	$ 39,443

Note 8. Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill, at the reporting unit level, for the six months ended June 30, 2005 were as follows:

	Balance December 31, 2004	Additions	Other (a)	Balance June 30, 2005
Public Services	$ 23,581	$	$	$ 23,581
Commercial Services	64,188			64,188
Financial Services	9,210			9,210
EMEA	485,401		(49,607)	435,794

Asia Pacific		73,459			(2,450)	71,009
Latin America		836			45	881
Corporate/Other		202				202
Total	$	656,877	$	$	(52,012)	$ 604,865

(a) Other changes in goodwill consist of foreign currency translation adjustments.

On April 20, 2005, the Company determined that a triggering event had occurred, causing the Company to perform a goodwill impairment test on all reporting units. The triggering event resulted from the Company s public announcement of likely restatements of prior period financial statements along with significant delays in filing 2004 annual results and

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anticipated delays in filing 2005 quarterly results. The Company determined this triggering event may have a significant adverse effect on its business climate and regulatory environment. As required by SFAS No. 142, Goodwill and Other Intangible Assets (SFAS 142), the Company applied a two-step impairment test to identify the potential impairment and, if necessary, to measure the amount of the impairment. The Company performed step one of the impairment test to identify the potential impairment and determined there was no impairments to any reporting units. As a result, the step two impairment test was not considered necessary.

In the fourth quarter of 2005, the Company determined that a triggering event had occurred, causing the Company to perform a goodwill impairment test on all of its reporting units. The triggering event resulted from a combination of various factors, including lower than previously expected results in the fourth quarter ended December 31, 2005 and the change in management s expectation of future results. As required by SFAS 142, the Company performed a two-step impairment test to identify the potential impairments and, if necessary, to measure the amount of the impairment. Under step one of the impairment test, the Company determined there were potential impairments in its Commercial Services and EMEA reporting units. In determining the fair value of its Commercial Services and EMEA reporting units, the Company revised certain assumptions relative to each reporting unit, which significantly decreased their fair value as compared to the fair value determined during the Company s most recent goodwill impairment test, which was performed as of April 20, 2005. For the Commercial Services reporting unit, these revisions included the negative impact on future periods from operating losses associated with the Hawaiian Telcom Communications, Inc. contract. For the EMEA reporting unit, these revisions included lowering operating margin growth expectations. In order to quantify the impairment, under step two of the impairment test, the Company completed a hypothetical purchase price allocation of the fair value determined in step one to all of the respective assets and liabilities of its Commercial Services and EMEA reporting units. As a result, during the fourth quarter of 2005, goodwill impairment losses of $64,188 and $102,227 were recognized in the Commercial Services and the EMEA reporting units, respectively, as the carrying amount of each reporting unit was greater than the revised fair value of that reporting unit (as determined using the expected present value of future cash flows), and the carrying amount of each reporting unit s goodwill exceeded the implied fair value of that goodwill. The goodwill impairment loss of $64,188 for the Commercial Services reporting unit represented a full impairment of the remaining goodwill in that reporting unit.

Identifiable intangible assets include finite-lived intangible assets, which primarily consist of market rights, order backlog, customer contracts and related customer relationships. Identifiable intangible assets are amortized using the straight-line method over their expected period of benefit, which generally ranges from one to five years. Identifiable intangible assets consist of the following:

	June 30, 2005	December 31, 2004
Other intangible assets:		
Backlog, customer contracts and related customer relationships	$ 1,307	$ 1,306
Market rights	10,297	10,297
Total other intangibles	11,604	11,603
Accumulated amortization:		
Backlog, customer contracts and related customer relationships	(1,203)	(1,100)
Market rights	(7,723)	(6,693)
Total accumulated amortization	(8,926)	(7,793)

Other intangible assets, net	$ 2,678	$ 3,810

Amortization expense related to identifiable intangible assets was $566 and $1,003 for the three months ended June 30, 2005 and 2004, respectively. Amortization expense related to identifiable intangible assets was $1,132 and $2,098 for the six months ended June 30, 2005 and 2004, respectively.

Note 9. Restructuring Activities

In connection with the Company s previously announced office space reduction effort, the Company recorded $0 and $19,605 in restructuring charges during the three and six months ended June 30, 2005, respectively, related to lease, facility and other exit activities. The $19,605 charge, recorded within the Corporate/Other operating segment for the six months ended June 30, 2005, included $15,309 related to the fair value of future lease obligations (net of estimated sublease income) and $4,296 in other costs associated with exiting facilities. Since July 2003, the Company has incurred a total of $92,740 in

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lease and facilities related restructuring charges in connection with its office space reduction effort relating to the following regions: $11,431 in EMEA, $697 in Asia Pacific and $80,612 in North America. As of June 30, 2005, the Company has a remaining lease and facilities accrual of $50,270, of which $14,727 and $35,543 have been identified as current and non-current portions, respectively. The remaining lease and facilities accrual will be paid over the remaining lease terms.

As of June 30, 2005, the Company s remaining severance accrual represents unpaid severance and termination benefits related to reduction in workforce charges recorded during the six months ended December 31, 2003. The remaining severance accrual is expected to be paid by the end of 2006.

Changes in the Company s accrual for restructuring charges for the six months ended June 30, 2005 were as follows:

	Severance	Lease and Facilities	Total
Balance at December 31, 2004	$ 532	$ 50,342	$ 50,874
Current period charges		19,605	19,605
Payments		(19,328)	(19,328)
Other (a)	(197)	(349)	(546)
Balance at June 30, 2005	$ 335	$ 50,270	$ 50,605

(a) Other changes in the restructuring accrual consist primarily of foreign currency translation and other adjustments.

The Company expects to record additional lease and facilities related restructuring charges ranging from $18,000 to $22,000 during the year ended December 31, 2006.

Note 10. Commitments and Contingencies

The Company currently is a party to a number of disputes which involve or may involve litigation or other legal or regulatory proceedings. Generally, there are three types of legal proceedings to which the Company has been made a party:

Claims and investigations arising from its continuing inability to timely file periodic reports under the Securities Exchange Act of 1934, as amended (the Exchange Act), and the restatement of its financial statements for certain prior periods to correct accounting errors and departures from generally accepted accounting principles for those years (SEC Reporting Matters);

Claims and investigations being conducted by agencies or officers of the U.S. Federal Government and arising in connection with its provision of services under contracts with agencies of the U.S. Federal Government (Government Contracting Matters); and

Claims made in the ordinary course of business by clients seeking damages for alleged breaches of contract or failure of performance and by current or former employees seeking damages for alleged acts of wrongful termination or discrimination (Other Matters).

The 2005 Credit Facility contains limits on the amounts of civil litigation payments that the Company is permitted to pay, as follows: up to $75,000 during the 24-month period ending July 18, 2007, and up to $15,000 during any twelve consecutive months thereafter, in each case, net of any insurance proceeds. Failure to abide by these limits could result in a default under the credit facility for which, after opportunity to cure the default, outstanding indebtedness under the 2005 Credit Facility could be accelerated.

The Company currently maintains insurance in types and amounts customary in its industry, including coverage for professional liability, general liability and management and director liability. The Company expenses legal fees as incurred. Based on its current assessment, management believes that the Company s financial statements include adequate provision for estimated losses that are likely to be incurred with regard to such matters.

SEC Reporting Matters

2003 Class Action Suits

As disclosed in the Company s prior reports, various separate complaints purporting to be class actions were filed in the U.S. District Court for the Eastern District of Virginia alleging that the Company and certain of its officers violated

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Section 10(b) of the Exchange Act, Rule 10b-5 promulgated thereunder, and Section 20(a) of the Exchange Act. The complaints contain varying allegations, including that the Company made materially misleading statements with respect to its financial results for the first three quarters of fiscal 2003 in its SEC filings and press releases. The Plaintiffs Amended Consolidated Complaint was filed on December 31, 2003. Defendants Motion to Dismiss was filed on February 10, 2004. On March 31, 2004, the parties filed a stipulation requesting that the court approve a settlement of this matter for $1,700, all of which is to be paid by the Company s insurer. On April 2, 2004, the court considered and gave preliminary approval to the proposed settlement. Notice of the proposed settlement was sent to the purported class of shareholders, and the court gave final approval to the proposed settlement on July 16, 2004.

2005 Class Action Suits

In and after April 2005, various separate complaints were filed in the U.S. District Court for the Eastern District of Virginia alleging that the Company and certain of its current and former officers and directors violated Section 10(b) of the Exchange Act, Rule 10b-5 promulgated thereunder and Section 20(a) of the Exchange Act by, among other things, making materially misleading statements between August 14, 2003 and April 20, 2005 with respect to the Company s financial results in its SEC filings and press releases. On January 17, 2006, the court certified a class, appointed class counsel and appointed a class representative. The plaintiffs filed an amended complaint on March 10, 2006 and the defendants, including the Company, subsequently filed a motion to dismiss that complaint, which was fully briefed and heard on May 5, 2006. It is not possible to predict with certainty whether or not the Company will ultimately be successful in this matter or, if not, what the impact might be. Accordingly, no liability has been recorded.

2005 Shareholders Derivative Demand

On May 21, 2005, the Company received a letter from counsel representing one of its shareholders requesting that the Company initiate a lawsuit against its Board of Directors and certain present and former officers of the Company, alleging breaches of the officers and directors duties of care and loyalty to the Company relating to the events disclosed in its report filed on Form 8-K, dated April 20, 2005. On January 21, 2006, the shareholder filed a derivative complaint in the Circuit Court of Fairfax County, Virginia, that was not served on the Company until March 2006. The shareholder s complaint alleged that his demand was not acted upon and alleged the breach of fiduciary duty claims previously stated in his demand. The complaint also included a non-derivative claim seeking the scheduling of an annual meeting in 2006. On May 18, 2006, following an extensive audit committee investigation and recommendation, the Company s Board of Directors responded to the shareholder s demand by declining at that time to file a suit alleging the claims asserted in the shareholder s demand. The shareholder did not amend the complaint to reflect the refusal of his demand. The Company filed demurrers and pleas in bar on August 11, 2006, which effectively sought to dismiss the matter related to the fiduciary duty claims. On November 3, 2006, the court granted the demurrers and dismissed the fiduciary claims based on the Board's refusal of the demand, with leave to file amended derivative claims. On January 3, 2007, the plaintiff filed an amended derivative complaint re-asserting the previously dismissed derivative claims and alleging that the Board s refusal of his demand was not in good faith. The amended derivative complaint does not re-assert the non-derivative claim seeking the scheduling of an annual meeting and states that that claim is now moot because the Company held its annual meeting in December 2006. It is not possible to predict the outcome of this matter, or what the impact might be. The Company believes, however, that claims for which money damages could be assessed are derivative claims asserted on the Company s behalf and for which the Company s liability would be limited to attorneys fees.

Series B Debenture Suit

On September 8, 2005, certain holders of the Series B Debentures provided a purported Notice of Default to the Company based upon its failure to timely file its Annual Report on Form 10-K for the year ended December 31, 2004 and Quarterly Reports on Form 10-Q for the periods ended March 31, 2005 and June 30, 2005. On or about November 17, 2005, the Company received a notice from these holders of the Series B Debentures, asserting that an event of default had occurred and was continuing under the indenture for the Series B Debentures and, as a result, the principal amount of the Series B Debentures, accrued and unpaid interest and unpaid damages were due and payable immediately.

Based on the foregoing, the indenture trustee for the Series B Debentures brought suit against the Company and, on September 19, 2006, the Supreme Court of New York ruled that the Company was in default under the indenture for the Series B Debentures and ordered that the amount of damages to be determined subsequently at trial. The Company believed the ruling to be in error and on September 25, 2006, appealed the court s ruling and moved for summary judgment on the matter of determination of damages.

After further negotiations, on November 7, 2006, the Company and the relevant holders of its Series B Debentures filed a stipulation to discontinue the lawsuit. Concurrent with the agreement to discontinue the lawsuit, the Company entered into a First Supplemental Indenture (the First Supplemental Indenture) with The Bank of New York, as trustee, which amends the subordinated indenture governing the Series A Debentures and the Series B Debentures. The First Supplemental Indenture includes a waiver of the Company s

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SEC reporting requirements under the subordinated indenture through October 31, 2008. Pursuant to the terms of the First Supplemental Indenture, effective as of November 7, 2006: (i) the interest rate payable on the Series A Debentures will increase from 3.00% per annum to 3.10% per annum (inclusive of any liquidated damages relating to the failure to file a registration statement for the Series A Debentures that may be payable) until December 23, 2011, and (ii) the interest rate payable on the Series B Debentures will increase from 3.25% per annum to 4.10% per annum (inclusive of any liquidated damages relating to the failure to file a registration statement for the Series B Debentures that may be payable) until December 23, 2014. The increased interest rates apply to all Series A Debentures and Series B Debentures outstanding.

In connection with the resolution of this matter and so as to cure any lingering claims of default or cross-default, on November 2, 2006, the Company entered into a First Supplemental Indenture with The Bank of New York, as trustee, which amends the indenture governing its April 2005 Senior Debentures. The supplemental indenture includes a waiver of its SEC reporting requirements through October 31, 2007 and provides for further extension through October 31, 2008 upon payment of an additional fee of 0.25% of the principal amount of the debentures. The Company paid to each consenting holder of these debentures a consent fee equal to 1.00% of the outstanding principal amount of the debentures. In addition, on November 9, 2006, the Company entered into an agreement with the holders of July 2005 Senior Debentures, pursuant to which the Company paid a consent fee equal to 1.00% of the outstanding principal amount of the debentures, in accordance with the terms of the purchase agreement governing the issuance of these debentures.

SEC Investigation

On April 13, 2005, pursuant to the same matter number as their inquiry concerning the Company s restatement of certain financial statements issued in 2003, the staff of the SEC s Division of Enforcement requested information and documents relating to the Company s March 18, 2005 Form 8-K. On September 7, 2005, the Company announced that the staff had issued a formal order of investigation in this matter. The Company subsequently received subpoenas from the staff seeking production of documents and information including certain information and documents related to an investigation conducted by the Audit Committee of the Company s Board of Directors.

In connection with the investigation by the Audit Committee, the Company became aware of incidents of possible non-compliance with the Foreign Corrupt Practices Act and its internal controls in connection with certain of its operations in China and voluntarily reported these matters to the SEC and U.S. Department of Justice in November 2005. Both the SEC and the Department of Justice have indicated they will investigate these matters in connection with the formal investigation described above. On March 27, 2006, the Company received a subpoena from the SEC regarding information related to these matters. The investigation is ongoing and the SEC is in the process of taking the testimony of current and former employees and a director. The Company has a reasonable possibility of loss in this matter, although no estimate of such loss can be determined at this time. Accordingly, no liability has been recorded.

Government Contracting Matters

Government Contracts

A significant portion of the Company s business relates to providing services under contracts with the U.S. Federal government or state and local governments. These contracts are subject to extensive legal and regulatory requirements and, from time to time, agencies of the U.S. Federal government or state and local governments investigate whether the Company s operations are being conducted in accordance with these requirements and the terms of the relevant contracts. In the ordinary course of business, various government investigations are ongoing. U.S. Federal government investigations of the Company, whether relating to these contracts or conducted for other reasons, could result in administrative, civil or criminal liabilities, including repayments, fines or penalties being imposed upon the Company, or could lead to suspension or debarment from future U.S. Federal government contracting. The Company believes that it has adequately reserved for any losses it may experience from these investigations. Whether such amounts could have a material effect on the results of operations in a particular quarter or fiscal year cannot be determined at this time.

Grand Jury Subpoena California

In December 2004, the Company was served with a subpoena by the Grand Jury for the U.S. District Court for the Central District of California. The subpoena sought records relating to twelve contracts between the Company and the U.S. Federal government, including two General Service Administration (GSA) schedules, as well as other documents and records relating to its U.S. Federal Government work. The Company has begun to produce documents in accordance with an agreement with the Assistant U.S. Attorney. The focus of the review is upon the Company s billing and time/expense practices, as well as alliance agreements where referral or commission payments were permitted. On July 20, 2005, the

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Company was served with a subpoena issued by the U.S. Army, requesting items related to Department of Defense contracts. The Company has subsequently been served with subpoenas issued by the Inspector General of the GSA. Given the broad scope of the subpoena and the limited information the Company has received from the U.S. Attorney s office regarding the status of its investigation, it is impossible to predict with any degree of accuracy how this matter will develop and how it will be resolved. The Company does not believe that it is either probable that the subpoena will result in a liability to the Company or that the amount or range of a future liability, if any, can be determined. Accordingly, no liability has been recorded.

Travel Rebate Investigation

In December 2005, the Company executed a settlement agreement with the Civil Division of the U.S. Department of Justice to settle allegations of potential understatement of travel credits to government contracts. Pursuant to the settlement agreement, in December 2005, the Company paid $15,500 in the aggregate, including related fees. The settlement payment is included as part of selling, general and administrative expenses in the Consolidated Statement of Operations for the year ended December 31, 2004.

Department of Interior

On September 29, 2005, the Company received a Termination for Cause notice (the Notice) directing it to cease work on a task order (Task Order 3) being completed for the Department of Interior (DOI). The Company complied and has properly reserved any outstanding amounts owed to it by the DOI as of December 31, 2004. The underlying Basic Purchase Agreement was subsequently terminated for cause as well, though the only task order that was potentially affected was Task Order 3. In the Notice, the DOI also stated that it may seek to recover excess reprocurement costs or pursue other legal remedies, but it has taken no action in this regard. The Company believes that it has a strong defense of excusable delay, and believes that where there is a meritorious case of excusable delay, terminations for cause have been overturned. The Company also believes that if the termination for cause is removed, any potential reprocurement cost liability is also removed. On July 28, 2006, the Company submitted a claim in the amount of approximately $20,000 to the Government for amounts it believes are owed to it by the DOI. The Company s efforts with the DOI to reach a negotiated settlement of this matter stalled, and the Company has filed a complaint with the Court of Federal Claims to overturn the termination for cause on September 26, 2006. Under the rules, the Company needs a decision from the contracting officer before it can appeal its claim to the court. The DOI informed the Company that the decision will be rendered on or before mid-January 2007. Accordingly, at this time a claim against the Company for additional amounts could be made by the DOI as part of a defensive strategy, but none has been made. If a claim by the Government is filed, the Company believes there is a reasonable possibility of loss in this matter. Due to the early stage of this matter and the nature of the potential claims, a range of any potential loss cannot be determined at this time. As such, no liability has been recorded.

USAID Contract

On October 25, 2005, the Company received a letter from USAID in which the Contracting Officer stated that she had determined to disallow approximately $10,746 in subcontractor costs for Kroll, the Company s security subcontractor in Iraq. The Company also received a final decision from the Contracting Officer, dated January 7, 2006, disallowing the Kroll costs. However, on July 10, 2006, based on review and analysis of additional documentation, the Contracting Officer issued a revised final decision that allowed $10,320 of the costs, while disallowing the remainder, which the Company substantially recovered from Kroll.

Core Financial Logistics System

There is an ongoing investigation of the Core Financial Logistics System (CoreFLS) project by the Inspector General s Office of the Department of Veterans Affairs and by the Assistant U.S. Attorney for the Central District of Florida. To date, the Company has been issued two subpoenas, in June 2004 and December 2004, seeking the production of documents relating to the CoreFLS project. The Company is cooperating with the investigation and has produced documents in response to the subpoenas. To date, there have been no specific allegations of criminal or fraudulent conduct on the part of the Company. Similarly, there have been no contractual claims filed against the Company by the Veterans Administration in connection with the CoreFLS project. Management believes that the Company has complied with all of its obligations under the CoreFLS contract. It is not possible to predict with certainty whether or not the Company will ultimately be successful in this matter or, if not, what the impact might be. As such, no liability has been recorded.

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General Services Administration Audit

The Office of the Inspector General of the GSA of the United States Government conducted an audit of the Company s GSA Management, Organizational, and Business Improvement Services (MOBIS) contract for the period beginning January 1, 2001 through December 31, 2002. The findings from this audit report allege non-compliance, which may have resulted in overcharges to Government customers. Specifically, the report alleges that the Company failed to report and pass on to GSA customers, the reduction it made to its commercial labor rate (Standard Bill Rate) for Administrative Support effective July 1, 2000. The Inspector General estimated a potential refund amounting to $2,400 for the period under audit and additional amounts of $2,300 related to the remainder of the contract extension period (through 2007).

The Company believes that it has not overcharged the Government and is working to resolve the outstanding issues with the contracting officer. Given the current stage of discussions, the outcome cannot yet be determined and management estimates the probable amount of loss is $1,200 (accrued as a liability as of June 30, 2005). In addition, the Company is discussing revisions to the contract with the contracting officer to better align its terms, including pricing, to the expectations of both parties.

Other Matters

Peregrine Litigation

The Company was named as a defendant in several civil lawsuits regarding certain software resale transactions with Peregrine Systems, Inc. during the period 1999 through 2001, in which purchasers and other individuals who acquired Peregrine stock alleged that the Company participated in or aided and abetted a fraudulent scheme by Peregrine to inflate Peregrine s stock price, and the Company was also sued by a trustee succeeding the interests of Peregrine for the same conduct. Specifically, the Company was named as a defendant in the following actions: *Ariko v. Moores* (Superior Court, County of San Diego), *Allocco v. Gardner* (Superior Court, County of San Diego), *Bains v. Moores* (Superior Court, County of San Diego), *Peregrine Litigation Trust v. KPMG LLP* (Superior Court, County of San Diego), and *In re Peregrine Systems, Inc. Securities Litigation* (U.S. District Court for the Southern District of California). The Company s former parent, KPMG LLP, also sought indemnity from the Company for certain liability it may face in the same litigations, and the Company agreed to indemnify them in certain of these matters.

As a result of tentative agreements reached in December 2005, the Company executed conditional settlement agreements whereby the Company is to be released from liability in the *Allocco, Ariko, Bains* and *Peregrine Litigation Trust* matters and in all claims for indemnity by KPMG LLP in each of these cases. On January 5, 2006, the Company finalized an agreement with KPMG LLP, providing conditional mutual releases to each other from such fee advancement and indemnification claims, with no settlement payment or other exchange of monies between the parties. On January 6, 2006, the Company filed applications for good faith settlement determinations in *Allocco, Ariko, Bains* and *the Peregrine Litigation Trust* matters with respect to the conditional settlements mentioned above. The applications were granted. On April 6, 2006, the Company s former co-defendants filed motions, seeking to appeal the *Allocco* and *Peregrine Litigation Trust* rulings. On June 19, 2006, the court denied the motions. The Company s former co-defendants then appealed to the California Supreme Court. On August 16, 2006, those appeals were denied. Payments of approximately $36,900 in principal and interest were made in September 2006. The expense relating to these settlement payments was included as part of costs of service in the Consolidated Statement of Operations for the year ended December 31, 2004.

The Company did not settle the *In re Peregrine Systems, Inc. Securities Litigation*. On January 19, 2005, the *In re Peregrine Systems, Inc. Securities Litigation* matter was dismissed by the trial court as it relates to the Company. The plaintiffs have appealed the dismissal of their lawsuit against the Company and briefing of the appeal is underway. The Company believes there is a reasonable possibility of loss on the appeal based on recent Ninth Circuit precedent. Due to the nature of that matter, a range of loss cannot be determined at this time. In addition, to the extent any judgment is entered in favor of the plaintiffs against KPMG LLP, KPMG LLP has notified the Company that it will seek indemnification for these sums.

On November 16, 2004, Larry Rodda, a former employee, pled guilty to one count of criminal conspiracy in connection with the Peregrine software resale transactions that continue to be the subject of the government inquiries. Mr. Rodda also was named in a civil suit brought by the SEC. The Company was not named in the indictment or civil suit, and is cooperating with the government investigations.

BearingPoint, Inc.
Notes to Consolidated Condensed Financial Statements (Continued)
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Hawaiian Telcom Communications, Inc.

The Company has a significant contract (the HT Contract) with Hawaiian Telcom Communications, Inc., a telecommunications industry client, under which the Company was engaged to design, build and operate various information technology systems for the client. The Company incurred losses of $113,257 under this contract in the first quarter of 2005. The HT Contract has experienced delays in its build and deployment phases, and contractual milestones have been missed. The client has alleged that the Company is responsible under the HT Contract to compensate it for certain costs and other damages incurred as a result of these delays and other alleged failures. The Company believes the client s nonperformance of its responsibilities under the HT Contract caused delays in the project and impacted its ability to perform, thereby causing the Company to incur significant damages. The Company also believes the terms of the HT Contract limit the client s ability to recover certain of their claimed damages. The Company is negotiating with the client to resolve these issues, apportion financial responsibility for these costs and alleged damages, and transition remaining work under the HT Contract to others, as requested by the client. During these negotiations, the Company is maintaining all of its options, including disputing the client s claims and asserting the Company s own claims in litigation. At this time, the Company cannot predict the likelihood that it will be able to resolve this dispute or the outcome of any litigation that might ensue if it is unable to resolve the dispute. While the Company believes it is probable that it may incur a loss with respect to this matter, at this time the Company is unable to reasonably estimate a range of amounts for the loss. Accordingly, no liability has been recorded.

Telecommunication Company

A telecommunication industry client has conducted an audit of certain of the Company s time and expense charges, alleging that the Company inappropriately billed the client for days claimed to be non-work days , such as days before and after travel days, travel days, overtime, and other alleged errors. A preliminary audit by the Company of the time and expense records for the project did not reveal the improprieties as alleged. While the client has threatened litigation, the Company continues to cooperate with the client in validating the prior charges and expenses for services rendered. The Company has no basis on which to believe the client s claims are well founded. While a loss is possible, it is not possible at this time to estimate a potential loss or range of loss. Accordingly, no liability has been recorded.

Michael Donahue

In March 2005, Mr. Donahue filed suit against the Company in connection with the termination of his employment in February 2005. Mr. Donahue alleges he is owed $3,000 under the terms and conditions of a Special Termination Agreement he executed in November 2001, between $1,700 and $2,400 as compensation for the value of stock options he was required to forfeit as the result of his discharge, and an additional $200 for an unpaid bonus. Mr. Donahue has also argued that a 25% penalty pursuant to Pennsylvania law should be added to each of these sums. In May 2005, the Company removed the matter to Federal court. On October 5, 2005, Donahue filed his Complaint in the case in Federal court, under seal. In this Complaint, in response to the Company s motion to compel arbitration, Donahue dropped his claims for his stock options and performance bonus, although he is free to bring those claims again at a later time. On January 31, 2006, Mr. Donahue filed his Demand for Arbitration, asserting all the claims he originally asserted, including his claims under the Special Termination Agreement, his claims for his stock options, and his claim for his annual bonus payment for 2004, in addition to the statutory penalties sought for these unpaid amounts. The parties are currently selecting arbitrators for the panel. It is reasonably possible that the Company will incur a loss ranging from $0 to $7,000, with no amount within this range a better estimate than any other amount. Accordingly, no liability has been recorded.

Canon Australia

On June 16, 2006, employees of the Australian subsidiary of Canon presented objections to the Company s Australian Country Director of deficiencies in the Company s work and alleged misrepresentations by the Company in connection with an implementation of an enterprise resource planning and customer relationship management system, which went live in January of 2005. Canon representatives presented arguments supporting their belief that Canon has suffered damages, including damages for lost profits and other consequential damages, as a result of the implementation. Canon has indicated that it desired to seek mediation. This matter is in its very preliminary stages. The contract limits the damages that may be claimed against the Company to no more than approximately $19,000. It is reasonably possible the Company will incur a loss. Due to the early stage of this matter and the nature of the potential claims, a range of loss cannot be determined at this time. Accordingly, no liability has been recorded.

BearingPoint, Inc.
Notes to Consolidated Condensed Financial Statements (Continued)
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Transition Services Provided By KPMG LLP

As described in Note 7, Transactions with KPMG LLP, the Company entered into a transition services agreement, and various other arrangements, with KPMG LLP during February 2001. Prior to the expiration date of the transition services agreement (February 13, 2004 for most non-technology services and February 13, 2005 for most technology-related services), the Company terminated certain services provided by KPMG LLP under the agreement and, in accordance with the agreement, was liable to KPMG LLP for termination costs.

KPMG LLP contends that the Company owes approximately $26,214 in termination costs and unrecovered capital for the termination of information technology services provided under the agreement. However, in accordance with the terms of the agreement, the Company does not believe that it is liable for termination costs arising upon the expiration of the agreement. The Company and KPMG LLP have begun proceeding under the dispute resolution mechanisms specified in the transition services agreement and are separately attempting to reach agreement as to the amount, if any, of additional costs payable by the Company to KPMG LLP in connection with the expiration of the agreement. Accordingly, the amount of additional termination costs, if any, that the Company will pay to KPMG LLP cannot be reasonably estimated at this time, and no liability has been recorded.

In connection with the expiration of the transition services agreement, the Company also agreed to settle a separate arrangement under which it pays KPMG LLP for the use of occupancy-related assets in the office facilities subleased by the Company from KPMG LLP. As such, during July 2005, the Company paid KPMG LLP $17,356 for its share of the cost of the occupancy-related assets that it believes relates to office locations that it subleased from KPMG LLP. However, KPMG LLP contends the Company owes an additional $5,347. The Company and KPMG LLP have begun proceeding under the dispute resolution mechanisms referred to in the preceding paragraph and are separately attempting to reach agreement as to the amount, if any, of additional costs payable by the Company to KPMG LLP. Approximately $9,660 of the total $17,356 paid to KPMG LLP related to office locations that were previously abandoned in connection with the Company s office space reduction effort. Accordingly, the Company has reserved for this amount as part of its lease and facilities restructuring charges recorded during the three and six months ended June 30, 2005 and 2004. The Company classified the remaining $7,696 paid to KPMG LLP as a prepaid service cost, which the Company plans to amortize over the remaining term of its respective sublease agreements with KPMG LLP. As of June 30, 2005, the remaining amount to be expensed was $7,076.

Other Commitments

In the normal course of business, the Company has indemnified third parties and has commitments and guarantees under which it may be required to make payments in certain circumstances. The Company accounts for these indemnities, commitments and guarantees in accordance with FASB Interpretation (FIN) No. 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others. These indemnities, commitments and guarantees include: indemnities of KPMG LLP with respect to the consulting business that was transferred to the Company in January 2000; indemnities to third parties in connection with surety bonds; indemnities to various lessors in connection with facility leases; indemnities to customers related to intellectual property and performance of services subcontracted to other providers; and indemnities to directors and officers under the organizational documents and agreements of the Company. The duration of these indemnities, commitments and guarantees varies, and in certain cases, is indefinite. Certain of these indemnities, commitments and guarantees do not provide for any limitation of the maximum potential future payments the Company could be obligated to make. The Company estimates that the fair value of these agreements was minimal. Accordingly, no liabilities have been recorded for these agreements as of June 30, 2005.

Some clients, largely in the state and local market, require the Company to obtain surety bonds, letters of credit or bank guarantees for client engagements. As of June 30, 2005, the Company had approximately $143,813 of outstanding surety bonds and $81,342 of outstanding letters of credit for which the Company may be required to make future payment.

BearingPoint, Inc.
Notes to Consolidated Condensed Financial Statements (Continued)
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Note 11. Pension and Postretirement Benefits

The components of the Company s net periodic pension cost and post-retirement medical cost for the three and six months ended June 30, 2005 and 2004 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Components of net periodic pension cost:				
Service cost	$ 1,591	$ 1,429	$ 3,182	$ 2,859
Interest cost	1,042	1,050	2,084	2,101
Expected return on plan assets	(293)	(258)	(586)	(516)
Amortization of loss	4	3	8	6
Amortization of prior service cost	194	192	388	384
Curtailment	(208)		(416)	
Settlement	(58)		(116)	
Net periodic pension cost	$ 2,272	$ 2,416	$ 4,544	$ 4,834
Components of net periodic postretirement medical cost:				
Service cost	$ 314	$ 259	$ 628	$ 518
Interest cost	143	103	286	205
Amortization of losses	18		36	
Amortization of prior service cost	120	117	240	234
Net periodic postretirement medical cost	$ 595	$ 479	$ 1,190	$ 957

Note 12. Income Taxes

For the three and six months ended June 30, 2005, the Company recognized losses before taxes of $45 and $150,890, respectively, and provided for income taxes of $4,841 and $86,554, respectively, resulting in an effective tax rate of (10,757.8%) and (57.4%), respectively. For the three months ended June 30, 2005, the effective tax rate varied from the U.S. Federal statutory tax rate, primarily as a result of a change in valuation allowance, the mix of income attributable to foreign versus domestic jurisdictions, non-deductible meals and entertainment, changes in income tax reserves, other items, and state and local taxes. For the six months ended June 30, 2005, the effective tax rate varied from the U.S. Federal statutory tax rate, primarily as a result of a change in valuation allowance, changes in income tax reserves, the mix of income attributable to foreign versus domestic jurisdictions, state and local taxes, non-deductible meals and entertainment and other items.

For the three months ended June 30, 2004, the Company earned income before taxes of $10,266 and provided for income taxes of $32,684, resulting in an effective tax rate of 318.4%. For the six months ended June 30, 2004, the Company realized a loss before taxes of $4,842 and provided for income taxes of $34,586, resulting in an effective tax rate of (714.3%). The effective tax rate varied from the U.S. Federal statutory tax rate for the three and six months ended June 30, 2004, primarily as a result of the impact of foreign recapitalization, the mix of income attributable to foreign versus domestic tax jurisdictions, changes in income tax reserves, non-deductible meals and entertainment, and state and local taxes.

Note 13. Recently Issued Accounting Pronouncements

As described in Note 2, the Company will adopt SFAS 123R which replaced SFAS 123 and superseded APB 25 on January 1, 2006.

In March 2005, the FASB issued FIN No. 47, Accounting for Conditional Asset Retirement Obligations (FIN 47). This is an interpretation of SFAS No. 143, Accounting for Asset Retirement Obligations (SFAS 143), which applies to all entities and addresses the legal obligations with the retirement of tangible long-lived assets that result from the acquisition, construction, development or normal operation of a long-lived asset. SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. FIN 47 further clarifies what the term conditional asset retirement obligation means with respect to recording the asset retirement obligation discussed in SFAS 143. The provisions of FIN 47 were effective no later than

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December 31, 2005. The Company s adoption of FIN 47 did not have a material impact on its Consolidated Financial Statements.

In May 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections a replacement of APB Opinion No. 20 and FASB Statement No. 3 (SFAS 154). SFAS 154 replaces APB Opinion No. 20, Accounting Changes (APB 20) and SFAS No. 3 Reporting Accounting Changes in Interim Financial Statements, and changes the requirements for the accounting for and reporting of a change in accounting principle. SFAS 154 requires restatement of prior period financial statements, unless impracticable, for changes in accounting principle. The retroactive application of a change in accounting principle should be limited to the direct effect of the change. Changes in depreciation, amortization or depletion methods should be accounted for as a change in accounting estimate. Corrections of accounting errors should be accounted for under the guidance contained in APB 20. The effective date of this new pronouncement is for fiscal years beginning after December 15, 2005 and prospective application is required. The Company does not expect the adoption of SFAS 154 to have a material impact on its Consolidated Financial Statements.

In June 2006, the FASB issued FIN 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an entity s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes . It prescribes a recognition threshold and measurement attribute for financial statement disclosure of tax positions taken or expected to be taken. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006. The Company will be required to adopt this interpretation in the first quarter of fiscal year 2007. Management is currently evaluating the requirements of FIN 48 and has not yet determined the impact on its Consolidated Financial Statements.

In September 2006, the SEC staff issued SAB No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements (SAB 108). SAB 108 was issued in order to eliminate the diversity of practice surrounding how public companies quantify financial statement misstatements. SAB 108 requires registrants to quantify the impact of correcting all misstatements using both the rollover method, which focuses primarily on the impact of a misstatement on the income statement and is the method currently used by the Company, and the iron curtain method, which focuses primarily on the effect of correcting the period-end balance sheet. The use of both of these methods is referred to as the dual approach and should be combined with the evaluation of qualitative elements surrounding the errors in accordance with SAB No. 99, Materiality (SAB 99). The Company does not expect the adoption of SAB 108 to have a material impact on its Consolidated Financial Statements.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS 157). SFAS 157 defines fair value, establishes a framework for measuring fair value in accordance with generally accepted accounting principles, and expands disclosures about fair value measurements. The provisions of SFAS 157 are effective for the fiscal year beginning January 1, 2008. The Company is currently evaluating the impact of the provisions of SFAS 157.

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans (SFAS 158). SFAS 158 requires employers to fully recognize the obligations associated with single-employer defined benefit pension, retiree healthcare and other postretirement plans in their financial statements. The provisions of SFAS 158 are effective as of the end of the fiscal year ending December 31, 2006. The Company is currently evaluating the impact of the provisions of SFAS 158.

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PART I, ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following Management s Discussion and Analysis of Financial Condition and Results of Operations (MD&A) should be read in conjunction with the interim Consolidated Condensed Financial Statements and the Notes to the Consolidated Condensed Financial Statements included elsewhere in this Quarterly Report on Form 10-Q.

Disclosure Regarding Forward-Looking Statements

Some of the statements in this Quarterly Report on Form 10-Q constitute forward-looking statements within the meaning of the United States Private Securities Litigation Reform Act of 1995. These statements relate to our operations that are based on our current expectations, estimates and projections. Words such as may, will, could, would, should, anticipate, predict, potential, continue, expects, intends, plans, projects, believes and similar expressions are used to identify these forward-looking statements. Forward-looking statements are only predictions and as such are not guarantees of future performance and involve risks, uncertainties and assumptions that are difficult to predict. Forward-looking statements are based upon assumptions as to future events or our future financial performance that may not prove to be accurate. Actual outcomes and results may differ materially from what is expressed or forecast in these forward-looking statements. The reasons for these differences include changes that occur in our continually changing business environment, and the following factors:

Our continuing failure to timely file certain periodic reports with the SEC poses significant risks to our business, each of which could materially and adversely affect our financial condition and results of operations.

In fiscal 2004, we identified material weaknesses in our internal control over financial reporting, which could materially and adversely affect our business and financial condition, and as of December 31, 2005, these material weaknesses remain.

We face risks related to securities litigation and regulatory actions that could adversely affect our financial condition and business.

Our business may be adversely impacted as a result of changes in demand, both globally and in individual market segments, for consulting and systems integration services.

Our operating results will suffer if we are not able to maintain our billing and utilization rates or control our costs.

The systems integration consulting markets are highly competitive, and we may not be able to compete effectively if we are not able to maintain our billing rates or control our costs.

We have incurred significant operating losses under our contract with Hawaiian Telcom Communications, Inc. and could incur significant additional losses and cash outflows in fiscal 2006.

Contracting with the Federal government is inherently risky and exposes us to risks that may materially and adversely affect our business.

Our ability to attract, retain and motivate our managing directors and other key employees is critical to the success of our business. We continue to experience sustained, higher-than-industry average levels of voluntary turnover among our workforce, which has impacted our ability to grow our business.

Our contracts can be terminated by our clients with short notice, or our clients may cancel or delay projects.

If we are not able to keep up with rapid changes in technology or maintain strong relationships with software providers, our business could suffer.

Loss of our joint marketing relationships could reduce our revenue and growth prospects.

We are not likely to be able to significantly grow our business through mergers and acquisitions in the near term.

There will not be a consistent pattern in our financial results from quarter to quarter, which may result in increased volatility of our stock price.

Our profitability may decline due to financial, regulatory and operational risks inherent in worldwide operations.

We may bear the risk of cost overruns relating to our services, thereby adversely affecting our profitability.

We may face legal liabilities and damage to our professional reputation from claims made against our work.

Our services may infringe upon the intellectual property rights of others.

We have only a limited ability to protect our intellectual property rights, which are important to our success.

Our current cash resources might not be sufficient to meet our expected near-term cash needs, especially to fund intra-quarter operating cash requirements and non-recurring cash requirements (e.g., to settle lawsuits).

We have been unable to issue shares of our common stock under our ESPP since February 1, 2005. The longer we are unable to issue shares of our common stock, the more likely our ESPP participants may elect to withdraw their accumulated cash contributions from the ESPP at rates higher than those we have historically experienced.

We have limited availability under our 2005 Credit Facility to borrow additional amounts or issue additional letters of credit, and we may not be able to refinance our debt or to do so on favorable terms.

Our 2005 Credit Facility imposes a number of restrictions on the way in which we operate our business and may negatively affect our ability to finance future needs, or do so on favorable terms. If we violate these restrictions, we will be in default under the 2005 Credit Facility, which may cross-default to our other indebtedness.

If our operating performance is materially and adversely affected, we may not be able to service our indebtedness.

We may be required to post collateral to support our obligations under our surety bonds, and we may be unable to obtain new surety bonds, letters of credit or bank guarantees in support of client engagements on acceptable terms.

Downgrades of our credit ratings may increase our borrowing costs and materially and adversely affect our financial condition.

Our leverage may adversely affect our business and financial performance and may restrict our operating flexibility.

The holders of our debentures have the right, at their option, to require us to purchase some or all of their debentures upon certain dates or upon the occurrence of certain designated events, which could have a material adverse effect on our liquidity.

The price of our common stock may decline due to the number of shares that may be available for sale in the future.

There are significant limitations on the ability of any person or company to acquire the Company without the approval of our Board of Directors.

The termination of services provided under the transition services agreement with KPMG LLP could involve significant expense, which could adversely affect our financial results.

For a more detailed discussion of these factors, see the information under Item 1A, Risk Factors, in the Company s 2005 Form 10-K and filed as Exhibit 99.2 in this Quarterly Report on Form 10-Q. These statements speak only as of the date they were made, and we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Overview

We provide strategic consulting applications services, technology solutions and managed services to government organizations, Global 2000 companies and medium-sized businesses in the United States and internationally. In North America, we provide consulting services through our Public Services, Commercial Services and Financial Services industry groups in which we focus significant industry-specific knowledge and service offerings to our clients. Outside of North America, we are organized on a geographic basis, with operations in EMEA, the Asia Pacific region and Latin America.

Beginning in 2007, we intend to begin transitioning our business to a more integrated, global delivery model. This transition will begin by more closely aligning our senior personnel worldwide who have significant industry specific expertise with our existing North American Public Services, Commercial Services and Financial Services industry groups. Our non-managing director employees will then be assigned, as needed, across all of our industry-specific operations. We expect this change to improve our utilization and provide added training for our professional personnel.

Economic and Industry Factors

We believe that our clients spending for consulting services is partially correlated to, among other factors, the performance of the domestic and global economy as measured by a variety of indicators such as gross domestic product, government policies, mergers and acquisitions activity, corporate earnings, U.S. Federal and state government budget levels, inflation and interest rates and client confidence levels, among others. As economic uncertainties increase, clients interests in business and technology consulting historically have turned more to improving existing processes and reducing costs rather than investing in new innovations. Demand for our services, as evidenced by new contract bookings, also does not uniformly follow changes in economic cycles. Consequently, we may experience rapid decreases in new contract bookings at the onset of significant economic downturns while the benefits of economic recovery may take longer to realize.

The markets in which we provide services are increasingly competitive and global in nature. While supply and demand in certain lines of business and geographies may support price increases for some of our standard service offerings from time to time, to maintain and improve our profitability we must constantly seek to improve and expand our unique service offerings and deliver our services at increasingly lower cost levels. Our Public Services industry group, which is our largest, also must operate within the U.S. Federal, state and local government markets where unique contracting, budgetary and regulatory regimes control how contracts are awarded, modified and terminated. Budgetary constraints or reductions in government funding may result in the modification or termination of long-term government contracts, which could dramatically affect the outlook of that business.

Revenue and Income Drivers

We derive substantially all of our revenue from professional services activities. Our revenue is driven by our ability to continuously generate new opportunities to serve clients, by the prices we obtain for our service offerings, and by the size and utilization of our professional workforce. Our ability to generate new business is directly influenced by the economic conditions in the industries and regions we serve, our anticipation and response to technological change, the type and level of technology spending by our clients and by our clients perception of the quality of our work. Our ability to generate new business is also indirectly and increasingly influenced by our clients perceptions of our ability to manage our ongoing issues surrounding our financial accounting, internal controls and SEC reporting capabilities.

Our gross profit is predominantly a function of the factors affecting revenue mentioned above and how well we manage our costs of services. The primary components of our costs of services include professional compensation and other direct contract expenses. Professional compensation consists of payroll costs and related benefits associated with client service professional staff (including the vesting of RSUs, tax equalization for employees on foreign and long-term domestic assignments and costs associated with reductions in workforce). Other direct contract expenses include costs directly attributable to client engagements. These costs include out-of-pocket costs such as travel and subsistence for client service professional staff, costs of hardware and software, and costs of subcontractors. If we are unable to adequately control or estimate these costs, or properly anticipate the sizes of our client service and support staff, our profitability will suffer.

Our operating profit reflects our revenue less costs of services and certain additional items that include, primarily, selling, general and administrative (SG&A) expenses, which include costs related to marketing, information systems, depreciation and amortization, finance and accounting, human resources, sales force, and other expenses related to managing and growing our business. Write-downs in the carrying value of goodwill and amortization of intangible assets have also reduced our operating profit.

Our operating cash flow is predominantly a function of the factors affecting gross profits mentioned above and our ability to manage our receivables and payables and efficiently manage our sources of capital and use of these various sources of capital.

Key Performance Indicators

In evaluating our financial condition and operating performance, we focus on the following key performance indicators: bookings, revenue growth, operating margin (gross profit as a percentage of revenue), utilization, days sales outstanding, free cash flow and attrition.

Bookings. We believe that information regarding our new contract bookings provides useful trend information regarding how the volume of our new business changes over time. Information regarding our new bookings should not be compared to, or substituted for, an analysis of our revenue over time. There are no third-party standards or requirements governing the calculation of bookings. New contract bookings are recorded using then existing currency exchange rates and are not subsequently adjusted for currency fluctuations. These amounts represent our estimate at contract signing of the net revenue expected over the term of that contract and involve estimates and judgments regarding new contracts as well as renewals, extensions and additions to existing contracts. Subsequent cancellations, extensions and other matters may affect the amount of bookings previously reported. Bookings do not include potential revenue that could be earned from a client relationship as a result of future expansion of service offerings to that client, nor does it reflect option years under contracts that are subject to client discretion. Although our level of bookings provides some indication of how our business is performing, we do not characterize our bookings, or our engagement contracts associated with new bookings, as backlog because our engagements generally can be cancelled or terminated on short notice or without notice.

Revenue Growth. Unlike bookings, which provide only a general sense of future expectations, period-over-period comparisons of revenue provide a meaningful depiction of how successful we have been in growing our business over time.

Gross Margin (gross profit as a percentage of revenue). Gross margin is a meaningful tool for monitoring our ability to control costs. Analysis of the various cost elements, including foreign currency translation adjustments and the use of subcontractors, as a percentage of revenue over time can provide additional information as to the key challenges we are facing in executing our business model. The cost of subcontractors is generally more expensive than the cost of our own workforce and can negatively impact our gross profit. While the use of subcontractors can help us to win larger, more complex deals, and also may be mandated by our clients, we focus on limiting the use of subcontractors whenever possible in order to minimize our costs.

Utilization. Utilization represents the percentage of time our consultants are performing work that is chargeable to a client, and is defined as total hours charged to client engagements divided by total available hours for any specific time period. In 2006, we modified the calculation to include the available hours of employees working on non-chargeable internal projects that had a general relationship to client matters, which will have the effect of lowering our reported utilization figure by an insignificant amount. We also further modified this calculation in 2006 by excluding the holiday and paid vacation time for our employees from the available hours figure. This will have the effect of raising the utilization rate but will make our reporting of this metric more consistent with how we believe our industry peer group measures utilization.

Days Sales Outstanding (DSO). DSO is an operational metric that approximates the amount of earned revenue that remains unpaid by clients at a given time. DSOs are derived by dividing the sum of our outstanding accounts receivable and unbilled revenue, less deferred revenue, by our average net revenue per day. Average net revenue per day is determined by dividing total net revenue for the most recently ended trailing twelve-month period divided by 365.

Free Cash Flow. Free cash flow is calculated by subtracting purchases of property and equipment from cash provided by operating activities. We believe free cash flow is a useful measure because it allows better understanding and assessment of our ability to meet debt service requirements and the amount of recurring cash generated from operations after expenditures for fixed assets. Free cash flow does not represent the Company s residual cash flow available for discretionary expenditures as it excludes certain mandatory expenditures such as repayment of maturing debt. We use free cash flow as a measure of recurring operating cash flow. Free cash flow is a non-GAAP financial measure. The most directly comparable financial measure calculated in accordance with GAAP is net cash provided by operating activities.

Attrition. Attrition, or voluntary total employee turnover, is calculated by dividing the number of our employees who have chosen to leave the Company within a certain period by the total average number of all employees during that same period. Previously, we had provided attrition figures for our billable employees and did not take into account our non-consultant employees. Starting in 2006, we intend to provide attrition figures for all of our employees, which we believe provides metrics that are more compatible with, and comparable to, those of our competitors.

Readers should understand that each of the performance indicators identified above are utilized by many companies in our industry and by those who follow our industry. There are no uniform standards or requirements for computing these performance indicators, and, consequently, our computations of these amounts may not be comparable to those of our competitors.

Three and Six Months Ended June 30, 2005 Highlights

During the three months ended June 30, 2005, we continued to face many of the challenges that negatively affected our performance in the three months ended June 30, 2004. While our core business delivered results generally consistent with the three months ended June 30, 2004 and we achieved success in addressing some challenges, much remains to be done, particularly with respect to the process, training and system issues related to financial accounting for our North American operations and the remediation of material weaknesses in our internal controls.

New contract bookings for the three months ended June 30, 2005 were $963.1 million, compared to new contract bookings of $864.9 million for the three months ended June 30, 2004. New contract bookings for the six months ended June 30, 2005 were $1,657.3 million, compared to new contract bookings of $1,571.0 million for the six months ended June 30, 2004. New contract bookings for the three months ended June 30, 2005 increased in all three industry groups in North America, driven primarily by strong bookings in our Commercial Services industry group, which offset decreased bookings in the Asia Pacific and Latin America regions. For the six months ended June 30, 2005, new contract bookings increased in all three industry groups in North America, driven primarily by strong bookings in Financial Services and Commercial Services, which offset decreased bookings in the EMEA, Asia Pacific and Latin America regions.

Our revenue for the three months ended June 30, 2005 was $895.2 million, representing an increase of $19.9 million, or 2.3%, over the three months ended June 30, 2004 revenue of $875.4 million. Our revenue for the six months ended June 30, 2005 was $1,766.6 million, representing an increase of $2.6 million, or 0.1%, over the six months ended June 30, 2004 revenue of $1,764.0 million.

Our gross profit for the three months ended June 30, 2005 was $177.3 million compared with $185.5 million for the three months ended June 30, 2004. Gross profit as a percentage of revenue decreased to 19.8% during the three months ended June 30, 2005 from 21.2% during the three months ended June 30, 2004. Our gross profit for the six months ended June 30, 2005 was $202.3 million compared with $328.3 million for the six months ended June 30, 2004. Gross profit as a percentage of revenue decreased to 11.4% during the three months ended June 30, 2005 from 18.6% during the six months ended June 30, 2004. This decrease was primarily attributable to a $113.3 million loss recognized on the HT Contract, which is described below.

We have a significant contract (the HT Contract) with Hawaiian Telcom Communications, Inc., a telecommunications industry client, under which we were engaged to design, build and operate various information technology systems for the client. We incurred losses of $113.3 million under this contract in the first quarter of 2005. The HT Contract has experienced delays in its build and deployment phases and contractual milestones have been missed. The client has alleged that we are responsible under the HT Contract to compensate it for certain costs and other damages incurred as a result of these delays and other alleged failures. We believe the client s nonperformance of its responsibilities under the HT Contract caused delays in the project and impacted our ability to perform, thereby causing us to incur significant damages. We also believe the terms of the HT Contract limit the client s ability to recover certain of their claimed damages. We are negotiating with the client to resolve these issues, apportion financial responsibility for these costs and alleged damages, and transition remaining work under the HT Contract to others, as requested by the client. During these negotiations, we are maintaining all of our options, including disputing the client s claims and asserting our own claims in litigation. At this time we cannot predict the likelihood that we will be able to resolve this dispute or the outcome of any litigation that might ensue if we are unable to resolve the dispute. Even if resolved, we could incur substantial additional losses under the HT Contract or agree to pay additional amounts to facilitate termination of the HT Contract. The incurrence of additional losses or the payment of additional amounts to the client could materially and adversely affect our profitability, results of operations or cash flow over the near term.

For the three and six months ended June 30, 2005, all of the material weaknesses in our internal control over financial reporting cited for fiscal 2004 remain. For information on the developments and progress made in fiscal 2005, please see Item 4, Controls and Procedures Remediation of Material Weaknesses in Internal Control over Financial Reporting.

During the three months ended June 30, 2005, we realized a net loss of $4.9 million, or a loss of $0.02 per share, compared to a net loss of $22.4 million, or a loss of $0.11 per share, during the three months ended June 30, 2004. During the six months ended June 30, 2005, we realized a net loss of $237.4, or a loss of $1.18 per share, compared to a net loss of $39.4, or a loss of $0.20 per share, during the six months ended June 30, 2004. Included in our results for the six months ended June 30, 2005 were $113.3 million of operating losses related to the HT Contract, a $57.3 million increase in the valuation allowance primarily against our U.S. deferred tax assets, and $19.6 million of lease and facilities restructuring charges.

Utilization for the three months ended June 30, 2005 was 69.8%, an increase of 50 basis points from the three months ended June 30, 2004. Utilization for the six months ended June 30, 2005 was 70.0% an increase of 200 basis points from the six months ended June 30, 2004.

At June 30, 2005, our DSOs stood at 111 days, representing a decrease of 8 days, or 7%, from our DSOs at June 30, 2004. Given our ongoing systems issues related to financial accounting for our North American operations, we are currently unable to calculate DSOs for dates later than December 31, 2005. We continue to focus on this metric during 2006 as we believe we are at a level that is higher than the industry average, resulting in a suboptimal use of our cash.

Free cash flow for the six months ended June 30, 2005 was ($117.0) million. Net cash used in operating activities during the six months ended June 30, 2005 was ($98.6) million. Purchases of property and equipment during the six months ended June 30, 2005 were ($18.4) million. When this amount is subtracted from net cash used in operating activities, the result is ($117.0) million, which is free cash flow. We use free cash flow as a measure of recurring operating cash flow. Free cash flow is a non GAAP financial measure. The most directly comparable financial measure calculated in accordance with GAAP is net cash provided by (used in) operating activities.

On March 25, 2005, the Compensation Committee of our Board of Directors approved the issuance of up to an aggregate of $165 million in restricted stock units (RSUs) under our Long-Term Incentive Plan (the LTIP) to our current managing directors and a limited number of key employees (the Retention RSUs), and delegated to our officers the authority to grant these awards. During the three and six months ended June 30, 2005, we recorded non-cash stock compensation expense of $1.5 million and $1.5 million, respectively, related to the vesting of Retention RSUs, which significantly impacted both our gross profit and operating income.

During fiscal 2005, we completed a number of private securities offerings in an effort to improve our overall liquidity. We issued an additional $25.0 million aggregate principal amount of our Series A Debentures and $25.0 million aggregate principal amount of our Series B Debentures. We also issued an aggregate principal amount of $200.0 million of our April 2005 Senior Debentures and an aggregate principal amount of $40.0 million of our July 2005 Senior Debentures. In total, we received approximately $280.3 million in net proceeds from all of these offerings. For additional information regarding our debt restructuring, see Liquidity and Capital Resources and Note 3, Notes Payable, of the Notes to Consolidated Condensed Financial Statements.

Segments

Our reportable segments for fiscal 2005 consist of our three North America industry groups (Public Services, Commercial Services, and Financial Services), our three international regions (EMEA, Asia Pacific and Latin America) and the Corporate/Other category (which consists primarily of infrastructure costs). Revenue and gross profit information about our segments are presented below, starting with each of our industry groups and then with each of our three international regions (in order of size).

Our chief operating decision maker, the Chief Executive Officer, evaluates performance and allocates resources among the segments. Upon consolidation, all intercompany accounts and transactions are eliminated. Inter-segment revenue is not included in the measure of profit or loss for each reportable segment. Performance of the segments is evaluated on operating income excluding the costs of infrastructure functions (such as information systems, finance and accounting, human resources, legal and marketing) as described in Note 6, Segment Reporting, of the Notes to Consolidated Condensed Financial Statements. During fiscal 2005, we combined our Communications, Content and Utilities and Consumer, Industrial and Technology industry groups to form the Commercial Services industry group. Beginning in 2007, we intend to begin transitioning our business to a more integrated, global delivery model.

Three Months ended June 30, 2005 Compared to Three Months ended June 30, 2004

Revenue. Our revenue for the three months ended June 30, 2005 was $895.2 million, an increase of $19.9 million, or 2.3%, over revenue of $875.4 million for the three months ended June 30, 2004. The following tables present certain revenue information and performance metrics for each of our reportable segments for the three months ended June 30, 2005 and 2004. Amounts are in thousands, except percentages.

	Three Months Ended June 30,			
	2005	**2004**	**$ Change**	**% Change**
Revenue				
Public Services	$ 346,337	$ 356,403	$ (10,066)	(2.8%)
Commercial Services	177,177	171,310	5,867	3.4%
Financial Services	87,818	75,172	12,646	16.8%
EMEA	181,031	163,047	17,984	11.0%
Asia Pacific	80,264	84,765	(4,501)	(5.3%)
Latin America	22,145	20,701	1,444	7.0%
Corporate/Other	473	3,989	(3,516)	n/m
Total	$ 895,245	$ 875,387	$ 19,858	2.3%

	Impact of currency fluctuations	**Revenue growth (decline), net of currency impact**	**Total**
Revenue			
Public Services	0.0%	(2.8%)	(2.8%)
Commercial Services	0.0%	3.4%	3.4%
Financial Services	0.0%	16.8%	16.8%
EMEA	4.8%	6.2%	11.0%
Asia Pacific	4.3%	(9.6%)	(5.3%)
Latin America	15.3%	(8.3%)	7.0%
Corporate/Other	n/m	n/m	n/m
Total	1.7%	0.6%	2.3%

n/m = not meaningful

Public Services revenue decreased during the three months ended June 30, 2005, primarily attributable to an expected reduction of $20.2 million in revenue derived from our subcontractors and resales of procured materials (which we must bill our clients, thereby increasing our revenue), which more than offset increases in headcount and chargeable hours resulting from our expanding use of employees at lower average bill rates.

Commercial Services revenue increased during the three months ended June 30, 2005, primarily driven by revenue growth in the Transportation sector.

Financial Services revenue increased during the three months ended June 30, 2005, primarily due to especially strong revenue growth in the Global Market sector. Revenue growth was principally due to an increase in demand for our services. Our average billing rates improved slightly quarter-over-quarter, as our ability to obtain higher rates per hour on certain of our market offerings offset the increasing use of lower-priced offshore personnel as a component of our overall pricing model.

EMEA revenue increased during the three months ended June 30, 2005, primarily due to combined revenue growth in France and the United Kingdom of $17.6 million, partially offset by revenue decline in Germany. Our business in France experienced a significant shift into systems integration work, while revenue growth in the United Kingdom was driven by our continued expansion in that region. Revenue for Germany declined as a result of utilization decreasing slightly as a result of continued deterioration of market conditions which, consequently, led us to lower billable headcount.

Asia Pacific revenue decreased during the three months ended June 30, 2005, driven primarily by the planned elimination of subcontractor usage in the region, which more than offset improved billing rates achieved across the region in the three months ended June 30, 2005 due to significantly lower revenue write-offs during the year.

Latin America revenue increased during the three months ended June 30, 2005, primarily as a function of the weakening of the U.S. dollar against local currencies in Latin America (particularly the Brazilian Real). The combined impact of these foreign currency fluctuations and modest revenue growth in Brazil offset significant declines in revenue in most other countries in which we operate in the region.

Corporate/Other: Our Corporate/Other segment does not contribute significantly to our revenue.

Gross Profit. During the three months ended June 30, 2005, our revenue increased $19.9 million and total costs of service increased $28.0 million when compared to the three months ended June 30, 2004, resulting in a decrease in gross profit of $8.2 million, or 4.4%. Gross profit as a percentage of revenue decreased to 19.8% for the three months ended June 30, 2005 from 21.2% for the three months ended June 30, 2004. The change in gross profit for the three months ended June 30, 2005 compared to the three months ended June 30, 2004 resulted primarily from the following:

Professional compensation expense increased as a percentage of revenue to 45.4% for the three months ended June 30, 2005, compared to 42.5% for the three months ended June 30, 2004. We experienced a net increase in professional compensation expense of $34.6 million, or 9.3%, to $406.3 million for the three months ended June 30, 2005 from $371.7 million for the three months ended June 30, 2004. The increase in professional compensation expense is primarily the result of hiring additional billable employees in response to overall market demand for our services. Additionally, $3.1 million of this amount was related to the vesting of Retention RSUs.

Other direct contract expenses decreased as a percentage of revenue to 27.6% for the three months ended June 30, 2005 compared to 29.1% for the three months ended June 30, 2004. We experienced a net decrease in other direct contract expenses of $7.6 million, or 3.0%, to $247.1 million for the three months ended June 30, 2005 from $254.7 million for the three months ended June 30, 2004. The change was driven primarily by reduced subcontractor expenses as a result of the increased use of internal resources.

Other costs of service as a percentage of revenue increased to 7.2% for the three months ended June 30, 2005 from 6.3% for the three months ended June 30, 2004. We experienced a net increase in other costs of service of $9.4 million, or 17.0%, to $64.5 million for the three months ended June 30, 2005 from $55.1 million for the three months ended June 30, 2004. The change was driven primarily by an increase in additional outside services and recruiting charges.

During the three months ended June 30, 2004 we recorded, within the Corporate/Other operating segment, a charge of $8.4 million for lease and facilities restructuring costs. These costs for the three months ended June 30, 2004 related to our previously announced reduction in office space primarily within the North America, EMEA and Asia Pacific regions.

Gross Profit by Segment. The following tables present certain gross profit and margin information and performance metrics for each of our reportable segments for the three months ended June 30, 2005 and 2004. Amounts are in thousands, except percentages.

	Three Months Ended June 30, 2005	Three Months Ended June 30, 2004	$ Change	% Change
Gross Profit				
Public Services	$ 79,816	$ 100,616	$ (20,800)	(20.7%)
Commercial Services	34,764	38,816	(4,052)	(10.4%)
Financial Services	27,097	25,016	2,081	8.3%
EMEA	34,585	31,255	3,330	10.7%
Asia Pacific	15,721	12,295	3,426	27.9%
Latin America	4,508	4,904	(396)	(8.1%)
Corporate/Other	(19,188)	(27,442)	8,254	n/m
Total	$ 177,303	$ 185,460	$ (8,157)	(4.4%)

	Three Months Ended June 30, 2005	Three Months Ended June 30, 2004
Gross Profit as a % of revenue		
Public Services	23.0%	28.2%
Commercial Services	19.6%	22.7%
Financial Services	30.9%	33.3%
EMEA	19.1%	19.2%
Asia Pacific	19.6%	14.5%
Latin America	20.4%	23.7%
Corporate/Other	n/m	n/m
Total	19.8%	21.2%

n/m = not meaningful

Changes in gross profit by segment were as follows:

Public Services gross profit decreased in the three months ended June 30, 2005, in large measure due to a $20.7 million increase in compensation expense (including non-cash compensation expense of $0.6 million relating to the vesting of Retention RSUs) and a $10.1 million reduction in gross revenue, which on a combined basis, more than offset a $10.5 million reduction in other direct contract expenses.

Commercial Services gross profit decreased in the three months ended June 30, 2005, as higher gross revenue was eroded by increases in compensation expense, including non-cash compensation expense related to the vesting of Retention RSUs of $0.5 million.

Financial Services gross profit increased in the three months ended June 30, 2005, as higher revenue in the Global Market sector more than offset significant incremental increases in compensation expense related to a substantial increase in headcount.

EMEA gross profit increased in the three months ended June 30, 2005, as increases in revenue more than offset incremental increases in compensation expense due to an increase in headcount in France and the United Kingdom and non-cash compensation expense of $1.2 million related to the vesting of the Retention RSUs.

Asia Pacific gross profit increased in the three months ended June 30, 2005 despite a decrease in revenue, due in large measure to significant demonstrated improvements in cost management and realization of contract revenue.

Latin America gross profit decreased in the three months ended June 30, 2005, as increases in compensation expense attributable to salaries/fringe benefits and non-cash compensation expense related to Retention RSUs offset modest revenue growth in the region.

Corporate/Other consists primarily of rent expense and other facilities related charges, which increased in the three months ended June 30, 2005 primarily due to the lease and facilities restructuring charges discussed above.

Amortization of Purchased Intangible Assets. Amortization of purchased intangible assets decreased $0.4 million to $0.6 million for the three months ended June 30, 2005 from $1.0 million for the three months ended June 30, 2004.

Selling, General and Administrative Expenses. Selling, general and administrative expenses decreased $3.5 million, or 2.1%, to $164.4 million for the three months ended June 30, 2005 from $167.9 million for the three months ended June 30, 2004. Selling, general and administrative expenses as a percentage of gross revenue decreased to 18.4% in the three months ended June 30, 2005 from 19.2% for the three months ended June 30, 2004. The decrease was primarily due to the termination of services provided under our transition services agreement with KPMG LLP.

Interest Income. Interest income was $1.7 million and $0.1 million in the three months ended June 30, 2005 and 2004, respectively. Interest income is earned primarily from cash and cash equivalents, including money-market investments. The increase in interest income was due to a higher level of cash available to be invested in money-markets during the three months ended June 30, 2005 as compared to the three months ended June 30, 2004.

Interest Expense. Interest expense was $8.8 million and $4.0 million in the three months ended June 30, 2005 and 2004, respectively. Interest expense is attributable to our debt obligations, consisting of interest due along with amortization of loan costs and loan discounts. The increase in interest expense was due to higher average debt balances in the three months ended June 30, 2005 as compared to the three months ended June 30, 2004.

Other Expense, net. Other expense, net was $5.3 million and $2.4 million in the three months ended June 30, 2005 and 2004, respectively. The balances in each period primarily consist of realized foreign currency exchange losses.

Income Tax Expense. We incurred income tax expense of $4.8 million for the three months ended June 30, 2005 and an income tax expense of $32.7 million for the three months ended June 30, 2004. The principal reasons for the difference between the effective income tax rate on loss from continuing operations of (10,757.8)% and 318.4% for the three months ended June 30, 2005 and 2004, is primarily as a result of a change in valuation allowance, the mix of income attributable to foreign versus domestic tax jurisdictions, non-deductible meals and entertainment, changes in income tax reserves, other items and state and local income taxes.

Net Income (Loss). For the three months ended June 30, 2005, we incurred a net loss of $4.9 million, or a loss of $0.02 per share. For the three months ended June 30, 2004, we incurred a net loss of $22.4 million, or a loss of $0.11 per share. Included in our results for the three months ended June 30, 2004 is $8.4 million of lease and facilities restructuring charges.

Six Months ended June 30, 2005 Compared to Six Months ended June 30, 2004

Revenue. Our revenue for the six months ended June 30, 2005 was $1,766.6 million, an increase of $2.6 million, or 0.1%, over revenue of $1,764.0 million for the six months ended June 30, 2004. The following tables present certain revenue information and performance metrics for each of our reportable segments for the six months ended June 30, 2005 and 2004. Amounts are in thousands, except percentages.

	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004	$ Change	% Change
Revenue				
Public Services	$ 678,438	$ 735,290	$ (56,852)	(7.7%)
Commercial Services	349,964	349,077	887	0.3%
Financial Services	178,517	142,604	35,913	25.2%
EMEA	352,571	316,981	35,590	11.2%
Asia Pacific	163,975	172,320	(8,345)	(4.8%)
Latin America	42,178	41,516	662	1.6%
Corporate/Other	935	6,202	(5,267)	n/m
Total	$ 1,766,578	$ 1,763,990	$ 2,588	0.1%

	Impact of currency fluctuations	Revenue growth (decline), net of currency impact	Total
Revenue			
Public Services	0.0%	(7.7%)	(7.7%)
Commercial Services	0.0%	0.3%	0.3%
Financial Services	0.0%	25.2%	25.2%
EMEA	5.1%	6.1%	11.2%
Asia Pacific	3.6%	(8.4%)	(4.8%)
Latin America	10.2%	(8.6%)	1.6%
Corporate/Other	n/m	n/m	n/m
Total	1.5%	(1.4%)	0.1%

n/m = not meaningful

Public Services revenue decreased during the six months ended June 30, 2005, primarily attributable to our expanding use of employees at lower average bill rates (despite overall headcount and engagement hours increasing) and an expected reduction of $28.6 million in revenue derived from our subcontractors and resales of procured materials (which we must bill our clients, thereby increasing our revenue).

Commercial Services revenue increased slightly during the six months ended June 30, 2005, primarily driven by revenue growth in the Transportation sector, which was partially offset by revenue declines in the Communications & Content and Energy sectors.

Financial Services revenue increased during the six months ended June 30, 2005, primarily due to revenue growth in all sectors, with especially strong growth in the Insurance and Global Market sectors. Revenue growth was principally due to an increase in demand for our services. Our average billing rates declined period-over-period, as we increased our use of lower-priced offshore personnel as a component of our overall pricing model.

EMEA revenue increased during the six months ended June 30, 2005, primarily due to combined revenue growth in France and the United Kingdom of $29.9 million. Our business in France experienced a significant shift into systems integration work, while revenue growth in the United Kingdom was driven by our continued expansion in that region.

Asia Pacific revenue decreased during the six months ended June 30, 2005, driven primarily by the planned elimination of subcontractor usage in the region, which more than offset the improved billing rates achieved across the region in the six months ended June 30, 2005 due to significantly lower revenue write-offs during the year.

Latin America revenue increased during the six months ended June 30, 2005, primarily as a function of the weakening of the U.S. dollar against local currencies in Latin America (particularly the Brazilian Real). The combined impact of these foreign currency fluctuations and modest revenue growth in Brazil offset significant declines in revenue in most other countries in which we operate in the region.

Corporate/Other: Our Corporate/Other segment does not contribute significantly to our revenue.

Gross Profit. During the six months ended June 30, 2005, our revenue increased $2.6 million and total costs of service increased $128.6 million when compared to the six months ended June 30, 2004, resulting in a decrease in gross profit of $126.1 million, or 38.4%. Gross profit as a percentage of revenue decreased to 11.4% for the six months ended June 30, 2005 from 18.6% for the six months ended June 30, 2004. The change in gross profit for the six months ended June 30, 2005 compared to the six months ended June 30, 2004 resulted primarily from the following:

Professional compensation expense increased as a percentage of revenue to 50.0% for the six months ended June 30, 2005, compared to 42.5% for the six months ended June 30, 2004. We experienced a net increase in professional compensation expense of $132.7 million, or 17.7%, to $882.9 million for the six months ended June 30, 2005 from $750.2 million for the six months ended June 30, 2004. The increase in professional compensation expense is primarily the result of hiring additional billable employees in response to overall market demand for our services and additional compensation cost related to the loss accrual for the HT Contract. Additionally, $4.9 million of this amount was related to the vesting of Retention RSUs.

Other direct contract expenses decreased as a percentage of revenue to 30.1% for the six months ended June 30, 2005 compared to 31.1% for the six months ended June 30, 2004. We experienced a net decrease in other direct contract expenses of $18.0 million, or 3.3%, to $531.0 million for the six months ended June 30, 2005 from $549.0 million for the six months ended June 30, 2004. The change was driven primarily by reduced subcontractor expenses as a result of the increased use of internal resources, partially offsetting additional subcontractor expense accruals for the HT Contract.

Other costs of service as a percentage of revenue increased to 7.4% for the six months ended June 30, 2005 from 7.1% for the six months ended June 30, 2004. We experienced a net increase in other costs of service of $6.0 million, or 4.8%, to $130.8 million for the six months ended June 30, 2005 from $124.8 million for the six months ended June 30, 2004. The change was driven primarily by an increase in additional outside services and recruiting charges.

During the six months ended June 30, 2005 we recorded, within the Corporate/Other operating segment, a charge of $19.6 million for lease and facilities restructuring costs, compared to an $11.7 million charge for lease and facilities restructuring costs during the six months ended June 30, 2004. These costs for the six months ended June 30, 2005 related to our previously announced reduction in office space primarily within the North America, EMEA and Asia Pacific regions.

Gross Profit by Segment. The following tables present certain gross profit and margin information and performance metrics for each of our reportable segments for the six months ended June 30, 2005 and 2004. Amounts are in thousands, except percentages.

	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004	$ Change	% Change
Gross Profit				
Public Services	$ 157,514	$ 197,586	$ (40,072)	(20.3%)
Commercial Services	(44,531)	73,092	(117,623)	(160.9%)
Financial Services	53,186	39,931	13,255	33.2%
EMEA	62,387	46,698	15,689	33.6%
Asia Pacific	31,821	27,241	4,580	16.8%
Latin America	9,205	8,229	976	11.9%
Corporate/Other	(67,329)	(64,463)	(2,866)	n/m
Total	$ 202,253	$ 328,314	$ (126,061)	(38.4%)

	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
Gross Profit as a % of revenue		
Public Services	23.2%	26.9%
Commercial Services	(12.7%)	20.9%
Financial Services	29.8%	28.0%
EMEA	17.7%	14.7%
Asia Pacific	19.4%	15.8%
Latin America	21.8%	19.8%
Corporate/Other	n/m	n/m
Total	11.4%	18.6%

n/m = not meaningful

Changes in gross profit by segment were as follows:

Public Services gross profit decreased in the six months ended June 30, 2005, in large measure due to a $42.1 million increase in compensation expense (including non-cash compensation expense of $0.6 million relating to the vesting of Retention RSUs) and the previously described $56.9 million reduction in gross revenue, which on a combined basis, more than offset significant reductions of $60.0 million in other direct contract expenses.

Commercial Services gross profit decreased in the six months ended June 30, 2005, as slightly higher gross revenue was eroded by significant cost overruns and loss accruals, most notably $113.3 million on the previously described HT Contract. These cost overruns drove the increase in compensation expense along with increases in subcontractor expense accruals and hardware and software purchases that collectively increased our other direct contract expenses by $49.0 million, which are substantially not recoverable. Additionally, compensation expense increased due to non-cash compensation expense relating to the vesting of Retention RSUs of $0.7 million, also contributed to the decrease in gross profit.

Financial Services gross profit increased in the six months ended June 30, 2005, as higher revenue across all sectors more than offset significant incremental increases in compensation expense related to a substantial increase in headcount.

EMEA gross profit increased in the six months ended June 30, 2005, as increases in revenue more than offset incremental increases in compensation expense due to a substantial increase in headcount in both France and the United Kingdom and non-cash compensation expense relating to vesting of Retention RSUs.

Asia Pacific gross profit increased in the six months ended June 30, 2005 despite a decrease in revenue, due in large measure to significant demonstrated improvements in cost management and realization of contract revenue.

Latin America gross profit increased in the six months ended June 30, 2005, as cost of services slightly declined with the modest revenue growth in the region.

Corporate/Other consists primarily of rent expense and other facilities related charges, which increased in the six months ended June 30, 2005 primarily due to the lease and facilities restructuring charges discussed above.

Amortization of Purchased Intangible Assets. Amortization of purchased intangible assets decreased $1.0 million to $1.1 million for the six months ended June 30, 2005 from $2.1 million for the six months ended June 30, 2004.

Selling, General and Administrative Expenses. Selling, general and administrative expenses increased $9.3 million, or 2.9%, to $327.8 million for the six months ended June 30, 2005 from $318.5 million for the six months ended June 30, 2004. Selling, general and administrative expenses as a percentage of gross revenue increased to 18.6% in the six months ended June 30, 2005 from 18.1% for the six months ended June 30, 2004. The increase was primarily due to significant costs for contracted labor and other costs directly related to the financial statement closing process incurred in fiscal 2005.

Interest Income. Interest income was $3.0 million and $0.3 million in the six months ended June 30, 2005 and 2004, respectively. Interest income is earned primarily from cash and cash equivalents, including money-market investments. The increase in interest income was due to a higher level of cash available to be invested in money-markets during the six months ended June 30, 2005 as compared to the six months ended June 30, 2004.

Interest Expense. Interest expense was $16.9 million and $8.4 million in the six months ended June 30, 2005 and 2004, respectively. Interest expense is attributable to our debt obligations, consisting of interest due along with amortization of loan costs and loan discounts. The increase in interest expense was due to higher average debt balances in the six months ended June 30, 2005 as compared to the six months ended June 30, 2004.

Other Expense, net. Other expense, net was $10.4 million and $4.4 million in the six months ended June 30, 2005 and 2004, respectively. The balances in each period primarily consist of realized foreign currency exchange losses.

Income Tax Expense. We incurred income tax expense of $86.5 million for the six months ended June 30, 2005 and income tax expense of $34.6 million for the six months ended June 30, 2004. The principal reasons for the difference between the effective income tax rate on loss from continuing operations of (57.4)% and (714.3)% for the six months ended June 30, 2005 and 2004, respectively, were: a change in valuation allowance, changes in income tax reserves, the mix of income attributable to foreign versus domestic tax jurisdictions, state and local income taxes, non-deductible meals and entertainment, and other items.

Net Income (Loss). For the six months ended June 30, 2005, we incurred a net loss of $237.4 million, or a loss of $1.18 per share. Included in our results for the six months ended June 30, 2005 were $113.3 million in operating losses related to the HT Contract, a $57.3 million increase in the valuation allowance primarily against our U.S. deferred tax assets, and $19.6 million of lease and facilities restructuring charges. For the six months ended June 30, 2004, we incurred a net loss of $39.4 million, or a loss of $0.20 per share. Included in our results for the six months ended June 30, 2004 is $11.7 million of lease and facilities restructuring charges.

Liquidity and Capital Resources

The following table presents the cash flow statements for the six months ended June 30, 2005 and 2004 (amounts are in thousands):

	Six Months Ended June 30,		
	2005	**2004**	**2005 to 2004 Change**
Net cash provided by (used in):			
Operating activities	$ (98,592)	$ 23,950	$ (122,542)
Investing activities	(111,249)	(37,133)	(74,116)
Financing activities	251,906	28,928	222,978
	(8,513)	(2,105)	(6,408)

Effect of exchange rate changes on cash and cash equivalents			
Net increase in cash and cash equivalents	$ 33,552	$ 13,640	$ 19,912

Operating Activities. Net cash used in operating activities during the six months ended June 30, 2005 increased $122.5 million over the six months ended June 30, 2004. This increase was due to a net loss of $237.4 million, adjusted by

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stock-based compensation expense of $5.1 million during the six months ended June 30, 2005 as compared to a net loss of $39.4 million, adjusted by stock-based compensation expense of $5.0 million during the six months ended June 30, 2004. These items were partially offset by $77.0 million in cash generated from accounts receivable and unbilled revenue, primarily due to a decrease in our DSOs to 111 days at June 30, 2005 from 119 days at June 30, 2004, largely due to more aggressive collections efforts, and $24.9 million in income tax refunds received during second quarter of 2005.

Investing Activities. Net cash used in investing activities during the six months ended June 30, 2005 increased $74.1 million over the six months ended June 30, 2004. This increase was due to an increase in restricted cash of $92.8 million for cash collateral posted in support of bank guarantees for letters of credit and surety bonds, which was partially offset by a decrease in capital expenditures of $18.7 million. Capital expenditures were $18.4 million and $37.1 million in the first half of 2005 and 2004, respectively. The decline in capital expenditures was due primarily to higher hardware and software costs incurred during fiscal 2004 for the implementation of our North America financial accounting systems.

Financing Activities. Net cash provided by financing activities for the six months ended June 30, 2005 was $251.9 million, resulting primarily from the proceeds on the issuance of debentures with an aggregate principal amount of $250.0 million.

In addition, issuances of common stock from our ESPP and stock option exercises generated $14.9 million and $13.4 million in cash during the six months ended June 30, 2005 and 2004, respectively. Because we are not current in our SEC filings, we are unable to issue freely tradable shares of our common stock. Consequently, we were unable to make any public offerings of our common stock in 2005 and have not issued shares under the LTIP or the ESPP since early 2005. These sources of financing will remain unavailable to us until we are again current in our SEC filings. If we are unable to become current in our SEC filings by April 30, 2007, we may also experience increased withdrawals by our employees of their accumulated contributions to our ESPP. For more information, see Item 1A, Risk Factors, of the Company s 2005 Form 10-K, included as Exhibit 99.2 filed with this Quarterly Report.

For additional information on our liquidity and capital resources, see to Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources, included in our 2005 Form 10-K.

Recently Issued Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123 (revised 2004), Share-Based Payment (SFAS 123R), which replaces SFAS No. 123, Accounting for Stock-Based Compensation (SFAS 123), and supersedes Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees (APB 25). SFAS 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values beginning with the first reporting period following the fiscal year that begins on or after June 15, 2005. The pro forma disclosures previously permitted under SFAS 123 no longer will be an alternative to financial statement recognition. We are required to adopt SFAS 123R in the first quarter of fiscal 2006, beginning January 1, 2006. Under SFAS 123R, we must determine the appropriate fair value model to be used for valuing share-based payments, the amortization method for compensation cost and the transition method to be used at date of adoption. The transition methods include modified prospective and modified retroactive adoption options. Under the modified retroactive option, prior periods may be restated either as of the beginning of the year of adoption or for all periods presented. The modified prospective method requires that compensation expense be recorded for all unvested stock options and restricted stock at the beginning of the first quarter of adoption of SFAS 123R, while the modified retroactive method would record compensation expense for all unvested stock options and restricted stock beginning with the first period restated. In March 2005, Staff Accounting Bulletin (SAB) No. 107, Share-Based Payment (SAB 107) was issued regarding the SEC s interpretation of SFAS 123R and the valuation of share-based payments for public companies. We currently utilize the Black-Scholes option pricing model to estimate the fair value for the above pro forma calculations and will continue using the same methodology in the foreseeable future. We will use the modified prospective method for adoption of SFAS 123R, and expect that the incremental compensation cost to be recognized as a result of the adoption of SFAS 123R and SAB 107 for fiscal 2006 will range from $22.0 million to $28.0 million.

In March 2005, the FASB issued Interpretation (FIN) No. 47, Accounting for Conditional Asset Retirement Obligations (FIN 47). This is an interpretation of SFAS No. 143, Accounting for Asset Retirement Obligations (SFAS 143), which applies to all entities and addresses the legal obligations with the retirement of tangible long-lived assets that result from the acquisition, construction, development or normal operation of a long-lived asset. SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. FIN 47 further clarifies what the term conditional asset retirement obligation means with respect to recording the asset retirement obligation discussed in SFAS 143. The provisions of FIN 47 are effective no later than December 31, 2005. The adoption of FIN 47 did not have a material impact on our Consolidated Financial Statements.

In May 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections a replacement of APB Opinion No. 20 and FASB Statement No. 3 (SFAS 154). SFAS 154 replaces APB Opinion No. 20, Accounting Changes (APB 20), and SFAS No. 3, Reporting Accounting Changes in Interim Financial Statements, and changes the requirements for the accounting for and reporting of a change in accounting principle. SFAS 154 requires restatement of prior period financial statements, unless impracticable, for changes in accounting principle. The retroactive application of a change in accounting principle should be limited to the direct effect of the change. Changes in depreciation, amortization or depletion methods should be accounted for as a change in accounting estimate. Corrections of accounting errors will be accounted for under the guidance contained in APB 20. The effective date of this new pronouncement is for fiscal years beginning after December 15, 2005 and prospective application is required. We do not expect the adoption of SFAS 154 to have a material impact on our Consolidated Financial Statements.

In June 2006, the FASB issued FIN No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN 48). This interpretation clarifies the accounting for uncertainty in income taxes recognized in an entity s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. It prescribes a recognition threshold and measurement attribute for financial statement disclosure of tax positions taken or expected to be taken. This interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosures, and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006. We will be required to adopt this interpretation in the first quarter of fiscal 2007. Management is currently evaluating the requirements of FIN 48 and has not yet determined the impact on our Consolidated Financial Statements.

In September 2006, the SEC staff issued SAB No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements (SAB 108). SAB 108 was issued in order to eliminate the diversity of practice surrounding how public companies quantify financial statement misstatements. SAB 108 requires registrants to quantify the impact of correcting all misstatements using both the rollover method, which focuses primarily on the impact of a misstatement on the income statement and is the method we currently use, and the iron curtain method, which focuses primarily on the effect of correcting the period-end balance sheet. The use of both of these methods is referred to as the dual approach and should be combined with the evaluation of qualitative elements surrounding the errors in accordance with SAB No. 99, Materiality (SAB 99). We do not expect the adoption of SAB 108 to have a material impact on our Consolidated Financial Statements.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS 157). SFAS 157 defines fair value, establishes a framework for measuring fair value in accordance with generally accepted accounting principles, and expands disclosures about fair value measurements. The provisions of SFAS 157 are effective for the fiscal year beginning January 1, 2008. We are currently evaluating the impact of the provisions of SFAS 157.

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans (SFAS 158). SFAS 158 requires employers to fully recognize the obligations associated with single-employer defined benefit pension, retiree healthcare and other postretirement plans in their financial statements. The provisions of SFAS 158 are effective as of the end of the fiscal year ending December 31, 2006. We are currently evaluating the impact of the provisions of SFAS 158.

PART I, ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

For a discussion of our market risk associated with the Company s market sensitive financial instruments as of December 31, 2005, see Quantitative and Qualitative Disclosures About Market Risk in Part II, Item 7A, of the Company s 2005 Form 10-K. During the six months ended June 30, 2005, there have been no material changes in our market risk exposure.

PART I, ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As of the end of the period covered by this Quarterly Report on Form 10-Q, management performed, with the participation of our Chief Executive Officer and our Chief Financial Officer, an evaluation of the effectiveness of our disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act). Our disclosure controls and procedures are designed to ensure that information required to be disclosed in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and our Chief Financial Officer, to allow timely decisions regarding required disclosures. Based on the evaluation and the identification of the material weaknesses in internal control over financial reporting as disclosed in Form 10K for the year ended December 31, 2005, management concluded that, as of December 31, 2005 and June 30, 2005, the Company s disclosure controls and procedures were not effective.

Because of the material weaknesses identified in our evaluation of internal control over financial reporting as disclosed in Form 10K for the year ended December 31, 2005, we performed additional procedures so that our consolidated financial statements as of and for the year ended December 31, 2005, including quarterly periods, are presented in accordance with generally accepted accounting principles in the United States of America (GAAP). Our procedures included, but were not limited to: i) recalculating North America revenue and related accounts, such as accounts receivable, unbilled revenue, deferred revenue and costs of service by validating data to independent source documentation; ii) performing a comprehensive search for unrecorded liabilities; iii) performing a comprehensive global search to identify the complete population of employees deployed on expatriate assignments during 2005 and recalculating related compensation expense classified as costs of service, and employee income tax liabilities; iv) performing additional closing procedures, including detailed reviews of journal entries, re-performance of account reconciliations and analyses of balance sheet accounts; and v) performing procedures in areas related to our income taxes in order to provide reasonable assurance as to the related financial statement amounts and disclosures.

These and other procedures resulted in the identification of accounting and audit adjustments related to our consolidated financial statements for the year ended December 31, 2005 and our consolidated condensed financial statements for the three and six months ended June 30, 2005.

We believe that because we performed the substantial additional procedures described above and made appropriate adjustments, the Consolidated Condensed Financial Statements for the periods included in this Quarterly Report on Form 10-Q are fairly stated in all material respects in accordance with GAAP.

Remediation of Material Weaknesses in Internal Control over Financial Reporting

We have engaged in, and continue to engage in, substantial efforts to address the material weaknesses in our internal control over financial reporting and the ineffectiveness of our disclosure controls and procedures. We have established a formal global remediation team, under the direction of the Chief Financial Officer and Audit Committee, to drive remediation efforts of all material weaknesses, as well as provide oversight and direction in an effort to establish an effective control environment. The following paragraphs describe the on-going changes to our internal control over financial reporting subsequent to December 31, 2005 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting:

We significantly strengthened our executive management team, including the appointment of a GAAP Policy Group (Q4 05), Corporate Tax Director (Q1 06) & Assistant Corporate Tax Director (Q1 06), General Counsel (Q2 06), Treasurer (Q2 06), Director of Internal Audit (Q2 06), Chief Risk Officer (Q2 06), Chief Compliance Officer (Q2 06), and Chief Information Officer (Q2 06). We also hired a Senior Controller within our Public Service line of business (Q1 06). Additionally, we replaced the regional and certain country-level leaders in our Asia Pacific region.

We have strengthened our ongoing communication by senior management of the importance of adherence to internal controls and company policies. We established a worldwide policies & procedures program management office in September 2005. This function is housed within the Office of the Chief Compliance Officer, as a component of the Company s overall remediation efforts. It is designed to govern policies and procedures across the Company and to increase employee understanding of and compliance with policies and procedures. We have established a policy management methodology. We are also standardizing global policies and developing a library and supporting technology to provide employees a single access point for all Company policies and procedures, and we are striving to achieve improved operational efficiencies and compliance with those established policies and procedures.

During the second quarter of fiscal 2006 we began to implement certain initiatives in relation to the identification and monitoring of employees working away from their principal residence for extended periods of time.

We commenced planning, designing and implementing new processes, adding new people, training employees, and building/buying new technology all of which is expected to assist in this initiative. In addition these actions will allow for the improved accuracy of the related compensation expense and income tax liability attributable to both the individual employee and the Company.

During the second quarter of fiscal 2005 and continuing into fiscal 2006, we began implementing a finance transformation program. This program is designed to develop and implement remediation strategies to address the material weaknesses, improve operational performance of our finance and accounting processes and underlying information systems, establish greater organizational accountability and lines of approval, and develop an organizational model that better supports our redesigned processes and operations. In the second quarter of fiscal 2006, we began designing and implementing a revised closing procedure. The procedures are designed to improve the closing process in an effort to allow us to meet our filing requirements on a timely basis, as well as improve the accuracy of the financial information.

During fiscal 2005, we substantially improved our compliance hotline. Specifically, we continue to improve our investigative procedures surrounding the detection and resolution of internal control overrides. Third-party legal and accounting resources have also been retained to perform in depth reviews of issues in a timely manner. Additionally, remediation activities have been undertaken in response to senior management and Audit Committee investigations of internal control overrides.

We continue to dedicate substantial resources (employees and outside accounting professionals and consultants) to our finance, accounting and tax departments. The number of resources in this area has substantially increased during the first three quarters of fiscal 2006. We continue to recognize the changing requirements of our business and the regulatory environment. We continue to manage the required competencies through staff increases and executive management involvement in the day to day operations of the Company.

During the fourth quarter of fiscal 2005 we began to implement, and throughout fiscal 2006 the Company deployed, a significant Program Control function, currently consisting of approximately 200 professionals, designed to support the completeness and accuracy of project accounting details in North America. This function is comprised of individuals with a mix of experience in accounting, government contracting, auditing, and controlling functions. This function will actively support the proper and timely evaluation of contracts using comprehensive revenue recognition guidance checklists with additional support provided by the Company s GAAP Policy group for complex evaluations. The Program Control function will also support the timely assembly and review of revenue and other cost elements as part of the Company s quarterly update of each contract s estimate to complete, estimate at complete, revenue, accounts receivable, unbilled revenue, and deferred revenue.

During the first quarter of fiscal 2006, the Company completed the design and development of an application to automate the comprehensive review of contract and project set-up data within the accounting system. The application is undergoing user acceptance testing and will be deployed thereafter. Combined with other process changes, enhanced controls, workflow and reporting this application will improve the overall accuracy and timely update of contract and project data in North America.

During fiscal 2005, we provided additional training materials to certain US employees regarding the estimate to complete process. Our Public Services Business Unit also continues to conduct government compliance training for all employees including timekeeping certification.

During the first quarter of fiscal 2006, the Company began to design, develop, and deploy an application referred to as the Project Control Workbench. Combined with other process changes, enhanced controls, and reporting, this application will improve the accuracy and timeliness of submission of project accounting data needed for estimate-to-complete, and revenue recognition in North America.

In the third quarter of fiscal 2006, we implemented an Engagement Financial Management Toolkit. This web-based initiative is designed to provide North America employees with key forms, policies, training, and reference materials to assist in both compliance with standard policies and procedures.

During the third quarter of fiscal 2006 we implemented on a pilot basis, and will fully implement in the fourth quarter of fiscal 2006, an E-Invoicing system for supplier billing in North America in order to systematically receive supplier invoices, track, process, and record amounts due to vendors, including subcontractors. The application will enable the timely recording, tracking, and processing of outstanding supplier obligations in North America.

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Management has made significant progress towards achieving an operationally effective control environment. The remediation efforts noted above are subject to the Company s internal control assessment, testing and evaluation processes. While these efforts continue, we will rely on additional substantive procedures and other measures as needed to assist us with meeting the objectives otherwise fulfilled by an effective control environment. As a result, we expect that our internal control over financial reporting will not be effective as of December 31, 2006.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal control over financial reporting during the most recently completed fiscal quarter 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

Please refer to Note 10, Commitments and Contingencies, of the Notes to Consolidated Condensed Financial Statements and Item 3, Legal Proceedings, included in the Company s 2005 Form 10-K and filed as Exhibit 99.1 to this Quarterly Report, which sections are incorporated herein by reference.

ITEM 1A: RISK FACTORS

Please refer to Item 1A, Risk Factors, included in the Company s 2005 Form 10-K, which section is incorporated herein by reference and filed as Exhibit 99.2 to this Quarterly Report.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Sales of Securities Not Registered Under the Securities Act

Please refer to Item 5, Market for the Registrant s Common Stock, Related Stockholder Matters and Issuer Purchases of Equity Securities Sales of Securities Not Registered under the Securities Act, included in the Company s 2005 Form 10-K, which section is incorporated herein by reference and filed as Exhibit 99.3 to this Quarterly Report.

Issuer Purchases of Equity Securities

We did not repurchase any of our common stock during the second quarter of fiscal 2005.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

There were no matters submitted to a vote of security holders during the second quarter of fiscal 2005.

ITEM 5. OTHER INFORMATION

a) None.

b) None.

ITEM 6. EXHIBITS

a) Exhibits

Exhibit No.	Description
3.1	Amended and Restated Certificate of Incorporation, dated as of February 7, 2001, which is incorporated herein by reference to Exhibit 3.1 from the Company s Form 10-Q for the quarter ending March 31, 2001.
3.2	Amended and Restated Bylaws, amended and restated as of May 5, 2004, which is incorporated herein by reference to Exhibit 3.1 from the Company s Form 10-Q for the quarter ending March 31, 2004.
3.3	Certificate of Ownership and Merger merging Bones Holding into the Company, dated October 2, 2002, which is incorporated herein by reference to Exhibit 3.3 from the Company s Form 10-Q for the quarter ended September 30, 2002.
4.1	Rights Agreement, dated as of October 2, 2001, between the Company and EquiServe Trust Company, N.A., which is incorporated herein by reference to Exhibit 1.1 from the Company s Registration Statement on Form 8-A dated October 3, 2001.
4.2	Certificate of Designation of Series A Junior Participating Preferred Stock, which is incorporated herein by reference to Exhibit 1.2 from the Company s Registration Statement on Form 8-A dated October 3, 2001.
4.3	Amendment No. 1 to the Rights Agreement between the Company and EquiServe Trust Company, N.A., which is incorporated herein by reference to Exhibit 99.1 from the Company s Form 8-K filed on September 6, 2002.
10.1	Amendment No. 2 to Amended and Restated 401(k) Plan dated June 24, 2005, which is incorporated by reference to Exhibit 10.24 from the Company s Form 10-K for the year ended December 31, 2004.
10.2	Amendment No. 1 to Security Agreement, dated as of April 26, 2005, among the Company, the Guarantors and Bank of America, N.A., as Administrative Agent, which is incorporated by reference to Exhibit 10.49 from the Company s Form 10-K for the year ended December 31, 2004.
10.3	Amendment No. 1 to Guaranty Agreement, dated as of April 26, 2005, among the Company, the Guarantors and Bank of America, N.A., as Administrative Agent, which is incorporated by reference to Exhibit 10.51 from the Company s Form 10-K for the year ended December 31, 2004.
10.4	Letter of Credit Cash Collateral Agreement, dated as of April 26, 2005, by and among BearingPoint, Inc., the Administrative Agent and each of Bank of America, N.A. and JPMorgan Chase Bank, N.A., which is incorporated by reference to Exhibit 10.52 from the Company s Form 10-K for the year ended December 31, 2004.
10.5	Form of 5.00% Convertible Senior Subordinated Debentures due 2025, which is incorporated by reference to Exhibit 10.71 from the Company s Form 10-K for the year ended December 31, 2004.
10.6	Form of Securities Purchase Agreement, dated April 21, 2005, among the Company and the purchasers named therein, which is incorporated by reference to Exhibit 10.72 from the Company s Form 10-K for the year ended December 31, 2004.
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	Indenture, dated as of April 27, 2005, by and between the Company and the Bank of New York, as trustee, which is incorporated by reference to Exhibit 99.2 from the Company s Form 8-K filed on March 10, 2006.
10.8	Registration Rights Agreement, dated April 27, 2005, between the Company and the placement agents, which is incorporated by reference to Exhibit 10.74 from the Company s Form 10-K for the year ended December 31, 2004.
10.9	Independent Contractor Letter Agreement, dated May 24, 2005 between the Company and Joseph Corbett, which is incorporated by reference to Exhibit 10.85 from the Company s Form 10-K for the year ended December 31, 2004.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a).
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a).
32.1	Certification of Chief Executive Officer pursuant to Section 1350.

Exhibit No.	Description
32.2	Certification of Chief Financial Officer pursuant to Section 1350.
99.1	Legal Proceedings section of the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2005.
99.2	Risk Factors section of the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2005.
99.3	Market for the Registrant s Common Stock, Related Stockholder Matters and Issuer Purchases of Equity Securities Sales of Securities Not Registered under the Securities Act section of the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2005.

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.

BearingPoint, Inc.

DATE: January 17, 2007	By: /s/ Judy A. Ethell
	Judy A. Ethell **Chief Financial Officer**

Exhibit Index

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99.2 Risk Factors section of the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2005.

99.3 Market for the Registrant s Common Stock, Related Stockholder Matters and Issuer Purchases of Equity Securities Sales of Securities Not Registered under the Securities Act section of the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2005.

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Other

Cost/Equity	26	18		$422	$444

(a) The carrying value of our investment in Frac Tech is in excess of our underlying equity in net assets by approximately $145 million as of September 30, 2009. This excess amount is attributed to certain intangibles associated with the specialty services provided by Frac Tech and is being amortized over the estimated life of the intangibles.

(b) Our investees have been impacted by the dramatic slowing of the worldwide economy and the tightening of the credit markets in the fourth quarter of 2008 and into 2009. The economic weakness has resulted in significantly reduced oil and natural gas prices leading to a meaningful decline in the overall level of activity in the markets served by our investees. Associated with the weakness in performance of certain of the investees, as well as an evaluation of their financial condition and near-term prospects, we recognized during the Current Period that an other than temporary impairment had occurred on March 31, 2009 on the following investments: Chaparral Energy of $51 million, DHS Drilling Company of $19 million, Gastar Exploration Ltd. of $70 million and Mountain Drilling Company of $9 million. We have monitored and will continue to monitor the performance of our investments and it is reasonably possible that we may experience additional impairments, although we do not believe that our exposure to future charges would be material to our condensed consolidated results of operations.

(c) The carrying value of our investment in Chaparral is in excess of our underlying equity in net assets by approximately $46 million as of September 30, 2009. This excess is attributed to the natural gas and oil reserves held by Chaparral and is being amortized over the estimated life of these reserves based on a unit of production rate.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

12. Fair Value Measurements

Effective January 1, 2008, we adopted ASC 820, *Fair Value Measurements and Disclosures* for our financial assets and liabilities measured on a recurring basis. Our nonfinancial assets and liabilities became subject to the statement effective January 1, 2009. This statement establishes a framework for measuring the fair value of assets and liabilities and expands disclosures about fair value measurements.

ASC 820 defines fair value as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the financial asset or liability and have the lowest priority. Chesapeake uses appropriate valuation techniques based on available inputs, including counterparty quotes, to measure the fair values of its assets and liabilities. Counterparty quotes are generally assessed as a Level 3 input.

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of September 30, 2009:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
Financial Assets (Liabilities):				
Cash equivalents	$ 510	$	$	$ 510
Derivatives, net	$	$ 351	$ (8)	$ 343
Investments	$ 33	$	$	$ 33
Other long-term assets	$ 30	$	$	$ 30
Long-term debt	$	$	$ (2,048)	$ (2,048)
Other long-term liabilities	$ (30)	$	$	$ (30)

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Level 1 Fair Value Measurements

Cash Equivalents. The fair value of cash equivalents is based on quoted market prices.

Investments. The fair value of Chesapeake s investment in Gastar Exploration Ltd. common stock is based on a quoted market price.

Other Long-Term Assets and Liabilities. The fair value of other long-term assets and liabilities, consisting of obligations under our Deferred Compensation Plan, is based on quoted market prices.

Level 2 Fair Value Measurements

Derivatives. The fair values of our natural gas, oil and diesel swaps are measured internally using established index prices and other sources. These values are based upon, among other things, futures prices and time to maturity. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Level 3 Fair Value Measurements

Derivatives. The fair value of our derivative instruments, excluding natural gas, oil and diesel swaps, have been established utilizing established index prices, volatility curves, discount factors and options pricing models. These estimates are compared to our counterparty values for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives.

Debt. The fair value of certain of our long-term debt is based on the face amount of that debt along with the value of the related interest rate swaps. The interest rate swap values are based on estimates provided by our respective counterparties and reviewed internally for reasonableness using future interest rate curves and time to maturity.

A summary of the changes in Chesapeake s assets (liabilities) classified as Level 3 measurements during the Current Period is presented below:

	Derivatives	Debt ($ in millions)	Total
Balance of Level 3 as of January 1, 2009	$ 292	$ (1,470)	$ (1,178)
Total gains (losses) (realized/unrealized):			
Included in earnings[(a)]	566	(128)	438
Included in other comprehensive income (loss)	123		123
Purchases, issuances and settlements	(989)	(450)[(b)]	(1,439)
Transfers in and out of Level 3			
Balance of Level 3 as of September 30, 2009	$ (8)	$ (2,048)	$ (2,056)

(a)

	Natural Gas and Oil Sales	Interest Expense
	($ in millions)	
Total gains (losses) related to derivatives included in earnings for the period	$ 398	$ 168
Change in unrealized gains (losses) relating to assets still held at reporting date	$ (380)	$ 149

(b) Amount represents a reduction in debt now recorded at fair value as a result of interest rate swaps that were terminated in the Current Period.

Fair Value of Other Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of ASC 825, *Financial Instruments*. We have determined the estimated fair values by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values of financial instruments comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term debt and our convertible preferred stock primarily using quoted market prices. Our carrying amounts for such debt, excluding the impact of interest rate derivatives, at September 30, 2009 and December 31, 2008 were $11.9 billion and $13.0 billion, respectively, compared to approximate fair values of $11.7 billion and $10.5 billion, respectively. The carrying amounts for our convertible preferred stock as of September 30, 2009 and December 31, 2008 were $466 million and $505 million, respectively, compared to approximate fair values of $402 million and $294 million, respectively.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Condensed Consolidating Financial Information

Chesapeake Energy Corporation is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. As of September 30, 2008, our obligations under our outstanding senior notes and contingent convertible senior notes listed in Note 6 were fully and unconditionally guaranteed, jointly and severally, by all of our wholly-owned subsidiaries, other than minor subsidiaries, on a senior unsecured basis. Since October 2008, following the restructuring of our non-Appalachian midstream operations, certain of our wholly-owned subsidiaries having significant assets and operations have not guaranteed our outstanding notes. The CMD credit facility and the CMP credit facility referred to in Note 6 each contain a covenant restricting the payment of dividends or distributions or the making of loans to Chesapeake.

Set forth below are condensed consolidating financial statements for Chesapeake Energy Corporation (the parent) on a stand-alone, unconsolidated basis, and its combined guarantor and combined non-guarantor subsidiaries as of September 30, 2009 and December 31, 2008 and for the three and nine months ended September 30, 2009 and 2008. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the subsidiaries operated as independent entities.

CONDENSED CONSOLIDATING BALANCE SHEET

AS OF SEPTEMBER 30, 2009

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 363	$ 157	$	$ 520
Other	9	1,831	208	(60)	1,988
Total Current Assets	9	2,194	365	(60)	2,508
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full-cost accounting		20,527	205		20,732
Other property and equipment		2,820	2,826		5,646
Total Property and Equipment		23,347	3,031		26,378
Other assets	201	608	24		833
Investments in subsidiaries and intercompany advance	3,738	244		(3,982)	
TOTAL ASSETS	$ 3,948	$ 26,393	$ 3,420	$ (4,042)	$ 29,719
CURRENT LIABILITIES:					
Current liabilities	$ 211	$ 2,231	$ 133	$ (61)	$ 2,514
Intercompany payable (receivable) from parent	(19,118)	17,091	2,012	15	

Total Current Liabilities	(18,907)	19,322	2,145	(46)	2,514
LONG-TERM LIABILITIES:					
Long-term debt, net	10,443	1,618	12		12,073
Deferred income tax liabilities	311	860	159	(14)	1,316
Other liabilities	123	855	9		987
Total Long-Term Liabilities	10,877	3,333	180	(14)	14,376
EQUITY:					
Chesapeake stockholders equity	11,978	3,738	244	(3,982)	11,978
Noncontrolling interest			851		851
Total Equity	11,978	3,738	1,095	(3,982)	12,829
TOTAL LIABILITIES AND EQUITY	$ 3,948	$ 26,393	$ 3,420	$ (4,042)	$ 29,719

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING BALANCE SHEET

AS OF DECEMBER 31, 2008

(Adjusted)

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 1,749	$	$	$ 1,749
Other	13	2,392	169	(31)	2,543
Total Current Assets	13	4,141	169	(31)	4,292
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full-cost accounting		28,474	4		28,478
Other property and equipment		2,481	2,349		4,830
Total Property and Equipment		30,955	2,353		33,308
Other assets	140	838	15		993
Investments in subsidiaries and intercompany advance	8,452	143		(8,595)	
TOTAL ASSETS	$ 8,605	$ 36,077	$ 2,537	$ (8,626)	$ 38,593
CURRENT LIABILITIES:					
Current liabilities	$ 257	$ 3,324	$ 131	$ (91)	$ 3,621
Intercompany payable (receivable) from parent	(18,274)	16,636	1,578	60	
Total Current Liabilities	(18,017)	19,960	1,709	(31)	3,621
LONG-TERM LIABILITIES:					
Long-term debt, net	9,241	3,474	460		13,175
Deferred income tax liabilities	438	3,543	219		4,200
Other liabilities	(74)	648	6		580
Total Long-Term Liabilities	9,605	7,665	685		17,955
EQUITY:					

Chesapeake stockholders equity		17,017		8,452		143		(8,595)		17,017
Noncontrolling interest										
Total Equity		17,017		8,452		143		(8,595)		17,017
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$	8,605	$	36,077	$	2,537	$	(8,626)	$	38,593

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Three Months Ended September 30, 2009:					
REVENUES:					
Natural gas and oil sales	$	$ 1,184	$ 3	$	$ 1,187
Marketing, gathering and compression sales		504	126	(55)	575
Service operations revenue		49			49
Total Revenues		1,737	129	(55)	1,811
OPERATING COSTS:					
Production expenses		217	1		218
Production taxes		25			25
General and administrative expenses		86	9		95
Marketing, gathering and compression expenses		517	54	(25)	546
Service operations expense		49			49
Natural gas and oil depreciation, depletion and amortization		293	2		295
Depreciation and amortization of other assets	1	36	26	(1)	62
Impairment of natural gas and oil properties and other assets			86		86
Loss on sale of other property and equipment			38		38
Restructuring costs					
Total Operating Costs	1	1,223	216	(26)	1,414
INCOME (LOSS) FROM OPERATIONS	(1)	514	(87)	(29)	397
OTHER INCOME (EXPENSE):					
Other income (expense)	175	(30)		(175)	(30)
Interest expense	(161)	(57)		175	(43)
Loss on exchanges of Chesapeake debt	(17)				(17)
Equity in net earnings of subsidiary	195	(72)		(123)	
Total Other Income (Expense)	192	(159)		(123)	(90)
INCOME (LOSS) BEFORE INCOME TAXES	191	355	(87)	(152)	307
INCOME TAX EXPENSE (BENEFIT)	(1)	160	(33)	(11)	115
NET INCOME (LOSS)	192	195	(54)	(141)	192
Net income (loss) attributable to noncontrolling interest					

NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE COMMON STOCKHOLDERS	$	192	$	195	$	(54)	$	(141)	$	192

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

(Adjusted)

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Three Months Ended September 30, 2008:					
REVENUES:					
Natural gas and oil sales	$	$ 6,408	$	$	$ 6,408
Marketing, gathering and compression sales		994	87	(43)	1,038
Service operations revenue		45			45
Total Revenues		7,447	87	(43)	7,491
OPERATING COSTS:					
Production expenses		239			239
Production taxes		87			87
General and administrative expenses		104	4		108
Marketing, gathering and compression expenses		984	34	(4)	1,014
Service operations expense		37			37
Natural gas and oil depreciation, depletion and amortization		480			480
Depreciation and amortization of other assets	(1)	36	12	1	48
Total Operating Costs	(1)	1,967	50	(3)	2,013
INCOME (LOSS) FROM OPERATIONS	1	5,480	37	(40)	5,478
OTHER INCOME (EXPENSE):					
Other income (expense)	186	(19)	7	(186)	(12)
Interest expense	(160)	(60)		186	(34)
Loss on exchanges of Chesapeake debt	(31)				(31)
Equity in net earnings of subsidiary	3,324	2		(3,326)	
Total Other Income (Expense)	3,319	(77)	7	(3,326)	(77)
INCOME (LOSS) BEFORE INCOME TAXES	3,320	5,403	44	(3,366)	5,401
INCOME TAX EXPENSE (BENEFIT)	(2)	2,079	17	(15)	2,079
NET INCOME (LOSS)	3,322	3,324	27	(3,351)	3,322
Net income (loss) attributable to noncontrolling interest					
	$ 3,322	$ 3,324	$ 27	$ (3,351)	$ 3,322

NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE COMMON STOCKHOLDERS

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Nine Months Ended September 30, 2009:					
REVENUES:					
Natural gas and oil sales	$	$ 3,678	$ 3	$	$ 3,681
Marketing, gathering and compression sales		1,461	354	(155)	1,660
Service operations revenue		139			139
Total Revenues		5,278	357	(155)	5,480
OPERATING COSTS:					
Production expenses		670			670
Production taxes		71			71
General and administrative expenses		239	20		259
Marketing, gathering and compression expenses		1,436	148	(15)	1,569
Service operations expense		136			136
Natural gas and oil depreciation, depletion and amortization		1,035	2		1,037
Depreciation and amortization of other assets		110	67		177
Impairment of natural gas and oil properties and other assets		9,635	86		9,721
Loss on sale of other property and equipment			38		38
Restructuring costs		34			34
Total Operating Costs		13,366	361	(15)	13,712
INCOME (LOSS) FROM OPERATIONS		(8,088)	(4)	(140)	(8,232)
OTHER INCOME (EXPENSE):					
Other income (expense)	512	(27)	2	(512)	(25)
Interest expense	(447)	(112)	(5)	512	(52)
Impairment of investments		(148)	(14)		(162)
Loss on exchanges of Chesapeake debt	(19)				(19)
Equity in net earnings of subsidiary	(5,335)	(101)		5,436	
Total Other Income (Expense)	(5,289)	(388)	(17)	5,436	(258)
INCOME (LOSS) BEFORE INCOME TAXES	(5,289)	(8,476)	(21)	5,296	(8,490)
INCOME TAX EXPENSE (BENEFIT)	17	(3,141)	(8)	(52)	(3,184)
NET INCOME (LOSS)	(5,306)	(5,335)	(13)	5,348	(5,306)
Net income (loss) attributable to noncontrolling interest					

NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE COMMON STOCKHOLDERS	$	(5,306)	$	(5,335)	$	(13)	$	5,348	$	(5,306)

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

(Adjusted)

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Nine Months Ended September 30, 2008:					
REVENUES:					
Natural gas and oil sales	$	$ 5,587	$	$	$ 5,587
Marketing, gathering and compression sales		2,810	235	(111)	2,934
Service operations revenue		127			127
Total Revenues		8,524	235	(111)	8,648
OPERATING COSTS:					
Production expenses		658			658
Production taxes		250			250
General and administrative expenses		279	9		288
Marketing, gathering and compression expenses		2,767	97		2,864
Service operations expense		104			104
Natural gas and oil depreciation, depletion and amortization		1,518			1,518
Depreciation and amortization of other assets		92	32		124
Total Operating Costs		5,668	138		5,806
INCOME (LOSS) FROM OPERATIONS		2,856	97	(111)	2,842
OTHER INCOME (EXPENSE):					
Other income (expense)	525	(29)	6	(525)	(23)
Interest expense	(426)	(285)		525	(186)
Loss on exchanges of Chesapeake debt	(31)				(31)
Equity in net earnings of subsidiary	1,558	(5)		(1,553)	
Total Other Income (Expense)	1,626	(319)	6	(1,553)	(240)
INCOME (LOSS) BEFORE INCOME TAXES	1,626	2,537	103	(1,664)	2,602
INCOME TAX EXPENSE (BENEFIT)	26	979	40	(43)	1,002
NET INCOME (LOSS)	1,600	1,558	63	(1,621)	1,600
Net income (loss) attributable to noncontrolling interest					
	$ 1,600	$ 1,558	$ 63	$ (1,621)	$ 1,600

NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE COMMON STOCKHOLDERS

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Nine Months Ended September 30, 2009:					
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 3,074	$ 57	$	$ 3,131
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(3,475)	(199)		(3,674)
Proceeds from divestitures of natural gas and oil properties		1,729			1,729
Additions to other property and equipment		(661)	(701)		(1,362)
Other investing activities		(386)	39		(347)
Cash used in investing activities		(2,793)	(861)		(3,654)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings		4,894	669		5,563
Payments on credit facilities borrowings		(6,749)	(1,117)		(7,866)
Proceeds from issuance of senior notes, net of offering costs	1,346				1,346
Proceeds from sales of noncontrolling, interest in midstream joint venture			588		588
Other financing activities	(153)	(167)	(17)		(337)
Intercompany advances, net	(1,193)	355	838		
Cash provided by financing activities		(1,667)	961		(706)
Net increase (decrease) in cash and cash equivalents		(1,386)	157		(1,229)
Cash and cash equivalents, beginning of period		1,749			1,749
Cash and cash equivalents, end of period	$	$ 363	$ 157	$	$ 520

	Parent	(Adjusted) Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Nine Months Ended September 30, 2008:					
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 4,234	$ 153	$	$ 4,387
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(11,922)			(11,922)
Proceeds from divestitures of natural gas oil properties		5,858	18		5,876
Additions to other property and equipment		(1,204)	(765)		(1,969)
Other investing activities		(268)			(268)
Cash used in investing activities		(7,536)	(747)		(8,283)

CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings		12,831			12,831
Payments on credit facilities borrowings		(11,307)			(11,307)
Proceeds from issuance of senior notes, net of offering costs	2,136				2,136
Proceeds from issuance of common stock, net of offering costs	2,598				2,598
Other financing activities	(405)	6			(399)
Intercompany advances, net	(4,329)	3,735	594		
Cash provided by financing activities		5,265	594		5,859
Net increase (decrease) in cash and cash equivalents		1,963			1,963
Cash and cash equivalents, beginning of period		1			1
Cash and cash equivalents, end of period	$	$ 1,964	$	$	$ 1,964

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

14. Recently Issued and Proposed Accounting Standards

The FASB recently issued the following standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

On December 31, 2008, the Securities and Exchange Commission (SEC) adopted major revisions to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves and that allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new disclosure requirements also require companies to report the independence and qualifications of the person primarily responsible for the preparation or audit of reserve estimates, and to file reports when a third party is relied upon to prepare or audit reserves estimates. The new rules also require that oil and gas reserves be reported and the full-cost ceiling value calculated using an average price based upon the prior 12-month period. The new oil and gas reporting requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, with early adoption not permitted. We are in the process of assessing the impact of these new requirements on our financial position, results of operations and financial disclosures.

In June 2009, the FASB issued SFAS No. 167, *Amendments to FASB Interpretation No. 46(R)*. Among other items, SFAS 167 responds to concerns about the application of certain key provisions of FIN 46(R), including those regarding the transparency of the involvement with variable interest entities. SFAS 167 is effective for calendar year companies beginning on January 1, 2010. We are currently assessing the impact that adoption of SFAS 167 will have on our financial position, results of operations, cash flows or disclosures.

In June 2009, the FASB issued Accounting Standards Update (ASU) 2009-01, *The FASB Accounting Standards Codification™ and the Hierarchy of Generally Accepted Accounting Principles*. This standard replaces SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles,* and establishes only two levels of U.S. GAAP, authoritative and nonauthoritative. The FASB Accounting Standards Codification has become the single source of authoritative nongovernmental U.S. GAAP, except for rules and interpretive releases of the SEC, which are sources of authoritative U.S. GAAP for SEC registrants. This standard is effective for financial statements for interim or annual reporting periods ended after September 15, 2009. We began to use the new guidelines and numbering system prescribed by the Codification when referring to GAAP in the Current Quarter. As the Codification was not intended to change or alter existing GAAP, it did not have any impact on our consolidated financial statements.

In August 2009, the FASB issued ASU 2009-05, *Fair Value Measurements and Disclosures (Topic 820) Measuring Liabilities at Fair Value*. This update provides clarification for the fair value measurement of liabilities. ASU 2009-05 is effective for the first reporting period beginning after issuance and we have adopted its provisions in the Current Quarter. ASU 2009-05 did not have a significant impact on our financial position, results of operations, cash flows or disclosures.

15. Subsequent Events

Subsequent to September 30, 2009, holders of $125 million of our 2.25% Contingent Convertible Senior Notes due 2038 exchanged their senior notes for 3.5 million shares of common stock in privately negotiated exchanges. The difference between the fair value of the notes that were exchanged and the fair value of the common stock issued will be recorded as a loss on exchange of debt of approximately $21 million.

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ITEM 2. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***
Overview

The following table sets forth certain information regarding the production volumes, natural gas and oil sales, average sales prices received, other operating income and expenses for the three and nine months ended September 30, 2009 (the Current Quarter and the Current Period) and the three and nine months ended September 30, 2008 (the Prior Quarter and the Prior Period):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008 (Adjusted)	2009	2008 (Adjusted)
Net Production:				
Natural gas (mmcf)	210,292	196,657	610,323	579,423
Oil (mbbls)	3,027	2,810	9,053	8,372
Natural gas equivalent (mmcfe)	228,454	213,517	664,641	629,655
Natural Gas and Oil Sales ($ in millions):				
Natural gas sales	$ 596	$ 1,717	$ 1,819	$ 5,046
Natural gas derivatives realized gains (losses)	675	(140)	1,771	(174)
Natural gas derivatives unrealized gains (losses)	(275)	3,854	(398)	325
Total natural gas sales	996	5,431	3,192	5,197
Oil sales	189	319	461	915
Oil derivatives realized gains (losses)	12	(106)	31	(280)
Oil derivatives unrealized gains (losses)	(10)	764	(3)	(245)
Total oil sales	191	977	489	390
Total natural gas and oil sales	$ 1,187	$ 6,408	$ 3,681	$ 5,587
Average Sales Price (excluding all gains (losses) on derivatives):				
Natural gas ($ per mcf)	$ 2.84	$ 8.73	$ 2.98	$ 8.71
Oil ($ per bbl)	$ 62.47	$ 113.53	$ 50.97	$ 109.28
Natural gas equivalent ($ per mcfe)	$ 3.44	$ 9.54	$ 3.43	$ 9.47
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Natural gas ($ per mcf)	$ 6.04	$ 8.02	$ 5.88	$ 8.41
Oil ($ per bbl)	$ 66.42	$ 75.74	$ 54.37	$ 75.82
Natural gas equivalent ($ per mcfe)	$ 6.44	$ 8.38	$ 6.14	$ 8.75
Other Operating Income (Loss)[a] ($ in millions):				
Marketing, gathering and compression	$ 29	$ 24	$ 91	$ 70
Service operations	$	$ 8	$ 3	$ 23
Other Operating Income (Loss)[a] ($ per mcfe):				
Marketing, gathering and compression	$ 0.13	$ 0.11	$ 0.14	$ 0.11
Service operations	$	$ 0.04	$	$ 0.04
Expenses ($ per mcfe):				
Production expenses	$ 0.96	$ 1.12	$ 1.01	$ 1.04
Production taxes	$ 0.11	$ 0.41	$ 0.11	$ 0.40
General and administrative expenses	$ 0.42	$ 0.51	$ 0.39	$ 0.46

Natural gas and oil depreciation, depletion and amortization	$ 1.29	$ 2.25	$ 1.56	$ 2.41
Depreciation and amortization of other assets	$ 0.27	$ 0.22	$ 0.27	$ 0.20
Interest expense[(b)]	$ 0.28	$ 0.20	$ 0.24	$ 0.31
Interest Expense ($ in millions):				
Interest expense	$ 70	$ 37	$ 177	$ 194
Interest rate derivatives realized (gains) losses	(7)	5	(19)	1
Interest rate derivatives unrealized (gains) losses	(20)	(8)	(106)	(9)
Total interest expense	$ 43	$ 34	$ 52	$ 186
Net Wells Drilled	224	455	700	1,388
Net Producing Wells as of the End of the Period	22,749	22,475	22,749	22,475

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

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

We are one of the leading producers of natural gas in the United States. We own interests in approximately 43,600 producing natural gas and oil wells that are currently producing approximately 2.6 bcfe per day, 93% of which is natural gas. Our strategy is focused on discovering, acquiring and developing conventional and unconventional natural gas reserves onshore in the U.S., primarily in the Big 4 natural gas shale plays: the Barnett Shale in the Fort Worth Basin of north-central Texas, the Haynesville Shale in the Ark-La-Tex area of northwestern Louisiana and East Texas, the Fayetteville Shale in the Arkoma Basin of central Arkansas and the Marcellus Shale in the northern Appalachian Basin of West Virginia, Pennsylvania and New York. We also have substantial operations in various other plays, both conventional and unconventional, in the Mid-Continent, Appalachian Basin, Permian Basin, Delaware Basin, South Texas, Texas Gulf Coast and Ark-La-Tex regions of the United States.

During the Current Period, Chesapeake continued the industry s most active drilling program drilling 853 gross operated wells (624 net with an average working interest of 73%) and participating in another 864 gross wells operated by other companies (76 net with an average working interest of 9%). The company s drilling success rate was 99% for company-operated wells and 98% for non-operated wells. Also during the Current Period, we invested $2.211 billion in operated wells (using an average of 102 operated rigs) and $330 million in non-operated wells (using an average of 57 non-operated rigs) for total drilling, completing and equipping costs of $2.541 billion (net of carries).

Our total Current Quarter production was 228.5 bcfe, comprised of 210.3 bcf (92% on a natural gas equivalent basis) and 3.027 mmbbls of oil and natural gas liquids (8% on a natural gas equivalent basis). Daily production for the Current Quarter averaged 2.483 bcfe, an increase of 162 mmcfe, or 7%, over the 2.321 bcfe produced per day in the Prior Quarter. Adjusted for our 2009 voluntary production curtailments due to low natural gas prices and involuntary production curtailments due to pipeline repairs (which together averaged approximately 45 mmcfe per day during the Current Quarter), our 2009 and third and fourth quarter 2008 volumetric production payment transactions (which combined averaged approximately 125 mmcfe per day during the Current Quarter) and the estimated impact from various divestitures (which would have averaged approximately 105 mmcfe per day during the Current Quarter), our year over year production growth rate would have been 14% after making similar adjustments to prior quarters.

Chesapeake began 2009 with estimated proved reserves of 12.051 tcfe and ended the Current Period with 11.994 tcfe, a decrease of 57 bcfe, or 0.5%. During the Current Period, we replaced 665 bcfe of production with an internally estimated 608 bcfe of new proved reserves, for a reserve replacement rate of 91%. The Current Period s reserve movement included 1.455 tcfe of extensions, 1.503 tcfe of positive performance revisions, 2.164 tcfe of downward revisions resulting primarily from a decrease in natural gas prices between December 31, 2008 and September 30, 2009 and 186 bcfe of net divestitures. Based on our current drilling schedule and budget, we expect that virtually all of the proved undeveloped reserves added in 2009 will begin producing within the next three to five years. Generally, proved developed reserves are producing at the time they are added or will begin producing within one year.

Since 2000, Chesapeake has built the largest combined inventories of onshore leasehold (14.1 million net acres) and 3-D seismic (23.3 million acres) in the U.S. and the largest inventory of U.S. Big 4 Shale play leasehold (2.8 million net acres). We are currently using 105 operated drilling rigs to further develop our inventory of approximately 36,000 net drillsites, which represents more than a 10-year inventory of drilling projects.

Our high level of hedging at attractive prices should continue to insulate us from potentially soft near-term natural gas prices during the remainder of 2009. We also believe that the remaining joint venture drilling carries of approximately $2.1 billion will enhance returns on invested capital, reduce our capital expenditures and improve our balance sheet.

Our debt, net of cash on hand, as a percentage of total capitalization (total capitalization is the sum of debt, net of cash on hand, and equity) was 47% as of September 30, 2009 and 40% as of December 31, 2008. The increase in this percentage is primarily due to the reduction of equity as the result of a $5.3 billion net loss caused by impairments of natural gas and oil properties and other assets of $9.7 billion in the Current Period. The average maturity of our long-term debt is over seven years with an average coupon interest rate of approximately 6.2%. No scheduled principal payments are required under our senior notes until 2013 when $864 million is due.

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Business Strategy

Our exploration, development and acquisition activities require us to make substantial capital expenditures. Through the middle of 2008, we increased our capital expenditure budget for 2008 and 2009 several times in response to higher leasehold acquisition costs and in order to accelerate leasehold acquisition and drilling primarily in the Haynesville, Barnett and Marcellus Shale plays. During the second half of 2008 and the first half of 2009, in response to a significant decrease in natural gas prices, deteriorating global economic conditions and outlook and concerns about an oversupply of natural gas in the U.S. market, and in recognition of the substantial reduction in capital requirements resulting from our innovative joint ventures with Plains Exploration & Production Company (PXP), BP America (BP) and StatoilHydro U.S.A. (STO), we significantly reduced our planned capital expenditures through year-end 2010. Our current budgeted capital expenditures, net of drilling carries, are $3.525 billion to $3.900 billion in 2009 and $4.625 billion to $5.000 billion in 2010. We anticipate directing approximately 75% of the drilling capital expenditures (before drilling carries) during 2009 and 2010 to our Big 4 shale plays.

During 2009, our exploration and development costs have been significantly lower than 2008 costs as a result of lower service costs and the benefit of approximately $959 million of joint venture drilling carries in three of our Big 4 shale plays. We expect low service costs to continue in 2010, and the remaining approximately $2.1 billion of drilling carries associated with our joint ventures create a significant cost advantage for us that will allow us to continue to drive down finding costs in our joint venture plays. The following table provides information about the joint venture drilling carries:

	Shale Play			
	Haynesville[(a)]	Fayetteville	Marcellus	Total
	($ in millions)			
Joint venture with	PXP	BP	STO	
Closing date	July 1, 2008	September 19, 2008	November 24, 2008	
Cash proceeds at closing	$ 1,650	$ 1,100	$ 1,250	$ 4,000
Total drilling carry	$ 1,650	$ 800	$ 2,125	$ 4,575
Carries billed as of September 30, 2009	$ 1,522	$ 723	$ 85	$ 2,330
Remaining drilling carry as of September 30, 2009	$	$ 77	$ 2,040	$ 2,117

(a) In August 2009, we amended our Haynesville Shale joint venture agreement with Plains Exploration & Production Company (PXP). As part of the amendment, PXP accelerated the payment of its remaining joint venture drilling carries as of September 30, 2009 in exchange for an approximate 10% reduction in the total amount of drilling carry obligations due to Chesapeake and we received cash of $1.1 billion instead of an estimated $1.23 billion in remaining carried drilling costs that PXP would have paid over the next three years under the original agreement. In addition, Chesapeake and PXP agreed to terminate a previous joint venture amendment that granted PXP a one-time option in June 2010 to avoid paying the last $800 million of the drilling carry obligations by conveying 50% of its Haynesville Shale assets to Chesapeake.

The joint ventures in three of our shale plays are a complementary part of our business strategy to maximize the value of our leasehold inventory and minimize our investment risk. We have previously announced our efforts to arrange a joint venture for some or all of our Barnett Shale leasehold which, if successful, would enable us to increase our Barnett drilling activity and production. There are other new plays we are identifying and developing which may become additional joint venture opportunities. Our 50/50 joint venture with Global Infrastructure Partners in the Current Quarter is another example of our joining with a strong partner to develop key assets which include all of our midstream assets in the Barnett Shale and other midstream assets in the Mid-Continent. Upon the closing of this transaction, we received proceeds of $588 million. During the Current Period, we sold non-core natural gas and oil assets for proceeds of $278 million, and we expect to close additional sales of non-core properties in the coming months. Over the next two years, we expect to be a net seller of leasehold and producing properties.

Apart from asset monetizations, cash flow from operations is our primary source of liquidity used to fund capital expenditures. Our three revolving bank credit facilities provide us with borrowing capacity of up to $4.25 billion for additional liquidity. In February 2009, we issued $1.425 billion principal amount of our 9.5% senior notes due 2015. Net proceeds of $1.346 billion were used to repay outstanding indebtedness under our revolving bank credit facility, which we reborrow from time to time to fund drilling and leasehold acquisition initiatives and for general corporate purposes. At September 30, 2009, we had borrowings of $1.630 billion and letters of credit of $11 million outstanding under our credit facilities.

We believe that our anticipated internally generated cash flow, cash resources, expected asset monetization transactions and other sources of liquidity will allow us to fully fund our capital expenditure requirements in 2009 and 2010. Further deterioration of the economy, continued low natural gas and oil prices and other factors, however, could require us to further curtail our spending.

Liquidity and Capital Resources

Sources and Uses of Funds

Cash flow from operations is a significant source of liquidity used to fund capital expenditures. Cash provided by operating activities was $3.131 billion in the Current Period compared to $4.387 billion in the Prior Period. The $1.256 billion decrease in the Current Period was primarily due to lower natural gas prices. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding non-cash items such as impairments of assets, depreciation, depletion and amortization, deferred income taxes and unrealized gains and (losses) on derivatives. See the discussion below under *Results of Operations*.

Changes in market prices for natural gas and oil directly impact the level of our cash flow from operations. To mitigate the risk of declines in natural gas and oil prices and to provide more predictable future cash flow from operations, we currently have hedged through swaps and collars 75% of our expected remaining natural gas and oil production in 2009 and 22% of our expected natural gas and oil production in 2010 at average prices of $7.29 per mcfe and $9.39 per mcfe, respectively. Our natural gas and oil hedges as of September 30, 2009 are detailed in Item 3 of Part I of this report. Depending on changes in natural gas and oil futures markets and management s view of underlying natural gas and oil supply and demand trends, we may increase or decrease our current hedging positions. As of September 30, 2009, we had a net natural gas and oil derivative asset of $384 million.

Our three revolving bank credit facilities, described below under *Bank Credit Facilities*, are other sources of liquidity. At November 4, 2009, there was $2.9 billion of borrowing capacity available under these credit facilities. We use the facilities and cash on hand to fund daily operating activities and capital expenditures as needed. We borrowed $5.563 billion and repaid $7.866 billion in the Current Period, and we borrowed $12.831 billion and repaid $11.307 billion in the Prior Period.

On February 2, 2009, we completed a public offering of $1.0 billion aggregate principal amount of senior notes due 2015, which have a stated coupon rate of 9.5% per annum. The senior notes were priced at 95.071% of par to yield 10.625%. On February 17, 2009, we completed an offering of an additional $425 million aggregate principal amount of the 9.5% Senior Notes due 2015. The additional senior notes were priced at 97.75% of par plus accrued interest from February 2 to February 17, 2009 to yield 10.0% per annum. Net proceeds of $1.346 billion from these two offerings were used to repay outstanding indebtedness under our general corporate revolving bank credit facility, which we reborrow from time to time to fund drilling and leasehold acquisition initiatives and for general corporate purposes. The following table reflects the proceeds from sales of securities we issued in the Current Period and the Prior Period ($ in millions):

	For the Nine Months Ended September 30,			
	2009		2008	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
Senior notes	$ 1,425	$ 1,346	$ 800	$ 787
Contingent convertible senior notes			1,380	1,349
Common stock			2,698	2,598
Total	$ 1,425	$ 1,346	$ 4,878	$ 4,734

Our primary use of funds is for capital expenditures related to exploration, development and acquisition of natural gas and oil properties. As described under *Business Strategy*, our joint venture drilling carries have reduced and will continue to reduce our capital expenditures. We refer you to the table under *Investing Activities* below, which sets forth the components of our natural gas and oil investing activities and our other investing activities for the Current Period and the Prior Period. We retain a significant degree of control over the timing of our capital expenditures which permits us to defer or accelerate certain capital expenditures if necessary to address any potential liquidity issues. In addition, changes in drilling and field operating costs, drilling results that alter planned development schedules, acquisitions or other factors could cause us to revise our drilling program, which is largely discretionary.

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We paid dividends on our common stock of $135 million and $106 million in the Current Period and the Prior Period, respectively. Dividends paid on our preferred stock decreased to $18 million in the Current Period from $29 million in the Prior Period as a result of conversions and exchanges of preferred stock into common stock during 2008 and 2009.

In the Current Period and Prior Period, we received $19 million and paid $146 million, respectively, to settle a portion of the derivative liabilities assumed in our November 2005 acquisition of Columbia Natural Resources, LLC.

ASC 718 requires tax benefits resulting from stock-based compensation deductions in excess of amounts reported for financial reporting purposes to be reported as cash flows from financing activities. In the Current Period and the Prior Period, we reported a tax benefit from stock-based compensation of $0 and $42 million, respectively.

Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists decreased $305 million in the Current Period and increased $210 million in the Prior Period. All disbursements are funded on the day they are presented to our bank using available cash on hand or draws on our revolving bank credit facilities.

In the Current Period, we formed a joint venture with Global Infrastructure Partners (GIP), a New York-based private equity fund, to own and operate natural gas midstream assets. As part of the transaction, we contributed certain natural gas gathering and processing assets into a new entity, Chesapeake Midstream Partners, L.L.C. (CMP), and GIP purchased a 50% interest in CMP. Chesapeake retained the remaining 50% interest in CMP and received a $588 million cash distribution from CMP. The transaction is discussed in Note 8 of our condensed consolidated financial statements included in this report.

In the Current Period, we received net proceeds of $54 million from the mortgage financing of one of our buildings. The interest-only loan has a five-year term at a floating rate of prime plus 275 basis points. At our option, we may prepay the loan in full without penalty beginning in year four.

In the Current Period, we financed 113 real estate surface assets in the Barnett Shale area in and around Fort Worth, Texas for net proceeds of approximately $145 million and entered into a master lease agreement under which we agreed to lease the assets for 40 years for approximately $15 million to $27 million annually. As of September 30, 2009, the minimum aggregate future lease payments were approximately $862 million.

Credit Risk

A significant portion of our liquidity is concentrated in derivative instruments that enable us to hedge a portion of our exposure to natural gas and oil prices and interest rate volatility. These arrangements expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with investment-grade rated counterparties deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. During the more than 15 years we have engaged in hedging activities, we have experienced a counterparty default only once (Lehman Brothers in September 2008), and the total loss recorded in that instance was immaterial (presently approximately $15 million without giving effect to possible future recoveries or the results of replacement hedges we entered into after the termination of our Lehman hedges pursuant to the terms of the ISDA agreement with Lehman). On September 30, 2009, our commodity and interest rate derivative instruments were spread among 14 counterparties. Additionally, our multi-counterparty secured hedging facility requires our counterparties to secure their natural gas and oil hedging obligations in excess of defined thresholds. We now use this facility for all of our commodity hedging.

Our accounts receivable are primarily from purchasers of natural gas and oil ($476 million at September 30, 2009) and exploration and production companies which own interests in properties we operate ($528 million at September 30, 2009). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit or parent guarantees for receivables from parties which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. During the Current Quarter and the Current Period, we recognized a nominal amount and $13 million, respectively, of bad debt expense related to potentially uncollectible receivables.

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Investing Activities

Cash used in investing activities decreased to $3.654 billion during the Current Period, compared to $8.283 billion during the Prior Period. We have been reducing our drilling program since the third quarter of 2008, and our leasehold and property acquisitions expenditures in the Current Period were 88% lower than in the Prior Period. The following table shows our cash used in (provided by) investing activities during these periods:

	Nine Months Ended September 30,	
	2009	**2008**
	($ in millions)	
Natural Gas and Oil Investing Activities:		
Exploration and development of natural gas and oil properties	$ 2,647	$ 4,407
Acquisition of leasehold and unproved properties	890	6,933
Acquisitions of natural gas and oil companies and proved properties, net of cash acquired	17	368
Geological and geophysical costs	120	214
Interest capitalized on unproved properties	464	390
Proceeds from sales of volumetric production payments	(408)	(1,210)
Proceeds from divestitures of proved and unproved properties and leasehold	(1,321)	(4,666)
Total natural gas and oil investing activities	2,409	6,436
Other Investing Activities:		
Additions to other property and equipment	1,362	1,969
Proceeds from sales of compressors	(68)	(114)
Proceeds from sales of drilling rigs and equipment		(46)
Additions to investments	40	61
Proceeds from sales of other assets	(89)	(23)
Total other investing activities	1,245	1,847
Total cash used in investing activities	$ 3,654	$ 8,283

Due to current general economic conditions, decreases in natural gas prices and concerns about an oversupply of natural gas in the U.S. market, we and other exploration and production companies have significantly decreased budgets for natural gas and oil investing activities in 2009. In connection with our reduced budget for acquisitions, we have used our common stock for some or all of the consideration for certain transactions. In December 2008, we registered 25 million shares of common stock and on July 14, 2009 we registered an additional 1,499,832 shares of common stock to acquire assets (including mineral interests), businesses or securities of other companies. As of July 15, 2009, we had issued all of the shares of common stock for proved and unproved properties and leasehold acquisitions.

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Bank Credit Facilities

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

	General Corporate Credit Facility	CMD Credit Facility ($ in millions)	CMP Credit Facility
Borrowing capacity	$ 3,500	$ 250	$ 500
Maturity date	November 2012	September 2012	September 2012
Borrowers	Chesapeake Exploration, L.L.C. and Chesapeake Appalachia, L.L.C.	Chesapeake Midstream Operating, L.L.C. (CMO)	Chesapeake Midstream Partners, L.L.C. (CMP)
Facility structure	Senior secured revolving	Senior secured revolving	Senior secured revolving
Amount outstanding as of September 30, 2009	$ 1,618		$ 12
Letters of credit outstanding as of September 30, 2009	$ 11		

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

General Corporate Credit Facility

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

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness (excluding discount on senior notes) to total capitalization ratio (as defined) not to exceed 0.70 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.75 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.41 to 1 and our indebtedness to EBITDA ratio was 3.48 to 1 at September 30, 2009. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness of Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $75 million.

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

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CMD Credit Facility

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

The CMD credit facility agreement contains various covenants and restrictive provisions which limit the ability of CMD and its restricted subsidiaries to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires maintenance of an indebtedness to EBITDA ratio (as defined) not to exceed 3.50 to 1, and an EBITDA (as defined) to interest expense coverage ratio of not less than 3.00 to 1. As defined by the credit facility agreement, our indebtedness to EBITDA ratio was 0.01 to 1 and our EBITDA to interest expense coverage ratio was 6.62 to 1 at September 30, 2009. If CMD or its restricted subsidiaries should fail to perform their obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the CMD facility could be declared immediately due and payable. The CMD credit facility agreement also has cross default provisions that apply to other indebtedness of CMD and its restricted subsidiaries may have with an outstanding principal amount in excess of $15 million.

CMP Credit Facility

Our Chesapeake Midstream Partners, L.L.C. (CMP) $500 million syndicated revolving bank credit facility was established concurrent with the midstream joint venture we formed on September 30, 2009 (see Note 8 for discussion regarding the midstream joint venture). As a result of that transaction, our existing CMD credit facility was amended and restated. Borrowings under the CMP credit facility are secured by all of the assets of the midstream companies organized under CMP, which is 50% owned by Chesapeake and 50% owned by our joint venture partner Global Infrastructure Partners, and bear interest at our option at either (i) the greater of the reference rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50%, and the one-month LIBOR plus 1.00%, all of which would be subject to a margin that varies from 2.00% to 2.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined) or (ii) the LIBOR plus a margin that varies from 3.00% to 3.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined). The unused portion of the facility is subject to a commitment fee of 0.50% per annum according to the most recent indebtedness to EBITDA ratio (as defined). Interest is payable quarterly or, if LIBOR applies, it may be paid at more frequent intervals.

The CMP credit facility agreement contains various covenants and restrictive provisions which limit the ability of CMP and its subsidiaries to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires maintenance of an indebtedness to EBITDA ratio (as defined) not to exceed 3.50 to 1, and an EBITDA (as defined) to interest expense coverage ratio of not less than 3.00 to 1. As defined by the credit facility agreement, our indebtedness to EBITDA ratio was 0.09 to 1 and our EBITDA to interest expense coverage ratio was 17.49 to 1 at September 30, 2009. If CMP or its subsidiaries should fail to perform their obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the CMP facility could be declared immediately due and payable. The CMP credit facility agreement also has cross default provisions that apply to other indebtedness CMP and its subsidiaries may have with an outstanding principal amount in excess of $15 million.

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Hedging Facilities

We began 2009 with six secured hedging facilities, each of which permitted us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to a stated maximum value. Outstanding transactions under each of the facilities were collateralized by certain of our natural gas and oil properties that did not secure any of our other obligations. On June 11, 2009, we entered into a multi-counterparty hedge facility with 13 counterparties that have committed to provide approximately 3.9 tcfe of trading capacity and an aggregate mark-to-market capacity of $10.4 billion under the terms of the facility. The new multi-counterparty facility was intended to consolidate and replace the six secured hedge facilities. As of September 30, 2009, there were trades outstanding on three of the six secured hedge facilities with a fair value of $86 million, and trades covering 122.9 bcfe had been novated into the multi-counterparty facility. As of November 6, 2009, all remaining trades had been novated and pledged collateral transferred to the multi-counterparty facility, resulting in 905.7 bcfe hedged and collateral value of approximately $4.1 billion. These trades will continue to be subject to pre-existing exposure fees, if any, but we are not required to pay an exposure fee for any new trades in the multi-counterparty facility.

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

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Senior Note Obligations

In addition to outstanding borrowings under our revolving bank credit facilities discussed above, as of September 30, 2009, senior notes represented approximately $10.4 billion of our total debt and consisted of the following ($ in millions):

7.5% Senior Notes due 2013	$ 364
7.625% Senior Notes due 2013	500
7.0% Senior Notes due 2014	300
7.5% Senior Notes due 2014	300
6.375% Senior Notes due 2015	600
9.5% Senior Notes due 2015	1,425
6.625% Senior Notes due 2016	600
6.875% Senior Notes due 2016	670
6.25% Euro-denominated Senior Notes due 2017[a]	878
6.5% Senior Notes due 2017	1,100
6.25% Senior Notes due 2018	600
7.25% Senior Notes due 2018	800
6.875% Senior Notes due 2020	500
2.75% Contingent Convertible Senior Notes due 2035[b]	451
2.5% Contingent Convertible Senior Notes due 2037[b]	1,378
2.25% Contingent Convertible Senior Notes due 2038[b]	888
Discount on senior notes[c]	(991)
Interest rate derivatives[d]	80
	$ 10,443

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.4630 to 1.00 as of September 30, 2009. See Note 2 of our condensed consolidated financial statements included in this report for information on our related cross currency swap.

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

Contingent	Repurchase Dates	Common Stock Price Conversion	Contingent Interest

Convertible Senior Notes		Thresholds		First Payable (if applicable)
2.75% due 2035	November 15, 2015, 2020, 2025, 2030	$	48.81	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$	64.36	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$	107.36	June 14, 2019

(c) Included in this discount is $859 million associated with the equity component of our contingent convertible senior notes. See Note 6 of our condensed consolidated financial statements for a description of the accounting treatment applied to these notes.

(d) See Note 2 of our condensed consolidated financial statements included in this report for discussion related to these instruments.

As of September 30, 2009 and currently, debt ratings for the senior notes are Ba3 by Moody s Investor Service (stable outlook), BB by Standard & Poor s Ratings Services (stable outlook) and BB by Fitch Ratings (negative outlook).

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Our senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. Our senior note obligations are guaranteed by certain of our wholly-owned subsidiaries. See Note 13 of the financial statements included in this report for condensed consolidating financial information regarding our guarantor and non-guarantor subsidiaries. We may redeem the senior notes, other than the contingent convertible senior notes, at any time at specified make-whole or redemption prices. Senior notes issued before July 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; incur liens; enter into sale/leaseback transactions; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. Senior notes issued after June 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur certain secured indebtedness; enter into sale/leaseback transactions; and consolidate, merge or transfer assets. The debt incurrence covenants do not presently restrict our ability to borrow under or expand our revolving bank credit facility. As of September 30, 2009, we estimate that secured commercial bank indebtedness of approximately $5.691 billion could have been incurred under the most restrictive indenture covenant.

Other Contractual Obligations

Chesapeake has various financial obligations which are not recorded as liabilities in its condensed consolidated balance sheet at September 30, 2009. These include commitments related to drilling rig, compressor and real estate surface asset leases, transportation and drilling contracts, natural gas and oil purchase obligations and lending and guarantee agreements. These commitments are discussed in Note 3 of our condensed consolidated financial statements included in this report.

Results of Operations Three Months Ended September 30, 2009 vs. September 30, 2008

General. For the Current Quarter, Chesapeake had net income of $192 million, or $0.30 per diluted common share, on total revenues of $1.811 billion. This compares to net income of $3.322 billion, or $5.62 per diluted common share, on total revenues of $7.491 billion during the Prior Quarter. The Prior Quarter included an unrealized non-cash after-tax mark-to-market gain of $2.840 billion related to future period natural gas and oil hedges resulting primarily from lower natural gas and oil prices as of September 30, 2008 compared to June 30, 2008.

Natural Gas and Oil Sales. During the Current Quarter, natural gas and oil sales were $1.187 billion compared to $6.408 billion in the Prior Quarter. In the Current Quarter, Chesapeake produced 228.5 bcfe at a weighted average price of $6.44 per mcfe, compared to 213.5 bcfe produced in the Prior Quarter at a weighted average price of $8.38 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on natural gas and oil derivatives of ($285) million and $4.618 billion in the Current Quarter and the Prior Quarter, respectively). In the Current Quarter, the decrease in prices resulted in a decrease in revenue of $443 million and increased production resulted in a $125 million increase, for a net decrease in revenues of $318 million (excluding unrealized gains or losses on natural gas and oil derivatives). The increase in production from the Prior Quarter to the Current Quarter was primarily generated by organic growth.

For the Current Quarter, we realized an average price per mcf of natural gas of $6.04, compared to $8.02 in the Prior Quarter (weighted average prices exclude the effect of unrealized gains or (losses) on derivatives). Oil prices realized per barrel (excluding unrealized gains or (losses) on derivatives) were $66.42 and $75.74 in the Current Quarter and Prior Quarter, respectively. Realized gains or losses from our natural gas and oil derivatives resulted in a net increase in natural gas and oil revenues of $687 million, or $3.00 per mcfe, in the Current Quarter and a decrease of $246 million, or $1.15 per mcfe, in the Prior Quarter.

Changes in natural gas and oil prices have a significant impact on our natural gas and oil revenues and cash flows. Assuming the Current Quarter production levels, a change of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in revenues and cash flow of approximately $23 million and $22 million, respectively, and a change of $1.00 per barrel of oil sold would have resulted in an increase or decrease in revenues and cash flow of approximately $3 million without considering the effect of derivative activities.

The following table shows our production by region for the Current Quarter and the Prior Quarter:

	For the Three Months Ended September 30,			
	2009		2008	
	Bcfe	Percent	Bcfe	Percent
Mid-Continent[(a)(b)]	79.5	35%	88.5	42%
Barnett Shale	58.6	26	47.7	22
Haynesville Shale	24.0	10	7.4	4
Fayetteville Shale[(a)]	23.1	10	15.3	7
Permian and Delaware Basins	18.8	8	20.4	9
South Texas/Gulf Coast/Ark-La-Tex	12.8	6	24.7	11
Appalachian Basin	6.6	3	8.7	4
Marcellus Shale	5.1	2	0.8	1
Total production	228.5	100%	213.5	100%

(a) The Current Quarter and the Prior Quarter production was reduced by an estimated 9.7 bcfe and 4.1 bcfe, respectively, of production related to divestitures.

(b) The Current Quarter and the Prior Quarter production was reduced by 11.7 bcfe and 2.9 bcfe, respectively, of production related to VPP transactions that closed in 2008 and 2009.

Natural gas production represented approximately 92% of our total production volume on a natural gas equivalent basis in both the Current Quarter and the Prior Quarter.

Marketing, Gathering and Compression Sales and Operating Expenses. Marketing, gathering and compression activities are substantially for third parties who are owners in Chesapeake-operated wells. Chesapeake realized $575 million in marketing, gathering and compression sales in the Current Quarter, with corresponding marketing, gathering and compression expenses of $546 million, for a net margin before depreciation of $29 million. This compares to sales of $1.038 billion, expenses of $1.014 billion and a net margin before depreciation of $24 million in the Prior Quarter. In the Current Quarter, Chesapeake realized an increase in marketing, gathering and compression net margin primarily due to an increase in third-party marketing volumes.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. Chesapeake recognized $49 million in service operations revenue in the Current Quarter with corresponding service operations expense of $49 million, for a net margin before depreciation of a nominal amount. This compares to revenue of $45 million, expenses of $37 million and a net margin before depreciation of $8 million in the Prior Quarter. The decrease in margin during the Current Quarter was the result of both a reduction in drilling rates and ongoing fixed operating expenses associated with rigs that were not in operation during the Current Quarter.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $218 million in the Current Quarter compared to $239 million in the Prior Quarter. On a unit-of-production basis, production expenses were $0.96 per mcfe in the Current Quarter compared to $1.12 per mcfe in the Prior Quarter. The decrease in the Current Quarter was primarily due to lower service costs in the field as a result of the economic downturn.

Production Taxes. Production taxes were $25 million in the Current Quarter compared to $87 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.11 per mcfe in the Current Quarter compared to $0.41 per mcfe in the Prior Quarter. The $62 million decrease in production taxes in the Current Quarter is primarily due to a decrease in the average realized sales price of natural gas and oil of $6.10 per mcfe (excluding gains or losses on derivatives) which was partially offset by an increase in production of 15 bcfe. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas and oil prices are higher.

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General and Administrative Expenses. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our natural gas and oil properties, were $95 million in the Current Quarter and $108 million in the Prior Quarter. General and administrative expenses were $0.42 and $0.51 per mcfe for the Current Quarter and Prior Quarter, respectively. The decrease in the Current Quarter is primarily due to a reduction in advertising costs partially offset by an increase in payroll costs. Included in general and administrative expenses is stock-based compensation of $22 million for the Current Quarter and $26 million the Prior Quarter.

Our stock-based compensation for employees and non-employee directors is in the form of restricted stock. Prior to 2004, stock-based compensation awards were only in the form of stock options. Employee stock-based compensation awards generally vest over a period of four or five years. Our non-employee director awards vest over a period of three years. The discussion of stock-based compensation in Note 5 of our condensed consolidated financial statements included in Part I of this report provides additional detail on the accounting for and reporting of our restricted stock and stock options.

Chesapeake follows the full-cost method of accounting under which all costs associated with natural gas and oil property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $91 million and $101 million of internal costs in the Current Quarter and the Prior Quarter, respectively, directly related to our natural gas and oil property acquisition, exploration and development efforts.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of natural gas and oil properties was $295 million and $480 million during the Current Quarter and the Prior Quarter, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $1.29 and $2.25 in the Current Quarter and in the Prior Quarter, respectively. The $0.96 decrease in the average DD&A rate is due primarily to the reduction of our natural gas and oil full-cost pool resulting from divestitures in 2008 and 2009, the utilization of joint venture drilling carries in the Current Quarter and the impairment of natural gas and oil properties in 2008 and 2009.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $62 million in the Current Quarter and $48 million in the Prior Quarter. Depreciation and amortization of other assets was $0.27 and $0.22 per mcfe for the Current Quarter and the Prior Quarter, respectively. The increase in the Current Quarter is a result of the significant increase in our investment in gathering systems, buildings and rigs. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 10 to 39 years, gathering facilities are depreciated over 20 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to ten years. To the extent company-owned drilling rigs and equipment are used to drill our wells, a substantial portion of the depreciation is capitalized in natural gas and oil properties as exploration or development costs.

Impairment of Natural Gas and Oil Properties and Other Assets. In the Current Quarter, we recorded an $82 million impairment of certain of the gathering systems contributed to the joint venture with GIP, as well as a $4 million impairment of debt issuance costs associated with the portion of our $460 million CMD credit facility that was reduced to $250 million.

Loss on Sale of Other Property and Equipment. In the Current Quarter, we recorded a $38 million loss on the sale of two gathering systems.

Other Income (Expense). Other income (expense) was ($30) million and ($12) million in the Current Quarter and in the Prior Quarter, respectively. The Current Quarter consisted of $1 million of interest income, a ($24) million loss related to our equity in certain investments and ($7) million of miscellaneous expense. The Prior Quarter consisted of $5 million of interest income, a ($17) million loss related to our equity in certain investments, ($10) million of consent solicitation fees and $10 million of miscellaneous income.

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Interest Expense. Interest expense increased to $43 million in the Current Quarter compared to $34 million in the Prior Quarter as follows:

	Three Months Ended September 30,	
	2009	2008
	($ in millions)	
Interest expense on senior notes	$ 195	$ 171
Interest expense on credit facilities	18	23
Capitalized interest	(153)	(166)
Realized (gain) loss on interest rate derivatives	(7)	5
Unrealized (gain) loss on interest rate derivatives	(20)	(8)
Amortization of loan discount and other	10	9
Total interest expense	$ 43	$ 34
Average long-term borrowings on senior notes	$ 11,372	$ 10,929

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.28 per mcfe in the Current Quarter compared to $0.20 in the Prior Quarter. The increase in interest expense per mcfe is primarily due to the February 2009 issuance of $1.425 billion of our 9.5% Senior Notes due 2015. Capitalized interest decreased by $13 million as a result of a decrease in both unevaluated properties, the base on which interest is capitalized, and our average borrowing rates in the Current Quarter compared to the Prior Quarter.

Loss on Exchanges of Chesapeake Debt. In the Current Quarter, we privately exchanged approximately $153 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 4,176,671 shares of our common stock valued at approximately $110 million. Through these transactions, we were able to redeem this debt for common stock valued at less than 80% of the face value of the notes. Associated with these exchanges, we recorded a loss of $17 million. In connection with ASC 470-20, we are required to account for the liability and equity components of our convertible debt instruments separately. Of the $153 million principal amount of convertible notes exchanged in the Current Quarter, $96 million was allocated to the debt component and the remaining $57 million was allocated to the equity conversion feature and was recorded as an adjustment to paid-in-capital. The difference between the debt component and value of the common stock exchanged in these transactions resulted in a $14 million loss. In addition, we expensed $3 million in deferred charges associated with the exchanges. In the Prior Quarter, we repurchased $300 million of our 7.75% Senior Notes due 2015 in order to re-finance a portion of our long-term debt at a lower rate of interest. In connection with the transaction we recorded a $31 million loss, which consisted of a $12 million premium and $19 million of discounts, interest rate derivatives and deferred charges associated with the notes.

Income Tax Expense (Benefit). Chesapeake recorded income tax expense of $115 million in the Current Quarter, compared to income tax expense of $2.079 billion in the Prior Quarter. Of the $1.964 billion decrease in income tax expense recorded in the Current Quarter, $1.961 billion was the result of the decrease in net income before income taxes and $3 million was due to a decrease in the effective tax rate. Our effective income tax rate was 37.5% in the Current Quarter and 38.5% in the Prior Quarter. Our effective tax rate fluctuates as a result of the impact of state income taxes and permanent differences.

Results of Operations Nine Months Ended September 30, 2009 vs. September 30, 2008

General. For the Current Period, Chesapeake had a net loss of $5.306 billion, or $8.78 per diluted common share, on total revenues of $5.480 billion. This compares to net income of $1.600 billion, or $2.76 per diluted common share, on total revenues of $8.648 billion during the Prior Period. The Current Period loss was due to a non-cash impairment expense of approximately $6.0 billion, net of tax, as a result of a 36% decrease in NYMEX natural gas prices from $5.71 per mcf at December 31, 2008 to $3.63 per mcf at March 31, 2009.

Natural Gas and Oil Sales. During the Current Period, natural gas and oil sales were $3.681 billion compared to $5.587 billion in the Prior Period. In the Current Period, Chesapeake produced 664.6 bcfe at a weighted average price of $6.14 per mcfe, compared to 629.7 bcfe produced in the Prior Period at a weighted average price of $8.75 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on natural gas and oil derivatives of ($401) million and $80 million in the Current Period and Prior Period, respectively). In the Current Period, the decrease in prices resulted in a decrease in revenue of $1.730 billion and increased production resulted in a $306 million increase, for a net decrease in revenues of $1.424 billion (excluding unrealized gains or losses on natural gas and oil derivatives). The increase in production from the Prior Period to the Current Period was primarily generated by organic growth.

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For the Current Period, we realized an average price per mcf of natural gas of $5.88, compared to $8.41 in the Prior Period (weighted average prices for both periods exclude the effect of unrealized gains or losses on derivatives). Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $54.37 and $75.82 in the Current Period and Prior Period, respectively. Realized gains or losses from our natural gas and oil derivatives resulted in a net increase in natural gas and oil revenues of $1.802 billion, or $2.71 per mcfe, in the Current Period and a decrease of $454 million, or $0.72 per mcfe, in the Prior Period.

Changes in natural gas and oil prices have a significant impact on our natural gas and oil revenues and cash flows. Assuming the Current Period production levels, a change of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in revenues and cash flow of approximately $66 million and $64 million, respectively, and a change of $1.00 per barrel of oil sold would have resulted in an increase or decrease in revenues and cash flow of approximately $9 million without considering the effect of derivative activities.

The following table shows our production by region for the Current Period and the Prior Period:

	For the Nine Months Ended September 30,			
	2009		2008	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent[(a)(b)]	231.4	35%	277.4	44%
Barnett Shale	175.4	26	129.0	20
Haynesville Shale	49.5	7	18.6	3
Fayetteville Shale[(a)]	61.8	9	39.4	6
Permian and Delaware Basins	57.5	9	59.9	10
South Texas/Gulf Coast/Ark-La-Tex	56.6	9	79.0	12
Appalachian Basin	23.4	4	24.7	4
Marcellus Shale	9.0	1	1.7	1
Total production	664.6	100%	629.7	100%

(a) The Current Period and the Prior Period production was reduced by an estimated 25.1 bcfe and 4.1 bcfe, respectively, of production related to divestitures.

(b) The Current Period and the Prior Period production was reduced by 29.7 bcfe and 2.9 bcfe, respectively, of production related to VPP transactions that closed in 2008 and 2009.

Natural gas production represented approximately 92% in both the Current Period the Prior Period of our total production volume on a natural gas equivalent basis.

Marketing, Gathering and Compression Sales and Operating Expenses. Marketing, gathering and compression activities are substantially for third parties who are owners in Chesapeake-operated wells. Chesapeake realized $1.660 billion in marketing, gathering and compression sales in the Current Period, with corresponding marketing, gathering and compression expenses of $1.569 billion, for a net margin before depreciation of $91 million. This compares to sales of $2.934 billion, expenses of $2.864 billion and a net margin before depreciation of $70 million in the Prior Period. In the Current Period, Chesapeake realized an increase in marketing, gathering and compression net margin primarily due to an increase in third-party marketing volumes.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. Chesapeake recognized $139 million in service operations revenue in the Current Period with corresponding service operations expense of $136 million, for a net margin before depreciation of $3 million. This compares to revenue of $127 million, expenses of $104 million and a net margin before depreciation of $23 million in the Prior Period. The decrease in margin during the Current Period was the result of both a reduction in drilling rates and ongoing fixed operating expenses associated with rigs that were not in operation during the Current Period.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $670 million in the Current Period compared to $658 million in the Prior Period. On a unit-of-production basis, production expenses were $1.01 per mcfe in the Current Period compared to $1.04 per mcfe in the Prior Period. The decrease in the Current Period per unit of production was primarily due to lower service costs in the field as a result of the economic downturn.

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Production Taxes. Production taxes were $71 million in the Current Period compared to $250 million in the Prior Period. On a unit-of-production basis, production taxes were $0.11 per mcfe in the Current Period compared to $0.40 per mcfe in the Prior Period. The $179 million decrease in production taxes in the Current Period is primarily due to a decrease in the average realized sales price of natural gas and oil of $6.04 per mcfe (excluding gains or losses on derivatives) which was partially offset by an increase in production of 35 bcfe. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas and oil prices are higher.

General and Administrative Expenses. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our natural gas and oil properties, were $259 million in the Current Period and $288 million in the Prior Period. General and administrative expenses were $0.39 and $0.46 per mcfe for the Current Period and Prior Period, respectively. The decrease in the Current Period is primarily due to a reduction in advertising costs partially offset by an increase in payroll costs. Included in general and administrative expenses is stock-based compensation of $60 million and $66 million for the Current Period and the Prior Period, respectively.

Our stock-based compensation for employees and non-employee directors is in the form of restricted stock. Prior to 2004, stock-based compensation awards were only in the form of stock options. Employee stock-based compensation awards generally vest over a period of four or five years. Our non-employee director awards vest over a period of three years. The discussion of stock-based compensation in Note 5 of our condensed consolidated financial statements included in Part I of this report provides additional detail on the accounting for and reporting of our restricted stock and stock options.

Chesapeake follows the full-cost method of accounting under which all costs associated with natural gas and oil property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $282 million and $268 million of internal costs in the Current Period and the Prior Period, respectively, directly related to our natural gas and oil property acquisition, exploration and development efforts.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of natural gas and oil properties was $1.037 billion and $1.518 billion during the Current Period and the Prior Period, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $1.56 and $2.41 in the Current Period and in the Prior Period, respectively. The $0.85 decrease in the average DD&A rate is due primarily to the reduction of our natural gas and oil full-cost pool resulting from divestitures in 2008 and 2009, the utilization of joint venture drilling carries in the Current Period and the impairment of natural gas and oil properties in 2008 and 2009.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $177 million in the Current Period and $124 million in the Prior Period. Depreciation and amortization of other assets was $0.27 and $0.20 per mcfe for the Current Period and the Prior Period, respectively. The increase in the Current Period is a result of the significant increase in our investment in gathering systems, buildings and rigs. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 10 to 39 years, gathering facilities are depreciated over 20 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to ten years. To the extent company-owned drilling rigs and equipment are used to drill our wells, a substantial portion of the depreciation is capitalized in natural gas and oil properties as exploration or development costs.

Impairment of Natural Gas and Oil Properties and Other Assets. We account for our natural gas and oil properties using the full-cost method of accounting, which limits the amount of costs we can capitalize and requires us to write off these costs if the carrying value of natural gas and oil assets in the evaluated portion of our full-cost pool exceeds the sum of the present value of expected future net cash flows of proved reserves, using a 10% pre-tax discount rate based on constant pricing and cost assumptions, and the present value of certain natural gas and oil hedges.

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We reported a non-cash impairment charge of $9.6 billion for the Current Period due to a 36% decrease in NYMEX natural gas prices from $5.71 per mcf at December 31, 2008 to $3.63 per mcf at March 31, 2009. Included in this write-down was the impairment of approximately $1.9 billion of unevaluated leasehold. In connection with our scaled-back drilling program, lower natural gas prices and our more focused development efforts in the Big 4 natural gas shale plays, we determined that certain of our unevaluated leasehold positions would likely not be developed and would be allowed to expire. Accordingly, the carrying costs of the impaired leasehold were transferred to the amortization base of our full-cost pool during the Current Period and were consequently included in our ceiling test impairment during the Current Period.

Also in the Current Period, we recorded an $82 million impairment of certain of the gathering systems contributed to the joint venture with GIP, as well as a $4 million impairment of debt issuance costs associated with the portion of our $460 million CMD credit facility that was reduced to $250 million.

Finally, we recognized a $22 million charge in the Current Period for a deposit on canceled contracts that were not refunded.

Loss on Sale of Other Property and Equipment. In the Current Period, we recorded a $38 million loss on the sale of two gathering systems.

Restructuring Costs. In the Current Period, we recorded $34 million of restructuring and relocation costs in our Eastern Division and certain other workforce reduction costs. We restructured our Charleston, West Virginia-based Eastern Division from a regional corporate headquarters to a regional field office consistent with the business model we use elsewhere in the country. As a result, we consolidated the management of our Eastern Division land, legal, accounting, information technology, geoscience and engineering departments into our corporate offices in Oklahoma City. The costs of the restructuring include termination benefits, consolidating or closing facilities and relocating employees. The discussion of restructuring costs in Note 10 of our condensed consolidated financial statements included in Part I of this report provides additional detail on the accounting for and reporting of these costs.

Other Income (Expense). Other income (expense) was ($25) million in the Current Period compared to ($23) million in the Prior Period. The Current Period consisted of $6 million of interest income, an ($32) million loss related to our equity in certain investments and $1 million of miscellaneous income. The Prior Period income consisted of $9 million of interest income, a ($34) million loss related to our equity in certain investments, ($10) million of consent solicitation fees and $12 million of miscellaneous income.

Interest Expense. Interest expense decreased to $52 million in the Current Period compared to $186 million in the Prior Period as follows:

	Nine Months Ended September 30,	
	2009	**2008**
	($ in millions)	
Interest expense on senior notes	$ 572	$ 472
Interest expense on credit facilities	47	83
Capitalized interest	(467)	(390)
Realized (gain) loss on interest rate derivatives	(19)	1
Unrealized (gain) loss on interest rate derivatives	(106)	(9)
Amortization of loan discount and other	25	29
Total interest expense	$ 52	$ 186
Average long-term borrowings on senior notes	$ 11,172	$ 9,974

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.24 per mcfe in the Current Period compared to $0.31 in the Prior Period. The decrease in interest expense per mcfe is primarily due to an increase in capitalized interest and increased production volumes offset by an increase in interest expense associated with the February 2009 issuance of $1.425 billion of our 9.5% Senior Notes due 2015. Capitalized interest increased by $77 million as a result of a significant increase in unevaluated properties, the base on which interest is capitalized, in the Current Period compared to the Prior Period.

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

Loss on Exchanges of Chesapeake Debt. In the Current Period, we privately exchanged approximately $238 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 6,707,321 shares of our common stock valued at approximately $164 million. Through these transactions, we were able to redeem this debt for common stock valued at less than 80% of the face value of the notes. Associated with these exchanges, we recorded a loss of $19 million. In connection with ASC 470-20, we are required to account for the liability and equity components of our convertible debt instruments separately. Of the $238 million principal amount of convertible notes exchanged in the Current Period, $148 million was allocated to the debt component and the remaining $90 million was allocated to the equity conversion feature and was recorded as an adjustment to paid-in capital. The difference between the debt component and value of the common stock exchanged in these transactions resulted in a $16 million loss. In addition, we expensed $3 million in deferred charges associated with the exchanges. In the Prior Period, we repurchased $300 million of our 7.75% Senior Notes due 2015 in order to re-finance a portion of our long-term debt at a lower rate of interest. In connection with the transaction we recorded a $31 million loss, which consisted of a $12 million premium and $19 million of discounts, interest rate derivatives and deferred charges associated with the notes.

Income Tax Expense (Benefit). Chesapeake recorded an income tax benefit of $3.184 billion in the Current Period, compared to an income tax expense of $1.002 billion in the Prior Period. Of the $4.186 billion decrease in income tax expense recorded in the Current Period, $4.271 billion was the result of the decrease in net income before income taxes which was offset by $85 million due to a decrease in the effective tax rate. Our effective income tax rate was 37.5% in the Current Period and 38.5% in the Prior Period. Our effective tax rate fluctuates as a result of the impact of state income taxes and permanent differences.

Critical Accounting Policies

We consider accounting policies related to hedging, natural gas and oil properties, income taxes and business combinations to be critical policies. These policies are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our annual report on Form 10-K for the year ended December 31, 2008 (2008 Form 10-K).

Recently Issued and Proposed Accounting Standards

The Financial Accounting Standards Board (FASB) recently issued the following standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

On December 31, 2008, the Securities and Exchange Commission (SEC) adopted major revisions to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves and that allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new disclosure requirements also require companies to report the independence and qualifications of the person primarily responsible for the preparation or audit of reserve estimates, and to file reports when a third party is relied upon to prepare or audit reserves estimates. The new rules also require that oil and gas reserves be reported and the full-cost ceiling value calculated using an average price based upon the prior 12-month period. The new oil and gas reporting requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, with early adoption not permitted. We are in the process of assessing the impact of these new requirements on our financial position, results of operations and financial disclosures.

In June 2009, the FASB issued SFAS No. 167, *Amendments to FASB Interpretation No. 46(R)*. Among other items, SFAS 167 responds to concerns about the application of certain key provisions of FIN 46(R), including those regarding the transparency of the involvement with variable interest entities. SFAS 167 is effective for calendar year companies beginning on January 1, 2010. We are currently assessing the impact that adoption of SFAS 167 will have on our financial position, results of operations, cash flows or disclosures.

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In June 2009, the FASB issued Accounting Standards Update (ASU) 2009-01, *The FASB Accounting Standards Codification™ and the Hierarchy of Generally Accepted Accounting Principles*. This standard replaces SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles,* and establishes only two levels of U.S. GAAP, authoritative and nonauthoritative. The FASB Accounting Standards Codification has become the single source of authoritative nongovernmental U.S. GAAP, except for rules and interpretive releases of the SEC, which are sources of authoritative U.S. GAAP for SEC registrants. This standard is effective for financial statements for interim or annual reporting periods ended after September 15, 2009. We began to use the new guidelines and numbering system prescribed by the Codification when referring to GAAP in the Current Quarter. As the Codification was not intended to change or alter existing GAAP, it did not have any impact on our consolidated financial statements.

In August 2009, the FASB issued ASU 2009-05, *Fair Value Measurements and Disclosures (Topic 820) Measuring Liabilities at Fair Value*. This update provides clarification for the fair value measurement of liabilities. ASU 2009-05 is effective for the first reporting period beginning after issuance and we have adopted its provisions in the Current Quarter. ASU 2009-05 did not have a significant impact on our financial position, results of operations, cash flows or disclosures.

Forward-Looking Statements

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

Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under Risk Factors in Item 1A of our 2008 Form 10-K and in Item 1A in Part II of our 2009 second quarter Form 10-Q. They include:

- the volatility of natural gas and oil prices,
- the limitations our level of indebtedness may have on our financial flexibility,
- impacts the current financial crisis may have on our business and financial condition,
- declines in the values of our natural gas and oil properties resulting in ceiling test write-downs,
- the availability of capital on an economic basis, including planned asset monetization transactions, to fund reserve replacement costs,
- our ability to replace reserves and sustain production,
- uncertainties inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and the amount and timing of development expenditures,
- exploration and development drilling that does not result in commercially productive reserves,

leasehold terms expiring before production can be established,

hedging activities resulting in lower prices realized on natural gas and oil sales and the need to secure hedging liabilities,

uncertainties in evaluating natural gas and oil reserves of acquired properties and potential liabilities,

the negative effect lower natural gas and oil prices could have on our ability to borrow,

drilling and operating risks, including potential environmental liabilities,

transportation capacity constraints and interruptions that could adversely affect our cash flow,

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potential increased operating costs resulting from proposed legislative and regulatory changes affecting our business,

losses possible from pending or future litigation.

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

ITEM 3. ***Quantitative and Qualitative Disclosures About Market Risk***

Natural Gas and Oil Hedging Activities

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

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

We use a wide range of derivative instruments to achieve our risk management objectives, including swaps, swaps with imbedded puts (knockouts), various collar arrangements and options (puts or calls). All of these are described in more detail below. We typically use swaps or knockouts for a large portion of the natural gas and oil volume we hedge. Swaps are used when the price level is acceptable, and we are not paid a sufficient premium for selling an additional put (a knockout) that could cause the swap to become ineffective if the NYMEX future price closes below the knockout threshold on the pricing date. We use knockouts when we think the put level is less likely to be reached and we are able to obtain a premium for the put thereby increasing our effective swap price. Historically, swaps which have become ineffective as a result of knockouts have had an immaterial effect on our results of operations and cash flows. For example, after a precipitous drop in natural gas and oil prices in the second half of 2008, swaps that were knocked out covered 2.7% of the company s total natural gas and oil production (2.3% of natural gas production and 7.1% of oil production) during the six months ended December 31, 2008 and 1.5% of the company s total natural gas and oil production (less than 1% of natural gas production and 8.2% of oil production) during the nine months ended September 30, 2009. We also sell calls, taking advantage of the volatility inherent in the market, for a portion of our projected production volumes when the strike price levels and the premiums are attractive to us. In other words, we sell calls when we believe it to be more likely than not that the future natural gas or oil price will stay below the call strike price plus the premium we will receive.

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

Hedging positions, including swaps, knockouts and collars, are adjusted in response to changes in prices and market conditions as part of an ongoing dynamic process. We review our hedging positions continuously and if future market conditions change, and prices have fallen to levels we believe could jeopardize the effectiveness of a position, we will mitigate such risk by either doing a cash settlement with our counterparty, restructuring the position, or by entering into a new swap that effectively reverses the current position (a counter-swap). In September 2008, for example, in response to declining natural gas and oil prices, we began restructuring knockout swap positions which we considered at risk. This restructuring allowed us to recover approximately $700 million of value for the nine months ended September 30, 2009 that would have been lost under the original positions. The factors we consider in closing or restructuring a position before the settlement date are identical to those we reviewed when deciding to enter into the original hedge position.

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As of September 30, 2009, our natural gas and oil derivative instruments were comprised of the following:

Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.

Collars: These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the put and the call strike price, no payments are due from either party. On occasion, we make a three-way collar by selling an additional put option with the collar in exchange for a more favorable strike price on the collar. This eliminates the counterparty s downside exposure below the second put option.

Knockout swaps: Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty s exposure to zero, in any given month, if the floating market price is lower than certain pre-determined knockout prices.

Call options: Chesapeake receives a premium from the counterparty in exchange for the sale of a call option. If the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess. If the market price settles below the fixed price of the call option, no payment is due from either party.

Put options: Chesapeake receives a premium from the counterparty in exchange for the sale of a put option. If the market price falls below the fixed price of the put option, Chesapeake pays the counterparty such shortfall. If the market price settles above the fixed price of the put option, no payment is due from either party.

Basis protection swaps: These instruments are arrangements that guarantee a price differential to NYMEX for natural gas from a specified delivery point. For non-Appalachian Basin basis protection swaps, which typically have negative differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. For Appalachian Basin basis protection swaps, which typically have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.

In accordance with ASC 815 and ASC 210, to the extent that a legal right of set-off exists, Chesapeake nets the value of its derivative arrangements with the same counterparty in the accompanying condensed consolidated balance sheets.

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As of September 30, 2009, we had the following open natural gas and oil derivative instruments (including derivatives assumed through our acquisition of CNR in November 2005) designed to hedge a portion of our natural gas and oil production for periods after September 30, 2009:

	Volume (bbtu)	Weighted Average Fixed Price to be Received per mmbtu	Weighted Average Put Fixed Price per mmbtu	Weighted Average Call Fixed Price per mmbtu	Weighted Average Differential per mmbtu	ASC 815 Hedge	Net Premiums ($ in millions)	Fair Value at September 30, 2009 ($ in millions)
Natural Gas:								
Swaps:								
Q4 2009	103,183	$ 6.90	$	$	$	Yes	$	$ 197
Q1 2010	17,048	9.24				Yes		56
Q2 2010	15,641	8.21				Yes		35
Q3 2010	8,732	9.04				Yes		25
Q4 2010	9,972	9.27				Yes		25
CNR Swaps[(a)]:								
Q4 2009	4,600	5.18				Yes		2
Other Swaps[(b)]:								
Q4 2009	3,680	11.15				No		23
Q1 2010	3,600	11.35				No		
Q2 2010	8,190	9.89				No		(1)
Q3 2010	8,280	9.89				No		
Q4 2010	8,280	9.89				No		(1)
2011	4,500	8.73				No		
Counter Swaps								
Q4 2009	(3,680)	9.26				No		(17)
Collars:								
Q4 2009	17,220		7.36	8.24		Yes		47
Q1 2010	22,500		6.00	8.00		Yes		12
CNR Collars[(a)]:								
Q4 2009	920		4.50	6.00		Yes		
Other Collars[(c)]:								
Q4 2009	34,910		5.40/7.01	9.51		No	6	83
Q1 2010	20,700		4.86/7.03	9.06		No		23
Q2 2010	16,380		5.12/7.04	9.17		No	5	18
Q3 2010	3,680		7.60	11.75		No	4	7
Q4 2010	3,680		7.60	11.75		No	4	5
2011	7,300		7.70	11.50		No	7	10
Knockout Swaps:								
Q4 2009	1,830	9.43	6.00			No		1
Q1 2010	11,700	10.71	6.33			No		12
Q2 2010	11,830	9.66	6.00			No		9
Q3 2010	23,000	9.81	6.21			No		12
Q4 2010	23,000	9.99	6.20			No		11
2011	23,650	9.86	6.29			No		8
Call Options:								
Q4 2009	6,405			9.90		No	20	
Q1 2010	65,700			10.19		No	42	(3)
Q2 2010	66,430			10.10		No	42	(4)
Q3 2010	67,160			10.20		No	42	(7)

Q4 2010	67,160	10.31	No	43	(13)
2011	68,438	10.35	No	42	(13)
2012 2020	180,872	11.70	No	100	(85)

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	Volume (bbtu)	Weighted Average Fixed Price to be Received per mmbtu	Weighted Average Put Fixed Price per mmbtu	Weighted Average Call Fixed Price per mmbtu	Weighted Average Differential per mmbtu	ASC 815 Hedge	Net Premiums ($ in millions)	Fair Value at September 30, 2009 ($ in millions)
Put Options:								
Q4 2009	(9,200)		3.00			No	1	
Q1 2010	(9,000)		5.75			No	1	(5)
Q2 2010	(9,100)		5.75			No	1	(6)
Q3 2010	(9,200)		5.75			No	1	(6)
Q4 2010	(9,200)		5.75			No	1	(6)
2011	(36,500)		5.75			No	26	(20)
Basis Protection Swaps:								
Non-Appalachian Basin:								
Q4 2009	10,420				(1.64)	No		(15)
2011	45,090				(0.82)	No	(3)	(12)
2012 2018	57,961				(0.90)	No	(3)	(19)
Basis Protection Swaps:								
Appalachian Basin:								
Q4 2009	4,438				0.27	No		1
Q1 2010	2,294				0.27	No		
Q2 2010	2,513				0.27	No		
Q3 2010	2,660				0.26	No		
Q4 2010	2,732				0.26	No		
2011	12,086				0.25	No		
2012 2022	134				0.11	No		
Total Natural Gas							382	389

	Volume (mbbls)	Weighted Average Fixed Price to be Received per bbl	Weighted Average Put Fixed Price per bbl	Weighted Average Call Fixed Price per bbl	Weighted Average Differential per bbl	ASC 815 Hedge	Net Premiums ($ in millions)	Fair Value at September 30, 2009 ($ in millions)
Oil:								
Counter Swaps:								
Q4 2009	(230)	69.10				No		
Knockout Swaps:								
Q4 2009	1,288	85.71	52.79			No	(17)	18
Q1 2010	1,170	90.25	60.00			No		10
Q2 2010	1,183	90.25	60.00			No		6
Q3 2010	1,196	90.25	60.00			No		3
Q4 2010	1,196	90.25	60.00			No		1
2011	1,095	104.75	60.00			No		7
2012	732	109.50	60.00			No		5
Call Options:								
Q4 2009	920			112.50		No	(1)	(1)
Q1 2010	810			115.00		No	(1)	(1)
Q2 2010	819			115.00		No	(1)	(1)
Q3 2010	828			115.00		No	(1)	(2)
Q4 2010	828			115.00		No	(1)	(3)

2011	3,650	105.00	No	16	(20)
2012	3,660	105.00	No	16	(27)
Total Oil				10	(5)
Total Natural Gas and Oil				$ 392	$ 384

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(a) We assumed certain liabilities related to open derivative positions in connection with our acquisition of Columbia Natural Resources, LLC in November 2005. In accordance with ASC 805, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million ($11 million liability remaining as of September 30, 2009). The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our natural gas and oil revenues upon settlement. For example, if the fair value of the derivative positions assumed does not change, then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to natural gas and oil revenues related to the derivative positions. If, however, the actual sales price is different from the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in natural gas and oil revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes at market prices on the date of our acquisition of CNR.

Pursuant to ASC 815, the derivative instruments assumed in connection with the CNR acquisition are deemed to contain a significant financing element and all cash flows associated with these positions are reported as financing activity in the statement of cash flows for the periods in which settlement occurs.

(b) Included in Other Swaps are options to extend existing swaps for an additional 12 months, one for 40,000 mmbtu/day at $11.35/mmbtu and the other for 50,000 mmbtu/day at $8.73/mmbtu, callable by the counterparty in December 2009 and March 2010, respectively.

(c) Included in Other Collars for 2009 and 2010 are 11,420 bbtu and 26,220 bbtu of three-way collars which have written put options with weighted average prices of $5.40 and $4.97, respectively, which limit the counterparty s exposure.

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

The table below reconciles the Current Period change in fair value of our natural gas and oil derivatives. Of the $384 million fair value asset, $531 million relates to contracts maturing in the next 12 months, of which we expect to transfer approximately $340 million (net of income taxes) from accumulated other comprehensive income to net income (loss), and ($147) million relates to contracts maturing after 12 months. All transactions hedged as of September 30, 2009 are expected to mature by December 31, 2022.

	2009 ($ in millions)
Fair value of contracts outstanding, as of January 1	$ 1,305
Change in fair value of contracts	1,202
Fair value of contracts when entered into	(46)
Contracts realized or otherwise settled	(1,674)
Fair value of contracts when closed	(403)
Fair value of contracts outstanding, as of September 30	$ 384

The change in natural gas and oil prices during the Current Period increased the value of our derivative assets by $1.202 billion. This gain is recorded in natural gas and oil sales or in accumulated other comprehensive income. We entered into new contracts which had premiums of $46 million, and a liability was recorded. We settled and closed out contracts, reducing our assets by $1.674 billion and $403 million, respectively, and the realized gain is recorded in natural gas and oil sales in the month of related production.

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Pursuant to ASC 815, certain derivatives qualify for designation as cash flow hedges. Following these provisions, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in accumulated other comprehensive income until the hedged item is recognized in earnings as the physical transactions being hedged occur. Any change in fair value resulting from ineffectiveness is currently recognized in natural gas and oil sales as unrealized gains (losses). Changes in the fair value of non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within natural gas and oil sales. Realized gains (losses) are included in natural gas and oil sales in the month of related production.

Chesapeake enters into counter-swaps from time to time for the purpose of locking-in the value of a swap. Under the counter-swap, Chesapeake receives a floating price for the hedged commodity and pays a fixed price to the counterparty. The counter-swap is 100% effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap. Generally, at the time Chesapeake enters into a counter-swap, Chesapeake removes the original swap s designation as a cash flow hedge and classifies the original swap as a non-qualifying hedge under ASC 815. The reason for this new designation is that collectively the swap and the counter-swap no longer hedge the exposure to variability in expected future cash flows. Instead, the swap and counter-swap effectively lock-in a specific gain or loss that will be unaffected by subsequent variability in natural gas and oil prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to natural gas and oil sales in the month of related production.

The components of natural gas and oil sales for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period are presented below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	($ in millions)			
Natural gas and oil sales	$ 785	$ 2,036	$ 2,280	$ 5,961
Realized gains (losses) on natural gas and oil derivatives	687	(246)	1,802	(454)
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(278)	4,543	(484)	134
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(7)	75	83	(54)
Total natural gas and oil sales	$ 1,187	$ 6,408	$ 3,681	$ 5,587

To mitigate our exposure to the fluctuation in price of diesel fuel which is used in our exploration and development activities, we have entered into diesel swaps from October 2009 to March 2010 for a total of 19,800,000 gallons with an average fixed price of $1.58 per gallon. Chesapeake pays the fixed price and receives the floating price. The fair value of these swaps as of September 30, 2009 was an asset of $6 million.

Interest Rate Risk

The table below presents principal cash flows ($ in millions) and related weighted average interest rates by expected maturity dates.

	Years of Maturity						
	2009	2010	2011	2012	2013	Thereafter	Total
Liabilities:							
Long-term debt fixed rate[(a)]	$	$	$	$	$ 864	$ 10,490	$ 11,354
Average interest rate					7.6%	6.1%	6.2%
Long-term debt variable rate	$	$	$	$ 1,630	$	$	$ 1,630
Average interest rate				2.91%			2.91%

(a) This amount does not include the discount included in long-term debt of ($991) million and interest rate derivatives of $80 million.

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

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Interest Rate Derivatives

To mitigate our exposure to volatility in interest rates related to our senior notes and credit facilities, we enter into interest rate derivatives. As of September 30, 2009 our interest rate derivative instruments were comprised of the following types of instruments:

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

Collars: These instruments contain a fixed floor rate (floor) and a ceiling rate (cap). If the floating rate is above the cap, we have a net receivable from the counterparty and if the floating rate is below the floor, we have a net payable to the counterparty. If the floating rate is between the floor and the cap, there is no payment due from either party. Collars are used to manage our interest rate exposure related to our bank credit facilities borrowings.

Call options: Occasionally we sell call options for a premium when we think it is more likely that the option will expire unexercised. The option allows the counterparty to terminate an open swap at a specific date.

Swaptions: Occasionally we sell an option to a counterparty for a premium which allows the counterparty to enter into a swap with us on a specific date.

As of September 30, 2009, the following interest rate derivatives were outstanding:

	Notional Amount ($ in millions)	Weighted Average Fixed Rate	Weighted Average Floating Rate(b)	Fair Value Hedge	Net Premiums ($ in millions)	Fair Value ($ in millions)
Fixed-to-Floating Interest Rate:						
Swaps						
April 2009 December 2018	$ 1,200	8.02%	1 6 mL plus 537 bp	Yes	$	$ (29)
May 2008 November 2020	$ 750	8.63%	1 mL plus 562 bp	No	$ (3)	$ 1
Call Options						
November 2009	$ 250	6.88%	1 mL plus 287 bp	No	$	$ (9)
Floating-to-Fixed Interest Rate:						
Swaps						
November 2007 July 2012	$ 1,375	3.30%	1 6 mL	No	$	$ (46)
Collars(a)						
August 2007 August 2010	$ 250	4.52%	6 mL	No	$	$ (8)
					$ (3)	$ (91)

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

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

In the Current Period, we closed interest rate derivatives for gains totaling $50 million, of which $25 million was recognized in interest expense. The remaining $25 million was from interest rate derivatives designated as fair value hedges which are accounted for as a reduction to our senior notes. The settlement amounts received will be amortized as a reduction to realized interest expense over the remaining term of the related senior notes ranging from four to eleven years.

For interest rate derivative instruments designated as fair value hedges (in accordance with ASC 815), changes in fair value are recorded on the condensed consolidated balance sheets as assets (liabilities), and the debt s carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Changes in the fair value of non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within interest expense.

Gains or losses from interest rate derivative transactions are reflected as adjustments to interest expense on the condensed consolidated statements of operations. The components of interest expense for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period are presented below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	($ in millions)			
Interest expense on senior notes	$ 195	$ 171	$ 572	$ 472
Interest expense on credit facilities	18	23	47	83
Capitalized interest	(153)	(166)	(467)	(390)
Realized (gains) losses on interest rate derivatives	(7)	5	(19)	1
Unrealized (gains) losses on interest rate derivatives	(20)	(8)	(106)	(9)
Amortization of loan discount and other	10	9	25	29
Total interest expense	$ 43	$ 34	$ 52	$ 186

Foreign Currency Derivatives

On December 6, 2006, we issued 600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the Euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties pay Chesapeake 19 million and Chesapeake pays the counterparties $30 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake 600 million and Chesapeake will pay the counterparties $800 million. The terms of the cross currency swap were based on the dollar/euro exchange rate on the issuance date of $1.3325 to 1.00. Through the cross currency swap, we have eliminated any potential variability in Chesapeake s expected cash flows related to changes in foreign exchange rates and therefore the swap qualifies as a cash flow hedge under ASC 815. The fair value of the cross currency swap is recorded on the condensed consolidated balance sheet as an asset of $44 million at September 30, 2009. The euro-denominated debt in notes payable has been adjusted to $878 million at September 30, 2009 using an exchange rate of $1.4630 to 1.00.

ITEM 4. ***Controls and Procedures***

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed by Chesapeake in reports filed or submitted by it under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. At the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of Chesapeake management, including Chesapeake s Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of Chesapeake s disclosure controls and procedures pursuant to Securities Exchange Act Rule 13a-15(b). Based upon that evaluation our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective.

No changes in Chesapeake s internal control over financial reporting occurred during the Current Quarter that have materially affected, or are reasonably likely to materially affect, Chesapeake s internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. ***Legal Proceedings***

We refer you to Litigation in Note 3 of the notes to the condensed consolidated financial statements included in Part I, Item 1 of this Form 10-Q.

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

Our business has many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock, preferred stock or senior notes are described under Risk Factors in Item 1A of our 2008 Form 10-K and our Form 10-Q for the 2009 second quarter. This information should be considered carefully, together with other information in this report and other reports and materials we file with the Securities and Exchange Commission.

ITEM 2. ***Unregistered Sales of Equity Securities and Use of Proceeds***

The following table presents information about repurchases of our common stock during the three months ended September 30, 2009:

Period	Total Number of Shares Purchased[a]	Average Price Paid Per Share [a]	Total Number Of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs[b]
July 1, 2009 through July 31, 2009	727,462	$ 19.173		
August 1, 2009 through August 31, 2009	1,363,414	23.349		
September 1, 2009 through September 30, 2009	31,275	28.495		
Total	2,122,151	$ 21.993		

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

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

ITEM 3. ***Defaults Upon Senior Securities***

Not applicable.

ITEM 4. ***Submission of Matters to a Vote of Security Holders***

Not applicable.

ITEM 5. ***Other Information***

Not applicable.

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ITEM 6. ***Exhibits***

The following exhibits are filed as a part of this report:

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
3.1.1	Chesapeake s Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	08/10/2009		
3.1.3	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B).	10-Q	001-13726	3.1.4	11/10/2008		
3.1.4	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005), as amended.	10-K	001-13726	3.1.5	02/29/2008		
3.1.5	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock.	10-Q	001-13726	3.1.6	08/11/2008		
3.2	Chesapeake s Amended and Restated Bylaws.	8-K	001-13726	3.1	11/17/2008		
10.1.1	Chesapeake s 2003 Stock Incentive Plan, as amended					X	
10.1.14	Chesapeake s Amended and Restated Long Term Incentive Plan.					X	
10.2.2	Employment Agreement dated as of September 30, 2009 between Marcus C. Rowland and Chesapeake Energy Corporation.	8-K	001-13726	10.2.2	10/01/2009		
10.2.3	Employment Agreement dated as of September 30, 2009 between Steven C. Dixon and Chesapeake Energy Corporation.	8-K	001-13726	10.2.3	10/01/2009		
10.2.4	Employment Agreement dated as of September 30, 2009 between J. Mark Lester and Chesapeake Energy Corporation.	8-K	001-13726	10.2.4	10/01/2009		
10.2.5	Employment Agreement dated as of September 30, 2009 between Douglas J. Jacobson and Chesapeake Energy Corporation.	8-K	001-13726	10.2.5	10/01/2009		
10.2.7	Form of Employment Agreement between Senior Vice President and Chesapeake Energy Corporation.					X	
12	Ratios of Earnings to Fixed Charges and Preferred Dividends.					X	
31.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
31.2	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	

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32.2	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X	
101.INS	XBRL Instance Document.						X
101.SCH	XBRL Taxonomy Extension Schema Document.						X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.						X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.						X
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.						X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.						X

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SIGNATURES

Pursuant to the requirement of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

	CHESAPEAKE ENERGY CORPORATION
Date: November 9, 2009	By: /s/ AUBREY K. MCCLENDON Aubrey K. McClendon *Chairman of the Board and* *Chief Executive Officer*
Date: November 9, 2009	By: /s/ MARCUS C. ROWLAND Marcus C. Rowland *Executive Vice President and* *Chief Financial Officer*

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3.1.5	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock.	10-Q	001-13726	3.1.6	08/11/2008		
3.2	Chesapeake s Amended and Restated Bylaws.	8-K	001-13726	3.1	11/17/2008		
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