UNITED STATES

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

☑ **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 1-9397

Baker Hughes Incorporated

(Exact name of registrant as specified in its charter)

Delaware	**76-0207995**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
2929 Allen Parkway, Suite 2100, Houston, Texas	**77019-2118**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (713) 439-8600

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 ☑ NO ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, 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 ☑ 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 ☑	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 ☑

As of July 18, 2013, the registrant has outstanding 443,042,857 shares of Common Stock, $1 par value per share.

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PART I — FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

Baker Hughes Incorporated
Consolidated Condensed Statements of Income
(In millions, except per share amounts)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Revenue:				
Sales	$ 1,869	$ 1,811	$ 3,618	$ 3,540
Services	3,618	3,515	7,099	7,141
Total revenue	5,487	5,326	10,717	10,681
Costs and expenses:				
Cost of sales	1,467	1,404	2,851	2,772
Cost of services	3,124	2,850	6,066	5,747
Research and engineering	131	128	258	252
Marketing, general and administrative	329	305	651	644
Total costs and expenses	5,051	4,687	9,826	9,415
Operating income	436	639	891	1,266
Interest expense, net	(60)	(50)	(115)	(104)
Income before income taxes	376	589	776	1,162
Income taxes	(131)	(151)	(263)	(344)
Net income	245	438	513	818
Net (income) loss attributable to noncontrolling interests	(5)	1	(6)	—
Net income attributable to Baker Hughes	$ 240	$ 439	$ 507	$ 818
Basic earnings per share attributable to Baker Hughes	$ 0.54	$ 1.00	$ 1.14	$ 1.86
Diluted earnings per share attributable to Baker Hughes	$ 0.54	$ 1.00	$ 1.14	$ 1.86
Cash dividends per share	$ 0.15	$ 0.15	$ 0.30	$ 0.30

See accompanying Notes to Unaudited Consolidated Condensed Financial Statements.

Baker Hughes Incorporated

Consolidated Condensed Statements of Comprehensive Income

(In millions)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net income	$ 245	$ 438	$ 513	$ 818
Other comprehensive (loss) income:				
Currency translation adjustments	(30)	(57)	(110)	(2)
Pension and other postretirement benefits, net of tax	3	6	13	19
Hedge transactions, net of tax	(3)	1	(3)	1
Other comprehensive (loss) income	(30)	(50)	(100)	18
Comprehensive income	215	388	413	836
Comprehensive (income) loss attributable to noncontrolling interests	(5)	1	(6)	—
Comprehensive income attributable to Baker Hughes	$ 210	$ 389	$ 407	$ 836

See accompanying Notes to Unaudited Consolidated Condensed Financial Statements.

Baker Hughes Incorporated
Consolidated Condensed Balance Sheets
(In millions)
(Unaudited)

	June 30, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,123	$ 1,015
Accounts receivable - less allowance for doubtful accounts (2013 - $274; 2012 - $308)	5,197	4,815
Inventories, net	3,838	3,781
Deferred income taxes	299	266
Other current assets	473	540
Total current assets	10,930	10,417
Property, plant and equipment - less accumulated depreciation (2013 - $6,705; 2012 - $6,315)	8,855	8,707
Goodwill	5,954	5,958
Intangible assets, net	934	993
Other assets	677	614
Total assets	$ 27,350	$ 26,689
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 2,211	$ 1,737
Short-term debt and current portion of long-term debt	1,068	1,079
Accrued employee compensation	568	646
Income taxes payable	194	226
Other accrued liabilities	467	436
Total current liabilities	4,508	4,124
Long-term debt	3,841	3,837
Deferred income taxes and other tax liabilities	674	745
Liabilities for pensions and other postretirement benefits	565	579
Other liabilities	135	136
Commitments and contingencies		
Equity:		
Common stock	443	441
Capital in excess of par value	7,577	7,495
Retained earnings	9,984	9,609
Accumulated other comprehensive loss	(576)	(476)
Baker Hughes stockholders’ equity	17,428	17,069
Noncontrolling interests	199	199
Total equity	17,627	17,268
Total liabilities and equity	$ 27,350	$ 26,689

See accompanying Notes to Unaudited Consolidated Condensed Financial Statements.

Baker Hughes Incorporated
Consolidated Condensed Statements of Equity
(In millions)
(Unaudited)

	Common Stock	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total
Balance at December 31, 2012	$ 441	$ 7,495	$ 9,609	$ (476)	$ 199	$ 17,268
Comprehensive income:						
Net income			507		6	513
Other comprehensive loss				(100)		(100)
Activity related to stock plans	2	22				24
Stock-based compensation		60				60
Cash dividends ($0.30 per share)			(132)			(132)
Net activity related to noncontrolling interests					(6)	(6)
Balance at June 30, 2013	$ 443	$ 7,577	$ 9,984	$ (576)	$ 199	$ 17,627

	Common Stock	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total
Balance at December 31, 2011	$ 437	$ 7,303	$ 8,561	$ (555)	$ 218	$ 15,964
Comprehensive income:						
Net income			818			818
Other comprehensive income				18		18
Activity related to stock plans	2	29				31
Stock-based compensation		61				61
Cash dividends ($0.30 per share)			(131)			(131)
Net activity related to noncontrolling interests		22			(24)	(2)
Balance at June 30, 2012	$ 439	$ 7,415	$ 9,248	$ (537)	$ 194	$ 16,759

See accompanying Notes to Unaudited Consolidated Condensed Financial Statements.

Baker Hughes Incorporated
Consolidated Condensed Statements of Cash Flows
(In millions)
(Unaudited)

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Cash flows from operating activities:		
Net income	$ 513	$ 818
Adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	839	743
Other noncash items	(107)	(200)
Changes in operating assets and liabilities:		
Accounts receivable	(494)	(130)
Inventories	(89)	(597)
Accounts payable	502	60
Other operating items, net	(86)	(570)
Net cash flows provided by operating activities	1,078	124
Cash flows from investing activities:		
Expenditures for capital assets	(1,041)	(1,442)
Proceeds from disposal of assets	183	203
Other investing items, net	(4)	—
Net cash flows used in investing activities	(862)	(1,239)
Cash flows from financing activities:		
Net (repayments) proceeds of commercial paper borrowings and other debt with three months or less original maturity	(40)	962
Net borrowings of short-term debt	40	—
Dividends paid	(132)	(131)
Other financing items, net	29	24
Net cash flows (used in) provided by financing activities	(103)	855
Effect of foreign exchange rate changes on cash and cash equivalents	(5)	2
Increase (decrease) in cash and cash equivalents	108	(258)
Cash and cash equivalents, beginning of period	1,015	1,050
Cash and cash equivalents, end of period	$ 1,123	$ 792
Supplemental cash flows disclosures:		
Income taxes paid, net of refunds	$ 343	$ 697
Interest paid	$ 121	$ 119
Supplemental disclosure of noncash investing activities:		
Capital expenditures included in accounts payable	$ 102	$ 146

See accompanying Notes to Unaudited Consolidated Condensed Financial Statements.

Baker Hughes Incorporated
Notes to Unaudited Consolidated Condensed Financial Statements

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations

Baker Hughes Incorporated ("Baker Hughes," "Company," "we," "our," or "us,") is a leading supplier of oilfield services, products, technology and systems used for drilling, formation evaluation, completion and production, pressure pumping, and reservoir development in the worldwide oil and natural gas industry. We also provide products and services for other businesses, including downstream refining, and process and pipeline services.

Basis of Presentation

Our unaudited consolidated condensed financial statements included herein have been prepared in accordance with accounting principles generally accepted ("GAAP") in the United States of America ("U.S.") and pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC") for interim financial information. Accordingly, certain information and disclosures normally included in our annual financial statements have been condensed or omitted. These unaudited consolidated condensed financial statements should be read in conjunction with our audited consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2012 ("2012 Annual Report"). We believe the unaudited consolidated condensed financial statements included herein reflect all adjustments (consisting of normal recurring adjustments) necessary for a fair presentation of the interim periods. The results of operations for the interim periods are not necessarily indicative of the results of operations to be expected for the full year. In the notes to the unaudited consolidated condensed financial statements, all dollar and share amounts in tabulations are in millions of dollars and shares, respectively, unless otherwise indicated.

New Accounting Standards Updates

In February 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2013-02, *Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income.* This ASU requires entities to present separately, among other items, the amount of the change that is due to reclassifications, and the amount that is due to current period other comprehensive income. We adopted the new presentation requirements in the notes to our financial statements in the first quarter of 2013.

NOTE 2. VENEZUELAN CURRENCY DEVALUATION

In February 2013, Venezuela's currency was devalued from the prior exchange rate of 4.3 Bolivars Fuertes per U.S. Dollar to 6.3 Bolivars Fuertes per U.S. Dollar, which applies to our local currency denominated balances. The impact of this devaluation was a loss of $23 million that was recorded in marketing, general and administrative expense in the first quarter of 2013.

Baker Hughes Incorporated
Notes to Unaudited Consolidated Condensed Financial Statements

NOTE 3. EARNINGS PER SHARE

A reconciliation of the number of shares used for the basic and diluted earnings per share ("EPS") computations is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Weighted average common shares outstanding for basic EPS	443	439	443	439
Effect of dilutive securities - stock plans	1	1	1	1
Adjusted weighted average common shares outstanding for diluted EPS	444	440	444	440
Future potentially dilutive shares excluded from diluted EPS:				
Options with an exercise price greater than the average market price for the period	7	8	7	8

NOTE 4. INVENTORIES

Inventories, net of reserves, are comprised of the following:

	June 30, 2013	December 31, 2012
Finished goods	$ 3,390	$ 3,336
Work in process	227	228
Raw materials	221	217
Total inventories	$ 3,838	$ 3,781

NOTE 5. INTANGIBLE ASSETS

Intangible assets are comprised of the following:

	June 30, 2013			December 31, 2012		
	Gross Carrying Amount	Less: Accumulated Amortization	Net	Gross Carrying Amount	Less: Accumulated Amortization	Net
Definite lived intangibles:						
Technology	$ 815	$ 308	$ 507	$ 787	$ 282	$ 505
Contract-based	16	11	5	16	10	6
Trade names	121	71	50	121	60	61
Customer relationships	494	138	356	494	117	377
Subtotal	1,446	528	918	1,418	469	949
Indefinite lived intangibles:						
In-process research and development	16	—	16	44	—	44
Total intangible assets	$ 1,462	$ 528	$ 934	$ 1,462	$ 469	$ 993

Intangible assets are generally amortized on a straight-line basis with estimated useful lives ranging from 3 to 30 years. Amortization expense included in net income for the three months and six months ended June 30, 2013 was $30 million and $59 million, respectively, as compared to $34 million and $68 million reported in 2012 for the same periods, and is estimated to be $ 59 million for the remainder of fiscal year 2013. Estimated amortization expense for each of the subsequent five fiscal years is expected to be as follows: 2014 - $105 million; 2015 - $97 million; 2016 - $95 million; 2017 - $92 million; and 2018 - $86 million.

NOTE 6. FINANCIAL INSTRUMENTS

Our financial instruments include cash and cash equivalents, accounts receivable, accounts payable, debt and foreign currency forward contracts. Except as described below, the estimated fair value of such financial instruments at June 30, 2013 and December 31, 2012 approximates their carrying value as reflected in our unaudited consolidated condensed balance sheets.

The estimated fair value of total debt at June 30, 2013 and December 31, 2012 was $5,486 million and $5,829 million, respectively, which differs from the carrying amounts of $4,909 million and $4,916 million, respectively, included in our unaudited consolidated condensed balance sheets. The fair value was determined using quoted period-end market prices.

NOTE 7. SEGMENT INFORMATION

We conduct our business primarily through operating segments that are aligned with our geographic regions. We aggregate our operating segments within each reportable segment because they have similar economic characteristics and because the long-term financial performance of the operating segments is affected by similar economic conditions. The performance of our operating segments is evaluated based on profit before tax, which is defined as income before income taxes and before the following: net interest expense, corporate expenses and certain gains and losses not allocated to the operating segments.

Summarized financial information is shown in the following table.

	Three Months Ended June 30, 2013		Three Months Ended June 30, 2012	
Segments	Revenue	Profit (Loss) Before Taxes	Revenue	Profit (Loss) Before Taxes
North America	$ 2,677	$ 211	$ 2,672	$ 357
Latin America	557	(18)	604	77
Europe/Africa/Russia Caspian	966	151	925	156
Middle East/Asia Pacific	971	115	804	87
Industrial Services and Other	316	39	321	44
Total Operations	5,487	498	5,326	721
Corporate and Other	—	(62)	—	(82)
Interest expense, net	—	(60)	—	(50)
Total	$ 5,487	$ 376	$ 5,326	$ 589

Baker Hughes Incorporated
Notes to Unaudited Consolidated Condensed Financial Statements

	Six Months Ended June 30, 2013		Six Months Ended June 30, 2012	
Segments	**Revenue**	**Profit (Loss) Before Taxes**	**Revenue**	**Profit (Loss) Before Taxes**
North America	$ 5,280	$ 446	$ 5,535	$ 758
Latin America	1,147	31	1,177	144
Europe/Africa/Russia Caspian	1,820	244	1,818	309
Middle East/Asia Pacific	1,865	231	1,549	162
Industrial Services and Other	605	63	602	66
Total Operations	10,717	1,015	10,681	1,439
Corporate and Other	—	(124)	—	(173)
Interest expense, net	—	(115)	—	(104)
Total	$ 10,717	$ 776	$ 10,681	$ 1,162

NOTE 8. EMPLOYEE BENEFIT PLANS

We have both funded and unfunded noncontributory defined benefit pension plans covering certain employees primarily in the U.S., the U.K., Germany and Canada. We also provide certain postretirement health care benefits ("other postretirement benefits"), through an unfunded plan, to a closed group of U.S. employees who retire and have met certain age and service requirements.

The components of net periodic pension cost are as follows for the three months ended June 30:

	U.S. Pension Plans		Non-U.S. Pension Plans		Other Postretirement Benefits	
	2013	**2012**	**2013**	**2012**	**2013**	**2012**
Service cost	$ 16	$ 16	$ 4	$ 2	$ 2	$ 3
Interest cost	5	5	8	8	1	2
Expected return on plan assets	(10)	(9)	(10)	(9)	—	—
Amortization of prior service benefit	—	—	—	—	(2)	(1)
Amortization of net actuarial loss	4	4	2	2	1	—
Net periodic pension cost	$ 15	$ 16	$ 4	$ 3	$ 2	$ 4

The components of net periodic pension cost are as follows for the six months ended June 30:

	U.S. Pension Plans		Non-U.S. Pension Plans		Other Postretirement Benefits	
	2013	**2012**	**2013**	**2012**	**2013**	**2012**
Service cost	$ 32	$ 32	$ 8	$ 4	$ 4	$ 6
Interest cost	11	10	16	16	2	4
Expected return on plan assets	(20)	(18)	(20)	(18)	—	—
Amortization of prior service benefit	—	—	—	—	(4)	(2)
Amortization of net actuarial loss	7	8	4	3	2	1
Benefit settlement	—	—	—	6	—	—
Net periodic pension cost	$ 30	$ 32	$ 8	$ 11	$ 4	$ 9

NOTE 9. COMMITMENTS AND CONTINGENCIES

LITIGATION

We are subject to a number of lawsuits and claims arising out of the conduct of our business. The ability to predict the ultimate outcome of such matters involves judgments, estimates and inherent uncertainties. We insure against these risks to the extent deemed prudent by our management and to the extent insurance is available, but no assurance can be given that the nature and amount of that insurance will be sufficient to fully indemnify us against liabilities arising out of pending and future legal proceedings. Most of these insurance policies contain deductibles or self-insured retentions in amounts we deem prudent and for which we are responsible for payment. In determining the amount of self-insurance, it is our policy to self-insure those losses that are predictable, measurable and recurring in nature, such as claims for automobile liability, general liability and workers compensation. We record a liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated, including accruals for self-insured losses which are calculated based on historical claim data, specific loss development factors and other information as necessary.

Based on a consideration of all relevant facts and circumstances, we do not expect the ultimate outcome of any currently pending lawsuits or claims against us will have a material adverse effect on our financial position, results of operations or cash flows; however, there can be no assurance as to the ultimate outcome of these matters.

On May 30, 2013, we received a Civil Investigative Demand ("CID") from the United States Department of Justice ("DOJ") pursuant to the Antitrust Civil Process Act. The CID seeks documents and information from us for the period from May 29, 2011 through the date of the CID in connection with a DOJ investigation related to pressure pumping services in the United States. We are working with the DOJ to provide the requested documents and information. We are not able to predict what action, if any, might be taken in the future by the DOJ or other governmental authorities as a result of the investigation.

On September 19, 2012, our subsidiary, Baker Hughes Oilfield Operations, Inc. ("BHOO") terminated a sand supply agreement it had entered into with Hi-Crush Operating, LLC ("Hi-Crush") on October 28, 2011 (as amended by the First Amendment to Supply Agreement on May 10, 2012, collectively the "Supply Agreement") as a result of Hi-Crush's breach of the Supply Agreement. On November 12, 2012, Hi-Crush filed a lawsuit against BHOO in the 129th Judicial District Court in Harris County, Texas, *Cause No. 2012-67261; Hi-Crush Operating, LLC v. Baker Hughes Oilfield Operations, Inc.* In its petition, Hi-Crush claims that BHOO's termination was "invalid" constituting a breach and that BHOO "anticipatorily repudiated the Supply Agreement without just excuse." Hi-Crush claims that it is entitled to recover liquidated damages of $187 million based on the undelivered Minimum Purchase Requirement provision defined in the Supply Agreement; in the alternative, Hi-Crush seeks an unspecified amount of actual damages. On December 17, 2012, BHOO filed a responsive pleading denying Hi-Crush's allegations and also filed a counter claim for breach of contract. BHOO intends to vigorously defend itself and seeks to recover the damages it has incurred as a result of Hi-Crush's breach of contract. We do not expect the outcome of this matter to have a material adverse effect on our financial position, results of operations or cash flows; however, there can be no assurance as to the ultimate outcome of this matter.

OTHER

In the normal course of business with customers, vendors and others, we have entered into off-balance sheet arrangements, including surety bonds for performance, letters of credit and other bank guarantees, which totaled approximately $ 1.4 billion at June 30, 2013. It is not practicable to estimate the fair value of these financial instruments. None of the off-balance sheet arrangements either has, or is likely to have, a material effect on our unaudited consolidated condensed financial statements.

NOTE 10. ACCUMULATED OTHER COMPREHENSIVE LOSS

Total accumulated other comprehensive loss consists of the following:

	Pensions and Other Postretirement Benefits	Currency Translation Adjustments	Hedge Transactions	Accumulated Other Comprehensive Loss
Balance at December 31, 2012	$ (250)	$ (226)	$ —	$ (476)
Other comprehensive income (loss) before reclassifications	7	(110)	(3)	(106)
Amounts reclassified from accumulated other comprehensive loss	9	—	—	9
Deferred taxes	(3)	—	—	(3)
Balance at June 30, 2013	$ (237)	$ (336)	$ (3)	$ (576)

	Pensions and Other Postretirement Benefits	Currency Translation Adjustments	Hedge Transactions	Accumulated Other Comprehensive Loss
Balance at December 31, 2011	$ (251)	$ (304)	$ —	$ (555)
Other comprehensive income (loss) before reclassifications	12	(2)	1	11
Amounts reclassified from accumulated other comprehensive loss	10	—	—	10
Deferred taxes	(3)	—	—	(3)
Balance at June 30, 2012	$ (232)	$ (306)	$ 1	$ (537)

The amounts reclassified from accumulated other comprehensive loss during the six months ended June 30, 2012 and 2013 represent the amortization of prior service benefit and actuarial loss which are included in the computation of net periodic pension cost (see Note 8. Employee Benefit Plans for additional details). Net periodic pension cost is recorded in cost of sales and services, research and engineering, and marketing, general and administrative expenses.

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

Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") should be read in conjunction with the unaudited consolidated condensed financial statements and the related notes thereto, as well as our Annual Report on Form 10-K for the year ended December 31, 2012 ("2012 Annual Report"). Phrases such as "Company," "we," "our" and "us" intend to refer to Baker Hughes Incorporated when used.

EXECUTIVE SUMMARY

Baker Hughes is a leading supplier of oilfield services, products, technology and systems to the worldwide oil and natural gas industry. We provide products and services for:

- drilling and evaluation of oil and natural gas wells;
- completion and production of oil and natural gas wells; and
- other businesses, including downstream refining, and process and pipeline services.

We operate our business primarily through geographic regions that have been aggregated into five reportable segments: North America, Latin America, Europe/Africa/Russia Caspian, Middle East/Asia Pacific and Industrial Services and Other. The four geographical segments represent our oilfield operations.

Within our oilfield operations, the primary driver of our businesses is our customers' capital and operating expenditures dedicated to oil and natural gas exploration, field development and production. Our business is cyclical and is dependent upon our customers' expectations for future oil and natural gas prices, economic growth, hydrocarbon demand and estimates of current and future oil and natural gas production.

For the second quarter of 2013, we generated revenue of $5.49 billion, an increase of $161 million or 3% compared to the second quarter of 2012, and an increase of $257 million or 5% compared to the first quarter of 2013, or sequentially. Revenue for the six months ended June 30, 2013 was $10.72 billion compared to $10.68 billion for the same period in 2012. Net income attributable to Baker Hughes was $240 million for the second quarter of 2013 compared to $439 million for the second quarter of 2012, and $267 million for the first quarter of 2013. Net income attributable to Baker Hughes was $507 million for the first six months of 2013 compared to $818 million for the first six months of 2012.

North America oilfield revenue for the second quarter of 2013 of $2.68 billion was essentially flat compared to the second quarter of 2012, and increased 3% compared to the first quarter of 2013. North America oilfield profit before tax for the second quarter of 2013 was $211 million compared to $357 million for the second quarter of 2012, and $235 million for the first quarter of 2013. Our second quarter profitability for 2013 compared to the same quarter a year ago was impacted by reduced pricing in our pressure pumping business, which continued to be influenced by excess capacity in the market. Additionally, Canadian activity was lower than usual for the second quarter due to severe flooding, which also adversely impacted North America profitability. Sequentially, our North America oilfield revenue increased due to improved utilization in our pressure pumping business, increased activity in our completions and production product lines in U.S. Land, and continued improvement in the Gulf of Mexico, offset by the unusually wet weather in Canada. However, profit before tax is sequentially lower primarily due to sales mix, as higher margin Canadian revenue was replaced with lower margin pressure pumping revenue. Compared to the first quarter of 2013, North America profit before tax was also impacted by an $11 million charge for certain proppants used in pressure pumping. North America oilfield revenue for the six months ended June 30, 2013 was $5.28 billion, a decrease of 5% compared to the same period in 2012. North America oilfield profit before tax for the six months ended June 30, 2013 was $446 million compared to $758 million for the six months ended June 30, 2012.

Oilfield revenue outside of North America for the second quarter of 2013 was $2.49 billion, an increase of 7% compared to the second quarter of 2012 driven by strong growth in the Middle East/Asia Pacific segment. Sequentially, oilfield revenue outside of North America also increased 7% due to growth throughout the Eastern Hemisphere. Oilfield profitability outside of North America for the second quarter of 2013 was $248 million compared to $320 million for the second quarter of 2012 and $258 million for the first quarter of 2013. Although activity has increased in many of our international segments, unfavorable sales mix and other operating costs have reduced profitability year over year. Sequentially, despite improvement in the Europe/Africa/Russia Caspian segment, our profitability decreased due to a significant decline in our drilling activities in Brazil as well as increases in our allowance for doubtful accounts in Latin America. Oilfield revenue outside of North America for the six months ended June 30, 2013 was $4.83 billion, an increase of 6% compared to the six months ended June 30, 2012. Oilfield profitability outside of North America for the six months ended June 30, 2013 was $506 million compared to $615 million for the same period in 2012.

As of June 30, 2013, we had approximately 59,500 employees compared to approximately 58,800 employees as of December 31, 2012.

BUSINESS ENVIRONMENT

In North America, rig counts declined 11% in the second quarter of 2013 compared to the same period a year ago. Despite a cold winter and strong demand, continued natural gas production in the unconventional shale plays contributed to high natural gas working inventories and ultimately low commodity prices that do not support incremental investment in natural gas-directed rig activities. As a result, customer spending in the natural gas shale plays remained limited, with natural gas-directed rig activity declining 35% in the second quarter of 2013 compared to the same period a year ago. Customer spending for oil in the U.S. remained steady during the second quarter of 2013 as evidenced by the fact that the oil-directed rig count increased by 23 rigs, or 2%, compared to the same period in 2012. However, this was offset by a reduction of 28 oil-directed rigs, or 23%, in Canada for the same periods. High oil price differentials in Canada, primarily due to constrained refinery and pipeline capacity, and unusually wet weather resulted in reduced customer spending and subsequently, the reduction in rig counts.

Outside of North America, customer spending is most heavily influenced by Brent oil prices. On average, Brent oil prices decreased 5% in the second quarter of 2013 compared to the same period a year ago as Europe's economic concerns increased, growth in China showed signs of slowing and global oil supplies increased. Due to the long-term planning cycles associated with many international projects, customers do not tend to react to short-term movements in oil prices. As a result, despite lower prices, the international rig count grew by 6% in the second quarter of 2013 compared to the same quarter in 2012, with the largest gains seen in Africa and Europe.

Oil and Natural Gas Prices

Oil and natural gas prices are summarized in the table below as averages of the daily closing prices during each of the periods indicated.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Brent oil price ($/Bbl) (1)	$ 103.00	$ 108.95	$ 107.87	$ 113.74
WTI oil price ($/Bbl) (2)	94.13	93.42	94.24	98.14
Natural gas price ($/mmBtu) (3)	4.02	2.29	3.76	2.37

(1) Bloomberg Dated Brent (“Brent”)
(2) Bloomberg West Texas Intermediate (“WTI”) Cushing Crude Oil Spot Price
(3) Bloomberg Henry Hub Natural Gas Spot Price

Brent oil prices averaged $103.00/Bbl in the second quarter of 2013. Brent oil prices declined sharply in the early part of the second quarter of 2013 as unfavorable economic data in the U.S., China and Europe resulted in reductions in 2013 oil demand growth forecasts by the International Energy Agency ("IEA") and Organization of Petroleum Exporting Countries (“OPEC”). However, prices quickly rebounded back above $100/Bbl by late April, where they remained for the duration of the quarter. During the quarter, Brent oil prices ranged from a high of $110.42/Bbl in early April 2013 to a low of $96.79/Bbl in mid April 2013. In its July 2013 Oil Market Report, the IEA revised its 2013 estimated global oil demand upward to 90.8 million barrels per day due to unseasonably cold late winter weather. In April, the IEA had revised its 2013 estimated global oil demand downward to 90.6 million barrels per day from its original estimate of 90.8 million barrels per day. The estimated 2013 global demand exceeds 2012 global demand of 89.9 million barrels per day.

WTI oil prices averaged $94.13/Bbl in the second quarter of 2013. Prices ranged from a high of $98.44/Bbl in June 2013 to a low of $86.68/Bbl in April 2013. WTI prices closed the quarter at $96.56/Bbl. During the quarter, the Brent-WTI spread, or the difference between the spot prices of Brent and WTI crude oils, narrowed considerably to within $5.60/Bbl. This represents the lowest spread in three years, and is primarily attributed to displacement of Brent-quality crude imports into North America by increased U.S. oil production and improved crude-by-rail and pipeline infrastructure within the U.S.

In North America, natural gas prices, as measured by the Henry Hub Natural Gas Spot Price, averaged $4.02/mmBtu in the second quarter of 2013. Natural gas prices, which have been low since late 2011, continued to rebound during the early part of the second quarter. Cold winter and spring seasons in key consuming regions of the U.S. increased demand, resulting in natural gas storage levels below the five year average for the first time since late 2011. Later in the quarter, mild weather conditions in key consuming regions reduced demand and led to increased inventories. Natural gas prices began to decline in late April and continued their slide throughout the remainder of the quarter despite an eighteen year low in the natural gas rig count. Overall for the quarter, prices ranged from a high of $4.38/mmBtu in April 2013 to a low of $3.57/mmBtu at the end of June 2013. According to the U.S. Department of Energy (“DOE”), working natural gas in storage at the end of the second quarter of 2013 was 2,605/Bcf, which was 16% or 497/Bcf below the corresponding period in 2012.

Baker Hughes Rig Count

Baker Hughes has been providing rig counts to the public since 1944. We gather all relevant data through our field service personnel, who obtain the necessary data from routine visits to the various rigs, customers, contractors and/or other outside sources. This data is then compiled and distributed to various wire services and trade associations and is published on our website. We believe the counting process and resulting data is reliable; however, it is subject to our ability to obtain accurate and timely information. Rig counts are compiled weekly for the U.S. and Canada and monthly for all international rigs. Published international rig counts do not include rigs drilling in certain locations, such as Russia, the Caspian, Iran and onshore China because this information is not readily available. As of February 2013, Syria is excluded from the rig count due to difficulty obtaining data as a result of continued civil unrest. In June 2012, Baker Hughes resumed publication of the rig count in Iraq for the first time since August 1990.

Rigs in the U.S. and Canada are counted as active if, on the day the count is taken, the well being drilled has been started but drilling has not been completed, and the well is anticipated to be of sufficient depth to be a potential consumer of drill bits. In international areas, rigs are counted on a weekly basis and deemed active if drilling activities occurred during the week. The weekly results are then averaged for the month and published accordingly. The rig count does not include rigs that are in transit from one location to another, rigging up, being used in non-drilling activities, including production testing, completion and workover, and are not expected to be significant consumers of drill bits.

The rig counts are summarized in the table below as averages for each of the periods indicated.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2013	2012	% Change	2013	2012	% Change
U.S. - land and inland waters	1,710	1,924	(11)%	1,708	1,935	(12)%
U.S. - offshore	52	47	11 %	52	45	16 %
Canada	152	177	(14)%	342	380	(10)%
North America	1,914	2,148	(11)%	2,102	2,360	(11)%
Latin America	425	438	(3)%	426	435	(2)%
North Sea	42	41	2 %	45	39	15 %
Continental Europe	91	76	20 %	88	76	16 %
Africa	127	90	41 %	121	86	41 %
Middle East	369	343	8 %	362	327	11 %
Asia Pacific	252	241	5 %	248	246	1 %
Outside North America	1,306	1,229	6 %	1,290	1,209	7 %
Worldwide	3,220	3,377	(5)%	3,392	3,569	(5)%

The rig count in North America decreased 11% in the second quarter of 2013 compared to the same period a year ago as natural gas-directed rig counts declined 35%. Oil-directed rig counts were flat year over year. The natural gas-directed rig count reflected a 39% decrease in the U.S. and a 9% increase in Canada. The oil-directed rig count increased 2% in the U.S., but was largely offset by a 23% decrease in Canada. Natural gas-directed drilling was negatively impacted by the continued weakness in North America natural gas prices which discouraged new investment in natural gas fields. The modest growth in oil-directed drilling in the U.S. was primarily a result of continued strong oil prices sufficient to support continued development of the liquids rich unconventional shale plays. In Canada, many operators continued to curtail their drilling plans during the second quarter of 2013 due to high oil price differentials as compared to WTI, reduced cash flows from natural gas activities, and unusually wet weather in June. Overall, the Canadian rig count declined 14% in the second quarter of 2013 as compared to the same quarter in 2012.

Outside North America, the rig count in the second quarter of 2013 increased 6% compared to the same period a year ago. The rig count in Latin America decreased 3% primarily due to lower land rig activity in Brazil and Colombia, partially offset by increased rig activity in Argentina and Ecuador. In Europe, the rig count in the North Sea increased 2%, while in Continental Europe, the rig count increased 20% primarily due to higher activity in Turkey, the Balkans and Sakhalin. The rig count increased 41% in Africa primarily due to the continued improvement of drilling activities in Libya, as well as higher activity in Algeria and Nigeria. The rig count increased 8% in the Middle East primarily due to the inclusion of Iraq in the rig count and higher activity in Pakistan. These gains were partially offset by reduced activity in Egypt, and the exclusion of Syria from the rig count. In Asia Pacific, the rig count increased 5% as a result of higher activity in India, Thailand and offshore China, partially offset by decreased activity in Indonesia.

Baker Hughes Well Count

Baker Hughes began providing well count data to the oil and natural gas industry in July 2013. The Baker Hughes Well Count is an extension of the Baker Hughes Rig Count, and provides a quarterly census of the number of new onshore oil and natural gas wells where drilling began, or spud, in the U.S. The Baker Hughes Well Count includes wells that are identified to be significant consumers of oilfield services and supplies, and excludes wells categorized as workover, plugged and abandoned or completed. We believe the counting process and resulting data is reliable; however, it is subject to our ability to obtain accurate and timely information.

During the second quarter of 2013, 8,800 wells were spud on land in the U.S. This compares to 9,582 wells spud in the second quarter of 2012, or a reduction of 8%. For the six months ended June 30, 2013, 17,334 wells were spud on land in the U.S. This compares to 18,755 wells during the first six months of 2012, or a reduction of 8%.

RESULTS OF OPERATIONS

The discussions below relating to significant line items from our unaudited consolidated condensed statements of income are based on available information and represent our analysis of significant changes or events that impact the comparability of reported amounts. Where appropriate, we have identified specific events and changes that affect comparability or trends and, where possible and practical, have quantified the impact of such items. In addition, the discussions below are based on total revenue and total cost of revenue because the business drivers for the individual components of product sales and services are similar. All dollar amounts in tabulations in this section are in millions of dollars, unless otherwise stated.

Revenue and Profit Before Tax

We conduct our business primarily through operating segments that are aligned with our geographic regions, which have been aggregated into five reportable segments. The performance of our operating segments is evaluated based on profit before tax, which is defined as income before income taxes and before the following: net interest expense, corporate expenses, and certain gains and losses not allocated to the segments.

	Three Months Ended June 30,				Six Months Ended June 30,			
	2013	2012	$ Change	% Change	2013	2012	$ Change	% Change
Revenue:								
North America	$ 2,677	$ 2,672	$ 5	—%	$ 5,280	$ 5,535	$ (255)	(5)%
Latin America	557	604	(47)	(8%)	1,147	1,177	(30)	(3)%
Europe/Africa/Russia Caspian	966	925	41	4%	1,820	1,818	2	— %
Middle East/Asia Pacific	971	804	167	21%	1,865	1,549	316	20 %
Industrial Services and Other	316	321	(5)	(2%)	605	602	3	— %
Total	$ 5,487	$ 5,326	$ 161	3%	$ 10,717	$ 10,681	$ 36	— %

	Three Months Ended June 30,				Six Months Ended June 30,			
	2013	2012	$ Change	% Change	2013	2012	$ Change	% Change
Profit Before Tax:								
North America	$ 211	$ 357	$ (146)	(41%)	$ 446	$ 758	$ (312)	(41)%
Latin America	(18)	77	(95)	(123%)	31	144	(113)	(78)%
Europe/Africa/Russia Caspian	151	156	(5)	(3%)	244	309	(65)	(21)%
Middle East/Asia Pacific	115	87	28	32%	231	162	69	43 %
Industrial Services and Other	39	44	(5)	(11%)	63	66	(3)	(5)%
Total Operations	498	721	(223)	(31%)	1,015	1,439	(424)	(29)%
Corporate and Other	(62)	(82)	20	(24%)	(124)	(173)	49	(28)%
Interest Expense, net	(60)	(50)	(10)	20%	(115)	(104)	(11)	11 %
Total	$ 376	$ 589	$ (213)	(36%)	$ 776	$ 1,162	$ (386)	(33)%

Second Quarter of 2013 Compared to the Second Quarter of 2012

Revenue for the second quarter of 2013 increased $161 million or 3% compared to the second quarter of 2012. North American revenue was essentially flat due to decreased demand and pricing for our pressure pumping product line, offset by improved activity in the Gulf of Mexico. International revenue increased primarily as a result of increased activity in the Middle East, Russia Caspian, Africa and Asia Pacific regions.

Profit before tax for the second quarter of 2013 decreased $213 million or 36% compared to the second quarter of 2012. Our profit before tax was significantly impacted by reduced pricing in our pressure pumping business in North America. Profit before tax also declined due to reduced pricing and lower activity in some of our key markets in Latin America coupled with increased reserves for inventory and doubtful accounts in Latin America, and increased operating costs and less favorable sales mix in the Europe and Russia Caspian regions.

North America

North America revenue for the second quarter of 2013 was flat compared to the second quarter of 2012, despite an 11% decrease in the overall North America rig count. Revenue from our pressure pumping product line in the U.S. decreased year over year due predominantly to the reduction in rig activity as well as pricing pressure resulting from surplus capacity and low natural gas prices. Further, in Canada, we experienced lower than usual activity for the second quarter due to severe flooding. In North America, our product lines other than pressure pumping were also impacted by the declining number of active rigs, particularly the drilling services and drilling and completion fluids product lines. However, the decline in revenue was mitigated by improved performance in the completion systems and upstream chemicals product lines. Additionally, revenue growth from the Gulf of Mexico surpassed the 11% year over year increase in the U.S. offshore rig count with all product lines showing improvement. In particular, we experienced revenue gains in the drilling and completion fluids, pressure pumping and completion product lines within our Gulf of Mexico operations.

North America profit before tax was $211 million in the second quarter of 2013, a decrease of $146 million compared to the second quarter of 2012. The decrease in profitability was primarily driven by excess capacity in the pressure pumping market, which led to reduced pricing for our pressure pumping business and lowered profitability. Further, as a result of the unusual spring flooding in Canada, activity levels dipped below their typical level for the second quarter resulting in an unfavorable shift in mix away from higher margin Canadian revenue. Reduced activity in drilling services and drilling fluids in the U.S. also contributed to the reduction in profitability. However, these decreases were partially offset by the increased activity in the Gulf of Mexico, particularly the favorable change in product mix to deepwater completions and pressure pumping services, which provide higher margins.

Latin America

Latin America revenue decreased 8% in the second quarter of 2013 compared to the second quarter of 2012 due primarily to lower activity levels in Brazil and Venezuela, partially offset by revenue growth in the other geomarkets. In Brazil, the rig count declined 27% in the second quarter of 2013 compared to the second quarter of 2012. The revenue decline experienced in Brazil was consistent with the reduction in active rigs, which impacted most product lines, but particularly drilling services, pressure pumping and artificial lift. In addition to reduced demand for our drilling services, we transitioned to a new drilling services contract at lower prices, which also contributed to the reduction in revenue in Brazil. In Venezuela, reduced activity levels led to lower revenue across most product lines, with the greatest reduction experienced in the pressure pumping product line. Further, we experienced a modest reduction in revenue in Venezuela due to the effect of the February 2013 currency devaluation on transactions denominated in the local currency. These reductions were partially mitigated by increases for pressure pumping business in Argentina, drilling services in both Mexico and the Andean plus artificial lift in the Andean.

Latin America profit before tax decreased 123% in the second quarter of 2013 compared to the second quarter of 2012. The decrease in profit before tax in Latin America was primarily related to Brazil where our activity and market share declined as we transitioned to a new drilling services contract at lower prices. Profit before tax in Brazil was further reduced by higher personnel costs and reserves for obsolete inventory. Additionally, profitability in Latin America was negatively impacted by an increase of $20 million in our allowance for doubtful accounts. During the second quarter of 2013, we began taking actions to reduce costs in our Latin America operations. This process should be substantially complete in the third quarter of 2013.

Europe/Africa/Russia Caspian

Europe/Africa/Russia Caspian ("EARC") revenue increased 4% in the second quarter of 2013 compared to the second quarter of 2012 due to activity growth in Africa and Russia Caspian, partially offset by declines in Europe. In Africa, revenue grew due to increased activity in Nigeria, South Africa, Mozambique and Angola mainly benefiting our drilling services product line. In Nigeria, revenue from our completions product lines also increased year over year. Revenue in the Russia Caspian region increased due to increased activity in the drilling services, artificial lift and pressure pumping product lines. Despite year over year increases in the Europe rig count, particularly in the Continental Europe geomarket, revenue in Europe decreased during the second quarter of 2013 compared to the second quarter of 2012. The primary drivers of the decrease were the completion of drilling services and drilling and completion fluids projects in the Eastern Mediterranean and lower activity in the United Kingdom for the same product lines. These declines were partially offset by increased revenue from performance-based bonuses associated with our new integrated drilling services contract in Norway.

EARC profit before tax decreased 3% in the second quarter of 2013 compared to the second quarter of 2012. Despite the slight increase in revenue, profit before tax declined due to several factors. The completion of several projects in the Eastern Mediterranean along with the general shift in activity from Europe to Russia Caspian and Africa resulted in an unfavorable change in sales mix to products and services with lower margins. Additionally, profit before tax was adversely impacted by start up costs in Norway associated with our integrated drilling services contract, partially offset by performance-based bonuses associated with the same contract. These start up activities were concluded during the quarter.

Middle East/Asia Pacific

Middle East/Asia Pacific ("MEAP") revenue increased 21% in the second quarter of 2013 compared to the second quarter of 2012. The increase in this segment was largely attributable to the Middle East where we experienced higher demand for drilling services in both Saudi Arabia and Kuwait as well as growth in our integrated operations contracts in Iraq and Saudi Arabia. In Asia Pacific, revenue improved in all geomarkets consistent with the increase in rig counts observed year over year. In particular, our pressure pumping business in Southeast Asia and Australia, drilling services in Indonesia and North Asia and wireline services in Australia benefited most from the increase in activity.

MEAP profit before tax increased 32% in the second quarter of 2013 compared to the second quarter of 2012. The primary driver of the increase in profit before tax was higher incremental profit on increased revenue in Asia Pacific and the Middle East. These profits were partially offset by higher third party costs associated with the integrated operations activities in Iraq and mobilization costs related to our pressure pumping fleet in Saudi Arabia.

Industrial Services and Other

For Industrial Services and Other, both revenue and profit before tax decreased $5 million in the second quarter of 2013 compared to the second quarter of 2012. The decrease in revenue and profit before tax was primarily driven by reduced activity in the downstream refining product lines, partially offset by our process and pipeline services business.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012

Revenue for the six months ended June 30, 2013 increased $36 million compared to the six months ended June 30, 2012. Revenue increases in the Middle East/Asia Pacific segment were offset by lower revenues in North America which were impacted by the pressure pumping product line in both the U.S. and Canada.

Profit before tax for the six months ended June 30, 2013 decreased $386 million or 33% compared to the six months ended June 30, 2012. The North America segment saw the largest decline due predominantly to lower pricing, decreased fleet utilization and increased costs for raw materials for the pressure pumping product line in both the U.S. and Canada. The Latin America segment saw deterioration in profit due to lower rig count activity in Brazil that impacted our drilling services and artificial lift product lines, the impact of the currency devaluation in Venezuela of $23 million, and additional reserves for doubtful accounts across the segment. The Europe/Africa/Russia Caspian segment experienced a decline in profit due to an unfavorable change in sales mix along with increased personnel and start up costs associated with our integrated drilling services contract in Norway. These reductions were partially offset by improvement in the Middle East/Asia Pacific segment for our drilling services product line and integrated operations throughout the region.

Costs and Expenses

The table below details certain unaudited consolidated condensed statement of income data and their percentage of revenue.

	Three Months Ended June 30,				Six Months Ended June 30,			
	2013		2012		2013		2012	
	$	%	$	%	$	%	$	%
Revenue	$ 5,487	100%	$ 5,326	100%	$ 10,717	100%	$ 10,681	100%
Cost of revenue	4,591	84%	4,254	80%	8,917	83%	8,519	80%
Research and engineering	131	2%	128	2%	258	2%	252	2%
Marketing, general and administrative	329	6%	305	6%	651	6%	644	6%

Cost of Revenue

Cost of revenue as a percentage of revenue was 84% and 83% for the three months and six months ended June 30, 2013 , respectively, and 80% for the three months and six months ended June 30, 2012 . The increase in cost of revenue as a percentage of revenue was due primarily to lower pricing coupled with increased depreciation expenses in our pressure pumping product line in North America. In Latin America, margins declined due to reduced pricing for drilling services, increased personnel costs, additional reserves for inventory in Brazil and by an increase of $20 million in our allowance for doubtful accounts. An increase in operating costs and third party expenses related to integrated operations contracts in the Middle East, start up costs associated with a new drilling services contract in Norway, and an unfavorable change in sales mix in Europe and Africa also reduced our margins.

Marketing, General and Administrative

Marketing, general and administrative expenses increased 8% and 1% for the three months and six months ended June 30, 2013 , respectively, compared to the same periods a year ago. The increase in expenses for the three months ended June 30, 2013 is in part due to foreign exchange losses caused by unfavorable movements in exchange rates for most foreign currencies against the U.S. Dollar, particularly the Russian Ruble and Australian Dollar, as well as higher marketing and other administrative costs. For the six months ended June 30, 2013, foreign exchange losses also include a loss of $23 million due to the currency devaluation in Venezuela that occurred in February 2013. These increases were partially offset by the winding down of our worldwide integration efforts subsequent to our acquisition of BJ Services. The conclusion of these efforts resulted in decreased costs related to technology, project management and personnel, and led to improved efficiencies among our global operations and support functions.

Income Taxes

Total income tax expense was $131 million and $263 million for the three months and six months ended June 30, 2013 , respectively. Our effective tax rate on income before income taxes for the three months and six months ended June 30, 2013 was 34.8% and 33.9%, respectively. The tax rate for the six months ended June 30, 2013 is lower than the U.S. statutory income tax rate of 35% primarily due to lower rates of tax in certain foreign jurisdictions, the tax benefits recorded as part of the American Taxpayer Relief Act of 2012, and a net decrease in reserves related to prior year tax positions, partially offset by state income taxes.

OUTLOOK

This section should be read in conjunction with the factors described in “Part II, Item 1A. Risk Factors” and in the “Forward-Looking Statements” section in this Part I, Item 2, both contained herein. These factors could impact, either positively or negatively, our expectation for: oil and natural gas demand; oil and natural gas prices; exploration and development spending and drilling activity; and production spending.

Our industry is cyclical, and past cycles have been driven primarily by alternating periods of ample supply or shortage of oil and natural gas relative to demand. As an oilfield services company, our revenue is dependent on spending by our customers for oil and natural gas exploration, field development and production. This spending is dependent on a number of factors, including our customers’ forecasts of future energy demand, their expectations for future energy prices, their access to resources to develop and produce oil and natural gas, their ability to fund their capital programs, and the impact of new government regulations.

Our outlook for exploration and development spending is based upon our expectations for customer spending in the markets in which we operate, and is driven primarily by our perception of industry expectations for oil and natural gas prices, and their likely impact on customer capital and operating budgets as well as other factors that could impact the economic return oil and natural gas companies expect for developing oil and natural gas reserves. Our forecasts are based on evaluating a number of external sources as well as our internal estimates. External sources include publications by the IEA, OPEC, the Energy Information Administration (“EIA”), and the Organization for Economic Cooperation and Development (“OECD”). We acknowledge that there is a substantial amount of uncertainty regarding these forecasts, thus, while we have internal estimates regarding economic expansion, hydrocarbon demand and overall oilfield activity, we position ourselves to be flexible and responsive to a wide range of potential outcomes.

The primary drivers impacting the 2013 business environment include the following:

- Worldwide Economic Growth - In general there is a strong linkage between overall economic activity, growth and the demand for hydrocarbons. The outlook for the remainder of 2013 is one of modest strengthening of economic activity amidst ongoing concerns fueled by sovereign debt issues in Europe, a slowdown of the rate of growth in the Chinese economy, and the moderate rate of economic growth in the U.S. The European sovereign debt crisis and the reduction in economic activity have impacted the economies of major exporters, including the U.S. and China. Although steps have been taken by governments to resolve this issue, the crisis and the worsening macroeconomic conditions in the Euro area remain a threat to the global economic outlook. China's rapid economic growth and industrialization has been a major factor in driving up world-wide economic growth since the recession of 2008/2009. China's economic growth rate slowed significantly to 7.8% in 2012, representing its slowest pace since 1999. The economy was projected to pick up in 2013 with year over year forecasts of 8.0% across the board. However, the first quarter 2013 growth rate came in at 7.7% and second quarter growth is currently forecast to be 7.5%. The International Monetary Fund and World Bank, among other major investment banks, have cut estimates for China's 2013 economic growth to approximately 7.7%. In the U.S., the expectation is for only modest economic growth throughout 2013. However, this growth may be hampered by weakness or further deterioration of the global economy, particularly in China and Europe. Additionally, the Federal Reserve has hinted on the potential withdrawal of quantitative easing by the middle of 2014, which would eliminate approximately $1 trillion in yearly liquidity injections. The reduction in quantitative easing could result in significant increases in interest rates, and therefore the cost of borrowing towards new capital projects.

- Demand for Hydrocarbons - In its July 2013 Oil Market Report, the IEA forecasted global demand for oil to increase 0.9 million barrels per day in 2013, to 90.8 million barrels per day. This expected increase in demand for oil, mainly driven by countries outside the OECD, should support increased expenditures within the oil and natural gas sector. In addition, natural gas is an increasingly important hydrocarbon to meet the world's energy needs. In its July 2013 Short-Term Energy Outlook, the EIA estimated that U.S. natural gas demand would increase by 0.4 billion cubic feet per day in 2013, to 70.1 billion cubic feet per day.
- Oil Production - The July 2013 IEA Oil Market Report projected non-OPEC production to grow by 1.2 million barrels per day in 2013 to 54.6 million barrels per day. This increase is largely due to continued production growth from U.S. tight oil formations and Canadian oil sands, fostered by sustained higher oil prices. North American output growth offsets lower European and Latin American supply. Global OPEC production is anticipated to fall by 0.5 million barrels per day in 2013 to 29.6 million barrels per day. Most of the decline comes from Saudi Arabia, in response to growth in non-OPEC supply. Significant investments are expected to be required to increase production capacity, especially in the context of declining production from mature fields and the rapid early well production declines observed in many unconventional plays. New production is anticipated to be increasingly sourced from technically challenging fields with high unit costs, such as in deepwater environments, shale plays and heavy oil resources. However, price volatility driven by global economic and geopolitical uncertainties may lead to delays in operator investment decisions across the rest of the world.
- Natural Gas Production - Worldwide natural gas production continues to grow. Despite this overall trend, low natural gas prices in North America have resulted in a reduction in the natural gas-directed rig and completion activity in this region. This impacted North America natural gas production in 2012, resulting in a gradual increase in Henry Hub spot gas prices in 2013. Relative cold weather in the later part of the winter season and slightly below average gas in storage has seen spot gas prices rise to a two-year high in April 2013. Overall, worldwide natural gas production will tend to be more stable as high natural gas prices in places such as Europe and Asia encourage sustained global growth.
- Oil Prices - With WTI oil prices trading between $86.68/Bbl and $98.44/Bbl, and Brent trading between $96.79/Bbl and $110.42/Bbl during the second quarter of 2013, we believe most oil developments globally will continue to provide adequate returns to encourage incremental investment. New midstream infrastructure in the U.S. is expected during the second half of 2013, which should help to narrow the price gap between WTI and Brent. Based on oil supply forecasts and modest anticipated economic growth globally, oil prices are expected to remain relatively stable throughout 2013, barring any major macro-economic event.
- Natural Gas Prices - With Henry Hub natural gas prices trading between $3.57/mmBtu and $4.38/mmBtu during the second quarter of 2013, particularly low prices when compared to oil on a Btu equivalent basis, we believe that the economics of most dry natural gas-directed investments in North America will continue to be marginal. This is primarily due to the abundant supplies available from the unconventional plays in North America, including natural gas produced in association with unconventional oil wells, which is expected to remain high in the second half of 2013. However, natural gas in storage in April, May and June 2013 fell below the five year average for that time of year. The decline of natural gas in storage resulted from the combination of increased demand for natural gas in the U.S. but flat overall production. In its July 2013 Short Term Energy Outlook, the EIA projected Henry Hub natural gas prices will increase to an average of $3.76/mmBtu in 2013. Future gas demand and gas pricing in the U.S. is sensitive to assumptions regarding fuel competition for power generation and the start of liquefied natural gas ("LNG") exports, currently anticipated to be in the fourth quarter of 2015.

Activity and Spending Outlook for North America - Overall customer spending in North America is expected to increase in 2013 compared to 2012, but the average annual rig count is expected to remain close to the levels set in the fourth quarter of 2012, in part reflecting improved efficiencies in drilling performance. The slowdown in spending directly related to natural gas development has been largely offset by incremental investment to develop unconventional plays with crude oil and natural gas liquids content. Overall service intensity has increased in North America as customers are demanding key technologies, such as advanced directional drilling, more complex completion systems and pressure pumping to develop the unconventional plays with liquids content. Despite this increase in demand, however, pricing has declined in some basins, particularly for hydraulic fracturing where current pressure pumping capacity exceeds demand. Activity on the continental shelf has been strong, and there has been a steady increase in the granting of new deepwater permits. It is expected that exploration drilling as well as completions and development activity in the Gulf of Mexico will continue to increase throughout the remainder of

2013, with additional deep water rigs being added. In Canada, overall rig activity in 2013 is expected to decline approximately 4% compared to 2012.

Activity and Spending Outlook Outside North America - International activity is driven primarily by the price of oil and natural gas, both of which are high enough to provide attractive economic returns in almost every region and to support some major natural gas export projects. Customers are expected to increase spending to develop new resources and offset declines from existing developed reserves, increasingly relying on advanced technology services to support exploration and production activities in deep water, heavy or viscous oils and tight reservoirs. Areas that are expected to see increased spending in 2013 include: the Middle East, in particular Iraq, including the Kurdistan province, and Saudi Arabia; and Latin America, with the largest growth expected in Mexico, Brazil, and Colombia. Within Southeast Asia, there is an increased focus on exploring and developing oil and natural gas resources to meet rapid local demand growth rather than the historic role of meeting exports. In Africa, traditional growth areas such as Angola and Nigeria are being augmented by new provinces such as Ghana, Uganda, Mozambique and Tanzania, while South Sudan resumed oil exports in the first quarter of 2013. Russia is striving to maintain 10 million barrels of oil per day until the end of the decade by investing in Eastern Siberia and eventually in the Arctic offshore. Efforts in Russia at developing tight oil using vertical drilling are already underway with potential for pilot projects in 2013 and beyond for more complex horizontal drilling and completions. Australia is leading the expansion of export LNG projects, requiring conventional offshore gas drilling in the northwest shelf as well as coal bed methane operations onshore Queensland. Large scale gas pipeline exports from the Caspian region to China and Europe are expected to grow significantly in the next five years, spurring drilling for deeper targets, both onshore and offshore, and increased natural gas process plant capacity. While overall unconventional drilling outside North America is still at its infancy, activities in Australia, China, Saudi Arabia and Argentina are showing early promise, with active interest at ministry and national oil company level in defining unconventional resource potential in almost all countries with active oil and natural gas industries.

LIQUIDITY AND CAPITAL RESOURCES

At June 30, 2013, we had cash and cash equivalents of $1.12 billion, compared to $1.02 billion of cash and cash equivalents held at December 31, 2012. Substantially all of the consolidated cash balances were held by foreign subsidiaries. A substantial portion of the cash held by foreign subsidiaries at June 30, 2013 was reinvested in our international operations as our intent is to use this cash to, among other things, fund the operations of our foreign subsidiaries. If we decide at a later date to repatriate those funds to the U.S., we may be required to provide taxes on certain of those funds based on applicable U.S. tax rates net of foreign taxes.

In addition, we have a $2.5 billion committed revolving credit facility with commercial banks and a commercial paper program under which we may issue up to $2.5 billion. The maximum combined borrowing at any time under both the credit facility and commercial paper program is $2.5 billion. At June 30, 2013, we had $881 million of commercial paper outstanding. We believe that cash on hand, cash flows from operating activities, and the available credit facility, including the issuance of commercial paper, will provide sufficient liquidity to manage our global cash needs.

Cash Flows

Our capital planning process is focused on utilizing cash flows generated from operations in ways that enhance the value of our Company. In the six months ended June 30, 2013, we used cash to pay for a variety of activities including working capital needs, capital expenditures and the payment of dividends.

The following table summarizes cash flows provided (used) by type of activity, for the six months ended June 30:

(In millions)	2013	2012
Operating activities	$ 1,078	$ 124
Investing activities	(862)	(1,239)
Financing activities	(103)	855

Operating Activities

Cash flows from operating activities provided $1,078 million in the six months ended June 30, 2013. Before changes in operating assets and liabilities, the major source of funds was net income, including noncontrolling interests, of $513 million plus the noncash provision for depreciation and amortization of $839 million. Net changes in operating assets and liabilities used $167 million for the six months ended June 30, 2013. This was primarily the result of an increase in accounts receivable of $494 million due to both an increase in revenue and slower collections, and an increase in inventory of $89 million offset by an increase in accounts payable of $502 million.

Investing Activities

Our principal recurring investing activity was the funding of capital expenditures to ensure that we have the appropriate levels and types of machinery and equipment and other infrastructure in place to support operations. Expenditures for capital assets totaled $1,041 million in the six months ended June 30, 2013. These expenditures were for machinery and equipment, new facilities, expansions of existing facilities and other infrastructure projects.

Proceeds from the disposal of assets were $183 million in the six months ended June 30, 2013. These disposals related to equipment that was lost-in-hole, and property, machinery, and equipment no longer used in operations that were sold throughout the period.

Financing Activities

We had net repayments related to commercial paper and other debt with three months or less original maturity of $40 million and net proceeds from borrowings of other short term debt of $40 million in the six months ended June 30, 2013. Total debt outstanding at June 30, 2013 was $4.91 billion, a decrease of $7 million compared to December 31, 2012. The total debt to total capitalization (defined as total debt plus equity) ratio was 0.22 at June 30, 2013 and December 31, 2012. We paid dividends of $132 million in the six months ended June 30, 2013.

Available Credit Facility

We have a $2.5 billion committed revolving credit facility with commercial banks that matures in September 2016. At June 30, 2013, we were in compliance with all of the facility's covenants. There were no direct borrowings under the committed credit facility during the quarter ended June 30, 2013. We also have an outstanding commercial paper program under which we may issue from time to time up to $2.5 billion in commercial paper with maturity of no more than 270 days. The maximum combined borrowing at any point in time under both the commercial paper program and the credit facility is $2.5 billion. At June 30, 2013, we had $881 million of commercial paper outstanding resulting in $1.6 billion available under the credit facility.

If market conditions were to change and our revenue was reduced significantly or operating costs were to increase, our cash flows and liquidity could be reduced. Additionally, it could cause the rating agencies to lower our credit rating. There are no ratings triggers that would accelerate the maturity of any borrowings under our committed credit facility. However, a downgrade in our credit ratings could increase our short-term borrowing costs or the cost of new debt financing.

We believe our current credit ratings would allow us to obtain additional financing over and above our existing credit facility for any currently unforeseen significant needs or growth opportunities. We also believe that such additional financing could be funded with subsequent issuances of long-term debt or equity, if necessary.

Cash Requirements

In 2013, we believe cash on hand, cash flows from operating activities and the available credit facility will provide us with sufficient capital resources and liquidity to manage our working capital needs, meet contractual obligations, fund capital expenditures, and support the development of our short-term and long-term operating strategies.

In 2013, we expect our capital expenditures to be approximately $2 billion, excluding any amount related to acquisitions. The expenditures are expected to be used primarily for normal, recurring items necessary to support our business and operations. A significant portion of our capital expenditures can be adjusted based on future activity of our customers, and accordingly, we will manage our capital expenditures to match market demand. In 2013, we also expect to make interest payments of between $225 million and $240 million, based on debt levels as of June 30, 2013. We anticipate making income tax payments of between $700 million and $800 million in 2013.

Our Board of Directors has authorized a program to repurchase our common stock. We may repurchase our common stock depending on market conditions, applicable legal requirements, our liquidity and other considerations. In the six months ended June 30, 2013 and 2012, we did not repurchase any shares of common stock. At June 30, 2013, we had authorization remaining to repurchase approximately $1.2 billion in common stock. We anticipate paying dividends of between $263 million and $273 million in 2013; however, the Board of Directors can change the dividend policy at any time.

During the six months ended June 30, 2013, we contributed approximately $183 million to our defined benefit, defined contribution and other postretirement plans. We expect to make additional contributions of between $200 million and $230 million to these plans for the remainder of 2013.

New Accounting Standards Updates

In February 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2013-02, *Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income.* This ASU requires entities to present separately, among other items, the amount of the change that is due to reclassifications, and the amount that is due to current period other comprehensive income. We adopted the new presentation requirements in the notes to our financial statements in the first quarter of 2013.

FORWARD-LOOKING STATEMENTS

MD&A and certain statements in the Notes to Unaudited Consolidated Condensed Financial Statements, includes forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act (each a "forward-looking statement"). The words "anticipate," "believe," "ensure," "expect," "if," "intend," "estimate," "probable," "project," "forecasts," "predict," "outlook," "aim," "will," "could," "should," "would," "potential, " "may," "likely" and similar expressions, and the negative thereof, are intended to identify forward-looking statements. Our forward-looking statements are based on assumptions that we believe to be reasonable but that may not prove to be accurate. The statements do not include the potential impact of future transactions, such as an acquisition, disposition, merger, joint venture or other transactions that could occur. We undertake no obligation to publicly update or revise any forward-looking statement. Our expectations regarding our business outlook, including changes in revenue, pricing, capital spending, profitability, strategies for our operations, impact of any common stock repurchases, oil and natural gas market conditions, the business plans of our customers, market share and contract terms, costs and availability of resources, legal, economic and regulatory conditions, and environmental matters are only our forecasts regarding these matters.

All of our forward-looking information is subject to risks and uncertainties that could cause actual results to differ materially from the results expected. Although it is not possible to identify all factors, these risks and uncertainties include the risk factors and the timing of any of those risk factors identified in "Part II, Item 1A. Risk Factors" section contained herein, as well as the risk factors described in our 2012 Annual Report, this filing and those set forth from time to time in our filings with the SEC. These documents are available through our website or through the SEC's Electronic Data Gathering and Analysis Retrieval System ("EDGAR") at http://www.sec.gov.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information about market risks for the six months ended June 30, 2013, does not differ materially from that discussed under Part II, Item 7(a), "Quantitative and Qualitative Disclosures About Market Risk," in our 2012 Annual Report on Form 10-K.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this Quarterly Report, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 of the Exchange Act of 1934, as amended (the “Exchange Act”). This evaluation was carried out under the supervision and with the participation of our management, including our principal executive officer and principal financial officer. Based on this evaluation, these officers have concluded that, as of June 30, 2013, our disclosure controls and procedures, as defined by Rule 13a-15(e) of the Exchange Act, are effective at a reasonable assurance level. There has been no change in our internal controls over financial reporting during the quarter ended June 30, 2013 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

Disclosure controls and procedures are our controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act, such as this Quarterly Report, is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

See discussion of legal proceedings in Note 9 of the Notes to Unaudited Consolidated Condensed Financial Statements in this Quarterly Report, Item 3 of Part I of our 2012 Annual Report and Note 11 of the Notes to Consolidated Financial Statements included in Item 8 of our 2012 Annual Report.

ITEM 1A. RISK FACTORS

As of the date of this filing, the Company and its operations continue to be subject to the risk factors previously disclosed in our "Risk Factors" in the 2012 Annual Report.

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

The following table contains information about our purchases of equity securities during the three months ended June 30, 2013.

Period	Total Number of Shares Purchased [(1)]	Average Price Paid Per Share [(1)]	Total Number of Shares Purchased as Part of a Publicly Announced Program [(2)]	Average Price Paid Per Share [(2)]	Total Number of Shares Purchased in the Aggregate	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Program [(2)]
April 1-30, 2013	27,156	$ 44.54	—	$ —	27,156	$ —
May 1-31, 2013	1,075	45.25	—	—	1,075	—
June 1-30, 2013	—	—	—	—	—	—
Total	28,231	$ 44.56	—	$ —	28,231	$ 1,197,127,803

(1) Represents shares purchased from employees to pay the option exercise price related to stock-for-stock exchanges in option exercises or to satisfy the tax withholding obligations in connection with the vesting of restricted stock awards and restricted stock units.
(2) Our Board of Directors has authorized a program to repurchase our common stock from time to time. During the three months ended June 30, 2013, we did not repurchase any shares of our common stock under the program. We had authorization remaining to repurchase up to a total of approximately $1.2 billion of our common stock.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Our barite mining operations, in support of our drilling fluids products and services business, are subject to regulation by the federal Mine Safety and Health Administration under the Federal Mine Safety and Health Act of 1977. Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K is included in Exhibit 95 to this Quarterly Report.

ITEM 5. OTHER INFORMATION

Section 219 of the Iran Threat Reduction and Syrian Human Rights Act of 2012 added Section 13(r) to the Exchange Act. Section 13(r) requires an issuer to disclose in its periodic reports whether it or any of its affiliates knowingly engaged in certain specified activities relating to Iran. Disclosure is required even where the activities are conducted outside the U.S. by non-U.S. affiliates in compliance with applicable law, and whether or not the activities are actionable under U.S. law.

We had no sales or services reported for Iran in 2012 and no sales or services will be made in 2013. In January 2012, Baker Eastern S.A., a non-U.S. controlled foreign subsidiary, made its final corporate income tax payment of USD equivalent of $443,000 which was owed due to profits made in Iran prior to ceasing operations pursuant to the December 31, 2006 deadline mandated by the Company.

ITEM 6. EXHIBITS

Each exhibit identified below is filed as a part of this report. Exhibits designated with an “*” are filed as an exhibit to this Quarterly Report on Form 10-Q. Exhibits designated with a "+" are identified as management contracts or compensatory plans or arrangements. Exhibits previously filed as indicated below are incorporated by reference.

3.1	Restated Bylaws of Baker Hughes Incorporated dated as of April 25, 2013 (filed as Exhibit 3.1 to the Current Report of Baker Hughes Incorporated on Form 8-K filed April 30, 2013).
10.1+	Amendment to the Restated and Superseding Employment Agreement by and between Chad C. Deaton and Baker Hughes Incorporated (filed as Exhibit 10.1 to the Current Report of Baker Hughes Incorporated on Form 8-K filed April 30, 2013).
10.2+	Amendment to the Baker Hughes Incorporated Employee Stock Purchase Plan (filed as Exhibit 10.2 to the Current Report of Baker Hughes Incorporated on Form 8-K filed April 30, 2013).
31.1*	Certification of Martin S. Craighead, Chairman and Chief Executive Officer, furnished pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Peter A. Ragauss, Senior Vice President and Chief Financial Officer, furnished pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934, as amended.
32*	Statement of Martin S. Craighead, Chairman and Chief Executive Officer, and Peter A. Ragauss, Senior Vice President and Chief Financial Officer, furnished pursuant to Rule 13a-14(b) of the Securities Exchange Act of 1934, as amended.
95*	Mine Safety Disclosure.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

SIGNATURES

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

BAKER HUGHES INCORPORATED
(Registrant)

Date:	July 24, 2013	By:	/s/ PETER A. RAGAUSS
			Peter A. Ragauss Senior Vice President and Chief Financial Officer
Date:	July 24, 2013	By:	/s/ ALAN J. KEIFER
			Alan J. Keifer Vice President and Controller

Exhibit 31.1

CERTIFICATION

I, Martin S. Craighead, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Baker Hughes Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 24, 2013

By: /s/ Martin S. Craighead
Martin S. Craighead
Chairman and
Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Peter A. Ragauss, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Baker Hughes Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date:	July 24, 2013	By:	/s/ Peter A. Ragauss
			Peter A. Ragauss
			Senior Vice President and Chief Financial Officer

Exhibit 32

CERTIFICATION PURSUANT TO

18 U.S.C. SECTION 1350

AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Baker Hughes Incorporated (the "Company") on Form 10-Q for the period ended June 30, 2013, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, Martin S. Craighead, Chairman and Chief Executive Officer of the Company, and Peter A. Ragauss, the Chief Financial Officer of the Company, each of the undersigned hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(i) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(ii) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company as of the dates and for the periods expressed in the Report.

The certification is given to the knowledge of the undersigned.

	/s/ Martin S. Craighead
Name:	Martin S. Craighead
Title:	Chairman and Chief Executive Officer
Date:	July 24, 2013
	/s/ Peter A. Ragauss
Name:	Peter A. Ragauss
Title:	Senior Vice President and Chief Financial Officer
Date:	July 24, 2013

Exhibit 95

Mine Safety Disclosure

The following disclosures are provided pursuant to Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K, which require certain disclosures by companies required to file periodic reports under the Securities Exchange Act of 1934, as amended, that operate mines regulated under the Federal Mine Safety and Health Act of 1977.

The table that follows reflects citations, orders, violations and proposed assessments issued by the Mine Safety and Health Administration (the "MSHA") for each mine of which Baker Hughes and/or its subsidiaries is an operator. The disclosure is with respect to the three months ended June 30, 2013. Due to timing and other factors, the data may not agree with the mine data retrieval system maintained by the MSHA at www.MSHA.gov.

Three Months Ended June 30, 2013

Mine or Operating Name/MSHA Identification Number	Section 104 S&S Citations	Section 104(b) Orders	Section 104(d) Citations and Orders	Section 110(b)(2) Violations	Section 107(a) Orders	Proposed MSHA Assessments [1]	Mining Related Fatalities	Received Notice of Pattern of Violations Under Section 104(e) (yes/no)	Received Notice of Potential to Have Pattern Under Section 104(e) (yes/no)	Legal Actions Pending as of Last Day of Period	Legal Actions Initiated During Period	Legal Actions Resolved During Period
Morgan City Grinding Plant/1601357	0	0	0	0	0	$ 100	0	N	N	0	0	0
Argenta Mine and Mill/2601152	2 [2]	0	0	0	0	$ 238	0	N	N	0	0	0
Corpus Christi Grinding Plant/4103112	0	0	0	0	0	$ —	0	N	N	0	0	0

(1) Amounts included are the total dollar value of proposed assessments received from MSHA during the three months ended June 30, 2013, regardless of whether the assessment has been challenged or appealed. Citations and orders can be contested and appealed, and as part of that process, are sometimes reduced in severity and amount, and sometimes dismissed. The number of citations, orders, and proposed assessments vary by inspector and also vary depending on the size and type of the operation.

(2) Two Section 104 S&S citations issued to an independent contractor (who is not a subsidiary of Baker Hughes) who is working at the Argenta Mine and Mill. MSHA had not yet proposed an assessment on these citations.