NATIONAL OILWELL VARCO INC
Form 10-Q
August 05, 2013

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark one)

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

FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2013

OR

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

Commission File Number 1-12317

NATIONAL OILWELL VARCO, INC.

(Exact name of registrant as specified in its charter)

Delaware	76-0475815
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

7909 Parkwood Circle Drive

Houston, Texas

77036-6565

(Address of principal executive offices)

(713) 346-7500

(Registrant s telephone number, including area code)

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

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

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

Large accelerated filer	x	Accelerated filer	¨
Non-accelerated filer	¨ (Do not check if a smaller reporting company)	Smaller reporting company	¨

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

As of August 1, 2013 the registrant had 427,518,321 shares of common stock, par value $.01 per share, outstanding.

PART I - FINANCIAL INFORMATION

Item 1. Financial Statements

NATIONAL OILWELL VARCO, INC.

CONSOLIDATED BALANCE SHEETS

(In millions, except share data)

	June 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,327	$ 3,319
Receivables, net	4,424	4,320
Inventories, net	6,083	5,891
Costs in excess of billings	1,448	1,225
Deferred income taxes	360	349
Prepaid and other current assets	579	574
Total current assets	15,221	15,678
Property, plant and equipment, net	3,210	2,945
Deferred income taxes	395	413
Goodwill	8,997	7,172
Intangibles, net	5,305	4,743
Investment in unconsolidated affiliates	357	393
Other assets	108	140
Total assets	$ 33,593	$ 31,484
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 1,232	$ 1,200
Accrued liabilities	2,681	2,571
Billings in excess of costs	1,159	1,189
Current portion of long-term debt and short-term borrowings		1
Accrued income taxes	248	355
Deferred income taxes	299	333
Total current liabilities	5,619	5,649
Long-term debt	4,120	3,148
Deferred income taxes	2,458	1,997
Other liabilities	445	334
Total liabilities	12,642	11,128
Commitments and contingencies		
Stockholders equity:		
Common stock - par value $.01; 1 billion shares authorized; 427,402,817 and 426,928,322 shares issued and outstanding at June 30, 2013 and December 31, 2012	4	4
Additional paid-in capital	8,805	8,743
Accumulated other comprehensive income (loss)	(201)	107
Retained earnings	12,251	11,385

Total Company stockholders equity	20,859	20,239
Noncontrolling interests	92	117
Total stockholders equity	20,951	20,356
Total liabilities and stockholders equity	$ 33,593	$ 31,484

See notes to unaudited consolidated financial statements.

NATIONAL OILWELL VARCO, INC.

CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(In millions, except per share data)

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Revenue	$ 5,601	$ 4,734	$ 10,908	$ 9,037
Cost of revenue	4,335	3,428	8,378	6,464
Gross profit	1,266	1,306	2,530	2,573
Selling, general and administrative	497	427	1,010	817
Operating profit	769	879	1,520	1,756
Interest and financial costs	(30)	(9)	(58)	(17)
Interest income	3	3	6	6
Equity income in unconsolidated affiliates	15	19	34	36
Other income (expense), net	13	(5)	(8)	(21)
Income before income taxes	770	887	1,494	1,760
Provision for income taxes	239	285	463	554
Net income	531	602	1,031	1,206
Net loss attributable to noncontrolling interests		(3)	(2)	(5)
Net income attributable to Company	$ 531	$ 605	$ 1,033	$ 1,211
Net income attributable to Company per share:				
Basic	$ 1.25	$ 1.42	$ 2.42	$ 2.85
Diluted	$ 1.24	$ 1.42	$ 2.41	$ 2.84
Cash dividends per share	$ 0.26	$ 0.12	$ 0.39	$ 0.24
Weighted average shares outstanding:				
Basic	426	425	426	424
Diluted	428	427	428	426

See notes to unaudited consolidated financial statements.

NATIONAL OILWELL VARCO, INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

(In millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net income	$ 531	$ 602	$ 1,031	$ 1,206
Currency translation adjustments	(121)	(121)	(238)	(56)
Changes in derivative financial instruments, net of tax	(22)	(53)	(70)	10
Comprehensive income	388	428	723	1,160
Comprehensive loss attributable to noncontrolling interest		(3)	(2)	(5)
Comprehensive income attributable to Company	$ 388	$ 431	$ 725	$ 1,165

See notes to unaudited consolidated financial statements.

NATIONAL OILWELL VARCO, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(In millions)

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Cash flows from operating activities:		
Net income	$ 1,031	$ 1,206
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation and amortization	364	305
Deferred income taxes	(115)	51
Equity income in unconsolidated affiliates	(34)	(36)
Dividend from unconsolidated affiliate	66	61
Other, net	37	43
Change in operating assets and liabilities, net of acquisitions:		
Receivables	4	(162)
Inventories	(13)	(785)
Costs in excess of billings	(222)	(360)
Prepaid and other current assets	24	(168)
Accounts payable	(38)	107
Billings in excess of costs	(30)	210
Income taxes payable	(105)	(557)
Other assets/liabilities, net	(99)	(232)
Net cash provided by (used in) operating activities	870	(317)
Cash flows from investing activities:		
Purchases of property, plant and equipment	(320)	(253)
Business acquisitions, net of cash acquired	(2,390)	(2,014)
Other	46	17
Net cash used in investing activities	(2,664)	(2,250)
Cash flows from financing activities:		
Borrowings against lines of credit and other debt	1,556	939
Repayments on debt	(586)	(2)
Cash dividends paid	(167)	(102)
Proceeds from stock options exercised	12	93
Other	13	27
Net cash provided by financing activities	828	955
Effect of exchange rates on cash	(26)	(6)
Decrease in cash and cash equivalents	(992)	(1,618)
Cash and cash equivalents, beginning of period	3,319	3,535
Cash and cash equivalents, end of period	$ 2,327	$ 1,917
Supplemental disclosures of cash flow information:		
Cash payments during the period for:		
Interest	$ 57	$ 12
Income taxes	$ 668	$ 1,021

See notes to unaudited consolidated financial statements.

NATIONAL OILWELL VARCO, INC.

Notes to Consolidated Financial Statements (Unaudited)

1. Basis of Presentation

The preparation of financial statements in conformity with generally accepted accounting principles (GAAP) in the United States requires management to make estimates and assumptions that affect reported and contingent amounts of assets and liabilities as of the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

The accompanying unaudited consolidated financial statements of National Oilwell Varco, Inc. (the Company) present information in accordance with GAAP in the United States for interim financial information and the instructions to Form 10-Q and applicable rules of Regulation S-X. They do not include all information or footnotes required by GAAP in the United States for complete consolidated financial statements and should be read in conjunction with our 2012 Annual Report on Form 10-K.

In our opinion, the consolidated financial statements include all adjustments, all of which are of a normal recurring nature, necessary for a fair presentation of the results for the interim periods. The results of operations for the three and six months ended June 30, 2013 are not necessarily indicative of the results to be expected for the full year.

Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents, receivables, and payables approximated fair value because of the relatively short maturity of these instruments. Cash equivalents include only those investments having a maturity date of three months or less at the time of purchase. See Note 7 for the fair value of long-term debt and Note 10 for the fair value of derivative financial instruments.

2. Inventories, net

Inventories consist of (in millions):

	June 30, 2013	December 31, 2012
Raw materials and supplies	$ 1,225	$ 1,268
Work in process	1,015	905
Finished goods and purchased products	3,843	3,718
Total	$ 6,083	$ 5,891

3. Accrued Liabilities

Accrued liabilities consist of (in millions):

	June 30, 2013	December 31, 2012
Customer prepayments and billings	$ 674	$ 699
Accrued vendor costs	633	444
Compensation	389	511
Warranty	205	194
Taxes (non income)	125	150
Insurance	119	108
Fair value of derivatives	59	18
Interest	12	14
Other	465	433
Total	$ 2,681	$ 2,571

Service and Product Warranties

The Company provides certain service and product warranties. The Company accrues liabilities under service and warranty policies based upon specific claims and a review of historical warranty and service claim experience in accordance with Accounting Standards Codification (ASC) Topic 450 Contingencies (ASC Topic 450). Adjustments are made to accruals as claim data and historical experience change. In addition, the Company incurs discretionary costs to service its products in connection with product performance issues and accrues for them when they are encountered. The Company monitors the actual cost of performing these discretionary services and adjusts the accrual based on the most current information available.

The changes in the carrying amount of service and product warranties are as follows (in millions):

Balance at December 31, 2012	$ 194
Net provisions for warranties issued during the year	45
Amounts incurred	(38)
Currency translation adjustments and other	4
Balance at June 30, 2013	$ 205

4. Costs and Estimated Earnings on Uncompleted Contracts

Costs and estimated earnings on uncompleted contracts consist of (in millions):

	June 30, 2013	December 31, 2012
Costs incurred on uncompleted contracts	$ 6,942	$ 5,731
Estimated earnings	3,527	3,160
	10,469	8,891
Less: Billings to date	10,180	8,855
	$ 289	$ 36

Costs and estimated earnings in excess of billings on uncompleted contracts	$ 1,448	$ 1,225
Billings in excess of costs and estimated earnings on uncompleted contracts	(1,159)	(1,189)
	$ 289	$ 36

5. Accumulated Other Comprehensive Income (Loss)

The components of accumulated other comprehensive income (loss) are as follows (in millions):

	Currency Translation Adjustments	Derivative Financial Instruments, Net of Tax	Defined Benefit Plans, Net of Tax	Total
Balance at December 31, 2012	$ 132	$ 42	$ (67)	$ 107
Accumulated other comprehensive income (loss) before reclassifications	(213)	(68)		(281)
Amounts reclassified from accumulated other comprehensive income (loss)	(25)	(2)		(27)
Balance at June 30, 2013	$ (106)	$ (28)	$ (67)	$ (201)

The components of amounts reclassified from accumulated other comprehensive income (loss) are as follows (in millions):

	Three Months Ended June 30,							
	2013				2012			
	Currency Translation Adjustments	Derivative Financial Instruments	Defined Benefit Plans	Total	Currency Translation Adjustments	Derivative Financial Instruments	Defined Benefit Plans	Total
Revenue	$	$ (2)	$	$ (2)	$	$ 2	$	$ 2
Cost of revenue		4		4		5		5
Other income (expense), net	(25)			(25)				
Tax effect						(2)		(2)
	$ (25)	$ 2	$	$ (23)	$	$ 5	$	$ 5

	Six Months Ended June 30,							
	2013				2012			
	Currency Translation Adjustments	Derivative Financial Instruments	Defined Benefit Plans	Total	Currency Translation Adjustments	Derivative Financial Instruments	Defined Benefit Plans	Total
Revenue	$	$ (4)	$	$ (4)	$	$ 6	$	$ 6
Cost of revenue		1		1		11		11
Other income (expense), net	(25)			(25)				
Tax effect		1		1		(5)		(5)
	$ (25)	$ (2)	$	$ (27)	$	$ 12	$	$ 12

The Company s reporting currency is the U.S. dollar. A majority of the Company s international entities in which there is a substantial investment have the local currency as their functional currency. As a result, currency translation adjustments resulting from the process of translating the entities financial statements into the reporting currency are reported in other comprehensive income or loss in accordance with ASC Topic 830 Foreign Currency Matters (ASC Topic 830). For the three and six months ended June 30, 2013 and 2012 a majority of these local currencies weakened against the U.S. dollar. This resulted in net other comprehensive loss of $96 million and $213 million, for the three and six months ended June 30, 2013, respectively, upon the translation from local currencies to the U.S. dollar. Due to the sale of a foreign subsidiary during the second quarter of 2013, $25 million of currency translation gains were reclassified from accumulated other comprehensive income (loss) into other income (expense), net in the Consolidated Statement of Income. For the three and six months ended June 30, 2012, this resulted in other comprehensive loss of $121 million and $56 million, respectively.

The effect of changes in the fair values of derivatives designated as cash flow hedges are accumulated in Other Comprehensive Income or Loss, net of tax, until the underlying transactions to which they are designed to hedge are realized. The movement in Other Comprehensive Income or

Loss from period to period will be the result of the combination of changes in fair value for open derivatives and the outflow of Other Comprehensive Income or Loss related to cumulative changes in the fair value of derivatives that have settled in the current or prior periods. The accumulated effect was Other Comprehensive Loss of $22 million (net of tax $8 million) and $70 million (net of tax of $27 million) for the three and six months ended June 30, 2013, respectively. The accumulated effect was Other Comprehensive Loss of $53 million (net of tax of $22 million) for the three months ended June 30, 2012 and Other Comprehensive Income of $10 million (net of tax of $4 million) for the six months ended June 30, 2012.

6. Business Segments

Operating results by segment are as follows (in millions):

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Revenue:				
Rig Technology	$ 2,833	$ 2,405	$ 5,461	$ 4,664
Petroleum Services & Supplies	1,749	1,776	3,450	3,480
Distribution & Transmission	1,295	780	2,522	1,344
Eliminations	(276)	(227)	(525)	(451)
Total Revenue	$ 5,601	$ 4,734	$ 10,908	$ 9,037
Operating Profit:				
Rig Technology	$ 574	$ 554	$ 1,124	$ 1,101
Petroleum Services & Supplies	273	390	528	778
Distribution & Transmission	58	46	121	89
Unallocated expenses and eliminations	(136)	(111)	(253)	(212)
Total Operating Profit	$ 769	$ 879	$ 1,520	$ 1,756
Operating Profit %:				
Rig Technology	20.3%	23.0%	20.6%	23.6%
Petroleum Services & Supplies	15.6%	22.0%	15.3%	22.4%
Distribution & Transmission	4.5%	5.9%	4.8%	6.6%
Total Operating Profit %	13.7%	18.6%	13.9%	19.4%

Included in operating profit are other costs related to acquisitions, such as administration costs and the amortization of backlog and inventory that was stepped up to fair value during purchase accounting. Other costs by segment are as follows (in millions):

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Other costs:				
Rig Technology	$ 13	$ 17	$ 20	$ 21
Petroleum Services & Supplies	31	3	87	3
Distribution & Transmission	13	8	15	8
Total other costs	$ 57	$ 28	$ 122	$ 32

The Company had revenues of 10% of total revenue from one of its customers for each of the three and six months ended June 30, 2013, respectively and 10% for each of the three and six months ended June 30, 2012, respectively. This customer, Samsung Heavy Industries, is a shipyard acting as a general contractor for its customers, who are drillship owners and drilling contractors. This shipyard s customers have specified that the Company s drilling equipment be installed on their drillships and have required the shipyard to issue contracts to the Company.

7. Debt

Debt consists of (in millions):

	June 30, 2013	December 31, 2012
Senior Notes, interest at 6.125% payable semiannually, principal due on August 15, 2015	$ 151	$ 151
Senior Notes, interest at 1.35% payable semiannually, principal due on December 1, 2017	500	500
Senior Notes, interest at 2.6% payable semiannually, principal due on December 1, 2022	1,395	1,395
Senior Notes, interest at 3.95% payable semiannually, principal due on December 1, 2042	1,096	1,096
Revolving Credit Facility, expires September 28, 2017	970	
Other	8	7
Total debt	4,120	3,149
Less current portion		1
Long-term debt	$ 4,120	$ 3,148

The Company has a $3.5 billion, five-year unsecured revolving credit facility which expires September 28, 2017. At June 30, 2013, there were $970 million in outstanding borrowings against the credit facility, and there were $858 million in outstanding letters of credit issued under the credit facility, resulting in $1,672 million of funds available under this revolving credit facility. Interest under this multicurrency facility is based upon LIBOR, NIBOR or EURIBOR plus 0.875% subject to a ratings-based grid, or the prime rate. The credit facility contains a financial covenant regarding maximum debt to capitalization and the Company was in compliance at June 30, 2013.

The Company also had $2,641 million of additional outstanding letters of credit at June 30, 2013, primarily in Norway, that are under various bilateral committed letter of credit facilities. Other letters of credit are issued as bid bonds and performance bonds.

The fair value of the Company s Senior Notes are estimated using Level 2 inputs in the fair value hierarchy and is based on quoted prices for those or similar instruments. At June 30, 2013 and December 31, 2012, the fair value of the Company s unsecured Senior Notes approximated $2,938 million and $3,190, respectively. At June 30, 2013 and December 31, 2012, the carrying value of the Company s unsecured Senior Notes was $3,142 million. The carrying value of the Company s variable rate borrowings approximates fair value.

8. Tax

The effective tax rate for the three and six months ended June 30, 2013 was 31.0% and 31.0%, respectively, compared to 32.1% and 31.5% for the same period in 2012. Compared to the U.S. statutory rate, the effective tax rate was positively impacted in the periods by the effect of lower tax rates on income earned in foreign jurisdictions, and the deduction in the U.S. for manufacturing activities. The effective tax rate for 2013 was negatively impacted by foreign exchange gains for tax reporting in Norway, while 2012 was positively impacted by foreign exchange losses for tax reporting in Norway.

The difference between the effective tax rate reflected in the provision for income taxes and the U.S. federal statutory rate of 35% was as follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	**2012**	**2013**	**2012**
Federal income tax at U.S. federal statutory rate	$ 270	$ 310	$ 523	$ 616
Foreign income tax rate differential	(65)	(57)	(122)	(80)
State income tax, net of federal benefit	4	9	12	17
Nondeductible expenses	8	10	16	23
Tax benefit of manufacturing deduction	(8)	(9)	(16)	(18)
Foreign dividends, net of foreign tax credits	8	14	12	20
Tax impact of foreign exchange	21	12	39	(18)
Other	1	(4)	(1)	(6)
Provision for income taxes	$ 239	$ 285	$ 463	$ 554

The balance of unrecognized tax benefits at June 30, 2013 was $128 million, $55 million of which if ultimately realized, would be recorded as income tax benefit. The Company recognized no material changes in the balance of unrecognized tax benefits for the three and six months ended June 30, 2013.

The Company does not anticipate that its total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitation within 12 months of this reporting date.

The Company is subject to taxation in the U.S., various states and foreign jurisdictions. The Company has significant operations in the United States, Canada, the United Kingdom, the Netherlands and Norway. Tax years that remain subject to examination by major tax jurisdiction vary by legal entity, but are generally open in the U.S. for tax years after 2007 and outside the U.S. for tax years after 2005.

To the extent penalties and interest would be assessed on any underpayment of income tax, such accrued amounts have been classified as a component of income tax expense in the financial statements.

9. Stock-Based Compensation

The Company has a stock-based compensation plan known as the National Oilwell Varco, Inc. Long-Term Incentive Plan (the Plan). The Plan provides for the granting of stock options, performance-based share awards, restricted stock, phantom shares, stock payments and stock appreciation rights. The number of shares authorized under the Plan was increased during the second quarter of 2013 and is 39.5 million. At June 30, 2013, 14,182,083 shares remain available for future grants under the Plan, all of which are available for grants of stock options, performance-based share awards, restricted stock awards, phantom shares, stock payments and stock appreciation rights. During the six months ended June 30, 2013, the Company concluded that the performance conditions relating to the performance-based restricted stock awards granted on February 16, 2010 were not met. As a result, the Company reversed $8 million in previously recognized stock-based compensation expense related to performance-based restricted stock awards that did not vest. Total stock based compensation for all stock-based compensation arrangements under the Plan was $25 million and $42 million for the three and six months ended June 30, 2013, respectively, and $22 million and $34 million for the three and six months ended June 30, 2012, respectively. The total income tax benefit recognized in the Consolidated Statements of Income for all stock-based compensation arrangements under the Plan was $8 million and $13 million for the three and six months ended June 30, 2013, respectively, and $8 million and $11 million for the three and six months ended June 30, 2012, respectively.

During the six months ended June 30, 2013, the Company granted 2,819,806 stock options with a fair value of $24.10 per share, 540,194 shares of restricted stock and restricted stock units with a fair value of $69.33 per share and 16,702 shares of restricted stock with a fair value of $69.17. In addition, the Company granted performance share awards to senior management employees with potential payouts varying from zero to 398,160 shares. The stock options were granted February 15, 2013 with an exercise price of $69.33. These options generally vest over a three-year period from the grant date. The restricted stock and restricted stock units were granted February 15, 2013 and vest on the third anniversary of the date of grant, except for a special grant of 16,352 restricted stock units which vest on the second anniversary of the date of grant (subject to the satisfaction of a performance condition). On May 22, 2013, the 16,702 restricted stock awards, with a fair value of $69.17, were granted to the non-employee members of the board of directors. These restricted stock awards vest in equal thirds over three years on the anniversary of the grant date. The performance share awards were granted on March 22, 2013 and can be earned based on performance against established goals over a three-year performance period. The performance share awards are divided into two equal, independent parts that are subject to two separate performance metrics: 50% with a TSR (total shareholder return) goal (the TSR Award) and 50% with an internal ROC (return on capital) goal (the ROC Award).

Performance against the TSR goal is determined by comparing the performance of the Company s TSR with the TSR performance of the members of the OSX index for the three year performance period. Performance against the ROC goal is determined by comparing the performance of the Company s actual ROC performance average for each of the three years of the performance period against the ROC goal set by the Company s Compensation Committee.

10. Derivative Financial Instruments

ASC Topic 815, Derivatives and Hedging (ASC Topic 815) requires a company to recognize all of its derivative instruments as either assets or liabilities in the Consolidated Balance Sheet at fair value. The accounting for changes in the fair value (i.e., gains or losses) of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and further, on the type of hedging relationship. For those derivative instruments that are designated and qualify as hedging instruments, a company must designate the hedging instrument, based upon the exposure being hedged, as a fair value hedge, cash flow hedge, or a hedge of a net investment in a foreign operation.

The Company is exposed to certain risks relating to its ongoing business operations. The primary risk managed by using derivative instruments is foreign currency exchange rate risk. Forward contracts against various foreign currencies are entered into to manage the foreign currency exchange rate risk on forecasted revenues and expenses denominated in currencies other than the functional currency of the operating unit (cash flow hedge). In addition, the Company will enter into non-designated forward contracts against various foreign currencies to manage the foreign currency exchange rate risk on recognized nonfunctional currency monetary accounts (non-designated hedge).

The Company records all derivative financial instruments at their fair value in its Consolidated Balance Sheet. Except for certain non-designated hedges discussed below, all derivative financial instruments that the Company holds are designated as cash flow hedges and are highly effective in offsetting movements in the underlying risks. Such arrangements typically have terms between 2 and 24 months, but may have longer terms depending on the underlying cash flows being hedged, typically related to the projects in our backlog. The Company may also use interest rate contracts to mitigate its exposure to changes in interest rates on anticipated long-term debt issuances.

At June 30, 2013, the Company has determined that the fair value of its derivative financial instruments representing assets of $34 million and liabilities of $74 million (primarily currency related derivatives) are determined using level 2 inputs (inputs other than quoted prices in active markets for identical assets and liabilities that are observable either directly or indirectly for substantially the full term of the asset or liability) in the fair value hierarchy as the fair value is based on publicly available foreign exchange and interest rates at each financial reporting date. At June 30, 2013, the net fair value of the Company s foreign currency forward contracts totaled a net liability of $40 million.

At June 30, 2013, the Company did not have any interest rate swaps and its financial instruments do not contain any credit-risk-related or other contingent features that could cause accelerated payments when the Company s financial instruments are in net liability positions. We do not use derivative financial instruments for trading or speculative purposes.

Cash Flow Hedging Strategy

To protect against the volatility of forecasted foreign currency cash flows resulting from forecasted revenues and expenses, the Company has instituted a cash flow hedging program. The Company hedges portions of its forecasted revenues and expenses denominated in nonfunctional currencies with forward contracts. When the U.S. dollar strengthens against the foreign currencies, the decrease in present value of future foreign currency revenues and expenses is offset by gains in the fair value of the forward contracts designated as hedges. Conversely, when the U.S. dollar weakens, the increase in the present value of future foreign currency cash flows is offset by losses in the fair value of the forward contracts.

For derivative instruments that are designated and qualify as a cash flow hedge (i.e., hedging the exposure to variability in expected future cash flows that is subject to a particular currency risk), the effective portion of the gain or loss on the derivative instrument is reported as a component of Other Comprehensive Income and reclassified into earnings in the same line item associated with the forecasted transaction and in the same period or periods during which the hedged transaction affects earnings (e.g., in revenues when the hedged transactions are cash flows associated with forecasted revenues). The remaining gain or loss on the derivative instrument in excess of the cumulative change in the present value of future cash flows of the hedged item, if any (i.e., the ineffective portion), or hedge components excluded from the assessment of effectiveness, is recognized in the Consolidated Statements of Income during the current period.

The Company had the following outstanding foreign currency forward contracts that were entered into to hedge nonfunctional currency cash flows from forecasted revenues and expenses (in millions):

	Currency Denomination			
Foreign Currency	**June 30, 2013**		**December 31, 2012**	
Norwegian Krone	NOK	9,440	NOK	6,281
U.S. Dollar	$	509	$	331
Euro	€	376	€	389
Danish Krone	DKK	195	DKK	134
British Pound Sterling	£	34	£	6
Singapore Dollar	SGD	16	SGD	14

Non-designated Hedging Strategy

The Company enters into forward exchange contracts to hedge certain nonfunctional currency monetary accounts. The purpose of the Company s foreign currency hedging activities is to protect the Company from risk that the eventual U.S. dollar equivalent cash flows from the nonfunctional currency monetary accounts will be adversely affected by changes in the exchange rates.

For derivative instruments that are non-designated, the gain or loss on the derivative instrument subject to the hedged risk (i.e., nonfunctional currency monetary accounts) is recognized in other income (expense), net in current earnings.

The Company had the following outstanding foreign currency forward contracts that hedge the fair value of nonfunctional currency monetary accounts (in millions):

	Currency Denomination			
Foreign Currency	**June 30, 2013**		**December 31, 2012**	
Norwegian Krone	NOK	2,979	NOK	1,684
Russian Ruble	RUB	1,841	RUB	1,467
U.S. Dollar	$	941	$	967
Euro	€	191	€	225
Danish Krone	DKK	183	DKK	177
Brazilian Real	BRL	172	BRL	135
Singapore Dollar	SGD	16	SGD	24
British Pound Sterling	£	11	£	9
Swedish Krone	SEK	1	SEK	5

The Company has the following gross fair values of its derivative instruments and their balance sheet classifications:

NATIONAL OILWELL VARCO, INC.

Fair Values of Derivative Instruments

(In millions)

	Asset Derivatives			Liability Derivatives		
	Balance Sheet Location	Fair Value June 30, 2013	Fair Value December 31, 2012	Balance Sheet Location	Fair Value June 30, 2013	Fair Value December 31, 2012
Derivatives designated as hedging instruments under ASC Topic 815						
Foreign exchange contracts	Prepaid and other current assets	$ 12	$ 57	Accrued liabilities	$ 32	$ 5
Foreign exchange contracts	Other Assets	2	24	Other Liabilities	15	1
Total derivatives designated as hedging instruments under ASC Topic 815		$ 14	$ 81		$ 47	$ 6
Derivatives not designated as hedging instruments under ASC Topic 815						
Foreign exchange contracts	Prepaid and other current assets	$ 20	$ 24	Accrued liabilities	$ 27	$ 13
Total derivatives not designated as hedging instruments under ASC Topic 815		$ 20	$ 24		$ 27	$ 13
Total derivatives		$ 34	$ 105		$ 74	$ 19

The Effect of Derivative Instruments on the Consolidated Statements of Income

($ in millions)

Derivatives in ASC Topic 815 Cash Flow Hedging Relationships	Amount of Gain (Loss) Recognized in OCI on Derivative (Effective Portion) (a) Six Months Ended June 30,		Location of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Amount of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) Six Months Ended June 30,		Location of Gain (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Amount of Gain (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing) (b) Six Months Ended June 30,	
	2013	2012		2013	2012		2013	2012

			Revenue	4	(6)			
Foreign exchange contracts	(95)	(5)	Cost of revenue	(1)	(11)	Other income (expense), net	5	4
Total	(95)	(5)		3	(17)		5	4

Derivatives Not Designated as Hedging Instruments under ASC Topic 815	**Location of Gain (Loss) Recognized in Income on Derivative**	**Amount of Gain (Loss) Recognized in Income on Derivative Six Months Ended June 30, 2013**	**2012**
Foreign exchange contracts	Other income (expense), net	12	13
Total		12	13

(a) The Company expects that $24 million of the Accumulated Other Comprehensive Income (Loss) will be reclassified into earnings within the next twelve months with an offset by gains from the underlying transactions resulting in no impact to earnings or cash flow.

(b) The amount of gain (loss) recognized in income represents nil and $(1) million related to the ineffective portion of the hedging relationships for the six months ended June 30, 2013 and 2012, respectively, and $5 million related to the amount excluded from the assessment of the hedge effectiveness for each of the six months ended June 30, 2013 and 2012, respectively.

11. Net Income Attributable to Company Per Share

The following table sets forth the computation of weighted average basic and diluted shares outstanding (in millions, except per share data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Numerator:				
Net income attributable to Company	$ 531	$ 605	$ 1,033	$ 1,211
Denominator:				
Basic weighted average common shares outstanding	426	425	426	424
Dilutive effect of employee stock options and other unvested stock awards	2	2	2	2
Diluted outstanding shares	428	427	428	426
Net income attributable to Company per share:				
Basic	$ 1.25	$ 1.42	$ 2.42	$ 2.85
Diluted	$ 1.24	$ 1.42	$ 2.41	$ 2.84
Cash dividends per share	$ 0.26	$ 0.12	$ 0.39	$ 0.24

ASC Topic 260, Earnings Per Share (ASC Topic 260) requires companies with unvested participating securities to utilize a two-class method for the computation of Net income attributable to Company per share. The two-class method requires a portion of Net income attributable to Company to be allocated to participating securities, which are unvested awards of share-based payments with non-forfeitable rights to receive dividends or dividend equivalents, if declared. Net income attributable to Company allocated to these participating securities was immaterial for the three and six months ended June 30, 2013 and 2012 and therefore not excluded from Net income attributable to Company per share calculation.

In addition, the Company had stock options outstanding that were anti-dilutive totaling 7 million shares for each of the three and six months ended June 30, 2013, and 5 million shares for each of the three and six months ended June 30, 2012, respectively.

12. Cash Dividends

On May 15, 2013, the Company s Board of Directors approved a cash dividend of $0.26 per share. The cash dividend was paid on June 28, 2013, to each stockholder of record on June 14, 2013. Cash dividends aggregated $111 million and $167 million for the three and six months ended June 30, 2013 and $51 million and $102 million for the three and six months ended June 30, 2012, respectively. The declaration and payment of future dividends is at the discretion of the Company s Board of Directors and will be dependent upon the Company s results of operations, financial condition, capital requirements and other factors deemed relevant by the Company s Board of Directors.

13. Commitments and Contingencies

We have received federal grand jury subpoenas and subsequent inquiries from governmental agencies requesting records related to our compliance with export trade laws and regulations. We have cooperated fully with agents from the Department of Justice, the Bureau of Industry and Security, the Office of Foreign Assets Control, and U.S. Immigration and Customs Enforcement in responding to the inquiries. We have also cooperated with an informal inquiry from the Securities and Exchange Commission in connection with the inquiries previously made by the aforementioned federal agencies. We have conducted our own internal review of this matter. At the conclusion of our internal review in the fourth quarter of 2009, we identified possible areas of concern and discussed these areas of concern with the relevant agencies. We are currently negotiating a potential resolution with the agencies involved related to these matters. We currently anticipate that any administrative fine or penalty agreed to as part of a resolution would be within established accruals, and would not have a material effect on our financial position or results of operations. To the extent a resolution is not negotiated, we cannot predict the timing or effect that any resulting government actions may have on our financial position or results of operations.

In 2011, the Company acquired Ameron International Corporation (Ameron). On or about November 21, 2008, the United States Department of Treasury, Office of Foreign Assets Control (OFAC) sent a Requirement to Furnish Information to Ameron. Ameron retained counsel and conducted an internal investigation. In 2009, Ameron, through its counsel, responded to OFAC. On or about January 21, 2011, OFAC issued an administrative subpoena to Ameron. OFAC and Ameron have entered into Tolling Agreements. All of the conduct under review occurred before acquisition of Ameron by the Company. We currently anticipate that any administrative fine or penalty agreed to as part of a resolution would be within established accruals, and would not have a material effect on our financial position or results of operations. To the extent a resolution is not negotiated, we cannot predict the timing or effect that any resulting government actions may have on our financial position or results of operations.

On February 20, 2013, the Company acquired Robbins & Myers, Inc. (R&M). R&M was subject to an ongoing investigation by the U.S. Department of Justice (DOJ) and the Department of Commerce Bureau of Industry and Security (BIS) regarding potential export controls violations arising from certain shipments by R&M s Belgian subsidiary to one customer in Iran, Sudan and Syria in 2005 and 2006. R&M has cooperated with the investigation and is currently negotiating a joint settlement with the DOJ and BIS. We currently anticipate that any administrative fine or criminal penalty agreed to as part of a resolution would be within established accruals, and would not have a material effect on our financial position or results of operations. To the extent a resolution is not negotiated, we cannot predict the timing or effect that any resulting government actions may have on our financial position or results of operations.

In addition, we are involved in various other claims, regulatory agency audits and pending or threatened legal actions involving a variety of matters. As of June 30, 2013, the Company recorded an immaterial amount for contingent liabilities representing all contingencies believed to be probable. The Company has also assessed the potential for additional losses above the amounts accrued as well as potential losses for matters that are not probable but are reasonably possible. The total potential loss on these matters cannot be determined; however, in our opinion, any ultimate liability, to the extent not otherwise provided for and except for the specific cases referred to above, will not materially affect our financial position, cash flow or results of operations. As it relates to the specific cases referred to above we currently anticipate that any administrative fine or penalty agreed to as part of a resolution would be within established accruals, and would not have a material effect on our financial position or results of operations. To the extent a resolution is not negotiated as anticipated, we cannot predict the timing or effect that any resulting government actions may have on our financial position, cash flow or results of operations. These estimated liabilities are based on the Company s assessment of the nature of these matters, their progress toward resolution, the advice of legal counsel and outside experts as well as management s intention and experience.

Our business is affected both directly and indirectly by governmental laws and regulations relating to the oilfield service industry in general, as well as by environmental and safety regulations that specifically apply to our business. Although we have not incurred material costs in connection with our compliance with such laws, there can be no assurance that other developments, such as new environmental laws, regulations and enforcement policies hereunder may not result in additional, presently unquantifiable, costs or liabilities to us.

14. Acquisition

On February 20, 2013, the Company completed its previously announced acquisition of all of the shares of Robbins & Myers, Inc., a U.S.-based designer and manufacturer of products and systems for the oil and gas industry. Under the merger agreement for this transaction, R&M shareholders received $60.00 in cash for each common share for an aggregate purchase price of $2,375 million, net of cash acquired.

The Company has included the financial results of R&M in its consolidated financial statements as of the date of acquisition with components of the R&M operations included in the Company s Rig Technology, Petroleum Services & Supplies and Distribution & Transmission segments. The Company believes the acquisition of R&M will advance its strategic goal of providing a broader selection of products and services to its customers.

The following table displays the total preliminary purchase price allocation for the R&M acquisition. The R&M purchase price allocation remains preliminary until the valuation is complete. The table summarizes the estimated fair values of the assets acquired and liabilities assumed at the date of acquisition. (in millions):

Current assets, net of cash acquired	$ 446
Property, plant and equipment	198
Intangible assets	969
Goodwill	1,538
Other assets	25
Total assets acquired	3,176
Current liabilities	190
Deferred taxes	491
Other liabilities	120
Total liabilities	801
Cash consideration, net of cash acquired	$ 2,375

The Company has preliminarily allocated $969 million to intangible assets (19 year weighted-average life). The intangible assets are expected to be amortizable and are comprised of: $817 million of customer relationships (20 year weighted-average life), $58 million of trademarks (15 year weighted-average life), and $94 million of other intangible assets (15 year weighted-average life). The amount allocated to goodwill represents the excess of the purchase price over the fair value of the net assets acquired. Goodwill resulting from the R&M acquisition is not expected to be deductible for tax purposes. Pro forma information is not included because the acquired operations would not have materially impacted the Company s consolidated operating results.

15. Recently Issued Accounting Standards

In February 2013, the Financial Accounting Standards Board issued Accounting Standard Update No. 2013-02 Reporting of Amounts Reclassified out of Accumulated Other Comprehensive Income (ASU No. 2013-02), which is an update for Accounting Standards Codification Topic No. 220 Comprehensive Income . The update improves the reporting of reclassifications out of accumulated other comprehensive income. The guidance was effective for the Company s interim and annual reporting periods beginning January 1, 2013, and applied prospectively. There was no significant impact to the Company s Consolidated Financial Statements from the adopted provisions of ASU No. 2013-02.

In March 2013, the FASB issued Accounting Standards Update No. 2013-05, Parent s Accounting for the Cumulative Translation Adjustment upon Derecognition of Certain Subsidiaries or Groups of Assets within a Foreign Entity or of an Investment in a Foreign Entity (a consensus of the FASB Emerging Issues Task Force). (ASU No. 2013-05), which amends Accounting Standards Codification Topic No. 830, Foreign Currency Matters, and Accounting Standards Codification Topic No. 810, Consolidation, to address diversity in practice related to the release of cumulative translation adjustments (CTA) into earnings upon the occurrence of certain derecognition events. ASU No. 2013-05 precludes the release of CTA for derecognition events that occur within a foreign entity, unless such events represent a complete or substantially complete liquidation of the foreign entity; however, derecognition events related to investments in a foreign entity result in the release of all CTA related to the derecognized foreign entity, even when a noncontrolling financial interest is retained. ASU No. 2013-05 also amends Accounting Standards Codification Topic No. 805, Business Combinations, for transactions that result in a company obtaining control of a business in a step acquisition by increasing an investment in a foreign entity from one accounted for under the equity method to one accounted for as a consolidated investment. ASU No. 2013-05 is effective for fiscal years beginning after December 15, 2013, and applied prospectively. Early adoption is permitted as of the beginning of the entity s fiscal year. The Company is currently assessing the impact ASU No. 2013-05 will have on its financial statements, but does not expect a significant impact from adoption of the pronouncement.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

Introduction

National Oilwell Varco, Inc. (the Company) is a worldwide leader in the design, manufacture and sale of equipment and components used in oil and gas drilling and production, the provision of oilfield services, and supply chain integration services to the upstream oil and gas industry.

Unless indicated otherwise, results of operations data are presented in accordance with accounting principles generally accepted in the United States (GAAP). In an effort to provide investors with additional information regarding our results of operations, certain non-GAAP financial measures, including operating profit excluding other costs, operating profit percentage excluding other costs and diluted earnings per share excluding other costs, are provided. See Non-GAAP Financial Measures and Reconciliations in Results of Operations for an explanation of our use of non-GAAP financial measures and reconciliations to their corresponding measures calculated in accordance with GAAP.

Rig Technology

Our Rig Technology segment designs, manufactures, sells and services complete systems for the drilling, completion, and servicing of oil and gas wells. The segment offers a comprehensive line of highly-engineered equipment that automates complex well construction and management operations, such as offshore and onshore drilling rigs; derricks; pipe lifting, racking, rotating and assembly systems; rig instrumentation systems; blowout preventers; coiled tubing equipment and pressure pumping units; well workover rigs; wireline winches; wireline trucks; cranes; flexible pipe for offshore production applications; and turret mooring systems and other products for floating production, storage and offloading vessels (FPSOs) and other offshore vessels and terminals. Demand for Rig Technology products is primarily dependent on capital spending plans by drilling contractors, oilfield service companies, and oil and gas companies; and secondarily on the overall level of oilfield drilling activity, which drives demand for spare parts for the segment s large installed base of equipment. We have made strategic acquisitions and other investments during the past several years in an effort to expand our product offering and our global manufacturing capabilities, including adding additional operations in the United States, Canada, Norway, Denmark, the United Kingdom, Brazil, China, Belarus, India, Russia, the Netherlands, Singapore, South Korea, South Africa, and Angola.

Petroleum Services & Supplies

Our Petroleum Services & Supplies segment provides a variety of consumable goods and services used to drill, complete, remediate and workover oil and gas wells and service drill pipe, tubing, casing, flowlines and other oilfield tubular goods. The segment manufactures, rents and sells a variety of products and equipment used to perform drilling operations, including drill pipe, wired drill pipe, transfer pumps, solids control systems, drilling motors, drilling fluids, drill bits, reamers and other downhole tools, and mud pump consumables. Demand for these services and supplies is determined principally by the level of oilfield drilling and workover activity by drilling contractors, oilfield service companies, major and independent oil and gas companies, and national oil companies. Oilfield tubular services include the provision of inspection and internal coating services and equipment for drill pipe, line pipe, tubing, casing and pipelines; and the design, manufacture and sale of coiled tubing pipe and advanced fiberglass composite pipe for application in highly corrosive environments. The segment sells its tubular goods and services to oil and gas companies; drilling contractors; pipe distributors, processors and manufacturers; and pipeline operators. This segment has benefited from several strategic acquisitions and other investments completed during the past few years, including additional operations in the United States, Canada, the United Kingdom, Brazil, China, Kazakhstan, Mexico, Russia, Argentina, India, Bolivia, the Netherlands, Singapore, Malaysia, Vietnam, Oman, and the United Arab Emirates.

Distribution & Transmission

Our Distribution & Transmission segment provides pipe, maintenance, repair and operating supplies (MRO) and spare parts to drill sites and production locations, pipeline operations, and processing plants worldwide. In addition to its comprehensive field location network, which supports land drilling operations throughout North America, the segment supports major land and offshore operations for all the major oil and gas producing regions throughout the world. The segment employs advanced information technologies to provide complete procurement, materials management and logistics services to its customers around the globe. The segment also has a global reach in oil and gas, waste water treatment, chemical, food and beverage, paper and pulp, mining, agriculture, and a variety of municipal markets and is a leading producer of water transmission pipe, fabricated steel products and specialized materials and products used in infrastructure projects. Demand for the segment s services is determined primarily by the level of drilling, servicing, and oil and gas production activities. It is also influenced by the domestic economy in general, housing starts and government policies. This segment has benefited from several strategic acquisitions and other investments completed around the world during the past few years, including the acquisition of the Wilson distribution business segment from Schlumberger Limited and CE Franklin Ltd. in Canada, both of which were completed in 2012, as well as additional operations in the United States, Canada, the United Kingdom, Kazakhstan, Singapore, Russia, and Malaysia.

Critical Accounting Policies and Estimates

In our annual report on Form 10-K for the year ended December 31, 2012, we identified our most critical accounting policies. In preparing the financial statements, we make assumptions, estimates and judgments that affect the amounts reported. We periodically evaluate our estimates and judgments that are most critical in nature which are related to revenue recognition under long-term construction contracts; allowance for doubtful accounts; inventory reserves; impairment of long-lived assets (excluding goodwill and other indefinite-lived intangible assets); goodwill and other indefinite-lived intangible assets; purchase price allocation of acquisitions; service and product warranties; and income taxes. Our estimates are based on historical experience and on our future expectations that we believe are reasonable. The combination of these factors forms the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results are likely to differ from our current estimates and those differences may be material.

EXECUTIVE SUMMARY

For its second quarter ended June 30, 2013, the Company generated $531 million in net income attributable to Company, or $1.24 per fully diluted share, on $5.6 billion in revenue. Compared to the first quarter of 2013, revenue increased $294 million or 6% and net income attributable to Company increased $29 million. Compared to the second quarter of 2012, revenue increased $867 million or 18%, and net income attributable to Company decreased $74 million or 12%.

The second quarter of 2013 included pre-tax other costs of $57 million, the first quarter of 2013 included pre-tax other costs of $73 million, and the second quarter of 2012 included pre-tax other costs of $28 million. Excluding the other costs from all periods, second quarter 2013 earnings were $1.33 per fully diluted share, compared to $1.29 per fully diluted share in the first quarter of 2013 and $1.46 per fully diluted share in the second quarter of 2012.

Pre-tax other costs of $57 million, $73 million, and $28 million for the second quarter of 2013, the first quarter of 2013 and the second quarter of 2012, respectively, included items such as administration costs and the amortization of backlog and inventory that was stepped up to fair value during purchase accounting.

Operating profit excluding other costs was $826 million or 14.7% of sales in the second quarter of 2013, compared to $816 million or 15.4% of sales in the first quarter of 2013, and $907 million or 19.2% of sales in the second quarter of 2012. Second quarter 2013 results include the first full quarter s results for Robbins & Myers, which was acquired February 20, 2013.

Also of note, in the second quarter of 2013, National Oilwell Varco doubled its regular dividend to $0.26 per share per quarter.

Oil & Gas Equipment and Services Market

Worldwide, developed economies turned down in late 2008 as looming housing-related asset write-downs at major financial institutions paralyzed credit markets and sparked a serious global banking crisis. Major central banks responded vigorously through 2009, but a credit-driven worldwide economic recession developed nonetheless. Developed economies struggled to recover throughout 2010 and 2011, facing additional economic weakness related to potential sovereign debt defaults in Europe. As a result, commodity prices, including oil and gas prices, have been volatile. After rising steadily for six years to peak at around $140 per barrel (West Texas Intermediate Crude Prices) earlier in 2008, oil prices collapsed back to average $43 per barrel during the first quarter of 2009, but slowly recovered into the $100 per barrel range by mid-2011 where they held relatively steady since (although the fourth quarter of 2012 dipped to average $88 per barrel). After trading in the range of $6 to $9 an mmbtu from 2004 to 2008, North American gas prices declined to average $3.17 per mmbtu in the third quarter of 2009. Gas prices recovered modestly, trading up above $5 six months later, but then slowly settled into the $3 to $4 per mmbtu through 2011 before turning down sharply in early 2012 to the $2 range. However, the average quarterly price per mmbtu has been steadily climbing since the second quarter of 2012, to an average of $4.01 in the second quarter of 2013. Still, gas supply out of unconventional shale reservoir developments across North America, including gas associated with liquids production from shales, will likely make it challenging for North American gas prices to move meaningfully higher.

The steadily rising oil and gas prices seen between 2003 and 2008 led to high levels of exploration and development drilling in many oil and gas basins around the globe by 2008, but activity slowed sharply in 2009 with lower oil and gas prices and tightening credit availability. Strengthening oil prices since then have led to steadily rising oil-drilling activity over the past two years.

The count of rigs actively drilling in the U.S. as measured by Baker Hughes (a good measure of the level of oilfield activity and spending) peaked at 2,031 rigs in September 2008, but decreased to a low of 876 in June, 2009. U.S. rig count increased steadily to 2,026 by late 2011, but began to decline with lower gas prices to average 1,761 rigs during the second quarter of 2013. Many oil and gas operators reliant on external financing to fund their drilling programs significantly curtailed their drilling activity in 2009, but drilling recovered across North America as gas prices improved. Recently low gas prices have caused operators to trim drilling, driving the average U.S. gas rig count down 52% from the fourth quarter of 2011, to an average of 360 in the second quarter of 2013. However, with high oil prices, many have redirected drilling efforts towards unconventional shale plays targeting oil, rather than gas. For the second quarter of 2013, oil-directed drilling rose to almost 80% of the total domestic drilling effort, and is only 22 rigs shy of its previous peak in the third quarter of 2012.

Most international activity is driven by oil exploration and production by national oil companies, which has historically been less susceptible to short-term commodity price swings; but, the international rig count exhibited modest declines nonetheless, falling from its September 2008 peak of 1,108 to 947 in August 2009. Recently, due to sustained high oil prices, international drilling has rebounded to average 1,305 rigs in the second quarter of 2013.

During 2009 the Company saw its Petroleum Services & Supplies and its Distribution & Transmission margins affected most acutely by a drilling downturn, through both volume and price declines. Resumption of drilling activity since enabled both of these segments to gain volume, stabilize and lift pricing, and improve margins since the fourth quarter of 2009. The Company s Rig Technology segment was less impacted by the 2009 downturn owing to its high level of contracted backlog, which it executed well. It posted higher revenues in 2009 than 2008 as a result. Its revenues declined in 2010 as its backlog declined, but increased 12% in 2011 as orders for new offshore rigs began to increase.

The economic decline beginning in late 2008 followed an extended period of high drilling activity which fueled strong demand for oilfield services between 2003 and 2008. Incremental drilling activity through the upswing shifted toward harsh environments, employing increasingly sophisticated technology to find and produce reserves. Higher utilization of drilling rigs tested the capability of the world s fleet of rigs, much of which is old and of limited capability. Technology has advanced significantly since most of the existing rig fleet was built. The industry invested little during the late 1980 s and 1990 s on new drilling equipment, but drilling technology progressed steadily nonetheless, as the Company and its competitors continued to invest in new and better ways of drilling. As a consequence, the safety, reliability, and efficiency of new, modern rigs surpass the performance of most of the older rigs at work today. Drilling rigs are now being pushed to drill deeper wells, more complex wells, highly deviated wells and horizontal wells, tasks which require larger rigs with more capabilities. The drilling process effectively consumes the mechanical components of a rig, which wear out and need periodic repair or replacement. This process was accelerated by very high rig utilization and wellbore complexity. Drilling consumes rigs; more complex and challenging drilling consumes rigs faster.

The industry responded by launching many new rig construction projects since 2005, to 1.) retool the existing fleet of jackup rigs (According to RigLogix, nearly 63% of the existing 504 jackups are greater than 25 years old); 2.) replace older mechanical and DC electric land rigs with improved AC power, electronic controls, automatic pipe handling and rapid rigup and rigdown technology; and 3.) build out additional deepwater floating drilling rigs, including semisubmersibles and drillships, to employ recent advancements in deepwater drilling to exploit unexplored deepwater basins. We believe that the newer rigs offer considerably higher efficiency, safety, and capability, and that many will effectively replace a portion of the existing fleet.

As a result of these trends the Company s Rig Technology segment grew its backlog of capital equipment orders from $0.9 billion at June 30, 2005, to $11.8 billion at September 30, 2008. However, as a result of the credit crisis and slowing drilling activity, orders declined below amounts flowing out of backlog as revenue, causing the backlog to decline to $4.9 billion by June 30, 2010. The backlog increased steadily since, as drillers began ordering more than the Company shipped out of backlog, and finished the second quarter of 2013 at a record $13.9 billion. Approximately $4.0 billion of these orders are scheduled to flow out as revenue during 2013, with the balance flowing out in 2014 and beyond. Of this backlog, 93% of the total is for equipment destined for offshore operations, with 7% destined for land. Equipment destined for international markets totaled 95% of the backlog.

Segment Performance

The Rig Technology segment generated $2.8 billion in revenues and $574 million in operating profit or 20.3% of sales in the second quarter of 2013. Compared to the prior quarter, revenues increased $205 million or 8%, and operating profit increased $24 million, representing 12% incremental operating leverage. Compared to the second quarter of 2012, segment revenues grew $428 million or 18%, and operating profit increased $20 million, representing 5% year-over-year operating leverage or flow-through. Margins have moved down steadily since mid-2010 due to an adverse mix shift in the segment, the addition of lower-margin acquisitions, and incremental expenses to support several strategic growth initiatives. The mix shift arises from offshore projects contracted at high prices in 2007 and 2008, which were subsequently manufactured in low cost environments in 2009 and 2010, resulting in high margins for the group which peaked in the third quarter of 2010. As these projects have been completed and replaced with lower priced projects, margins have gradually declined. Margins have also been negatively impacted by the compression of delivery schedules from our shipyard customers, which have challenged the limits of our supply chain and increased our overall project costs. Revenue out of backlog increased 7% sequentially, and increased 17% year-over-year. Non-backlog revenue, which is predominantly aftermarket spares and services, increased 10% sequentially, and increased 21% from the second quarter of 2012. Orders for eight deepwater floating rig equipment packages, and twelve drilling equipment packages for jackup rigs, contributed to total order additions to backlog of $3.1 billion during the second quarter. Interest in offshore rig construction has remained strong as announced dayrates for deepwater offshore rigs remain strong, rig building costs have stabilized at attractive levels, and financing appears to be available for most established drillers. The segment s well intervention and stimulation product sales grew 1% sequentially, as the continued decline in demand for pressure pumping equipment in North America was offset by the sales of coiled tubing units to international markets.

The Petroleum Services & Supplies segment generated $1.7 billion in revenue and $273 million in operating profit, or 15.6% of sales, for the second quarter of 2013. Compared to the prior quarter, revenue increased $48 million or 3%, and operating profit increased $18 million or 7%. Sequentially, a full quarter s contribution from the Robbins & Myers acquisition, coupled with almost 13% sequential growth in the segment s international operations, was more than enough to offset the seasonal slow-down in Canada, and the lower sales of drill pipe, downhole tools, and fiberglass pipe, which were directly attributable to a currently over-supplied U.S. land drilling and well service market. Compared to the second quarter of 2012, revenues decreased $27 million, and operating profit declined $117 million, as both pricing pressures and under-absorbed facilities continue to pressure margins. For the second quarter of 2013, approximately 52% of the segment s sales were into North American markets, and 48% of sales were into international markets.

The Distribution & Transmission segment generated $1.3 billion in revenue and $58 million in operating profit or 4.5% of sales during the second quarter of 2013. Revenues improved $68 million or 6% from the first quarter of 2013, while operating profit decreased $5 million. Compared to the second quarter of 2012, revenues increased $515 million or 66% and flow-through or operating leverage was 2%. Sequentially, a full quarter s contribution from the Robbins & Myers acquisition, coupled with modest growth in the U.S. and a 9% increase in international sales, more than offset the negative impact of the seasonal slow-down in Canada. The year over year revenue growth was due primarily to the acquisitions of Wilson and CE Franklin, made during the second and third quarters of 2012, respectively, and the first quarter 2013 acquisition of Robbins & Myers. For the second quarter of 2013, approximately 82% of the group s sales were into North American markets and 18% into international markets.

Outlook

Following the credit market downturn, global recession, and lower commodity prices of 2009, we saw signs of stabilization and recovery in many of our markets in 2010 and into 2011, led by higher drilling activity in North America and slowly improving international drilling activity. Order levels for new deepwater drilling rigs have rebounded sharply, and the Rig Technology segment continues to experience a high level of interest as dayrates for deepwater offshore rigs continue to improve. Still, margins, which were 20.3% in the second quarter of 2013, may continue to be challenged to expand beyond 20%, due to lower-margin contributions from recent subsea production equipment acquisitions, a soft outlook for land drilling, workover and pressure pumping equipment markets in North America, in view of low gas and natural gas liquids prices, higher costs of execution due to significantly compressed project timelines, continued flow through of lower priced projects, and incremental expenses to support long-term strategic growth initiatives.

Our outlook for the Company s Petroleum Services & Supplies segment and Distribution & Transmission segment remains closely tied to the rig count, particularly in North America. The second quarter saw U.S. rig counts relatively unchanged from the first quarter, resulting in an average U.S. rig count in the second quarter of 2013 that was down almost 11% from the second quarter of 2012. The second quarter saw average Canadian rig counts decline 71% sequentially, and 10% year-over-year. As a result, pricing and volumes are under pressure as pressure pumpers, drilling contractors and oil companies reduce operating and capital expenditures. Additionally, economic weakness may pressure oil prices, which could lead to further activity declines, particularly among North American operators which may rely on cash flows from gas production and/or external financing to fund their drilling operations. In contrast, activity generally seems to be continuing to increase in most international markets outside North America.

The Company believes it is well positioned, and should benefit from its strong balance sheet and capitalization, access to credit, global infrastructure, broad product and service offering, installed base of equipment, and a record level of contracted orders. In the event of a market downturn, the Company also believes that its long history of cost-control and downsizing in response to slowing market conditions, and of executing strategic acquisitions during difficult periods will enable it to capitalize on new opportunities to effect new organic growth and acquisition initiatives.

Operating Environment Overview

The Company s results are dependent on, among other things, the level of worldwide oil and gas drilling, well remediation activity, the prices of crude oil and natural gas, capital spending by other oilfield service companies and drilling contractors, and worldwide oil and gas inventory levels. Key industry indicators for the second quarter of 2013 and 2012, and the first quarter of 2013 include the following:

	2Q13*	2Q12*	1Q13*	% 2Q13 v 2Q12	% 2Q13 v 1Q13
Active Drilling Rigs:					
U.S.	1,761	1,970	1,758	(10.6%)	0.2%
Canada	155	173	536	(10.4%)	(71.1%)
International	1,305	1,229	1,274	6.2%	2.4%
Worldwide	3,221	3,372	3,568	(4.5%)	(9.7%)
West Texas Intermediate Crude Prices (per barrel)	$ 94.10	$ 93.42	$ 94.34	0.7%	(0.3%)
Natural Gas Prices ($ /mmbtu)	$ 4.01	$ 2.28	$ 3.49	75.9%	14.9%

* Averages for the quarters indicated. See sources below.

The following table details the U.S., Canadian, and international rig activity and West Texas Intermediate Oil prices for the past nine quarters ended June 30, 2013, on a quarterly basis:

Source: Rig count: Baker Hughes, Inc. (www.bakerhughes.com); West Texas Intermediate Crude and Natural Gas Prices: Department of Energy, Energy Information Administration (www.eia.doe.gov).

The worldwide quarterly average rig count decreased 10% (from 3,568 to 3,221), due to the seasonal decline in Canada, and the U.S. increased slightly (from 1,758 to 1,761), in the second quarter of 2013 compared to the first quarter of 2013. The average per barrel price of West Texas Intermediate Crude decreased slightly (from $94.34 per barrel to $94.10 per barrel) and natural gas prices increased 15% (from $3.49 per mmbtu to $4.01 per mmbtu) in the second quarter of 2013 compared to the first quarter of 2013.

U.S. rig activity at July 26, 2013 was 1,776 rigs, a slight increase compared to the second quarter average of 1,761 rigs. The price for West Texas Intermediate Crude was $104.70 per barrel at July 26, 2013, increasing 11% from the second quarter average. The price for natural gas was $3.56 per mmbtu at July 26, 2013, decreasing 11% from the second quarter average.

Results of Operations

Operating results by segment are as follows (in millions):

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2013	**2012**	**2013**	**2012**
Revenue:				
Rig Technology	$ 2,833	$ 2,405	$ 5,461	$ 4,664
Petroleum Services & Supplies	1,749	1,776	3,450	3,480
Distribution & Transmission	1,295	780	2,522	1,344
Eliminations	(276)	(227)	(525)	(451)
Total Revenue	$ 5,601	$ 4,734	$ 10,908	$ 9,037
Operating Profit:				
Rig Technology	$ 574	$ 554	$ 1,124	$ 1,101
Petroleum Services & Supplies	273	390	528	778
Distribution & Transmission	58	46	121	89
Unallocated expenses and eliminations	(136)	(111)	(253)	(212)
Total Operating Profit	$ 769	$ 879	$ 1,520	$ 1,756
Operating Profit %:				
Rig Technology	20.3%	23.0%	20.6%	26.3%
Petroleum Services & Supplies	15.6%	22.0%	15.3%	22.4%
Distribution & Transmission	4.5%	5.9%	4.8%	6.6%
Total Operating Profit %	13.7%	18.6%	13.9%	19.4%

Rig Technology

Three and Six Months Ended June 30, 2013 and 2012. Revenue from Rig Technology was $2,833 million for the three months ended June 30, 2013 compared to $2,405 for the three months ended June 30, 2012, an increase of $428 million (17.8%). For the six months ended June 30, 2013, revenue from Rig Technology was $5,461 million compared to $4,664 million for the six months ending June 30, 2012, an increase of $797 million (17.1%). Deepwater offshore demand as well as demand in international markets continues to be a driving force for the increase in revenue for Rig Technology as revenue out of backlog contributed $2,124 million and $4,105 million for the three and six months ended June 30, 2013, respectively. Increases in the Company s aftermarket and FPSO businesses as well as the acquisitions of Robbins & Myers, NKT and Enerflow also contributed to the increase in revenue for Rig Technology. North American markets, however, continue to see a decrease in demand for land drilling equipment. This is evidenced by a decrease in rig count in North America from 2012 and has resulted in lower sales of land rigs and pressure pumping equipment in the U.S. and Canada. The average rig count in the U.S. and Canada during the second quarter of 2013 decreased over 10% from the second quarter 2012 average.

Operating profit from Rig Technology was $574 million for the three months ended June 30, 2013 compared to $554 million for the three months ended June 30, 2012, an increase of $20 million (3.6%). Operating profit percentage decreased in the three months ended June 30, 2013 to 20.3%, from 23.0% in the three months ended June 30, 2012. For the six months ended June 30, 2013, operating profit from Rig Technology was $1,124 million compared to $1,101 million for the six months ended June 30, 2012, an increase of $23 million (2.1%). Operating profit percentage decreased to 20.6% in the six months ended June 30, 2013, from 23.6% in the six months ended June 30, 2012. The decrease in operating profit percentage continues to be primarily due to a shift in product mix as lower priced offshore projects replace projects contracted at higher prices in 2007 and 2008. FPSO revenue continues to increase with operating margins that are somewhat dilutive while land rig and pressure pumping equipment revenue, with margins that are generally accretive, continues to decline. In addition, our shipyard customers are compressing delivery schedules which have been leading to increased freight and personnel costs. Expenses associated with acquisition integration efforts, numerous strategic growth initiatives and capacity expansions worldwide have also contributed to the decrease in operating profit percentage.

Included in operating profit are other costs which include items such as administration costs and the amortization of backlog and inventory that was stepped up during purchase accounting. Other costs included in operating profit for Rig Technology were $13 million and $20 million for the three and six months ended June 30, 2013, respectively and $17 million and $21 million for the three and six months ended June 30, 2012, respectively.

The Rig Technology segment monitors its capital equipment backlog to plan its business. New orders are added to backlog only when the Company receives a firm written order for major drilling rig components or a signed contract related to a construction project. The capital equipment backlog was $13.9 billion at June 30, 2013, an increase of $2.6 billion (23.0%) from backlog of $11.3 billion at June 30, 2012. At June 30, 2013, approximately 93% of the capital equipment backlog was for offshore products and 7% was for land. In addition, at June 30, 2013, approximately 95% of the capital equipment backlog was for international markets and 5% was for domestic markets.

As the segment enters the third quarter of 2013, we expect orders for new Drilling Equipment Packages and FPSO s to remain strong and hope to see increased demand for new land rigs in Latin America and the Middle East. Continued congestion in our supply chain, the shift in product mix, and the fact that some of our larger capacity additions will not yet be fully online, we expect operating profit percentage to continue in the 20%-21% range for the remainder of the year.

Petroleum Services & Supplies

Three and Six Months Ended June 30, 2013 and 2012. Revenue from Petroleum Services & Supplies was $1,749 million for the three months ended June 30, 2013 compared to $1,776 for the three months ended June 30, 2012, a decrease of $27 million (1.5%). For the six months ended June 30, 2013, revenue from Petroleum Services & Supplies was $3,450 million compared to $3,480 million for the six months ending June 30, 2012, a slight decrease of $30 million (0.9%). These declines are primarily due to decreased activity in the North American markets evidenced by the decline in the U.S. and Canada rig count coupled with a Canada, spring break-up which occurred earlier than anticipated as well as severe weather conditions in Canada. Of the second quarter 2013 revenue for the segment, approximately 52% was derived from North American markets and 48% from international markets.

Operating profit from Petroleum Services & Supplies was $273 million for the three months ended June 30, 2013 compared to $390 million for the three months ended June 30, 2012, a decrease of $117 million (30.0%). Operating profit percentage decreased in the three months ended June 30, 2013 to 15.6%, from 22.0% in the three months ended June 30, 2012. For the six months ended June 30, 2013, operating profit from Petroleum Services & Supplies was $528 million compared to $778 million for the six months ended June 30, 2012, a decrease of $250 million (32.1%). Operating profit percentage decreased to 15.3% in the six months ended June 30, 2013, from 22.4% in the six months ended June 30, 2012. This decrease is primarily due to the decline in North American market activity which has led to pricing pressures across a number of products in the North American land market and caused under absorption in our various manufacturing plants and service facilities. Expenses associated with integrating recently acquired companies also contributed to the decrease in operating profit percentages.

Included in operating profit are other costs which include items such as administration costs and the amortization of backlog and inventory that was stepped up during purchase accounting. Other costs included in operating profit for Petroleum Services & Supplies were $31 million and $87 million for the three and six months ended June 30, 2013, respectively and $3 million for each of the three and six months ended June 30, 2012, respectively.

As the segment enters the third quarter of 2013, we expect Petroleum Services & Supplies segment revenue will improve in the low-to-mid single digit percentage range, as Canada comes out of break-up, activity in the Gulf of Mexico creates more demand for a number of our products and services, and our international business continues to gain momentum. Due to pricing pressures and incremental costs associated with integrating recently acquired, companies we expect margins in the third quarter of 2013 to be consistent with the second quarter of 2013, with the possibility for modest improvements as we finish the year.

27

Distribution & Transmission

Three and Six Months Ended June 30, 2012 and 2013. Revenue from Distribution & Transmission was $1,295 million for the three months ended June 30, 2013 compared to $780 for the three months ended June 30, 2012, an increase of $515 million (66.0%). For the six months ended June 30, 2013, revenue from Distribution & Transmission was $2,522 million compared to $1,344 million for the six months ending June 30, 2012, an increase of $1,178 million (87.7%). This increase was primarily attributable to the acquisition of Robbins & Myers during the first quarter of 2013, Wilson during the second quarter of 2012 and CE Franklin during the third quarter of 2012. Of the second quarter 2013 revenue for the segment, approximately 82% was derived from North American markets and 18% from international markets.

Operating profit from Distribution & Transmission was $58 million for the three months ended June 30, 2013 compared to $46 million for the three months ended June 30, 2012, an increase of $12 million (26.1%). Operating profit percentage decreased in the three months ended June 30, 2013 to 4.5%, from 5.9% in the three months ended June 30, 2012. For the six months ended June 30, 2013, operating profit from Distribution & Transmission was $121 million compared to $89 million for the six months ended June 30, 2012, an increase of $32 million (36.0%). Operating profit percentage decreased to 4.8% in the six months ended June 30, 2013, from 6.6% in the six months ended June 30, 2012. This decrease was primarily attributable to impact of businesses acquired during 2012 and 2013 combined with lower overall market activity.

Included in operating profit are other costs which include items such as administration costs and the amortization of backlog and inventory that was stepped up during purchase accounting. Other costs included in operating profit for Distribution & Transmission were $13 million and $15 million for the three and six months ended June 30, 2013, respectively and $8 million for each of the three and six months ended June 30, 2012, respectively.

As the segment enters the third quarter of 2013, we expect Distribution & Transmission revenue to grow in the mid-single-digit percentage range, primarily attributable to increasing activity in Canada following break-up. However, despite the incremental activity, we would expect margins to remain relatively flat in the third quarter of 2013, as we are absorbing incremental costs tied to our extensive integration activities of recently acquired companies.

Unallocated expenses and eliminations

Unallocated expenses and eliminations were $136 million and $253 million for the three and six months ended June 30, 2013, respectively, compared to $111 million and $212 million, respectively, for the same periods in 2012. This increase is primarily due to higher intersegment eliminations as a result of increased activity from recent acquisitions.

Interest and financial costs

Interest and financial costs were $30 million and $58 million for the three and six months ended June 30, 2013, respectively, compared to $9 million and $17 million, respectively, for the same periods in 2012. This increase is primarily due to an overall increase in average debt for the three and six months ended June 30, 2013 compared to the same periods in 2012.

Other income (expense), net

Other income (expense), net was income of $13 million and expense of $8 million for the three and six months ended June 30, 2013, respectively, compared to expense of $5 million and $21 million, respectively, for the same periods in 2012. The change was primarily due to gains on the sale of certain assets, partially offset by foreign exchange losses and increased bank charges and fees.

Provision for income taxes

The effective tax rate for each of the three and six months ended June 30, 2013 was 31.0%, compared to 32.1% and 31.5% for the same periods in 2012. Compared to the U.S. statutory rate, the effective tax rate was positively impacted in the periods by the effect of lower tax rates on income earned in foreign jurisdictions, and the deduction in the U.S. for manufacturing activities. The effective tax rate for 2013 was negatively impacted by foreign exchange gains for tax reporting in Norway, while 2012 was positively impacted by foreign exchange losses for tax reporting in Norway.

Non-GAAP Financial Measures and Reconciliations

In an effort to provide investors with additional information regarding our results as determined by GAAP, we disclose various non-GAAP financial measures in our quarterly earnings press releases and other public disclosures. The primary non-GAAP financial measures we focus on are: (i) operating profit excluding other costs, (ii) operating profit percentage excluding other costs, and (iii) diluted earnings per share excluding other costs. Each of these financial measures excludes the impact of certain other costs and therefore has not been calculated in accordance with GAAP. A reconciliation of each of these non-GAAP financial measures to its most comparable GAAP financial measure is included below.

We use these non-GAAP financial measures internally to evaluate and manage the Company s operations because we believe it provides useful supplemental information regarding the Company s on-going economic performance. We have chosen to provide this information to investors to enable them to perform more meaningful comparisons of operating results and as a means to emphasize the results of on-going operations.

The following tables set forth the reconciliations of these non-GAAP financial measures to their most comparable GAAP financial measures (in millions, except per share data):

	Three Months Ended			Six Months Ended	
	June 30,		March 31,	June 30,	
	2013	2012	2013	2013	2012
Reconciliation of operating profit:					
GAAP operating profit	$ 769	$ 879	$ 751	$ 1,520	$ 1,756
Other costs (1):					
Rig Technology	13	17	7	20	21
Petroleum Services & Supplies	31	3	56	87	3
Distribution & Transmission	13	8	2	15	8
Operating profit excluding other costs	$ 826	$ 907	$ 816	$ 1,642	$ 1,788

	Three Months Ended			Six Months Ended	
	June 30,		March 31,	June 30,	
	2013	2012	2013	2013	2012
Reconciliation of operating profit %:					
GAAP operating profit %	13.7%	18.6%	14.2%	13.9%	19.4%
Other costs %	1.0%	0.6%	1.2%	1.2%	0.4%
Operating profit % excluding other costs	14.7%	19.2%	15.4%	15.1%	19.8%

	Three Months Ended			Six Months Ended	
	June 30,		March 31,	June 30,	
	2013	2012	2013	2013	2012
Reconciliation of diluted earnings per share:					
GAAP earnings per share	$ 1.24	$ 1.42	$ 1.17	$ 2.41	$ 2.84
Other costs (1)	0.09	0.04	0.12	0.21	0.06
Earnings per share excluding other costs	$ 1.33	$ 1.46	$ 1.29	$ 2.62	$ 2.90

(1) Other costs primarily include items such as administration costs and the amortization of backlog and inventory that was stepped up to fair value during purchase accounting, items which are included in operating profit. For the three and six months ended June 30, 2013, other costs included in operating profit were $57 million and $122, respectively. For the three and six months ended June 30, 2012, other costs included in operating profit were $28 million and $32, respectively. Other costs for the three months ended March 31, 2013 totaled $65 million. Certain other costs are included in other income(expense), net and were nil and $8 million for the three and six months ended

June 30, 2013, respectively, nil and $3 million for the three and six months ended June 30, 2012, respectively, and $8 million for the three months ended March 31, 2013.

Liquidity and Capital Resources

Overview

The Company assesses liquidity in terms of its ability to generate cash to fund operating, investing and financing activities. The Company remains in a strong financial position, with resources available to reinvest in existing businesses, strategic acquisitions and capital expenditures to meet short- and long-term objectives. The Company believes that cash on hand, cash generated from expected results of operations and amounts available under its revolving credit facility will be sufficient to fund operations, anticipated working capital needs and other cash requirements including capital expenditures, debt and interest payments and dividend payments for the foreseeable future.

At June 30, 2013, the Company had cash and cash equivalents of $2,327 million, and total debt of $4,120 million. At December 31, 2012, cash and cash equivalents were $3,319 million and total debt was $3,149 million. The $1,963 million shift from net cash (cash less debt) to net debt (debt less cash) balance in 2013 was due primarily to $2,375 million in net cash paid for the Robbins & Myers acquisition completed on February 20, 2013. A significant portion of the consolidated cash balances are maintained in accounts in various foreign subsidiaries and, if such amounts were transferred among countries or repatriated to the U.S., such amounts may be subject to additional tax obligations. Of the $2,327 million of cash and cash equivalents at June 30, 2013, approximately $2,080 million is held outside the U.S. If opportunities to invest in the U.S. are greater than available cash balances, rather than repatriating this cash, the Company may choose to borrow against its revolving credit facility.

The Company s outstanding debt at June 30, 2013 was $4,120 million and consisted of $151 million in 6.125% Senior Notes, $500 million in 1.35% Senior Notes, $1,395 million in 2.60% Senior Notes, $1,096 million in 3.95% Senior Notes, $970 million in borrowings against its revolving credit facility and other debt of $8 million.

At June 30, 2013, in addition to $970 million in borrowings, there were $858 million in outstanding letters of credit issued, resulting in $1,672 million of funds available under the revolving credit facility.

The Company also had $2,641 million of additional outstanding letters of credit at June 30, 2013, primarily in Norway, that are under various bilateral committed letter of credit facilities. Other letters of credit are issued as bid bonds and performance bonds.

The following table summarizes our net cash provided by (used in) operating activities, net cash used in investing activities and net cash provided by financing activities for the periods presented (in millions):

	Six Months Ended June 30,	
	2013	**2012**
Net cash provided by (used in) operating activities	$ 870	$ (317)
Net cash used in investing activities	(2,664)	(2,250)
Net cash provided by financing activities	828	955

Operating Activities

For the first six months of 2013, cash provided by operating activities was $870 million compared to cash used in operating activities of $317 million in the same period of 2012. Before changes in operating assets and liabilities, net of acquisitions, cash was provided by operations primarily through net income of $1,031 million plus non-cash charges of $249 million and $66 million in a dividend received from Voest-Alpine Tubulars, an unconsolidated affiliate, less $34 million in equity income.

Net changes in operating assets and liabilities, net of acquisitions, used $479 million for the first six months of 2013 compared to $1,947 million used in the same period in 2012. This decrease was primarily the result of increased cash collections in the first half of 2013 as well as less inventory purchased and less cash paid for taxes when compared to the same period in 2012.

Investing Activities

For the first six months of 2013, net cash used in investing activities was $2,664 million compared to net cash used in investing activities of $2,250 million for the same period of 2012. Net cash used in investing activities continued to primarily be the result of acquisition activity and capital expenditures both of which increased in the first six months of 2013 compared to the first six months of 2012. The Company used approximately $2.5 billion for the purpose of acquiring Robbins & Myers during the first quarter of 2013. For the acquisition of Robbins & Myers, the Company borrowed approximately $1.4 billion under the $3.5 billion revolving credit facility and used approximately $1.1 billion of cash on hand to fund the acquisition. In addition, due to the continued growth in the Company worldwide both organically and through acquisition, the Company used $320 million during the first six months of 2013 for capital expenditures compared to $253 million for the same period of 2012.

Financing Activities

For the first six months of 2013, net cash provided by financing activities was $828 million compared to cash provided by financing activities of $955 million for the same period of 2012. While net borrowings on the Company s revolving credit facility increased slightly during the first six months of 2013 compared to the same period in 2012, the Company doubled its dividend in the second quarter of 2013 and received fewer proceeds from stock options exercised which led to an overall decrease in net cash provided by financing activities.

The effect of the change in exchange rates on cash flows was a negative $26 million and $6 million for the first six months of 2013 and 2012, respectively.

We believe that cash on hand, cash generated from operations and amounts available under our credit facilities and from other sources of debt will be sufficient to fund operations, working capital needs, capital expenditure requirements, dividends and financing obligations.

We intend to pursue additional acquisition candidates, but the timing, size or success of any acquisition effort and the related potential capital commitments cannot be predicted. We continue to expect to fund future cash acquisitions primarily with cash flow from operations and borrowings, including the unborrowed portion of the credit facility or new debt issuances, but may also issue additional equity either directly or in connection with acquisitions. There can be no assurance that additional financing for acquisitions will be available at terms acceptable to us.

Recently Issued Accounting Standards

In February 2013, the Financial Accounting Standards Board issued Accounting Standard Update No. 2013-02 Reporting of Amounts Reclassified out of Accumulated Other Comprehensive Income (ASU No. 2013-02), which is an update for Accounting Standards Codification Topic No. 220 Comprehensive Income . The update improves the reporting of reclassifications out of accumulated other comprehensive income. The guidance was effective for the Company s interim and annual reporting periods beginning January 1, 2013, and applied prospectively. There was no significant impact to the Company s Consolidated Financial Statements from the adopted provisions of ASU No. 2013-02.

In March 2013, the FASB issued Accounting Standards Update No. 2013-05, Parent s Accounting for the Cumulative Translation Adjustment upon Derecognition of Certain Subsidiaries or Groups of Assets within a Foreign Entity or of an Investment in a Foreign Entity (a consensus of the FASB Emerging Issues Task Force). (ASU No. 2013-05), which amends Accounting Standards Codification Topic No. 830, Foreign Currency Matters, and Accounting Standards Codification Topic No. 810, Consolidation, to address diversity in practice related to the release of cumulative translation adjustments (CTA) into earnings upon the occurrence of certain derecognition events. ASU No. 2013-05 precludes the release of CTA for derecognition events that occur within a foreign entity, unless such events represent a complete or substantially complete liquidation of the foreign entity; however, derecognition events related to investments in a foreign entity result in the release of all CTA related to the derecognized foreign entity, even when a noncontrolling financial interest is retained. ASU No. 2013-05 also amends Accounting Standards Codification Topic No. 805, Business Combinations, for transactions that result in a company obtaining control of a business in a step acquisition by increasing an investment in a foreign entity from one accounted for under the equity method to one accounted for as a consolidated investment. ASU No. 2013-05 is effective for fiscal years beginning after December 15, 2013, and applied prospectively. Early adoption is permitted as of the beginning of the entity s fiscal year. The Company is currently assessing the impact ASU No. 2013-05 will have on its financial statements, but does not expect a significant impact from adoption of the pronouncement.

Forward-Looking Statements

Some of the information in this document contains, or has incorporated by reference, forward-looking statements. Statements that are not historical facts, including statements about our beliefs and expectations, are forward-looking statements. Forward-looking statements typically are identified by use of terms such as may, will, expect, anticipate, estimate, and similar words, although some forward-looking statements a expressed differently. All statements herein regarding expected merger synergies are forward-looking statements. You should be aware that our actual results could differ materially from results anticipated in the forward-looking statements due to a number of factors, including but not limited to changes in oil and gas prices, customer demand for our products, difficulties encountered in integrating mergers and acquisitions, and worldwide economic activity. You should also consider carefully the statements under Risk Factors, as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2012, which address additional factors that could cause our actual results to differ from those set forth in the forward-looking statements. Given these uncertainties, current or prospective investors are cautioned not to place undue reliance on any such forward-looking statements. We undertake no obligation to update any such factors or forward-looking statements to reflect future events or developments.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to changes in foreign currency exchange rates and interest rates. Additional information concerning each of these matters follows:

Foreign Currency Exchange Rates

We have extensive operations in foreign countries. The net assets and liabilities of these operations are exposed to changes in foreign currency exchange rates, although such fluctuations generally do not affect income since their functional currency is typically the local currency. These operations also have net assets and liabilities not denominated in the functional currency, which exposes us to changes in foreign currency exchange rates that impact income. We recorded a foreign exchange loss in our income statement of approximately $19 million in the first six months of 2013, compared to approximately a $3 million foreign exchange loss in the same period of the prior year. The gains and losses are primarily due to exchange rate fluctuations related to monetary asset balances denominated in currencies other than the functional currency and adjustments to our hedged positions as a result of changes in foreign currency exchange rates. Strengthening of currencies against the U.S. dollar may create losses in future periods to the extent we maintain net assets and liabilities not denominated in the functional currency of the countries using the local currency as their functional currency.

Some of our revenues in foreign countries are denominated in U.S. dollars, and therefore, changes in foreign currency exchange rates impact our earnings to the extent that costs associated with those U.S. dollar revenues are denominated in the local currency. Similarly some of our revenues are denominated in foreign currencies, but have associated U.S. dollar costs, which also give rise to foreign currency exchange rate exposure. In order to mitigate that risk, we may utilize foreign currency forward contracts to better match the currency of our revenues and associated costs. We do not use foreign currency forward contracts for trading or speculative purposes.

The following table details the Company s foreign currency exchange risk grouped by functional currency and their expected maturity periods at June 30, 2013 (in millions, except contract rates):

	As of June 30, 2013				December 31,
Functional Currency	**2013**	**2014**	**2015**	**Total**	**2012**
CAD Buy USD/Sell CAD:					
Notional amount to buy (in Canadian dollars)	585			585	511
Average USD to CAD contract rate	1.0540			1.0540	0.9895
Fair Value at June 30, 2013 in U.S. dollars	(1)			(1)	5
Sell USD/Buy CAD:					
Notional amount to sell (in Canadian dollars)	88	14		102	255
Average USD to CAD contract rate	1.0380	1.0098		1.0340	1.0230
Fair Value at June 30, 2013 in U.S. dollars	(1)	(1)		(2)	6
EUR Buy USD/Sell EUR:					
Notional amount to buy (in euros)	5	2		7	7
Average USD to EUR contract rate	0.7638	0.7717		0.7660	0.7711
Fair Value at June 30, 2013 in U.S. dollars					
Sell USD/Buy EUR:					
Notional amount to buy (in euros)	141	59		200	205
Average USD to EUR contract rate	0.7726	0.7645		0.7702	0.7687
Fair Value at June 30, 2013 in U.S. dollars	1			1	4
KRW Buy USD/Sell KRW:					
Notional amount to buy (in South Korean won)	23,347			23,347	261
Average USD to KRW contract rate	1,159			1,159	919
Fair Value at June 30, 2013 in U.S. dollars					
Sell USD/Buy KRW:					
Notional amount to buy (in South Korean won)	170,615	142,305		312,920	697
Average USD to KRW contract rate	1,135	1,138		1,136	1,013
Fair Value at June 30, 2013 in U.S. dollars	(1)	(2)		(3)	

Functional Currency	2013	As of June 30, 2013 2014	2015	Total	December 31, 2012
GBP Buy USD/Sell GBP:					
Notional amount to buy (in British Pounds Sterling)	19			19	47
Average USD to GBP contract rate	0.6488			0.6488	0.6149
Fair Value at June 30, 2013 in U.S. dollars					
Sell USD/Buy GBP:					
Notional amount to buy (in British Pounds Sterling)	41	12		53	37
Average USD to GBP contract rate	0.6329	0.6362		0.6337	0.6347
Fair Value at June 30, 2013 in U.S. dollars	(3)	(1)		(4)	2
Buy GBP/Sell AUD:					
Notional amount to buy (in British Pounds Sterling)	1			1	
Average AUD to GBP contract rate	1.5916			1.5916	
Fair Value at June 30, 2013 in U.S. dollars					
USD Buy DKK/Sell USD:					
Notional amount to buy (in U.S. dollars)	38	15		53	42
Average DKK to USD contract rate	0.1749	0.1782		0.1758	0.1743
Fair Value at June 30, 2013 in U.S. dollars					
Buy EUR/Sell USD:					
Notional amount to buy (in U.S. dollars)	416	204		620	664
Average EUR to USD contract rate	1.3175	1.3153		1.3168	1.3095
Fair Value at June 30, 2013 in U.S. dollars	(5)	(2)		(7)	8
Buy GBP/Sell USD:					
Notional amount to buy (in U.S. dollars)	48	2		50	18
Average GBP to USD contract rate	1.5160	1.5173		1.5160	1.6044
Fair Value at June 30, 2013 in U.S. dollars					
Buy NOK/Sell USD:					
Notional amount to buy (in U.S. dollars)	659	730	294	1,683	1,065
Average NOK to USD contract rate	0.1697	0.1667	0.1637	0.1673	0.1671
Fair Value at June 30, 2013 in U.S. dollars	(20)	(16)	(4)	(40)	66
Buy SGD/Sell USD:					
Notional amount to buy (in U.S. dollars)	5	6	3	14	31
Average SGD to USD contract rate	0.7874	0.7960	0.7957	0.7928	0.8115
Fair Value at June 30, 2013 in U.S. dollars					
Sell BRL/Buy USD:					
Notional amount to buy (in U.S. dollars)	76			76	
Average BRL to USD contract rate	0.4423			0.4423	
Fair Value at June 30, 2013 in U.S. dollars					
Sell CAD/Buy USD:					
Notional amount to buy (in U.S. dollars)	2			2	
Average CAD to USD contract rate	0.9771			0.9771	
Fair Value at June 30, 2013 in U.S. dollars					
Sell DKK/Buy USD:					
Notional amount to buy (in U.S. dollars)	14			14	12
Average DKK to USD contract rate	0.1757			0.1757	0.1749
Fair Value at June 30, 2013 in U.S. dollars					
Sell EUR/Buy USD:					
Notional amount to sell (in U.S. dollars)	115	10		125	141
Average EUR to USD contract rate	1.3247	1.3408		1.3260	1.3109
Fair Value at June 30, 2013 in U.S. dollars	2			2	(1)
Sell GBP/Buy USD:					
Notional amount to sell (in U.S. dollars)	11	8		19	
Average GBP to USD contract rate	1.5422	1.5571		1.5646	
Fair Value at June 30, 2013 in U.S. dollars					
Sell NOK/Buy USD:					
Notional amount to sell (in U.S. dollars)	324	86		410	274
Average NOK to USD contract rate	0.1735	0.1736		0.1735	0.1723
Fair Value at June 30, 2013 in U.S. dollars	17	5		22	(10)

Functional Currency	2013	As of June 30, 2013 2014	2015	Total	December 31, 2012
Sell SGD/Buy USD:					
Notional amount to sell (in U.S. dollars)	11			11	
Average SGD to USD contract rate	0.7854			0.7854	
Fair Value at June 30, 2013 in U.S. dollars					
Sell RUB/Buy USD:					
Notional amount to sell (in U.S. dollars)	55			55	47
Average RUB to USD contract rate	0.0299			0.0299	0.0320
Fair Value at June 30, 2013 in U.S. dollars					
NOK Sell USD/Buy NOK:					
Notional amount to buy (in U.S. dollars)	563			563	617
Average NOK to USD contract rate	5.5160			5.5160	6.0467
Fair Value at June 30, 2013 in U.S. dollars	(9)			(9)	8
DKK Sell USD/Buy DKK:					
Notional amount to buy (in U.S. dollars)	85			85	111
Average DKK to USD contract rate	5.6613			5.6613	5.6126
Fair Value at June 30, 2013 in U.S. dollars					
Other Currencies					
Fair Value at June 30, 2013 in U.S. dollars		1		1	(2)
Total Fair Value at June 30, 2013 in U.S. dollars	(20)	(16)	(4)	(40)	86

The Company had other financial market risk sensitive instruments denominated in foreign currencies for transactional exposures totaling $585 million and translation exposures totaling $485 million as of June 30, 2013 excluding trade receivables and payables, which approximate fair value. These market risk sensitive instruments consisted of cash balances and overdraft facilities. The Company estimates that a hypothetical 10% movement of all applicable foreign currency exchange rates on the transactional exposures financial market risk sensitive instruments could affect net income by $38 million and the translational exposures financial market risk sensitive instruments could affect the future fair value by $48 million.

The counterparties to forward contracts are major financial institutions. The credit ratings and concentration of risk of these financial institutions are monitored on a continuing basis. In the event that the counterparties fail to meet the terms of a foreign currency contract, our exposure is limited to the foreign currency rate differential.

During the first quarter of 2013, the Venezuelan government officially devalued the Venezuelan bolivar against the U.S. dollar. As a result, the Company incurred approximately $8 million in devaluation charges in the first quarter of 2013. The Company s net investment in Venezuela was $35 million at June 30, 2013.

Interest Rate Risk

At June 30, 2013, long term borrowings consisted of $151 million in 6.125% Senior Notes, $500 million in 1.35% Senior Notes, $1,400 million in 2.60% Senior Notes and $1,100 million in 3.95% Senior Notes, and $970 million in borrowings under our revolving credit facility. Occasionally a portion of borrowings under our credit facility could be denominated in multiple currencies which could expose us to market risk with exchange rate movements. These instruments carry interest at a pre-agreed upon percentage point spread from either LIBOR, NIBOR or EURIBOR, or at the prime interest rate. Under our credit facility, we may, at our option, fix the interest rate for certain borrowings based on a spread over LIBOR, NIBOR or EURIBOR for 30 days to six months. Our objective is to maintain a portion of our debt in variable rate borrowings for the flexibility obtained regarding early repayment without penalties and lower overall cost as compared with fixed-rate borrowings.

Item 4. Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of the Company s management, including the Company s Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company s disclosure controls and procedures. The Company s disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by the Company in the reports it files under the Exchange Act is accumulated and communicated to the Company s management, including the Company s Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures and is recorded, processed, summarized and reported within the time period specified in the rules and forms of the Securities and Exchange Commission. Based upon that evaluation, the Company s Chief Executive Officer and Chief Financial Officer concluded that the Company s disclosure controls and procedures are effective as of the end of the period covered by this report at a reasonable assurance level.

There has been no change in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 4. Mine Safety Disclosures

Information regarding mine safety and other regulatory actions at our mines is included in Exhibit 95 to this Form 10-Q.

Item 6. Exhibits

Reference is hereby made to the Exhibit Index commencing on page 37.

SIGNATURE

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.

Date: August 5, 2013

By: /s/ Jeremy D. Thigpen
Jeremy D. Thigpen

Senior Vice President and Chief Financial Officer

(Duly Authorized Officer, Principal Financial and Accounting Officer)

INDEX TO EXHIBITS

(a) Exhibits

2.1	Amended and Restated Agreement and Plan of Merger, effective as of August 11, 2004 between National-Oilwell, Inc. and Varco International, Inc. (4)
2.2	Agreement and Plan of Merger, effective as of December 16, 2007, between National Oilwell Varco, Inc., NOV Sub, Inc., and Grant Prideco, Inc. (8)
3.1	Fifth Amended and Restated Certificate of Incorporation of National Oilwell Varco, Inc. (Exhibit 3.1) (1)
3.2	Amended and Restated By-laws of National Oilwell Varco, Inc. (Exhibit 3.1) (9)
10.1	Employment Agreement dated as of January 1, 2002 between Merrill A. Miller, Jr. and National Oilwell. (Exhibit 10.1) (2)
10.2	Employment Agreement dated as of January 1, 2002 between Dwight W. Rettig and National Oilwell. (Exhibit 10.2) (2)
10.3	Form of Amended and Restated Executive Agreement of Clay C. Williams. (Exhibit 10.12) (3)
10.4	National Oilwell Varco Long-Term Incentive Plan, as amended and restated. (5)*
10.5	Form of Employee Stock Option Agreement. (Exhibit 10.1) (6)
10.6	Form of Non-Employee Director Stock Option Agreement. (Exhibit 10.2) (6)
10.7	Form of Performance-Based Restricted Stock. (18 Month) Agreement (Exhibit 10.1) (7)
10.8	Form of Performance-Based Restricted Stock. (36 Month) Agreement (Exhibit 10.2) (7)
10.9	Credit Agreement, dated as of September 28, 2012, among National Oilwell Varco, Inc., the financial institutions signatory thereto, including Wells Fargo Bank, N.A., in their capacities as Administrative Agent, Co-Lead Arranger and Joint Book Runner. (Exhibit 10.1) (10)
10.10	First Amendment to Employment Agreement dated as of December 22, 2008 between Merrill A. Miller, Jr. and National Oilwell Varco. (Exhibit 10.1) (11)
10.11	Second Amendment to Executive Agreement, dated as of December 22, 2008 of Clay Williams and National Oilwell Varco. (Exhibit 10.2) (11)
10.12	First Amendment to Employment Agreement dated as of December 22, 2008 between Dwight W. Rettig and National Oilwell Varco. (Exhibit 10.4) (11)
10.13	Employment Agreement dated as of December 22, 2008 between Robert W. Blanchard and National Oilwell Varco. (Exhibit 10.5) (11)
10.14	Second Amendment to Employment Agreement dated as of December 31, 2009 between Merrill A. Miller, Jr. and National Oilwell Varco. (Exhibit 10.1) (12)
10.15	Third Amendment to Executive Agreement, dated as of December 31, 2009, of Clay Williams and National Oilwell Varco. (Exhibit 10.2) (12)
10.16	Second Amendment to Employment Agreement dated as of December 31, 2009 between Dwight W. Rettig and National Oilwell Varco. (Exhibit 10.4) (12)
10.17	First Amendment to Employment Agreement dated as of December 31, 2009 between Robert W. Blanchard and National Oilwell Varco. (Exhibit 10.5) (12)
10.18	Employment Agreement dated as of January 1, 2004 between Jeremy Thigpen and National Oilwell. (Exhibit 10.1) (13)
10.19	First Amendment to Employment Agreement dated as of December 22, 2008 between Jeremy Thigpen and National Oilwell Varco. (Exhibit 10.2) (13)

10.20 Second Amendment to Employment Agreement dated as of December 31, 2009 between Jeremy Thigpen and National Oilwell Varco. (Exhibit 10.3) (13)

10.21 Form of Performance Award Agreement (Exhibit 10.1) (14)

31.1 Certification pursuant to Rule 13a-14a and Rule 15d-14(a) of the Securities and Exchange Act, as amended.

31.2 Certification pursuant to Rule 13a-14a and Rule 15d-14(a) of the Securities and Exchange Act, as amended.

32.1 Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

95 Mine Safety Information persuant to section 1503 of the Dodd-Frank Act.

101 The following materials from our Annual Report on Form 10-Q for the period ended June 30, 2013 formatted in eXtensible Business Reporting Language (XBRL): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Income, (iii) Consolidated Statements of Cash Flows, and (iv) Notes to the Consolidated Financial Statements, tagged as block text. (15)

* Compensatory plan or arrangement for management or others.
(1) Filed as an Exhibit to our Quarterly Report on Form 10-Q filed on August 5, 2011.
(2) Filed as an Exhibit to our Annual Report on Form 10-K filed on March 28, 2002.
(3) Filed as an Exhibit to Varco International, Inc. s Quarterly Report on Form 10-Q filed on May 6, 2004.
(4) Filed as Annex A to our Registration Statement on Form S-4 filed on September 16, 2004.
(5) Filed as an Exhibit to our Current Report on Form 8-K filed on February 24, 2012.
(6) Filed as an Exhibit to our Current Report on Form 8-K filed on February 23, 2006.
(7) Filed as an Exhibit to our Current Report on Form 8-K filed on March 27, 2007.
(8) Filed as Annex A to our Registration Statement on Form S-4 filed on January 28, 2008.
(9) Filed as an Exhibit to our Current Report on Form 8-K filed on August 17, 2011.
(10) Filed as an Exhibit to our Current Report on Form 8-K filed on October 1, 2012
(11) Filed as an Exhibit to our Current Report on Form 8-K filed on December 23, 2008.
(12) Filed as an Exhibit to our Current Report on Form 8-K filed on January 5, 2010.
(13) Filed as an Exhibit to our Current Report on Form 8-K filed on December 7, 2012.
(14) Filed as an Exhibit to our Current Report on Form 8-K filed on March 27, 2013.
(15) As provided in Rule 406T of Regulation S-T, this information is furnished and not filed for purposes of Sections 11 and 12 of the Securities Act of 1933 and Section 18 of the Securities Exchange Act of 1934.

We hereby undertake, pursuant to Regulation S-K, Item 601(b), paragraph (4) (iii), to furnish to the U.S. Securities and Exchange Commission, upon request, all constituent instruments defining the rights of holders of our long-term debt not filed herewith.