BlackRock Utility & Infrastructure Trust
Form 4
March 24, 2015

FORM 4

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

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

OMB APPROVAL

OMB Number:	3235-0287
Expires:	January 31, 2005
Estimated average burden hours per response...	0.5

(Print or Type Responses)

1. Name and Address of Reporting Person *
Anderson Kathleen M

(Last) (First) (Middle)

55 EAST 52ND STREET

(Street)

NEW YORK, NY 10055

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
BlackRock Utility & Infrastructure Trust [BUI]

3. Date of Earliest Transaction (Month/Day/Year)
03/23/2015

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

_____ Director _____ 10% Owner
_____ Officer (give title below) __X__ Other (specify below)
Portfolio Manager

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Common Stock	03/23/2015		P		15,000	A	$ 19.797	25,000	D	

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

Persons who respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB control number.

SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)		8. Price of Derivative Security (Instr. 5)	9. Nu Deriv Secur Bene Owne Follo Repo Trans (Instr
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares		

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
Anderson Kathleen M 55 EAST 52ND STREET NEW YORK, NY 10055				Portfolio Manager

Signatures

/s/ Eugene Drozdetski as Attorney-in-Fact	03/24/2015
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. s New Roman" SIZE="2">88,707 50,562

Asset retirement obligation

343 386

Future income taxes

32,956 30,220 511,753 482,615

Shareholders equity:

Common shares (authorized unlimited number of voting and non-voting common shares; issued and outstanding September 30, 2009 36,038,476 voting common shares (March 31, 2009 36,038,476 voting common shares) (note 9(a))

299,973 299,973

Contributed surplus (note 9(b))

6,817 5,275

Deficit

(142,228) (157,811) 164,562 147,437 $676,315 $630,052 Contingencies (note 15)

See accompanying notes to unaudited interim consolidated financial statements.

2

Table of Contents

Interim Consolidated Statements of Operations, Comprehensive Income (Loss) and Deficit

(Expressed in thousands of Canadian Dollars, except per share amounts)

(Unaudited)

	Three Months Ended September 30,		Six Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
Revenue	**$ 171,110**	**$ 280,283**	**$ 318,213**	**$ 539,270**
Project costs	65,959	154,961	120,512	303,592
Equipment costs	44,359	60,787	90,403	106,597
Equipment operating lease expense	15,684	9,586	28,033	18,384
Depreciation	11,987	10,668	21,334	18,826
Gross profit	**33,121**	**44,281**	**57,931**	**91,871**
General and administrative costs	14,015	19,345	29,081	38,561
Loss on disposal of property, plant and equipment	260	1,612	301	2,756
Loss (gain) on disposal of assets held for sale	41	2	(276)	24
Amortization of intangible assets	236	276	484	554
Operating income before the undernoted	**18,569**	**23,046**	**28,341**	**49,976**
Interest expense, net (note 10)	8,980	6,440	17,617	12,889
Foreign exchange (gain) loss	(17,862)	8,236	(37,077)	6,595
Realized and unrealized loss on derivative financial instruments (note 11)	26,271	7,618	27,317	5,353
Other (income) expenses	(200)	(3)	333	(21)
Income before income taxes	**1,380**	**755**	**20,151**	**25,160**
Income taxes (note 12(c)):				
Current income taxes	1,264	62	1,264	62
Future income taxes (recovery)	(693)	1,915	3,304	7,224
Net income (loss) and comprehensive income (loss) for the period	**809**	**(1,222)**	**15,583**	**17,874**
(Deficit) Retained earnings, beginning of period as previously reported	(143,037)	800	(157,811)	(19,287)
Change in accounting policy related to inventories				991
Deficit, end of period	**$ (142,228)**	**$ (422)**	**$ (142,228)**	**$ (422)**
Net income (loss) per share basic (note 9(c))	**$ 0.02**	**$ (0.03)**	**$ 0.43**	**$ 0.50**
Net income (loss) per share diluted (note 9(c))	**$ 0.02**	**$ (0.03)**	**$ 0.43**	**$ 0.48**

See accompanying notes to unaudited interim consolidated financial statements.

Table of Contents

Interim Consolidated Statements of Cash Flows

(Expressed in thousands of Canadian Dollars)

(Unaudited)

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Six Months Ended September 30, 2009	Six Months Ended September 30, 2008
Cash provided by (used in):				
Operating activities:				
Net income (loss) for the period	$ 809	$ (1,222)	$ 15,583	$ 17,874
Items not affecting cash:				
Depreciation	11,987	10,668	21,334	18,826
Amortization of intangible assets	236	276	484	554
Amortization of deferred lease inducements	(35)	(27)	(61)	(53)
Loss on disposal of property, plant and equipment	260	1,612	301	2,756
Loss (gain) on disposal of assets held for sale	41	2	(276)	24
Unrealized foreign exchange (gain) loss on senior notes	(17,877)	8,147	(37,196)	6,316
Amortization of bond issue costs, premiums and financing costs (note 10)	212	184	433	358
Unrealized change in the fair value of derivative financial instruments	25,604	6,950	25,983	4,017
Stock-based compensation expense (note 14)	620	670	2,425	1,306
Accretion expense asset retirement obligation	(21)	57	(12)	106
Future income taxes (recovery)	(693)	1,915	3,304	7,224
Net changes in non-cash working capital (note 12(b))	2,042	(38,696)	(17,055)	(35,431)
	23,185	**(9,464)**	**15,247**	**23,877**
Investing activities:				
Acquisition (note 5)	(4,880)		(4,880)	
Purchase of property, plant and equipment	(23,555)	(16,177)	(43,265)	(75,526)
Additions to assets held for sale	(933)		(933)	
Proceeds on disposal of property, plant and equipment	558	3,296	696	4,648
Proceeds on disposal of assets held for sale	152	2	1,112	194
Net changes in non-cash working capital (note 12(b))	3,919	(38,214)	2,647	5,259
	(24,739)	**(51,093)**	**(44,623)**	**(65,425)**
Financing activities:				
Cheques issued in excess of cash deposits		665		665
Increase in long term debt (note 7)	21,200	10,000	33,000	10,000
Repayment of capital lease obligations	(1,477)	(1,465)	(2,947)	(2,690)
Cash settlement of stock options (note 9(b))	(66)		(66)	
Repayment of long term debt (note 5)	(652)		(652)	
Stock options exercised		25		702
Financing costs (note 7(a))	(8)		(1,123)	
	18,997	**9,225**	**28,212**	**8,677**
Increase, (decrease) in cash and cash equivalents	17,443	(51,332)	(1,164)	(32,871)
Cash and cash equivalents, beginning of period	80,273	51,332	98,880	32,871
Cash and cash equivalents, end of period	**$ 97,716**	**$**	**$ 97,716**	**$**

Supplemental cash flow information (note 12(a))

See accompanying notes to unaudited interim consolidated financial statements

4

Table of Contents

Notes to Interim Consolidated Financial Statements

For the three and six months ended September 30, 2009

(Expressed in thousands of Canadian Dollars, except per share amounts or unless otherwise specified)

(Unaudited)

1. Nature of Operations

North American Energy Partners Inc. (the Company), formerly NACG Holdings Inc. (NACG), was incorporated under the Canada Business Corporations Act on October 17, 2003. On November 26, 2003, the Company purchased all the issued and outstanding shares of North American Construction Group Inc. (NACGI), including subsidiaries of NACGI, from Norama Ltd. which had been operating continuously in Western Canada since 1953. The Company had no operations prior to November 26, 2003.

The Company undertakes several types of projects including heavy construction, commercial and industrial site development and pipeline and piling installations in Canada.

2. Basis of Presentation

These unaudited interim consolidated financial statements (the financial statements) are prepared in accordance with Canadian generally accepted accounting principles (GAAP) for interim financial statements and do not include all of the disclosures normally contained in the Company s annual consolidated financial statements. Since the determination of many assets, liabilities, revenues and expenses is dependent on future events, the preparation of these financial statements requires the use of estimates and assumptions. In the opinion of management, these financial statements have been prepared within reasonable limits of materiality. Except as disclosed in note 3, these financial statements follow the same significant accounting policies as described and used in the most recent annual consolidated financial statements of the Company for the year ended March 31, 2009 and should be read in conjunction with those consolidated financial statements.

These consolidated financial statements include the accounts of the Company, its wholly-owned subsidiaries, NACGI and NACG Finance LLC, the Company s proportionate share of the assets, liabilities, revenues, expenses and cash flows of its joint venture, Noramac Ventures Inc. and the following 100% owned subsidiaries of NACGI:

North American Caisson Ltd.	North American Road Inc.
North American Construction Ltd.	North American Services Inc.
North American Engineering Ltd.	North American Site Development Ltd.
North American Enterprises Ltd.	North American Site Services Inc.
North American Industries Inc.	North American Pile Driving Inc.
North American Mining Inc.	DF Investments Ltd.
North American Maintenance Ltd.	Drillco Foundation Co. Ltd.
North American Pipeline Inc.	

3. Recently adopted Canadian accounting pronouncements

i) Goodwill and intangible assets

Effective April 1, 2009, the Company adopted, on a retrospective basis, CICA Handbook Section 3064, Goodwill and Intangible Assets , which replaces Section 3062, Goodwill and Other Intangible Assets , and Section 3450, Research and Development Costs and establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The provisions relating to the definition and initial recognition

5

Table of Contents

Notes to Interim Consolidated Financial Statements

For the three and six months ended September 30, 2009

(Expressed in thousands of Canadian Dollars, except per share amounts or unless otherwise specified)

(Unaudited)

of intangible assets, including internally generated intangible assets, are equivalent to the corresponding provisions of International Accounting Standard IAS 38, Intangible Assets . The adoption of this standard did not have a material impact on the Company s interim consolidated financial statements.

ii) Business combinations

Effective July 1, 2009, the Company early adopted CICA Handbook Section 1582, Business Combinations , which replaces the existing standard. This section establishes standards for the accounting of business combinations, and states that all assets and liabilities of an acquired business will be recorded at fair value. Obligations for contingent considerations and contingencies will also be recorded at fair value at the acquisition date. The standard also states that acquisition related costs will be expensed as incurred, that restructuring charges will be expensed in periods after the acquisition date and that non-controlling interests should be measured at fair value at the date of acquisition. This standard is to be applied prospectively to business combinations with acquisition dates on or after July 1, 2009. This new standard was applied to the acquisition of DF Investments Ltd. and its subsidiary Drillco Foundation Co. Ltd. (see note 5).

iii) Consolidated financial statements

Effective July 1, 2009, the Company early adopted CICA Handbook Section 1601, Consolidated Financial Statements , which replaces Section 1600 Consolidated Financial Statements . This Section carries forward existing Canadian guidance for preparing consolidated financial statements other than guidance for non-controlling interests. The adoption of this standard did not have a material impact on the Company s interim consolidated financial statements.

iv) Non-controlling interests

Effective July 1, 2009, the Company early adopted CICA Handbook Section 1602, Non-Controlling Interests , which establishes standards for the accounting of non-controlling interests of a subsidiary in the preparation of consolidated financial statements subsequent to a business combination. The adoption of this standard did not have a material impact on the Company s interim consolidated financial statements.

v) Equity

In August 2009, the CICA amended presentation requirements of Handbook Section 3251, Equity as a result of issuing Section 1602, Non-Controlling Interests . The amendments apply only to entities that have adopted Section 1602. The Company early adopted this standard effective July 1, 2009. The adoption of this standard did not have a material impact on the Company s interim consolidated financial statements.

vi) Financial instruments recognition and measurement

Effective July 1, 2009, the Company adopted CICA amendments to Handbook Section 3855, Financial Instruments Recognition and Measurement which add guidance concerning the assessment of embedded derivatives upon reclassification of a financial asset out of the held-for-trading category. These amendments apply to reclassifications made on or after July 1, 2009. The adoption of these amendments did not have a material impact on the Company s interim consolidated financial statements.

Table of Contents

Notes to Interim Consolidated Financial Statements

For the three and six months ended September 30, 2009

(Expressed in thousands of Canadian Dollars, except per share amounts or unless otherwise specified)

(Unaudited)

4. Recent Canadian accounting pronouncements not yet adopted

i) Accounting changes

In June 2009, the CICA amended Handbook Section 1506, Accounting Changes , to exclude from its scope changes in accounting policies upon the complete replacement of an entity s primary basis of accounting. The amendment applies to interim and annual financial statements relating to fiscal years beginning on or after July 1, 2009. The Company is currently evaluating the impact of the amendments to the standard.

ii) Financial instruments recognition and measurement

In June 2009, the CICA amended Handbook Section 3855, Financial Instruments Recognition and Measurement , to clarify the application of the effective interest method after a debt instrument has been impaired. The Section has also been amended to clarify when an embedded prepayment option is separated from its host instrument for accounting purposes. The amendments apply to interim and annual financial statements relating to fiscal years beginning on or after May 1, 2009 for the amendments relating to the effective interest method and on or after January 1, 2011 for the amendments relating to embedded prepayment options. The Company is currently evaluating the impact of the amendments to the standard.

iii) Financial instruments disclosure

In June 2009, the CICA amended Handbook Section 3862, Financial Instruments Disclosures , to include additional disclosure requirements about fair value measurements of financial instruments and to enhance liquidity risk disclosure requirements. The amendments apply to annual financial statements relating to fiscal years ending after September 30, 2009. The Company is currently evaluating the impact of the amendments to the standard.

iv) Comprehensive revaluation of assets and liabilities

In August 2009, the CICA amended Handbook Section 1625 Comprehensive Revaluation of Assets and Liabilities as a result of issuing Section 1582, Business Combinations , Section 1601, Consolidated Financial Statements , and Section 1602, Non-Controlling Interests in January 2009. The amendments apply prospectively to comprehensive revaluations of assets and liabilities occurring in fiscal years beginning on or after January 1, 2011. Earlier adoption is permitted as of the beginning of a fiscal year, provided that Section 1582 is also adopted. The Company is currently evaluating the impact of the amendments to the standard.

v) International Financial Reporting Standards (IFRS)

In 2006, the Canadian Accounting Standards Board (AcSB) published a new strategic plan that significantly affects financial reporting requirements for Canadian public companies. The AcSB strategic plan outlines the convergence of Canadian GAAP with IFRS over an expected five-year transitional period.

In February 2008, the AcSB confirmed that IFRS will be mandatory in Canada for profit-oriented publicly accountable entities for fiscal periods beginning on or after January 1, 2011, unless, as permitted by Canadian securities regulations, the Company was to adopt U.S. GAAP on or before this date. Should the Company decide to adopt IFRS, its first annual IFRS financial statements would be for the year ending March 31, 2012 and would include the comparative period of the year ending March 31, 2011. Starting for the three months ending June 30, 2011, the Company would provide unaudited consolidated financial information in accordance with IFRS including comparative figures for the three month period ending June 30, 2010.

7

Notes to Interim Consolidated Financial Statements

For the three and six months ended September 30, 2009

(Expressed in thousands of Canadian Dollars, except per share amounts or unless otherwise specified)

(Unaudited)

The Company has completed a gap analysis of the accounting and reporting differences under IFRS, Canadian GAAP and U.S. GAAP, however, management has not yet finalized its determination of the impact of these differences on the consolidated financial statements. This analysis will, in part, determine whether the Company adopts IFRS or U.S. GAAP once Canadian GAAP ceases to exist. The Company is also closely monitoring standard-setting activity and regulatory developments in Canada, the United States and internationally that may affect the timing of its adoption of either IFRS or U.S. GAAP in future periods.

5. Acquisition

On August 1, 2009, the Company acquired all of the issued and outstanding shares of DF Investments Ltd. and its subsidiary Drillco Foundation Co. Ltd., piling companies based in Milton, Ontario, for preliminary consideration of $6,069 of which $4,880 has been paid. This acquisition gives the Company access to piling markets and customers in the region. The transaction has been accounted for using the acquisition method with the results of operations included in the financial statements from the date of acquisition. The goodwill acquired is not deductible for tax purposes. The preliminary purchase price allocation is as follows:

Net assets acquired at assigned values:	
Working capital	$ 2,439
Property, plant and equipment	2,873
Land	281
Intangible assets	609
Goodwill (assigned to the Piling segment)	1,489
Future income tax liability	(970)
Long term debt	(652)
	$ 6,069

The allocation of the purchase price to the fair value of the assets acquired and liabilities assumed is preliminary and may be subject to adjustments.

6. Property, plant and equipment

September 30, 2009	Cost	Accumulated Depreciation	Net Book Value
Heavy equipment	$ 352,707	$ 88,017	$ 264,690
Major component parts in use	28,601	5,166	23,435
Other equipment	23,785	9,257	14,528
Licensed motor vehicles	14,421	8,810	5,611
Office and computer equipment	17,257	7,042	10,215
Buildings	20,611	5,606	15,005
Land	281		281
Leasehold improvements	9,487	2,289	7,198

Assets under capital lease	25,148	11,692	13,456
	$ 492,298	$ 137,879	$ 354,419

8

Notes to Interim Consolidated Financial Statements

For the three and six months ended September 30, 2009

(Expressed in thousands of Canadian Dollars, except per share amounts or unless otherwise specified)

(Unaudited)

March 31, 2009	Cost	Accumulated Depreciation	Net Book Value
Heavy equipment	$ 319,706	$ 76,130	$ 243,576
Major component parts in use	25,187	2,535	22,652
Other equipment	22,056	8,268	13,788
Licensed motor vehicles	12,760	7,445	5,315
Office and computer equipment	14,614	5,644	8,970
Buildings	19,822	4,956	14,866
Leasehold improvements	6,494	1,845	4,649
Assets under capital lease	27,953	12,064	15,889
	$ 448,592	$ 118,887	$ 329,705

During the three and six months ended September 30, 2009, additions to property, plant and equipment included $33 and $656 respectively, of assets that were acquired by means of capital leases (three and six months ended September 30, 2008 $3,952 and $5,116 respectively). Depreciation of equipment under capital lease of $978 and $2,137 for the three and six months ended September 30, 2009, respectively was included in depreciation expense (three and six months ended September 30, 2008 $1,585 and $2,233 respectively).

7. Debt

a) Long term debt

On June 24, 2009, the Company entered into an amended and restated credit agreement which matures on June 8, 2011 to provide for borrowings of up to $125.0 million under which revolving loans, term loans and letters of credit may be issued. This facility includes a $75.0 million Revolving Facility and a $50.0 million Term Facility. The Term Facility commitments were available until August 31, 2009 and aggregate borrowings under this facility had to exceed $25.0 million. Any undrawn amount under the Term Facility, up to a maximum of $15.0 million, could be reallocated to the Revolving Facility. On August 31, 2009, the maximum undrawn portion of the Term Facility totaling $15.0 million was reallocated to the Revolving Facility resulting in Revolving Facility commitments of $90.0 million.

As of September 30, 2009, the Company had issued $20.3 million (March 31, 2009 $20.8 million) in letters of credit under the Revolving Facility to support performance guarantees associated with customer contracts. The total credit facility commitments are $123.0 million at September 30, 2009 and include the $90.0 million Revolving Facility and the outstanding borrowings of $33.0 million, net of a $1.7 million repayment in the quarter, (March 31, 2009 $nil) under the Term Facility. The funds available under the Revolving Facility are reduced by any outstanding letters of credit. The Company s unused borrowing availability under the Revolving Facility was $69.7 million at September 30, 2009.

Borrowings under the Revolving Facility may be repaid and borrowed from time to time at the option of the Company. The Term Facility is fully utilized and requires quarterly principal repayments. At September 30, 2009, there were no borrowings under the Revolving Facility.

Beginning September 30, 2009, and at the end of each fiscal quarter thereafter, the Company must make quarterly payments of principal in an amount equal to 4.375% of the outstanding principal drawn under the Term

9

Table of Contents

Notes to Interim Consolidated Financial Statements

For the three and six months ended September 30, 2009

(Expressed in thousands of Canadian Dollars, except per share amounts or unless otherwise specified)

(Unaudited)

Facility at August 31, 2009 (equal to $1,518). The credit facility bears interest at Canadian prime rate, U.S. Dollar Base Rate, Canadian bankers acceptance rate or London interbank offered rate (LIBOR) (all such terms as used or defined in the credit facility), plus applicable margins. In each case, the applicable pricing margin depends on the Company s credit rating.

The credit facility is secured by a first priority lien on substantially all of the Company s existing and after-acquired property and contains certain restrictive covenants including, but not limited to, incurring additional debt, transferring or selling assets, making investments including acquisitions or to pay dividends or redeem shares of capital stock. The Company is also required to meet certain financial covenants under the credit agreement and was in compliance with these covenants at September 30, 2009.

During the three and six months ended September 30, 2009, financing fees of $8 and $1,123 respectively were incurred in connection with the modifications made to the amended and restated credit agreement. These fees have been recorded as an intangible asset and are being amortized on a straight-line basis over the remaining term of the credit facility.

b) Senior notes

	September 30, 2009	March 31, 2009
8 3/ 4% senior unsecured notes due 2011 ($US)	$ 200,000	$ 200,000
Unrealized foreign exchange	14,440	52,040
Unamortized financing costs and premiums, net	(2,020)	(2,857)
Fair value of embedded prepayment and early redemption options (note 11)	(2,024)	3,716
	$ 210,396	$ 252,899

The 8 3/4% senior notes were issued on November 26, 2003 in the amount of U.S. $200 million (Canadian $263 million). These notes mature on December 1, 2011 with interest payable semi-annually on June 1 and December 1 of each year. The 8 3/4% senior notes are unsecured senior obligations and rank equally with all other existing and future unsecured senior debt and senior to any subordinated debt that may be issued by the Company or any of its subsidiaries. The notes are effectively subordinated to all secured debt to the extent of the outstanding amount of such debt.

The 8 3/4% senior notes are redeemable at the option of the Company, in whole or in part, at any time on or after: December 1, 2007 at 104.4% of the principal amount; December 1, 2008 at 102.2% of the principal amount; December 1, 2009 at 100.0% of the principal amount; plus, in each case, interest accrued to the redemption date.

If a change of control occurs, the Company will be required to offer to purchase all or a portion of each holder s 8 3/4% senior notes, at a purchase price in cash equal to 101.0% of the principal amount of the notes offered for repurchase plus accrued interest to the date of purchase. As at September 30, 2009, the Company s effective weighted average interest rate on its 8 3/4% senior notes, including the effect of financing costs and premiums, net, was approximately 9.42%.

Table of Contents

Notes to Interim Consolidated Financial Statements

For the three and six months ended September 30, 2009

(Expressed in thousands of Canadian Dollars, except per share amounts or unless otherwise specified)

(Unaudited)

8. Deferred lease inducements

Lease inducements applicable to lease contracts are deferred and amortized as a reduction of general and administrative costs on a straight-line basis over the lease term, which includes the initial lease term and renewal periods only where renewal is determined to be reasonably assured. During the three and six months ended September 30, 2009, the Company recorded inducements from a lessor in the form of leasehold improvements to a new office facility of $195.

	September 30, 2009	March 31, 2009
Balance, beginning of period	$ 836	$ 941
Additions	195	
Amortization	(61)	(105)
Balance, end of period	$ 970	$ 836

9. Shares

a) Common shares

Authorized:

Unlimited number of common voting shares

Unlimited number of common non-voting shares Issued and outstanding:

	Number of Shares	Amount
Common voting shares		
Issued and outstanding at September 30, 2009 and March 31, 2009	36,038,476	$ 299,973

b) Contributed surplus

Balance, March 31, 2009	$ 5,275
Stock-based compensation (note 14(a))	1,330
Deferred performance share unit plan (note 14(b))	278
Cash settlement of stock options	(66)
Balance, September 30, 2009	$ 6,817

Table of Contents

Notes to Interim Consolidated Financial Statements

For the three and six months ended September 30, 2009

(Expressed in thousands of Canadian Dollars, except per share amounts or unless otherwise specified)

(Unaudited)

c) Net income (loss) per share

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Six Months Ended September 30, 2009	Six Months Ended September 30, 2008
Net income (loss) available to common shareholders	$ 809	$ (1,222)	$ 15,583	$ 17,874
Weighted average number of common shares	36,038,476	36,037,867	36,038,476	36,003,454
Basic net income (loss) per share	$ 0.02	$ (0.03)	$ 0.43	$ 0.50
Net income (loss) available to common shareholders	$ 809	$ (1,222)	$ 15,583	$ 17,874
Weighted average number of common shares	36,038,476	36,037,867	36,038,476	36,003,454
Dilutive effect of stock options	668,955		615,232	952,872
Weighted average number of diluted common shares	36,707,431	36,037,867	36,653,708	36,956,326
Diluted net income (loss) per share	$ 0.02	$ (0.03)	$ 0.43	$ 0.48

For the three months ended September 30, 2008, the effect of outstanding stock options on loss per share was anti-dilutive. As such, the effect of outstanding stock options used to calculate the diluted net loss per share has not been disclosed.

For the three and six months ended September 30, 2009, there were 922,126 and 859,783 options respectively, which were anti-dilutive and therefore were not considered in computing diluted earnings per share (three and six months ended September 30, 2008 709,016 and 709,432 options respectively).

d) Capital disclosures

The Company s overall strategy with respect to capital risk management remains unchanged from March 31, 2009.

Table of Contents

Notes to Interim Consolidated Financial Statements

For the three and six months ended September 30, 2009

(Expressed in thousands of Canadian Dollars, except per share amounts or unless otherwise specified)

(Unaudited)

10. Interest expense

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Six Months Ended September 30, 2009	Six Months Ended September 30, 2008
Interest expense on 8 3/4% senior notes	$ 10,572	$ 5,834	$ 21,551	$ 11,669
Interest income on 8 3/4% senior notes swaps[(i)]	(2,638)		(5,804)	
Interest on 8 3/4% senior notes	7,934	5,834	15,747	11,669
Interest on capital lease obligations	270	264	561	545
Amortization of bond issue costs and premiums	212	184	433	358
Interest on credit facilities	197	90	492	90
Interest on long-term debt	8,613	6,372	17,233	12,662
Other interest	367	68	384	227
	$ 8,980	$ 6,440	$ 17,617	$ 12,889

(i) As a result of the U.S. Dollar interest rate swap cancelation, effective December 17, 2008, the Company now receives floating quarterly interest payments from its SWAP counterparties at a rate of 4.2% over three-month LIBOR. These floating interest payments occur every March 1, June 1, September 1, and December 1 until the notes mature on December 1, 2011.

11. Financial instruments and risk management

There have been no significant changes to the Company s risk management strategies since March 31, 2009.

Derivative financial instruments consist of the following:

September 30, 2009	Derivative Financial Instruments	Senior Notes
Cross-currency and interest rate swaps	$ 78,701	$
Embedded price escalation features in a long-term revenue construction contract	5,949	
Embedded price escalation features in certain long-term supplier contracts	9,074	
Embedded prepayment and early redemption options on senior notes		(2,024)
Total fair value of derivative financial instruments	93,724	(2,024)

Less: current portion	5,017	
	$ 88,707	$ (2,024)

13

Table of Contents

Notes to Interim Consolidated Financial Statements

For the three and six months ended September 30, 2009

(Expressed in thousands of Canadian Dollars, except per share amounts or unless otherwise specified)

(Unaudited)

March 31, 2009	Derivative Financial Instruments	Senior Notes
Cross-currency and interest rate swaps	$ 39,547	$
Embedded price escalation features in a long-term revenue construction contract	(324)	
Embedded price escalation features in certain long-term supplier contracts	22,778	
Embedded prepayment and early redemption options on senior notes		3,716
Total fair value of derivative financial instruments	62,001	3,716
Less: current portion	11,439	
	$ 50,562	$ 3,716

The realized and unrealized loss on derivative financial instruments is comprised as follows:

	Three Months Ended September 30,		Six Months Ended September 30,	
	2009	2008	2009	2008
Realized and unrealized loss (gain) on cross-currency and interest rate swaps	$ 26,292	$ (5,767)	$ 40,488	$ (6,220)
Unrealized loss (gain) on embedded price escalation features in a long-term revenue construction contract	2,986	(3,869)	6,273	(4,504)
Unrealized loss (gain) on embedded price escalation features in certain long-term supplier contracts	460	9,354	(13,704)	9,153
Unrealized (gain) loss on embedded prepayment and early redemption options on senior notes	(3,467)	7,900	(5,740)	6,924
	$ 26,271	$ 7,618	$ 27,317	$ 5,353

12. Other information

a) Supplemental cash flow information

	Three Months Ended September 30,		Six Months Ended September 30,	
	2009	2008	2009	2008
Cash paid during the period for:				
Interest	$ 5,573	$ 353	$ 25,241	$ 13,821
Income taxes	1,545		7,608	
Cash received during the period for:				
Interest	2,780	1	6,140	6

Income taxes		62		62
Non-cash transactions:				
Acquisition of property, plant and equipment by means of capital leases	33	3,952	656	5,116
Lease inducements	195		195	

Table of Contents

Notes to Interim Consolidated Financial Statements

For the three and six months ended September 30, 2009

(Expressed in thousands of Canadian Dollars, except per share amounts or unless otherwise specified)

(Unaudited)

b) Net change in non-cash working capital

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Six Months Ended September 30, 2009	Six Months Ended September 30, 2008
Operating activities:				
Accounts receivable	$ (13,319)	$ (12,735)	$ (5,166)	$ 25,704
Allowance for doubtful accounts	(416)	1,291	(493)	1,300
Unbilled revenue	(8,551)	(20,627)	(11,708)	(39,277)
Inventory	(2,303)	(2,502)	1,794	(4,206)
Prepaid expenses and deposits	1,466	207	(1,293)	913
Accounts payable	14,599	(14,553)	9,975	(22,591)
Accrued liabilities	8,438	8,958	(12,206)	(6,095)
Billings in excess of costs incurred and estimated earnings on uncompleted contracts	2,128	1,265	2,042	8,821
	$ 2,042	$ (38,696)	$ (17,055)	$ (35,431)
Investing activities:				
Accounts payable	$ 3,919	$ (38,214)	$ 2,647	$ 5,259

c) Income taxes

Income tax expense as a percentage of income before income taxes for the three and six months ended September 30, 2009 and the three and six months ended September 30, 2008 differs from the statutory rate of 28.91% and 29.38% respectively, primarily due to the impact of changes in enacted tax rates and the benefit from changes in the timing of the reversal of temporary differences.

13. Segmented information

a) General overview

The Company operates in the following reportable operating segments, which follow the organization, management and reporting structure within the Company:

Heavy Construction and Mining:
The Heavy Construction and Mining segment provides mining and site preparation services, including overburden removal and reclamation services, project management and underground utility construction, to a variety of customers throughout Canada.

Piling:

The Piling segment provides deep foundation construction and design build services to a variety of industrial and commercial customers throughout Western Canada and Ontario.

Pipeline:

The Pipeline segment provides both small and large diameter pipeline construction and installation services to energy and industrial clients throughout Western Canada.

Table of Contents

Notes to Interim Consolidated Financial Statements

For the three and six months ended September 30, 2009

(Expressed in thousands of Canadian Dollars, except per share amounts or unless otherwise specified)

(Unaudited)

The accounting policies of the reportable operating segments are the same as those described in the significant accounting policies in note 3 of the annual consolidated financial statements of the Company for the year ended March 31, 2009. Certain business units of the Company have been aggregated into the Heavy Construction and Mining segment as they have similar economic characteristics. These business units are considered to have similar economic characteristics based on similarities in the nature of the services provided, the customer base and the similarities in the production process and the resources used to provide these services.

b) Results by business segment

Three Months Ended September 30, 2009	Heavy Construction and Mining	Piling	Pipeline	Total
Revenues from external customers	$ 154,463	$ 15,058	$ 1,589	$ 171,110
Depreciation of property, plant and equipment	9,372	845	25	10,242
Segment profits	21,636	1,950	(138)	23,448
Segment assets	416,730	95,451	8,074	520,255
Capital expenditures	19,382			19,382

Three Months Ended September 30, 2008	Heavy Construction and Mining	Piling	Pipeline	Total
Revenues from external customers	$ 176,073	$ 48,642	$ 55,568	$ 280,283
Depreciation of property, plant and equipment	7,512	874	338	8,724
Segment profits	26,525	11,045	7,950	45,520
Segment assets	542,437	142,593	74,968	759,998
Capital expenditures	13,776	1,325	421	15,522

Six Months Ended September 30, 2009	Heavy Construction and Mining	Piling	Pipeline	Total
Revenues from external customers	$ 286,873	$ 29,676	$ 1,664	$ 318,213
Depreciation of property, plant and equipment	16,266	1,407	247	17,920
Segment profits	45,272	4,634	229	50,135
Segment assets	416,730	95,451	8,074	520,255
Capital expenditures	36,054	2		36,056

Six Months Ended September 30, 2008	Heavy Construction and Mining	Piling	Pipeline	Total
Revenues from external customers	$ 365,479	$ 91,145	$ 82,646	$ 539,270
Depreciation of property, plant and equipment	12,735	1,694	564	14,993
Segment profits	47,928	19,706	16,875	84,509
Segment assets	542,437	142,593	74,968	759,998
Capital expenditures	61,454	7,155	5,070	73,679

16

Table of Contents

Notes to Interim Consolidated Financial Statements

For the three and six months ended September 30, 2009

(Expressed in thousands of Canadian Dollars, except per share amounts or unless otherwise specified)

(Unaudited)

c) Reconciliations

i) Income before income taxes

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Six Months Ended September 30, 2009	Six Months Ended September 30, 2008
Total profit for reportable segments	$ 23,448	$ 45,520	$ 50,135	$ 84,509
Less: unallocated corporate expenses:				
General and administrative costs	14,015	19,345	29,081	38,561
Loss on disposal of property, plant and equipment	260	1,612	301	2,756
Loss (gain) on disposal of assets held for sale	41	2	(276)	24
Amortization of intangible assets	236	276	484	554
Interest expense	8,980	6,440	17,617	12,889
Foreign exchange (gain) loss	(17,862)	8,236	(37,077)	6,595
Realized and unrealized loss on derivative financial instruments	26,271	7,618	27,317	5,353
Other (income) expenses	(200)	(3)	333	(21)
Unallocated equipment (costs) and recoveries[(i)]	(9,673)	1,239	(7,796)	(7,362)
Income before income taxes	$ 1,380	$ 755	$ 20,151	$ 25,160

[(i)] Unallocated equipment costs represent actual equipment costs, including non-cash items such as depreciation, which have not been allocated to reportable segments. Unallocated equipment recoveries arise when actual equipment costs charged to the reportable segment exceed actual equipment costs incurred.

ii) Total assets

	September 30, 2009	March 31, 2009
Total assets for reportable segments	$ 520,255	$ 478,597
Corporate assets:		
Cash	97,716	98,880
Property, plant and equipment	31,381	25,549
Future income taxes	18,503	19,465
Other	8,460	7,561
Total corporate assets	156,060	151,455
Total assets	$ 676,315	$ 630,052

The Company s goodwill of $25,361 is assigned to the Piling segment. All of the Company s assets are located in Canada.

17

Table of Contents

Notes to Interim Consolidated Financial Statements

For the three and six months ended September 30, 2009

(Expressed in thousands of Canadian Dollars, except per share amounts or unless otherwise specified)

(Unaudited)

iii) Depreciation of property, plant and equipment

	Three Months Ended September 30,		Six Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
Total depreciation for reportable segments	$ 10,242	$ 8,724	$ 17,920	$ 14,993
Depreciation for corporate assets	1,745	1,944	3,414	3,833
Total depreciation	$ 11,987	$ 10,668	$ 21,334	$ 18,826

iv) Capital expenditures for property, plant and equipment

	Three Months Ended September 30,		Six Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
Total capital expenditures for reportable segments	$ 19,382	$ 15,522	$ 36,056	$ 73,679
Capital expenditures for corporate assets	4,173	655	7,209	1,847
Total capital expenditures	$ 23,555	$ 16,177	$ 43,265	$ 75,526

d) Customers

The following customers accounted for 10% or more of total revenues:

	Three Months Ended September 30,		Six Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
Customer A	55%	27%	55%	26%
Customer B	13%	10%	16%	13%
Customer C	12%	15%	11%	15%
Customer D	5%	13%	5%	17%
Customer E		20%		14%

The revenue by major customer was earned in Heavy Construction and Mining, Piling and Pipeline segments.

14. Stock-based compensation plan

a) Share option plan

Under the 2004 Amended and Restated Share Option Plan, directors, officers, employees and certain service providers to the Company are eligible to receive stock options to acquire voting common shares in the Company. Each stock option provides the right to acquire one common share in the Company and expires ten years from the grant date or on termination of employment. Options may be exercised at a price determined at the time the

18

Table of Contents

Notes to Interim Consolidated Financial Statements

For the three and six months ended September 30, 2009

(Expressed in thousands of Canadian Dollars, except per share amounts or unless otherwise specified)

(Unaudited)

option is awarded, and vest as follows: no options vest on the award date and twenty percent vest on each subsequent anniversary date.

	Three Months Ended September 30,			
	2009		2008	
	Number of options	Weighted average exercise price ($ per share)	Number of options	Weighted average exercise price ($ per share)
Outstanding, beginning of period	2,181,504	7.64	1,828,364	7.44
Granted			125,000	16.19
Exercised			(2,000)	(13.50)
Forfeited	(26,880)	(9.09)	(17,200)	(15.21)
Outstanding, end of period	2,154,624	7.62	1,934,164	7.93

	Six Months Ended September 30,			
	2009		2008	
	Number of options	Weighted average exercise price ($ per share)	Number of options	Weighted average exercise price ($ per share)
Outstanding, beginning of period	2,071,884	7.53	2,036,364	7.54
Granted	160,000	8.28	125,000	16.19
Exercised	(40,000)	5.00	(109,000)	(6.45)
Forfeited	(37,260)	(8.37)	(118,200)	(11.30)
Outstanding, end of period	2,154,624	7.62	1,934,164	7.93

At September 30, 2009, the weighted average remaining contractual life of outstanding options is 6.7 years (March 31, 2009 7.0 years). At September 30, 2009, the Company had 1,198,576 exercisable options (March 31, 2009 1,055,924) with a weighted average exercise price of $6.02 (March 31, 2009 $5.85).

For the six months ended September 30, 2009, the 40,000 options exercised were settled in cash.

The Company recorded $413 and $1,330 of compensation expense related to the stock options for the three and six months ended September 30, 2009, respectively (three and six months ended September 30, 2008 $679 and $933 respectively), with such amount being credited to contributed surplus. As at September 30, 2009, the total compensation costs related to non-vested awards not yet recognized was $3,295 and these costs are expected to be recognized over a weighted average period of 3.2 years.

Notes to Interim Consolidated Financial Statements

For the three and six months ended September 30, 2009

(Expressed in thousands of Canadian Dollars, except per share amounts or unless otherwise specified)

(Unaudited)

The fair value of each option granted by the Company was estimated on the grant date using the Black-Scholes option-pricing model with the following assumptions:

	Three Months Ended September 30,		Six Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
Number of options granted		125,000	160,000	125,000
Weighted average fair value per option granted ($)		6.43	5.89	6.43
Weighted average assumptions:				
Dividend yield		Nil%	Nil%	Nil%
Expected volatility		47.26%	77.47%	47.26%
Risk-free interest rate		3.59%	3.44%	3.59%
Expected life (years)		6.5	6.5	6.5

b) Deferred performance share unit plan

On March 19, 2008, the Company approved a Deferred Performance Share Unit (DPSU) Plan which became effective April 1, 2008.

DPSUs will be granted effective April 1 of each fiscal year in respect of services to be provided in that fiscal year and the following two fiscal years. The DPSUs vest at the end of a three-year term and are subject to the performance criteria approved by the Compensation Committee of the Board of Directors at the date of grant. Such performance criterion includes the passage of time and is based upon return on invested capital calculated as operating income divided by average operating assets. The date of the third fiscal year-end following the date of the grant of DPSUs shall be the maturity date for such DPSUs. At the maturity date, the Compensation Committee shall assess the participant against the performance criteria and determine the number of DPSUs that have been earned (earned DPSUs).

The settlement of the participant s entitlement shall be made in either cash at the value of the earned DPSUs equivalent to the number of earned DPSUs at the value of the Company s common shares at the date of maturity or in a number of common shares equal to the number of earned DPSUs. If settled in common shares, the common shares shall be purchased on the open market or through the issuance of shares from treasury.

Table of Contents

Notes to Interim Consolidated Financial Statements

For the three and six months ended September 30, 2009

(Expressed in thousands of Canadian Dollars, except per share amounts or unless otherwise specified)

(Unaudited)

The fair value of each unit under the DPSU Plan was estimated on the date of the grant using Black-Scholes option pricing model. The weighted average assumptions used in estimating the fair value of the units issued under the DPSU Plan are as follows:

	Three Months Ended September 30,		Six Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
Number of units granted			748,791	111,020
Weighted average fair value per unit granted ($)			3.65	12.34
Weighted average assumptions:				
Dividend yield			Nil%	Nil%
Expected volatility			95.49%	56.25%
Risk-free interest rate			1.35%	2.83%
Expected life (years)			3.0	3.0

	Three Months Ended September 30,		Six Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
	Number of Units		**Number of Units**	
Outstanding, beginning of period	820,795	111,020	91,005	
Granted			748,791	111,020
Exercised				
Forfeited	(12,894)	(9,384)	(31,895)	(9,384)
Outstanding, end of period	807,901	101,636	807,901	101,636

The weighted average exercise price per unit is $nil.

At September 30, 2009, the weighted average remaining contractual life of outstanding DPSU Plan units is 2.39 years (March 31, 2009 2.0 years). For the three and six months ended September 30, 2009, respectively, the Company granted nil and 748,791 units under the Plan and recorded compensation expense of $64 and $278 respectively (three and six months ended September 30, 2008 $29 and $142 respectively) which is included in general and administrative costs. This compensation expense was adjusted based upon management s assessment of performance against return on invested capital targets and the ultimate number of units expected to be issued. As at September 30, 2009, there was approximately $1,861 of total unrecognized compensation cost related to non-vested share-based payment arrangements under the DPSU Plan, which is expected to be recognized over a weighted average period of 2.39 years and is subject to performance adjustments.

c) Director s deferred stock unit plan

On November 27, 2007, the Company approved a Directors Deferred Stock Unit (DDSU) Plan, which became effective January 1, 2008. Under the DDSU Plan, non-officer directors of the Company shall receive 50% of their annual fixed remuneration (which is included in general and administrative expenses in the Consolidated Statement of Operations, Comprehensive Income (Loss) and Deficit) in the form of DDSUs and may elect to receive all or a part of their annual fixed remuneration in excess of 50% in the form of DDSUs. The number of DDSUs to be credited to the participants deferred share unit account shall be determined by dividing

21

Table of Contents

Notes to Interim Consolidated Financial Statements

For the three and six months ended September 30, 2009

(Expressed in thousands of Canadian Dollars, except per share amounts or unless otherwise specified)

(Unaudited)

the amount of the participant s deferred remuneration by the fair market value per common share on the date the DDSUs are credited to the Participant (the date the services are rendered by the participant). The DDSUs vest immediately upon grant and are only redeemable upon death or retirement of the participant for cash determined by the market price of the Company s common shares for the 5 trading day s immediately preceding death or retirement. Directors, who are not US taxpayers, may elect to defer the maturity date until a date no later than December 1st of the calendar year following the year in which the actual maturity date occurred.

	Three Months Ended September 30,		Six Months Ended September 30,	
	2009	2008	2009	2008
	Number of Units		Number of Units	
Outstanding, beginning of period	173,008	20,774	139,691	11,822
Granted	36,706	17,487	70,023	26,439
Exercised				
Forfeited				
Outstanding, end of period	209,714	38,261	209,714	38,261

For the three and six months ended September 30, 2009, the Company recorded an expense of $143 and $817 respectively, which is included in general and administrative costs (three and six months ended September 30, 2008 $(38) recovery and $231 respectively) related to the grants of DDSUs.

At September 30, 2009, the redemption value of these units was $6.50/unit (March 31, 2009 $3.91/unit). There is no unrecognized compensation expense related to deferred share units, since these awards vest immediately when granted.

15. Contingencies

During the normal course of the Company s operations, various legal and tax matters are pending. In the opinion of management, these matters will not have a material effect on the Company s consolidated financial position or results of operations.

16. Seasonality

The Company generally experiences a decline in revenues during the first quarter of each fiscal year due to seasonality, as weather conditions make operations in the Company s operating regions difficult during this period. The level of activity in the Heavy Construction and Mining and Pipeline segments declines when frost leaves the ground and many secondary roads are temporarily rendered incapable of supporting the weight of heavy equipment. The duration of this period is referred to as spring breakup and has a direct impact on the Company s activity levels. Revenues during the fourth quarter of each fiscal year are typically highest as ground conditions are most favorable in the Company s operating regions. As a result, full-year results are not likely to be a direct multiple of any particular quarter or combination of quarters. In addition to revenue variability, gross margins can be negatively impacted in less active periods because the Company is likely to incur higher maintenance and repair costs due to its equipment being available for service.

Table of Contents

Notes to Interim Consolidated Financial Statements

For the three and six months ended September 30, 2009

(Expressed in thousands of Canadian Dollars, except per share amounts or unless otherwise specified)

(Unaudited)

17. Claims revenue

For the three and six months ended September 30, 2009, due to the timing of receipt of signed change orders, the Heavy Construction and Mining segment had approximately $0.2 million and $0.9 million respectively in claims revenue recognized to the extent of costs incurred, the Piling segment had $0.2 million and $0.2 million respectively in claims revenue recognized to the extent of costs incurred, and the Pipeline segment had $1.5 million and $1.5 million respectively in claims revenue recognized to the extent of costs incurred.

18. Comparative figures

Certain of the comparative figures have been reclassified from statements previously presented to conform to the presentation of the current period consolidated financial statements.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

The following discussion and analysis is as of November 3, 2009 and should be read in conjunction with the attached unaudited consolidated financial statements for the three and six months ended September 30, 2009, the audited consolidated financial statements for the fiscal year ended March 31, 2009, together with our most recent annual Management s Discussion and Analysis. These statements have been prepared in accordance with Canadian generally accepted accounting principles (GAAP). Except where otherwise specifically indicated, all dollar amounts are expressed in Canadian dollars. These consolidated financial statements, our most recent annual Management s Discussion and Analysis and additional information relating to our business, including our most recent Annual Information Form (AIF), are available on the Canadian Securities Administrators SEDAR System at www.sedar.com and the Securities and Exchange Commission s website at www.sec.gov.

November 3, 2009

TABLE OF CONTENTS

1

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

A. Financial Results

Consolidated Three and Six Month Results

(dollars in thousands)	Three months ended September 30, 2009	% of Revenue	2008	% of Revenue	Change	Six months ended September 30, 2009	% of Revenue	2008	% of Revenue	Change
Revenue	**$ 171,110**	**100.0%**	**$ 280,283**	**100.0%**	**$ (109,173)**	**$ 318,213**	**100.0%**	**$ 539,270**	**100.0%**	**$ (221,057)**
Project costs	65,959	38.5%	154,961	55.3%	(89,002)	120,512	37.9%	303,592	56.3%	(183,080)
Equipment costs	44,359	25.9%	60,787	21.7%	(16,428)	90,403	28.4%	106,597	19.8%	(16,194)
Equipment operating lease expense	15,684	9.2%	9,586	3.4%	6,098	28,033	8.8%	18,384	3.4%	9,649
Depreciation	11,987	7.0%	10,668	3.8%	1,319	21,334	6.7%	18,826	3.5%	2,508
Gross profit	**33,121**	**19.4%**	**44,281**	**15.8%**	**(11,160)**	**57,931**	**18.2%**	**91,871**	**17.0%**	**(33,940)**
General & administrative costs	14,015	8.2%	19,345	6.9%	(5,330)	29,081	9.1%	38,561	7.2%	(9,480)
Operating income	18,569	10.9%	23,046	8.2%	(4,477)	28,341	8.9%	49,976	9.3%	(21,635)
Net income (loss)	**$ 809**	**0.5%**	**$ (1,222)**	**-0.4%**	**$ 2,031**	**$ 15,583**	**4.9%**	**$ 17,874**	**3.3%**	**$ (2,291)**
Per share information										
Net income (loss) basic	$ 0.02		$ (0.03)		$ 0.05	$ 0.43		$ 0.50		$ (0.07)
Net income (loss) diluted	$ 0.02		$ (0.03)		$ 0.05	$ 0.43		$ 0.48		$ (0.05)
EBITDA[1]	$ 22,583	13.2%	$ 18,139	6.5%	$ 4,444	$ 59,586	18.7%	$ 57,429	10.6%	$ (2,157)
Consolidated EBITDA[1] (as defined within our credit agreement)	**$ 31,755**	**18.6%**	**$ 36,226**	**12.9%**	**$ (4,471)**	**$ 51,340**	**16.1%**	**$ 72,953**	**13.5%**	**$ (21,613)**

(1) Non-GAAP Financial measures The body of generally accepted accounting principles applicable to us is commonly referred to as GAAP . A non-GAAP financial measure is generally defined by the Securities and Exchange Commission (SEC) and by the Canadian securities regulatory authorities as one that purports to measure historical or future financial performance, financial position or cash flows, but excludes or includes amounts that would not be so adjusted in the most comparable GAAP measures. EBITDA is calculated as net income before interest expense, income taxes, depreciation and amortization. Consolidated EBITDA is a measure defined by our credit agreement. This measure is defined as EBITDA, excluding the effects of unrealized foreign exchange gain or loss, realized and unrealized gain or loss on derivative financial instruments, non-cash stock-based compensation expense, gain or loss on disposal of property, plant and equipment and certain other non-cash items included in the calculation of net income. We believe that EBITDA is a meaningful measure of the performance of our business because it excludes items, such as depreciation and amortization, interest and taxes that are not directly related to the operating performance of our business. Management reviews EBITDA to determine whether plant and equipment are being allocated efficiently. In addition, our credit facility requires us to maintain a minimum interest coverage ratio and a maximum senior leverage ratio, which are calculated using Consolidated EBITDA. Non-compliance with these financial covenants could result in our being required to immediately repay all amounts outstanding under our credit facility. EBITDA and Consolidated EBITDA are non-GAAP financial measures and our computations of EBITDA and Consolidated EBITDA may vary from others in our industry. EBITDA and Consolidated EBITDA should not be considered as alternatives to operating income or net income as measures of operating performance or cash flows as measures of liquidity. EBITDA and Consolidated EBITDA have important limitations as analytical tools and should not be considered in isolation or as substitutes for analysis of our results as reported under Canadian GAAP or US GAAP. For example, EBITDA and Consolidated EBITDA do not:

reflect our cash expenditures or requirements for capital expenditures or capital commitments;

reflect changes in our cash requirements for our working capital needs;

reflect the interest expense or the cash requirements necessary to service interest or principal payments on our debt;

include tax payments that represent a reduction in cash available to us; and

reflect any cash requirements for assets being depreciated and amortized that may have to be replaced in the future.

Consolidated EBITDA excludes unrealized foreign exchange gains and losses and realized and unrealized gains and losses on derivative financial instruments, which, in the case of unrealized losses, may ultimately result in a liability that will need to be paid and in the case of realized losses, represents an actual use of cash during the period.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

A reconciliation of net income (loss) to EBITDA and Consolidated EBITDA is as follows:

	Three months ended September 30,			Six months ended September 30,		
(dollars in thousands)	**2009**	**2008**	**Change**	**2009**	**2008**	**Change**
Net income (loss)	**$ 809**	**$ (1,222)**	**$ 2,031**	**$ 15,583**	**$ 17,874**	**$ (2,291)**
Adjustments:						
Interest expense	8,980	6,440	2,540	17,617	12,889	4,728
Income taxes	571	1,977	(1,406)	4,568	7,286	(2,718)
Depreciation	11,987	10,668	1,319	21,334	18,826	2,508
Amortization of intangible assets	236	276	(40)	484	554	(70)
EBITDA	**$ 22,583**	**$ 18,139**	**$ 4,444**	**$ 59,586**	**$ 57,429**	**$ 2,157**
Adjustments:						
Unrealized foreign exchange (gain) loss on senior notes	(17,877)	8,147	(26,024)	(37,196)	6,316	(43,512)
Realized and unrealized loss on derivative financial instruments	26,271	7,618	18,653	27,317	5,353	21,964
Loss on disposal of property, plant and equipment and assets held for sale	301	1,614	(1,313)	25	2,780	(2,755)
Stock-based compensation expense	477	708	(231)	1,608	1,075	533
Consolidated EBITDA	**$ 31,755**	**$ 36,226**	**$ (4,471)**	**$ 51,340**	**$ 72,953**	**$ (21,613)**

Analysis of Results

Revenue

For the three months ended September 30, 2009, revenues of $171.1 million were $109.2 million lower than in the same period last year. As we anticipated, continued weakness in commercial and industrial construction markets, reduced development activity in the oil sands and a sharp decline in Pipeline segment revenues following our completion of the TMX[1] pipeline project resulted in lower project development revenues. Recurring services revenue was stable year-over-year, with overburden removal activity on our long-term contract with Canadian Natural[2] continuing to ramp up following the customer s successful production start-up this spring. We also continued to increase services to Shell Albian [3]s Muskeg River Mine and Jackpine Mine, under our three-year earthmoving and mine services contract.

For the six months ended September 30, 2009, revenues of $318.2 million were $221.1 million lower than the same period last year. Reduced development activity in the oil sands, a sharp decline in Pipeline segment revenues and the continued weakness in commercial and industrial construction markets resulted in significantly lower project development revenues year-over-year. Recurring services revenues were also lower on year-to-date basis. This reflects reduced overburden removal activity during Canadian Natural s production start-up in the

[1] Kinder Morgan s Trans Mountain Expansion (TMX) Anchor Loop pipeline
[2] Canadian Natural Resources Limited (Canadian Natural) Horizon project
[3] Shell Canada Energy, a division of Shell Canada Limited, the operator of the Shell Albian Sands (Shell Albian) oil sands mining and extraction operations on behalf of Athabasca Oil Sands Project (AOSP), a joint venture amongst Shell Canada Limited (60%), Chevron Canada Limited (20%) and Marathon Oil Canada Corporation (20%). Prior to January 1, 2009, these operations were run by Albian Sands Energy Inc.

3

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

three months ended June 30, 2009 and a major maintenance program at Syncrude[4], both of which were unrelated to market conditions.

Gross Profit

Gross profit for the three months ended September 30, 2009 was $33.1 million, a decrease of $11.2 million from the same period in the prior year. The decline in gross profit is primarily related to lower revenue. As a percentage of revenue, gross profit margin improved to 19.4%, from 15.8% in the same period of the prior year, reflecting the benefit of reduced equipment costs from the timing of planned repairs and maintenance as well as company-wide efforts to improve efficiency and reduce expenses.

Project costs, as a percent of revenue, decreased to 38.5% during the three months ended September 30, 2009, compared to 55.3% in the same period last year. Lower project costs were offset by an increase in equipment costs to 25.9% of revenue during the three months ended September 30, 2009, compared to 21.7% of revenue in the same period last year. The decrease in project costs, as a percent of revenue, was partially offset by, as a percent of revenue, increased equipment costs, higher operating lease expense and an increase in depreciation. The change in cost mix reflects reduced activity in the Pipeline segment, which is traditionally our most labour, material and subcontractor-intensive business, as well as increased contribution from the equipment-intensive Heavy Construction and Mining segment. Equipment operating lease expense increased $6.1 million year-over-year to $15.7 million, reflecting our commissioning of a second new electric cable shovel at the Canadian Natural site in December 2008, as well as growth in the size of our leased equipment fleet. Depreciation also increased to 7.0% of revenue in the current three month period ended September 30, 2009, compared to 3.8% in the same period last year, reflecting the increased contribution from the Heavy Construction and Mining segment, a reduction in the use of rental equipment and an accelerated depreciation charge of $1.5 million, compared to $0.3 million in the same period last year, as certain aging equipment was prepared for resale.

Gross profit for the six months ended September 30, 2009 was $57.9 million, a decrease of $33.9 million compared to the same period last year. The change in gross profit was primarily related to lower revenues. As a percentage of revenue, we increased our gross profit margin to 18.2%, reflecting the benefit of reduced equipment costs from the timing of planned repairs and maintenance and company-wide efforts to improve efficiency and reduce expenses. Prior-year gross profit margins of 17.0% were bolstered by the $5.3 million settlement of claims revenue on a pipeline project. Excluding this benefit, gross profit margins would have been 16.2% for the six-month period last year.

Project costs, as a percent of revenue, decreased to 37.9% during the six months ended September 30, 2009, from 56.3% in the same period last year. The decrease in project costs, as a percent of revenue, was partially offset by, as a percent of revenue, increased equipment costs, higher operating lease expense and an increase in depreciation. The change in cost mix reflects reduced activity in the Pipeline segment and increased contribution from the equipment-intensive Heavy Construction and Mining segment. Equipment costs increased to 28.4% of revenue during the six months ended September 30, 2009, from 19.8% of revenue in the same period last year. Equipment operating lease expense increased $9.6 million year-over-year to $28.0 million, reflecting the commissioning of the second new electric cable shovel at the Canadian Natural site in December 2008, as well as growth in the size of our leased equipment fleet. Depreciation also increased to 6.7% of revenue in the current

[4] Syncrude Canada Limited (Syncrude), a joint venture between Canadian Oil Sands Limited (36.74%), Imperial Oil Resources (25.0%), Suncor Energy Inc. (12.0%) (Previously Petro-Canada Ltd.), ConocoPhillips Oil Sands Partnership II (9.03%), Nexen Oil Sands Partnership (7.23%), Mocal Energy Limited (5.0%) and Murphy Oil Company Ltd. (5.0%). Syncrude is the project operator.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

six-month period ended September 30, 2009, compared to 3.5% in the same period last year, reflecting the increased contribution from the Heavy Construction and Mining segment, a reduction in the use of rental equipment and an accelerated depreciation charge of $3.2 million, compared to $0.8 million in the same period last year, as certain aging equipment was prepared for resale. Tire expenses for the six months ended September 30, 2009 were lower by $4.1 million compared to the same period last year as a result of lower operating hours and a reduction in tire prices reflecting improved worldwide availability.

Operating income

For the three months ended September 30, 2009, we recorded operating income of $18.6 million or 10.9% of revenue, compared to operating income of $23.0 million or 8.2% of revenue during the same period last year. General and administrative (G&A) costs decreased by $5.3 million compared to the same three-month period last year. The benefits of reorganization and cost-reduction initiatives implemented in the three months ended March 31, 2009, as well as process improvements implemented in the second half of the prior fiscal year contributed to the lower G&A costs in the current period.

For the six months ended September 30, 2009, we recorded operating income of $28.3 million or 8.9% of revenue, compared to operating income of $50.0 million or 9.3% of revenue, during the same period last year. G&A costs decreased by $9.5 million compared to the same six-month period last year. Lessening the benefits to current period G&A costs from the reorganization, cost-reduction and process improvement initiatives was a $1.1 million year-over-year increase to stock-based compensation, partially impacted by the volatility of our share price on our deferred director share units.

Net income (loss)

We recorded net income of $0.8 million (basic income per share of $0.02 and diluted income per share of $0.02) for the three months ended September 30, 2009, compared to a net loss of $1.2 million (basic loss per share of $0.03) during the same period last year. The non-cash items affecting these results included a loss on our cross-currency and interest rate swaps and a loss relating to embedded derivatives in a long-term customer contract and long-term supplier contracts. These items were partially offset by the positive foreign exchange impact of the strengthening Canadian dollar on our 8 3/4% senior notes and by the gain on the embedded derivative related to redemption options in our 8 3/4% senior notes. Excluding the non-cash items, net income would have been $6.6 million (basic income per share of $0.18 and diluted income per share of $0.17), compared to net income of $10.7 million (basic income per share of $0.30 and diluted income per share of $0.30) during the same period last year.

For the six months ended September 30, 2009, we recorded net income of $15.6 million (basic income per share of $0.43 and diluted income per share of $0.43), compared to net income of $17.9 million (basic income per share of $0.50 and diluted income per share of $0.48) during the same period last year. Non-cash items positively affecting net income included the positive foreign exchange impact of the strengthening Canadian dollar on our 8 3/4% senior notes, gains on embedded derivatives in long-term supplier contracts and the redemption options in our 8 3/4% senior notes. This was partially negated by a loss in our cross-currency and interest rate swaps and a loss relating to an embedded derivative in a long-term customer contract. Excluding these non-cash items in the current and prior period, net income would have been $7.0 million in the current period (basic income per share of $0.19 and diluted income per share of $0.19), compared to net income of $25.9 million in the prior period (basic income per share of $0.72 and diluted income per share of $0.70).

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

Segment Results

Heavy Construction and Mining

	Three months ended September 30,					Six months ended September 30,				
(dollars in thousands)	2009	% of Segment Revenue	2008	% of Segment Revenue	Change	2009	% of Segment Revenue	2008	% of Segment Revenue	Change
Segment revenue	$ 154,463		$ 176,073		$ (21,610)	$ 286,873		$ 365,479		$ (78,606)
Segment profit	21,636	14.0%	26,525	15.1%	(4,889)	45,272	15.8%	47,928	13.1%	(2,656)

For the three months ended September 30, 2009, the Heavy Construction and Mining segment reported revenues of $154.5 million, a $21.6 million decrease compared to the same period last year. The decrease primarily reflects a slowdown in oil sands project development activity as revenues from the supply of third party materials and services were significantly lower in our current three-month period. Recurring services revenue remained stable between the two periods, with increased activity at Shell Albian s Jackpine Mine site under our new three-year contract and haul truck rentals to Suncor offsetting a decline in contractor activity at the Syncrude sites while that customer undertook a major upgrader maintenance program. Overburden removal activity at the Canadian Natural site has been gradually ramping back up and is expected to return to planned operational levels over the next three months as both electric shovels become fully operational. Project development revenues in the prior year included project development activity at the Fort Hills[5] site, which has since been deferred, as well as site development activity at the Suncor[6] sites, which was completed in the first nine months of fiscal 2009. Also included in prior-year revenue was a tire premium surcharge in effect due to the increased cost of tires resulting from the worldwide tire shortage.*

For the six months ended September 30, 2009, the Heavy Construction and Mining segment reported revenues of $286.9 million, a $78.6 million decrease compared to the same period last year. Most of this decrease relates to the year-over-year decline in project development activity. Recurring services revenues were also down year-over-year, due to a temporary reduction in activity on our long-term overburden removal contract with Canadian Natural. We expect to return to planned operational levels over the next three months at Canadian Natural. Recurring services revenues were also negatively affected by reduced activity at the Syncrude site during that customer s upgrader maintenance program. These impacts were partially offset with the benefits of increased activity at the Jackpine Mine site and haul truck rentals to Suncor. Revenue results from last year also included a pass-through fuel supply contract and a tire premium surcharge that are no longer in effect.*

For the three months ended September 30, 2009, segment margin was 14.0%, compared to 15.1% during the same period last year. The change in segment margin primarily reflects a forecasted cost increase on a large project, which resulted in a reduction in overall margins for the project. This was partially offset by an increase in higher-margin site services work and lower equipment rental costs during the period. Segment margin in the prior-year period also benefited from the timing of change order approvals. Excluding the positive impact of the change orders, the corresponding prior-year period margins would have been 14.6% of revenue.

[5] Fort Hills LP (Fort Hills) a limited partnership between Suncor Energy Inc. (60%), UTS Energy Corporation (20%) and Teck Resources Limited (20%). Suncor Energy Inc., the new project operator, acquired Petro-Canada Limited, the previous majority partner and project operator in 2009.
[6] Suncor Energy Inc. (Suncor).

* This paragraph contains forward-looking information. Please refer to Forward-Looking Information and Risk Factors for a discussion on the risks and uncertainties related to such information.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

Heavy Construction and Mining segment margin for the six months ended September 30, 2009 increased to 15.8% of revenue from 13.1% during the same period last year. Segment margins in the current period benefited from high margin site services work and lower rental equipment costs which partially offset the margin reduction on a large project. Segment margins in the previous period were negatively impacted by challenges on a single project and a fuel supply contract at zero margin. Excluding these unusual items, segment margin would have been 15.6% for the six months ended September 30, 2008.

Piling

	Three months ended September 30,					Six months ended September 30,				
(dollars in thousands)	2009	% of Segment Revenue	2008	% of Segment Revenue	Change	2009	% of Segment Revenue	2008	% of Segment Revenue	Change
Segment revenue	$ 15,058		$ 48,642		$ (33,584)	$ 29,676		$ 91,145		$ (61,469)
Segment profit	1,950	12.9%	11,045	22.7%	(9,095)	4,634	15.6%	19,706	21.6%	(15,072)

The Piling segment recorded revenues of $15.1 million for the three months ended September 30, 2009, a decrease of $33.6 million compared to the same period last year. Revenues from our August 1, 2009 acquisition of Ontario based Drillco Foundation Co. Ltd. of $1.0 million are included in the current three-month period. For the six months ended September 30, 2009, revenues of $29.7 million were down $61.5 million compared to the same period last year. The change in Piling segment revenues for both the three-month and six-month periods reflects declining activity levels in the commercial and industrial construction markets due to the current economic slowdown, as well as a reduction in high-volume oil sands projects.

For the three months ended September 30, 2009, segment margins decreased to 12.9%, from 22.7% a year ago. For the six months ended September 30, 2009, segment margins decreased to 15.6% from 21.6% a year ago. The year-over-year declines in segment margin reflect the negative impact of reduced commercial and industrial construction market activity, increased competition for available work and the timing of customer approvals of submitted change orders.

Pipeline

	Three months ended September 30,					Six months ended September 30,				
(dollars in thousands)	2009	% of Segment Revenue	2008	% of Segment Revenue	Change	2009	% of Segment Revenue	62008	% of Segment Revenue	Change
Segment revenue	$ 1,589		$ 55,568		$ (53,979)	$ 1,664		$ 82,646		$ (80,982)
Segment profit	(138)	-8.7%	7,950	14.3%	(8,088)	229	13.8%	16,875	20.4%	(16,646)

Pipeline segment revenues for the three months ended September 30, 2009 of $1.6 million declined $54.0 million compared to the same period a year ago, reflecting the completion of the TMX project in October 2008. Current period revenues benefited from initial work on a contract with Terasen Gas Inc. to complete a small river pipeline crossing in British Columbia. Pipeline revenues for the six months ended September 30, 2009 of $1.7 million declined $81.0 million compared to the same period a year ago, again reflecting the completion of the TMX project.

Negative segment profit in the three months ended September 30, 2009 reflects the timing of costs for demobilization. For the six months ended September 30, 2009, segment profit was 13.8%, compared to 20.4%

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

during the same period last year. Pipeline margins in the prior-year period included the benefit of a $5.3 million settlement of claims revenue. Excluding this settlement, margins for the prior-year period would have been 15.0% of revenue.

Non-Operating Income and Expense

	Three months ended September 30,			Six months ended September 30,		
(dollars in thousands)	**2009**	**2008**	**Change**	**2009**	**2008**	**Change**
Interest expense						
Interest expense on 8 3/4% senior notes	$ 10,572	$ 5,834	$ 4,738	$ 21,551	$ 11,669	$ 9,882
Interest income on 8 3/4% senior note swaps	(2,638)		(2,638)	(5,804)		(5,804)
Interest on 8 3/4% senior notes	7,934	5,834	2,100	15,747	11,669	4,078
Interest on capital lease obligations	270	264	6	561	545	16
Amortization of deferred bond issue costs	212	184	28	433	358	75
Interest on credit facilities	197	90	107	492	90	402
Interest on long-term debt	8,613	6,372	2,241	17,233	12,662	4,571
Other interest	367	68	299	384	227	157
Total interest expense	$ 8,980	$ 6,440	$ 2,540	$ 17,617	$ 12,889	$ 4,728
Foreign exchange (gain) loss on senior notes	(17,862)	8,236	(26,098)	(37,077)	6,595	(43,672)
Realized and unrealized loss on derivative financial instruments	26,271	7,618	18,653	27,317	5,353	21,964
Other (income) expense	(200)	(3)	(197)	333	(21)	354
Income tax expense (recovery)	571	1,977	(1,406)	4,568	7,286	(2,718)

Interest expense

Total interest expense increased $2.5 million in the three months ended September 30, 2009 and $4.7 million in the six months ended September 30, 2009, compared to the same respective periods in the prior year. The increase in both periods is primarily due to the cancellation of a swap agreement on February 2, 2009, which was one of three swap agreements hedging the interest and currency risk associated with our US dollar denominated 8 3/4% senior notes. As a result of the counterparty s cancellation of this US dollar interest rate swap, we are incurring higher interest expense and we are now exposed to interest rate risk. As a partial offset, we recorded interest income from floating quarterly interest payments we receive from our swap counterparties at a rate of 4.2% over the three-month US LIBOR until the 8 3/4% senior notes mature on December 1, 2011. This partially offsets the higher interest expense resulting from the swap cancellation. Additionally, our credit facility was amended and restated on June 24, 2009 extending the maturity to June 8, 2011. At September 30, 2009 we had $33.0 million outstanding on the Term Facility ($11.8 million at June 30, 2009). Interest expense for the credit facility, for the three and six months ended September 30, 2009, was $0.2 million and $0.5 million respectively. A more detailed discussion about our interest rate risk can be found under Qualitative and Quantitative Disclosures about Market Risk Interest rate risk .

Foreign exchange (gain) loss on senior notes

The foreign exchange gains recognized in the current and prior year three-month periods relate primarily to changes in the strength of the Canadian dollar against the US dollar on conversion of the US$200 million 8 3/4% senior notes. A significant increase in the value of the Canadian dollar, from 0.7935 CAN/US at March 31, 2009 to 0.9327 CAN/US at September 30, 2009, resulted in a significant unrealized foreign exchange gain. A more detailed discussion about our foreign currency risk can be found under Qualitative and Quantitative Disclosures about Market Risk Foreign currency risk .

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

Realized and unrealized loss on derivative financial instruments

The realized and unrealized losses on derivative financial instruments reflect changes in the fair value of derivatives embedded in our US dollar denominated 8 3/4% senior notes, as well as changes in the fair value of the cross-currency and interest rate swaps that we employ to provide an economic hedge for our US dollar denominated 8 3/ 4% senior notes. Realized and unrealized losses and gains also include changes to embedded derivatives in a long-term construction contract and in supplier maintenance agreements. The realized and unrealized losses and (gains) on these derivative financial instruments, for the three and six months ended September 30, 2009, are detailed in the table below:

	Three months ended September 30,			Six months ended September 30,		
(dollars in thousands)	**2009**	**2008**	**Change**	**2009**	**2008**	**Change**
Swap liability loss (gain)	$ 25,625	$ (6,433)	$ 32,058	$ 39,154	$ (7,554)	$ 46,708
Redemption options embedded derivatives (gain) loss	(3,467)	7,900	(11,367)	(5,740)	6,924	(12,664)
Supplier contracts embedded derivatives loss (gain)	460	9,354	(8,894)	(13,704)	9,153	(22,857)
Customer contract embedded derivative loss (gain)	2,986	(3,870)	6,856	6,273	(4,504)	10,777
Swap interest payment loss	667	667		1,334	1,334	
Total	$ 26,271	$ 7,618	$ 18,653	$ 27,317	$ 5,353	$ 21,964

The swap liability loss (gain) reflects changes in the fair value of the swap that we employ to provide an economic hedge for our US dollar denominated 8 3/4% senior notes. Changes in the fair value of these swaps generally have an offsetting effect to changes in the value of our 8 3/4% senior notes (and resulting foreign exchange gains and losses), with both being triggered by variations in the Canadian/US exchange rate. However, the valuations of the derivative financial instruments are also impacted by changes in interest rates and the remaining present value of scheduled interest payments on the 8 3/4% senior notes, which occur in June and December of each year until maturity.

The redemption options embedded derivatives (gain) loss reflects changes in the fair value of derivatives embedded in our US dollar denominated 8 3/4% senior notes. The valuation process to determine the fair value of the implied derivative was to compare the rate on the 8 3/4% senior notes to the best financial alternative. Changes in fair value result from changes in long-term bond interest rates during a reporting period. The valuation process presumes a 100% probability of our implementing the inferred transaction (early redemption of the 8 3/4% senior notes) and does not permit a reduction in the probability if there are other factors that would impact the decision.

With respect to the supplier contracts, the embedded derivative related to a long-term maintenance contract was increased as a result of the addition of certain pieces of heavy equipment to the repair and maintenance program with the supplier contract in the three months ended September 30, 2009. For the six months ended September 30, 2009, the embedded derivative related to our equipment purchase agreement was reduced with the commissioning of certain pieces of heavy equipment. Included in the embedded derivative valuation was the impact of fluctuations in provisions that require a price adjustment to reflect changes in the Canadian/US dollar exchange rate and the United States government published Producers Price Index (US-PPI) for Mining Machinery and Equipment from the original contract amount.

With respect to the long-term construction contract, there is a provision that requires an adjustment to customer billings to reflect actual exchange rates and price indices. The embedded derivative instrument takes into account the impact on revenues, but does not consider the impact on costs as a result of fluctuations in these measures.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

The measurement of embedded derivatives, as required by GAAP, causes our reported net income to fluctuate as Canadian/US dollar exchange rates, interest rates and the US-PPI for Mining Machinery and Equipment change. The accounting for these derivatives has no impact on operations, Consolidated EBITDA (as defined within our credit agreement) or how we evaluate performance.

Income tax expense (recovery)

For the three months ended September 30, 2009, we recorded current income taxes of $1.3 million and future income tax recovery of $0.7 million for a net income tax expense of $0.6 million. This compares to combined income tax expense of $2.0 million for the same period last year. For the three months ended September 30, 2009, income tax expense as a percentage of income before income taxes differs from the statutory rate of 28.91% primarily due to the impact of changes in enacted tax rates and the benefit from changes in the timing of the reversal of temporary differences. For the three month period ended September 30, 2008, income tax expense as a percentage of income before income taxes differed from the statutory rate of 29.38% primarily due to the same reasons.

For the six months ended September 30, 2009, we recorded current income taxes of $1.3 million and future income tax expense of $3.3 million for a total income tax expense of $4.6 million. This compares to combined income tax expense of $7.3 million for the same period last year. For the six months ended September 30, 2009, income tax expense as a percentage of income before income taxes differs from the statutory rate of 28.91% primarily due to the impact of changes in enacted tax rates and the benefit from changes in the timing of the reversal of temporary differences. For the six month period ended September 30, 2008, income tax expense as a percentage of income before income taxes differed from the statutory rate of 29.38% primarily due to the same reasons.

Summary of Quarterly Results

	Three months ended,							
	Sept 30, 2009	**Jun 30, 2009**	**Mar 31, 2009**	**Dec 31, 2008**	**Sept 30, 2008**	**Jun 30, 2008**	**Mar 31, 2008**	**Dec 31, 2007**
(dollars in millions)	**Fiscal 2010**		**Fiscal 2009**				**Fiscal 2008**	
Revenue	$ 171.1	$ 147.1	$ 174.7	$ 258.6	$ 280.3	$ 259.0	$ 323.6	$ 274.9
Gross profit	33.1	24.8	32.5	51.0	44.3	47.6	62.6	50.6
Operating income (loss)	18.6	9.8	(129.5)	(2.2)	23.0	26.9	42.6	33.2
Net income (loss)	0.8	14.8	(142.7)	(14.7)	(1.2)	19.1	20.5	24.7
Income (loss) per share Basic[(1)]	$ 0.02	$ 0.41	$ (3.96)	$ (0.41)	$ (0.03)	$ 0.53	$ 0.57	$ 0.69
Income (loss) per share Diluted[(1)]	$ 0.02	$ 0.40	$ (3.96)	$ (0.41)	$ (0.03)	$ 0.52	$ 0.56	$ 0.67

(1) Net income (loss) per share for each quarter has been computed based on the weighted average number of shares issued and outstanding during the respective quarter; therefore, quarterly amounts may not add to the annual total. Per-share calculations are based on full dollar and share amounts.

A number of factors have the potential to contribute to variations in our quarterly financial results between periods, including the capital project-based nature of our project development revenue, seasonal weather and ground conditions, capital spending decisions by our customers on large oil sands projects, the timing of equipment maintenance and repairs, claims and change orders and the accounting for unrealized non-cash gains and losses on foreign exchange and derivative financial instruments.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

We generally experience a decline in revenues during the first three months of each fiscal year due to seasonality, as weather conditions make performance in our operating regions difficult during this period. The level of activity in the Heavy Construction and Mining and Pipeline segments declines when frost leaves the ground and many secondary roads are temporarily rendered incapable of supporting the weight of heavy equipment. The duration of this period is referred to as spring breakup and has a direct impact on our activity levels. Revenues during the three months ended March 31 of each fiscal year are typically highest as ground conditions are most favourable in our operating regions. As a result, full-year results are not likely to be a direct multiple of any particular three-month period or combination of three-month periods. In addition to revenue variability, gross margins can be negatively impacted in less active periods because we are likely to incur higher maintenance and repair costs due to our equipment being available for servicing.

The timing of large projects can influence quarterly revenues. For example, Pipeline segment revenues were as high as $87.5 million in the three-month period ended March 31, 2008, as low as $0.1 million in the three months ended June 30, 2009 and are currently at $1.6 million for the three-month period ended September 30, 2009. The Heavy Construction and Mining segment experienced reduced volumes in the three-month periods ending December 31, 2008 and March 31, 2009 as a result of the temporary shut-down of overburden removal at the Horizon project while Canadian Natural prepared for operations start-up. Changes in demand under our master service agreements with Albian and Syncrude had a positive effect on our revenues for the three-month periods ended June 30, 2008, September 30, 2008 and December 31, 2008 respectively while changes in demand with Syncrude had a negative effect on our revenues for the three-month periods ended March 31, 2009, June 30, 2009 and September 30, 2009 respectively.

Variations in quarterly results can also be caused by changes in our operating leverage. During periods of higher activity we have experienced improvements in operating margin. This reflects the impact of relatively fixed costs, such as general and administrative expenses, being spread over higher revenue levels. If activity decreases, these same fixed costs are spread over lower revenue levels. Net income and income per share are also subject to operating leverage as provided by fixed interest expense.

Profitability also varies from period-to-period as a result of claims and change orders. Claims and change orders are a normal aspect of the contracting business but can cause variability in profit margin due to the unmatched recognition of costs and revenues. For further explanation, see Claims and Change Orders . As an example, during the three-month period ending June 30, 2008, a $5.3 million claim was recognized causing gross margins for the Pipeline segment to be higher than normal. The additional costs relating to this claim were incurred and recognized in the year ended March 31, 2007 and in the three month period ended June 30, 2007.

We have also experienced net income variability in all periods due to the recognition of unrealized non-cash gains and losses on both derivative financial instruments and our 8 $^{3}/4$% senior notes, primarily driven by changes in the Canadian/ US dollar exchange rates.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

Consolidated Financial Position

(dollars in thousands)	As at September 30, 2009	As at March 31, 2009	Change
Current assets	$ 278,063	$ 256,738	$ 21,325
Current liabilities	(141,711)	(135,091)	(6,620)
Net working capital	136,352	121,647	14,705
Property, plant and equipment	354,419	329,705	24,714
Total assets	676,315	630,052	46,263
Capital lease obligations (including current portion)	(15,193)	(17,484)	2,291
Total long-term financial liabilities(1)	(335,773)	(316,082)	(19,691)

(1) Total long-term financial liabilities exclude the current portions of capital lease obligations, current portions of derivative financial instruments, long-term lease inducements, asset retirement obligation and both current and non-current future income tax balances.

At September 30, 2009, net working capital (current assets less current liabilities) was $136.4 million compared to $121.6 million at March 31, 2009, an increase of $14.7 million.

Current assets increased $21.3 million between March 31, 2009 and September 30, 2009. A $9.6 million increase to trade receivables and holdbacks along with an $11.7 million increase in unbilled revenue during the six-month period was partially offset by a $1.7 million reduction of inventory from consumption of tires, previously stockpiled for new leased haul trucks (haul trucks do not arrive with tires included) and a $1.2 million decrease in cash.

Current liabilities during the six month period increased by $6.6 million, primarily reflecting a $14.0 million increase in accounts payable and a $2.0 million increase in billings in excess partially offset by an $11.0 million reduction in accrued liabilities. Equipment purchases of $7.1 million, which are scheduled to be paid after the quarter-end, are included in accounts payable as of September 30, 2009.

Property, plant and equipment increased by $24.7 million between March 31, 2009 and September 30, 2009. This reflects the capital investment of $47.1 million of equipment purchases and new capital leases during the current six month period, offset by equipment disposals of $1.0 million (net book value) and depreciation of $21.3 million.

Total long-term financial liabilities increased by $19.7 million between March 31, 2009 and September 30, 2009, due to a $39.2 million increase related to the cross-currency and interest rate swap agreements, an increase of $25.4 million in the long-term portion of our term loan resulting from new term loans under our amended and restated credit agreement and an increase of $5.0 million in the value of the long-term portion of the embedded derivatives in a long-term revenue construction contract. This was partially offset by a $42.5 million decrease in the carrying amount of our 8 3/4% senior notes, a $6.0 million decrease related to the long-term portion of the embedded derivatives in long-term supplier contracts and a $2.2 million decrease in the non-current portion of our capital lease obligations.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

Claims and Change Orders

Due to the complexity of the projects we undertake, changes often occur after work has commenced. These changes include but are not limited to:

- changes in client requirements, specifications and design;
- changes in materials and work schedules; and
- changes in ground and weather conditions.

Contract change management processes require that we prepare and submit change orders to the client requesting approval of scope and/or price adjustments to the contract. Accounting guidelines require that we consider changes in cost estimates that have occurred up to the release of the financial statements and reflect the impact of these changes in the financial statements. Conversely, potential revenue associated with increases in cost estimates is not included in financial statements until an agreement is reached with a client or specific criteria for the recognition of revenue from unapproved change orders and claims are met. This can, and often does, lead to costs being recognized in one period and revenue being recognized in subsequent periods.

Occasionally, disagreements arise regarding changes, their nature, measurement, timing and other characteristics that impact costs and revenue under the contract. If a change becomes a point of dispute between our customer and us, we then consider it to be a claim. Historical claim recoveries should not be considered indicative of future claim recoveries.

At September 30, 2009, due to the timing of receipt of signed change orders, our Heavy Construction and Mining segment had approximately $0.2 million in claims revenue recognized to the extent of costs incurred ($0.7 million at June 30, 2009). Our Piling segment had $0.2 million in claims revenue recognized to the extent of costs incurred ($nil at June 30, 2009). Our Pipeline segment had $1.5 million in claims revenue recognized to the extent of costs incurred ($nil at June 30, 2009). We are working with our customers to come to resolution on additional amounts, if any, to be paid to us in respect to these additional costs.

B. Key Trends

A number of factors contribute to variations in our quarterly results, including weather, capital spending by our customers on large oil sands projects, our ability to manage our project-related business so as to avoid or minimize periods of relative inactivity, the Canadian and US dollar exchange rate and the strength of the Western Canadian economy.

Canadian and US Dollar Exchange Rate

We have experienced earnings variability in all periods due to the recognition of realized and unrealized non-cash gains and losses on derivative financial instruments and foreign exchange primarily driven by changes in the Canadian and US dollar exchange rates.

Backlog

Backlog is a measure of the amount of secured work we have outstanding and, as such, is an indicator of a base level of future revenue potential. Backlog is not a GAAP measure. As a result, the definition and determination of a backlog will vary among different organizations ascribing a value to backlog. Although backlog reflects business that we consider to be firm, cancellations or reductions may occur and may reduce backlog and future income.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

We define backlog as work that has a high certainty of being performed as evidenced by the existence of a signed contract or work order specifying job scope, value and timing. We have also set a policy that our definition of backlog will be limited to contracts or work orders with values exceeding $500,000 and work that will be performed in the next five years, even if the related contracts extend beyond five years.

Our measure of backlog does not define what we expect our future workload to be. We work with our customers using cost-plus, time-and-materials, unit-price and lump-sum contracts. This mix of contract types varies year-by-year. Our definition of backlog results in the exclusion of cost-plus and time-and-material contracts performed under master service agreements where scope is not clearly defined. While contracts exist for a range of services to be provided under these service agreements, for the most part, scope and value are not clearly defined resulting in the exclusion from backlog. For the three and six months ended September 30, 2009, the total amount of revenue earned from time-and-material contracts performed under our master services agreements was approximately $105.5 million and $189.0 million respectively.

Our estimated backlog by segment and contract type as at September 30, 2009 and 2008 as well as June 30, 2009 and March 31, 2009 was:

(dollars in thousands)	As at September 30, 2009	As at September 30, 2008	As at June 30, 2009	As at March 31, 2009
By Segment				
Heavy Construction and Mining	$ 740,665	$ 676,134	$ 696,412	$ 667,674
Piling	3,630	11,080	5,731	8,538
Pipeline	8,207	12,881		
Total	$ 752,502	$ 700,095	$ 702,143	$ 676,212
By Contract Type				
Unit-Price	$ 742,555	$ 678,811	$ 698,550	$ 672,725
Lump-Sum	9,947	8,403	2,165	3,487
Time-and-Materials and Cost-Plus		12,881	1,428	
Total	$ 752,502	$ 700,095	$ 702,143	$ 676,212

A contract with a single customer represented approximately $687.8 million of our September 30, 2009 backlog compared to $674.6 million reported as backlog in our interim Management s Discussion and Analysis for the three months ended June 30, 2009 and $664.1 million in our annual Management s Discussion and Analysis for the year ended March 31, 2009. The increase in the five-year backlog for this customer relates to the timing of scheduled volumes through the life of the contract.

We expect that approximately $225.4 million of total backlog will be performed and realized in the twelve months ending September 30, 2010.*

Other Key Trends

For a more detailed discussion of all of our key trends, see our most recent annual Management s Discussion and Analysis.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

C. Outlook

Our expectation for the second half of fiscal 2010 is for continued strong operating performance in a more competitive market environment. While weaker industrial and commercial construction market conditions, a more moderate pace of development in the oil sands and increasing competition for contracts are expected to continue to exert pressure on revenue growth and profit margins, we intend to leverage our recurring revenue business and favorable oil sands position to compete profitably in this new market environment.*

In the oil sands, recurring services volumes are expected to stabilize in the second half as we return to planned production levels at Canadian Natural s Horizon project, following mine start-up earlier in the year. Volumes at the Albian Sands Muskeg River Mine and Jackpine Mine are also expected to be strong under our new three-year contract with Shell Canada.*

On the project development front, we believe that reduced project costs and a gradual strengthening of oil prices are creating a more attractive environment for investment. Imperial Oil s decision to proceed with the Kearl project is an example of this. In addition, the merger between Suncor and Petro-Canada is expected to have a positive impact on oil sands investment by creating a single entity with the resources to support large capital projects. *

Although the pipeline construction market remains highly competitive, new projects continue to be tendered and we have bid successfully on a number of these. In August of 2009, we were awarded the construction of Terasen Gas Inc. s Fraser River South Arm Crossing project. This project involves installing two mid-sized pipelines below the Fraser River in British Columbia. Work is underway and is expected to be completed by February 2010. In October of 2009, we were awarded the construction of the North Maxhamish Loop project for Spectra Energy Corp. in Northern British Columbia. Construction of this 37-kilometer, 24 inch pipeline is scheduled to begin in November and be completed by February 2010. These new contract awards follow last quarter s win of a three-year contract to complete pipeline integrity excavations and hydrostatic retests on TransCanada Pipeline s mainline system in British Columbia, Saskatchewan, Manitoba and Ontario.*

Commercial and industrial construction activity remains well below fiscal 2008 and 2009 market levels and is not expected to improve this fiscal year; negatively affecting our Piling segment. As part of its geographic expansion strategy, the Piling division acquired Drillco Foundation Co. Ltd., a small Ontario-based piling company. The Ontario market is expected to benefit from $32.5 billion in announced federal and provincial government spending over the next two years and our Piling division is actively bidding on some of the available projects.*

Overall, while market conditions remain weak, opportunities continue to exist in all areas of our business. We are focused on pursuing those contracts that leverage our strengths and enable us to maintain reasonable margins as we work to sustain long-term business success.

* This paragraph contains forward-looking information. Please refer to Forward-Looking Information and Risk Factors for a discussion on the risks and uncertainties related to such information.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

D. Legal and Labour Matters

Laws and Regulations and Environmental Matters

Many aspects of our operations are subject to various federal, provincial and local laws and regulations, including, among others:

- permitting and licensing requirements applicable to contractors in their respective trades;
- building and similar codes and zoning ordinances;
- laws and regulations relating to consumer protection; and
- laws and regulations relating to worker safety and protection of human health.

For a more detailed discussion of laws and regulations and environmental matters applicable to us, see our most recent annual Management s Discussion and Analysis.

Employees and Labour Relations

As of September 30, 2009, we had 320 salaried employees and approximately 1,580 hourly employees. Our hourly workforce fluctuates according to the seasonality of our business and the staging and timing of projects by our customers. The hourly workforce typically ranges in size from 1,000 employees to approximately 2,100 employees depending on the time of year and duration of awarded projects. We also utilize the services of subcontractors in our construction business. An estimated 8% to 10% of the construction work we do is performed by subcontractors. Approximately 1,500 employees are members of various unions and work under collective bargaining agreements. The majority of our work is done through employees governed by our mining overburden collective bargaining agreement with the International Union of Operating Engineers Local 955, the primary term of which expired on October 31, 2009. Negotiations are underway for the renewal of this union agreement and we are confident that a renewal agreement will be reached without dispute. Other collective agreements in operation include the provincial Industrial, Commercial and Institutional (ICI) agreements in Alberta and Ontario with both the Operating Engineers and Labourers Unions, Piling sector collective agreements in Saskatchewan with the Operating Engineers and Labourers, Pipeline sector agreements in both British Columbia and Alberta with the Christian Labour Association of Canada (CLAC) as well as an all-sector agreement with CLAC in Ontario. We are subject to other industry and specialty collective agreements under which we complete work and the primary terms of all of these agreements are currently in effect. We believe that our relationships with all our employees, both union and non-union, are strong. We have not experienced a strike or lockout.*

E. Resources and Systems

Outstanding Share Data

We are authorized to issue an unlimited number of voting Common Shares and an unlimited number of non-voting Common Shares. As at November 3, 2009, there were 36,038,476 voting Common Shares outstanding (36,038,476 as at March 31, 2009). In comparison, 35,929,476 voting Common Shares were outstanding as at March 31, 2008. We had no non-voting Common Shares outstanding on any of the foregoing dates.

* This paragraph contains forward-looking information. Please refer to Forward-Looking Information and Risk Factors for a discussion on the risks and uncertainties related to such information.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

Liquidity and Capital Resources

Liquidity requirements

Our primary uses of cash are for property, plant and equipment purchases, to fulfill debt repayment and interest payment obligations, to fund operating lease obligations and to finance working capital requirements.

We maintain a significant equipment and vehicle fleet comprised of units with remaining useful lives covering a variety of time spans. It is important to adequately maintain our large revenue-producing fleet in order to avoid equipment downtime, which can impact our revenue stream and inhibit our ability to satisfactorily perform on our projects. Once units reach the end of their useful lives, they are replaced as it becomes cost prohibitive to continue to maintain them. As a result, we are continually acquiring new equipment both to replace retired units and to support our growth as we take on new projects. In order to maintain a balance of owned and leased equipment, we have financed a portion of our heavy construction fleet through operating leases. In addition, we continue to lease our motor vehicle fleet through our capital lease facilities.

We require between $30 million and $40 million annually for sustaining capital expenditures and our total capital requirements typically range from $125 million to $200 million depending on our growth capital requirements. With the potential future customer demand for larger-sized heavy equipment in the oil sands, we expect our capital needs in the current fiscal year to be approximately $140 to $180 million, including a possible further $50 million to $100 million of growth capital.*

We typically finance approximately 30% to 50% of our total capital requirements through our operating lease facilities and the remainder from cash flow from operations. We believe our operating and capital lease facilities and cash flow from operations will be sufficient to meet these requirements. Our equipment fleet value is currently split among owned (47%), leased (46%) and rented equipment (7%). Approximately 44% of our leased fleet is specific to one long-term overburden removal project. This equipment mix is a change from the mix reported in previous periods as a result of our declining need for the same levels of rental equipment along with the conversion of some rental equipment to operating leases to meet specific volume demands. Our equipment ownership strategy allows us to meet our customers variable service requirements while balancing the need to maximize equipment utilization with the need to achieve the lowest ownership costs. We are continually evaluating our capital needs and continue to monitor equipment lead times with suppliers to ensure that we control our capital spending while still being in a position to respond to opportunities when they materialize.*

We continue to receive interest from finance companies to support our current lease requirements and we have availability under one of our suppliers leasing program to meet our current equipment needs from this supplier. We are currently negotiating with these finance companies to secure financing for our other equipment needs over the balance of the fiscal year.

Our long-term debt includes US$200 million of 8 $^{3}/4$% senior notes due in December 2011. Prior to February 2, 2009, the foreign currency risk relating to both the principal and interest portions of these 8 $^{3}/4$% senior notes was managed with cross-currency and interest rate swaps, which went into effect concurrent with the issuance of the notes on November 26, 2003. The swap agreements were an economic hedge but had not been designated as hedges for accounting purposes. Interest totaling $13.0 million on the 8 $^{3}/4$% senior notes and

* This paragraph contains forward-looking information. Please refer to Forward-Looking Information and Risk Factors for a discussion on the risks and uncertainties related to such information.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

the swap is payable semi-annually in June and December of each year until the notes mature on December 1, 2011. The US$200 million principal amount was fixed at C$1.315=US$1.000, resulting in a principal repayment of $263.0 million due on December 1, 2011. There are no principal repayments required on the 8 $^{3}/4$% senior notes until maturity. Effective February 2, 2009, the US dollar interest rate swap was terminated by the counterparties and our interest expense increased by US$6.8 million per annum (based on the then current US LIBOR rates) for the remaining life of the 8 $^{3}/4$% senior notes. This increase is net of US dollar floating interest payments on the cross-currency swap agreement we now receive every March 1, June 1, September 1 and December 1, effective March 1, 2009 until the notes mature on December 1, 2011. The value of the quarterly floating rate US dollar payments we receive is the prevailing 3-month US LIBOR rate plus a spread of 4.2% on the notional amount of US$200 million. Our Canadian dollar interest rate swap and cross-currency swap agreements are not cancellable at the option of the counterparties and remain in effect.

A more detailed discussion of this cancellation can be found below in the Foreign currency risk and Interest rate risk sections of Quantitative and Qualitative Disclosures about Market Risk.

One of our major contracts allows the customer to require that we provide up to $50.0 million in letters of credit. As at September 30, 2009, we had $20.0 million in letters of credit outstanding in connection with this contract (we have $20.3 million in letters of credit outstanding in total for all customers as of September 30, 2009). Any change in the amount of the letters of credit required by this customer must be requested by November 1st in each year for an issue date of January 1st following the date of such request, for the remaining life of the contract. In the event that we require additional letters of credit for either this major contract or other contracts, we have included an option in our June 24, 2009 amended and restated credit agreement to request an increase to the revolving portion of the credit facility, on a one-time basis, by an amount up to the lesser of $25.0 million or the requested increase to the letters of credit for this customer.

Sources of liquidity

Our principal sources of cash are funds from operations and borrowings under our $125.0 million credit facility. As at September 30, 2009, we had approximately $69.7 million of available borrowings under our credit facility after taking into account $20.3 million of outstanding and undrawn letters of credit to support performance guarantees associated with customer contracts and $33.0 million of outstanding borrowings against the term facility provided for in our amended and restated credit agreement.

As at September 30, 2009, we had $21.6 million in trade receivables that were more than 30 days past due compared to $16.0 million as at March 31, 2009. We have currently provided an allowance for doubtful accounts related to our trade receivables of $2.1 million ($2.6 million at March 31, 2009). We continue to monitor the credit worthiness of our customers. To date our exposure to potential write-downs in trade receivables has been limited to the financial condition of developers of condominiums and high-rise developments.

Working capital fluctuations effect on cash

The seasonality of our business results in higher accounts receivable balance between December and early February during peak activity levels, which may result in an increase in our working capital requirements. Our working capital is also significantly affected by the timing of completion of projects. In some cases, our customers are permitted to withhold payment of a percentage of the amount owing to us for a stipulated period of time (such percentage and time period is usually defined by the contract and in some cases provincial legislation). This amount acts as a form of security for our customers and is referred to as a holdback. Typically, we are only entitled to collect payment on holdbacks once substantial completion of the contract is performed,

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

there are no outstanding claims by subcontractors or others related to work performed by us and we have met the time period specified by the contract (usually 45 days after completion of the work). However, in some cases, we are able to negotiate the progressive release of holdbacks as the job reaches various stages of completion. As at September 30, 2009, holdbacks totaled $4.8 million, down from $9.4 million as at March 31, 2009. Holdbacks represent 5.4% of our total accounts receivable as at September 30, 2009 (12.0% as at March 31, 2009). This decrease is attributable to the reduction of revenue in our Piling segment for the three months ended September 30, 2009 and March 31, 2009 compared to the same periods in the prior year. As at September 30, 2009, we carried $2.2 million in holdbacks for three large customers.*

Cash requirements

As at September 30, 2009, our cash balance of $97.7 million was $1.2 million lower than our cash balance at March 31, 2009. The change in cash balance reflects the timing of capital expenditures and the timing of processing change orders and payment certificates. Offsetting these outflows of cash was the cash inflow of $33.0 million secured through our amended and restated credit facility. We anticipate that we will generate a net cash surplus from operations at least through December 31, 2009. In the event that we require additional funding, we believe that any such funding requirements would be satisfied by the funds available from our credit facility described immediately below.*

Credit facility

We entered into an amended and restated credit agreement on June 24, 2009 with a syndicate of lenders that provided us with a credit facility, under which revolving loans, term loans and letters of credit may be issued. The facility will mature on June 8, 2011. The total credit facility remained unchanged at $125.0 million and included a $75.0 million Revolving Facility and a $50.0 million Term Facility. The Term Facility commitments were available until August 31, 2009 and aggregate borrowings under this facility had to exceed $25.0 million. Any undrawn amount under the Term Facility, up to a maximum of $15.0 million, could be reallocated to the Revolving Facility. On August 31, 2009, the maximum undrawn portion of the Term Facility totaling $15.0 million was reallocated to the Revolving Facility resulting in Revolving Facility commitments of $90.0 million.

As of September 30, 2009, we had issued $20.3 million (March 31, 2009 $20.8 million) in letters of credit under the Revolving Facility to support performance guarantees associated with customer contracts. The total credit facility is $123.0 million at September 30, 2009 and includes the $90.0 million Revolving Facility and the outstanding borrowings of $33.0 million, net of principal repayments (March 31, 2009 $nil) under the non-revolving Term Facility. The funds available under the Revolving Facility are reduced by any outstanding letters of credit. Our unused borrowing availability under the credit facility was $69.7 million at September 30, 2009.

Advances under the Revolving Facility may be repaid from time to time at our option. Beginning September 30, 2009, and at the end of each fiscal quarter thereafter, we must make quarterly principal repayments of $1.5 million, an amount equal to 4.375% of the outstanding principal drawn under the Term Facility. The credit facility bears interest at the Canadian prime rate, the US dollar base rate, the Canadian bankers acceptance rate or the London Interbank Offered Rate (LIBOR) (all such terms as used or defined in the credit facility) plus applicable margins. In each case, the applicable pricing margin depends on our current debt rating. For a discussion on our current debt rating refer to the Debt Ratings section of this Management s Discussion and Analysis.

* This paragraph contains forward-looking information. Please refer to Forward-Looking Information and Risk Factors for a discussion on the risks and uncertainties related to such information.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

During the six months ended September 30, 2009, financing fees of $1.1 million were incurred in connection with the modifications to the amended and restated credit agreement. These fees were recorded as an intangible asset and are amortized on a straight-line basis over the remaining term of the agreement.

Included in the amended and restated credit agreement is an option to request an increase to the total revolving credit facility commitments if our requirements for providing letters of credit to our customers exceed $21.0 million. In that event we are permitted to request, on a one-time basis, an increase to the overall revolving credit facility by an amount up to the lesser of $25.0 million or the requested increase to the letters of credit by our customers.

Under the credit agreement, we are required to satisfy certain financial covenants, including an amended minimum interest coverage ratio. The interest coverage covenant is determined based on a ratio of Consolidated EBITDA (as defined within the credit agreement), to consolidated cash interest expense. Measured as of the last day of each fiscal quarter, on a trailing four-quarter basis, the interest coverage ratio shall not be less than 2.0 times at any time up to June 29, 2010 and shall not be less than 2.5 times any time thereafter.

Covenants remaining unchanged in the credit agreement include:

- The senior leverage covenant, which is determined based on a ratio of senior debt to Consolidated EBITDA (as defined within the credit agreement). Measured as of the last day of each fiscal quarter on a trailing four-quarter basis, the senior leverage ratio shall not exceed 2.0 times.

- The current ratio covenant is determined based on the ratio of current assets to current liabilities (as defined within the credit agreement). Measured as of the last day of each fiscal quarter, the current ratio shall not be less than 1.25 times.

Consolidated EBITDA is defined within the credit agreement. The amended and restated credit agreement clarifies the definition of Consolidated EBITDA to be the sum, without duplication, of (a) consolidated net income, (b) consolidated interest expense, (c) provision for taxes based on income, (d) total depreciation expense, (e) total amortization expense, (f) costs and expenses incurred by us in entering into the credit facility, (g) accrual of stock-based compensation expense to the extent not paid in cash or if satisfied by the issuance of new equity, (h) the non-cash currency translation losses or mark-to-market losses on any hedge agreement (defined in the credit agreement) or any embedded derivative, and (i) other non-cash items including goodwill impairment (other than any such non-cash item to the extent it represents an accrual of or reserve for cash expenditures in any future period) but only, in the case of clauses (b)-(i), to the extent deducted in the calculation of consolidated net income, less (i) the non-cash currency translation gains or mark-to-market gains on any hedge agreement or any embedded derivative to the extent added in the calculation of consolidated net income, and (ii) other non-cash items added in the calculation of consolidated net income (other than any such non-cash item to the extent it will result in the receipt of cash payments in any future period), all of the foregoing as determined on a consolidated basis in conformity with Canadian GAAP. The clarification of the definition of Consolidated EBITDA (as defined within the credit agreement), did not change our measurement of Consolidated EBITDA.

The credit facility may be prepaid in whole or in part without penalty, except for bankers acceptances, which cannot be prepaid prior to their maturity. However, the credit facility requires prepayments under various circumstances, such as: (i) 100% of the net cash proceeds of certain asset dispositions, (ii) 100% of the net cash proceeds from our issuance of equity (unless the use of such securities proceeds is otherwise designated by the applicable offering document) and (iii) 100% of all casualty insurance and condemnation proceeds, subject to exceptions.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

For a complete discussion of our credit facility, see our most recent annual Management s Discussion and Analysis.

Debt Ratings

Our debt ratings were last assessed in December 2007 by Standard & Poor s and Moody s. Standard & Poor s upgraded our debt rating from the previous rating of B . Moody s maintained the rating of our debt.

Our corporate credit ratings from these two agencies are as follows:

Standard & Poor s	B+ (negative outlook)
Moody s	B2 (stable outlook)

Our 8 3/4 % senior notes are rated as follows:

Standard & Poor s	B+ (recovery rating of 4)
Moody s	B3 (loss given default rating of 5)

On June 29, 2009, Standard & Poor s revised its outlook on our corporate credit rating to negative from stable . At the same time, Standard & Poor s affirmed its B+ long-term corporate credit rating and its B+ senior unsecured debt rating.

A credit rating is a current opinion of the credit worthiness of an obligor with respect to a specific financial obligation, a specific class of financial obligations, or a specific financial program (including ratings on medium-term note programs and commercial paper programs). It takes into consideration the creditworthiness of guarantors, insurers, or other forms of credit enhancement on the obligation and takes into account the currency in which the obligation is denominated. The opinion evaluates the obligor s capacity and willingness to meet its financial commitments as they come due, and may assess terms, such as collateral security and subordination, which could affect ultimate payment in the event of default. A credit rating is not a statement of fact or recommendation to purchase, sell, or hold a financial obligation or make any investment decisions nor is it a comment regarding an issuer s market price or suitability for a particular investor. A credit rating speaks only as of the date it is issued and can be revised upward or downward or withdrawn at any time by the issuing rating agency if it decides circumstances warrant a revision.

A definition of the categories of each rating has been obtained from each respective rating organization s website as outlined below:

Standard and Poor s

An obligation rated B is regarded as having speculative characteristics, but the obligor currently has the capacity to meet its financial commitment on the obligation. Adverse business, financial, or economic conditions will likely impair the obligor s capacity or willingness to meet its financial commitment on the obligation. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

A recovery rating of 4 for the 8 3/4% senior notes indicates an expectation for an average of 30% to 50% recovery in the event of a payment default.

A Standard & Poor s rating outlook assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years). In determining a rating outlook, consideration is given to any changes in the economic and/or fundamental business conditions. An outlook is not necessarily a precursor of a rating change or future CreditWatch action. A Stable outlook means that a rating is not likely to change.

Moody s

Obligations rated B are considered speculative and are subject to high credit risk. Moody s appends numerical modifiers to each generic rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Loss Given Default (LGD) assessments are opinions about expected loss given default on fixed income obligations expressed as a percent of principal and accrued interest at the resolution of the default. An LGD assessment (or rate) is the expected LGD divided by the expected amount of principal and interest due at resolution. A LGD rating of 5 indicates a loss range of greater than or equal to 70% and less than 90%.

A Moody s rating outlook is an opinion regarding the likely direction of an issuer s rating over the medium term. Where assigned, rating outlooks fall into the following four categories: Positive (POS), Negative (NEG), Stable (STA), and Developing (DEV contingent upon an event). In the few instances where an issuer has multiple ratings with outlooks of differing directions, an (m) modifier (indicating multiple, differing outlooks) will be displayed, and Moody s written research will describe any differences and provide the rationale for these differences. A RUR (Rating(s) Under Review) designation indicates that the issuer has one or more ratings under review for possible change, and thus overrides the outlook designation. When an outlook has not been assigned to an eligible entity, NOO (No Outlook) may be displayed. A Stable outlook means that a rating is not likely to change.

Cash Flow and Capital Resources

	Three months ended September 30,			**Six months ended September 30,**		
(dollars in thousands)	**2009**	**2008**	**Change**	**2009**	**2008**	**Change**
Cash provided by (used in) operating activities	$ 23,185	$ (9,464)	$ 32,649	$ 15,247	$ 23,877	$ (8,630)
Cash (used in) investing activities	(24,739)	(51,093)	26,354	(44,623)	(65,425)	20,802
Cash provided by financing activities	18,997	9,225	9,772	28,212	8,677	19,535
Net increase (decrease) in cash and cash equivalents	$ 17,443	$ (51,332)	$ 68,775	$ (1,164)	$ (32,871)	$ 31,707

Operating activities

Cash provided by operating activities for the three months ended September 30, 2009 was an inflow of $23.2 million, compared to a cash outflow of $9.5 million for the three months ended September 30, 2008. Cash

22

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

provided by operating activities this year was positively affected by the timing of processing change orders and progress payment certificates from the preceding quarter while last year was negatively affected by the timing of processing change orders and progress payment certificates.

Cash provided by operating activities for the six months ended September 30, 2009 was an inflow of $15.2 million, compared to a cash inflow of $23.9 million for the six months ended September 30, 2008. Cash provided by operating activities this year was negatively affected by lower operating income compared to the prior six-month period.

Investing activities

Net investing activities were an outflow of $24.7 million for the three months ended September 30, 2009, compared with an outflow of $51.1 million for the same period a year ago. Investing activities this year include capital expenditures of $26.7 million along with $4.9 million for the acquisition of DF Investments Ltd., the parent company of Drillco Foundation Co. Ltd. Proceeds from asset disposals of $0.7 million and net inflow from non-cash working capital of $3.9 million lessened the effect of capital purchases and the acquisition. Investing activities last year included a net outflow from non-cash working capital of $38.2 million and capital expenditures of $16.2 million, offset by proceeds from asset disposals of $3.3 million.

Net investing activities for the six months ended September 30, 2009 were an outflow of $44.6 million compared with an outflow of $65.4 million, for the same period a year ago. Current period investing activities include capital expenditures of $46.4 million along with $4.9 million for the acquisition of DF Investments Ltd. Proceeds from asset disposals of $1.8 million and net inflow from non-cash working capital of $2.6 million lessened the effect of capital purchases and the acquisition. Investing activities last year included capital expenditures of $75.5 million, offset by proceeds from asset disposals of $4.8 million and a net inflow from non-cash working capital of $5.3 million.

Financing activities

Financing activities during the three month period ended September 30, 2009 resulted in a cash inflow of $19.0 million. Capital expenditure financing of $21.2 million, through our new term credit facility, was partially offset by the $1.5 million repayment of capital lease obligations and the repayment of debt we assumed with the acquisition of DF Investments Ltd. Cash settlement of stock options and financing costs for our amended and restated credit agreement make up the balance of the cash outflow. Cash inflow for the three month period ended September 30, 2008 of $9.2 million was a result of the drawing of $10.0 million from our revolving credit facility and cheques issued in excess of cash partially offset by the $1.5 million repayment of capital lease obligations.

Financing activities during the six month period ended September 30, 2009 resulted in a cash inflow of $28.2 million. Capital expenditure financing of $33.0 million, through our new term credit facility, was partially offset by the $2.9 million repayment of capital lease obligations, $1.1 million in financing costs for our amended and restated credit agreement and the repayment of debt assumed with the acquisition of DF Investments Ltd. Cash settlement of stock options makes up the balance of the cash outflow. Cash inflow for the six month period ended September 30, 2008 of $8.7 million was a result of the drawing of $10.0 million from our revolving credit facility, stock options exercised and cheques issued in excess of cash partially offset by the $2.7 million repayment of capital lease obligations.

Capital resources

We acquire our equipment requirements in three ways: capital expenditures; capital leases; and operating leases. Capital expenditures require the outflow of cash for the full value of the equipment at the time of

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

purchase. Capital leases, while not considered capital expenditures, are restricted under the terms of our credit agreement to a maximum of $30.0 million. Operating leases are not considered capital expenditures and are not restricted under the terms of our credit agreement.

We define our equipment requirements as either sustaining capital additions, those that are needed to keep our existing fleet of equipment at its optimal useful life through capital maintenance or replacement, or growth capital additions, those that are needed to perform larger or a greater number of projects.

A summary of equipment additions by nature and by period is shown on the table below:

	Three months ended September 30,			Six months ended September 30,		
(dollars in thousands)	2009	2008	Change	2009	2008	Change
Capital Expenditures						
Sustaining	$ 4,034	$ 8,823	$ (4,789)	$ 6,195	$ 13,107	$ (6,912)
Growth	22,675	7,354	15,321	40,224	62,419	(22,195)
Total	$ 26,709	$ 16,177	$ 10,532	$ 46,419	$ 75,526	$ (29,107)
Capital Leases						
Sustaining	$	$ 2,734	$ (2,734)	$	$ 2,888	$ (2,888)
Growth	33	1,218	(1,185)	656	2,228	(1,572)
Total	$ 33	$ 3,952	$ (3,919)	$ 656	$ 5,116	$ (4,460)
Total Sustaining Capital Additions	$ 4,034	$ 11,557	$ (7,523)	$ 6,195	$ 15,995	$ (9,800)
Total Growth Capital Additions	$ 22,708	$ 8,572	$ 14,136	$ 40,880	$ 64,647	$ (23,767)
Operating Leases	$ 27,252	$ 4,807	$ 22,445	$ 32,860	$ 26,070	$ 6,790

The reduction in sustaining capital additions, for the three and six months ended September 30, 2009, compared to the same periods in the prior year, is reflective of fewer equipment purchases due to lower volumes.

The increase in growth capital additions, for the three months ended September 30, 2009, reflects the scheduled equipment expenditures related to the Canadian Natural overburden project. The decrease in growth capital additions for the six months ended September 30, 2009 reflects fewer development projects as a result of the impact of the current economic slowdown.

The increase in operating leases, for the three and six months ended September 30, 2009, compared to the same periods in the previous year, reflects the scheduled equipment additions related to the Canadian Natural overburden project , partially offset by the impact of fewer development projects as a result of the current economic slowdown.

Capital Commitments

Contractual obligations and other commitments

Our principal contractual obligations relate to our long-term debt, capital and operating leases and supplier contracts. The following table summarizes our future contractual obligations, excluding interest payments, unless otherwise noted, as of September 30, 2009.

24

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

		Payments due by fiscal year				
(dollars in thousands)	Total	2010	2011	2012	2013	2014 and thereafter
Senior notes [(1)]	$ 263,000	$	$	$ 263,000	$	$
Term facility	33,000	4,554	6,072	22,374		
Capital leases (including interest)	16,740	3,041	5,591	5,012	2,771	325
Operating leases	166,341	27,690	49,049	40,082	26,275	23,245
Supplier contracts	28,587	3,266	8,178	9,796	7,347	
Total contractual obligations	$ 507,668	$ 38,551	$ 68,890	$ 340,264	$ 36,393	$ 23,570

(1) We have entered into cross-currency and interest rate swaps, which represent an economic hedge of the 8 3/4% senior notes. At maturity, we will be required to pay $263.0 million in order to retire these senior notes and the swaps. This amount reflects the fixed exchange rate of C$1.315=US$1.00 established as of November 26, 2003, the inception date of the swap contracts (see Interest rate risk in Quantitative and Qualitative Disclosures about Market Risk regarding the cancellation of the US dollar interest rate swap effective February 2, 2009). At September 30, 2009, the carrying value of the derivative financial instruments was $78.7 million, inclusive of the interest components.

Off-balance sheet arrangements

We have no off-balance sheet arrangements in place at this time.

Related Parties

We may receive consulting and advisory services provided by the principals or employees of companies owned or operated by certain of our directors (the Sponsors) with respect to the organization of our employee benefit and compensation arrangements, and other matters, and no fee is charged for these consulting and advisory services.

In order for the Sponsors to provide such advice and consulting, we provide the Sponsors with reports, financial data and other information. This permits them to consult with and advise our management on matters relating to our operations, company affairs and finances. In addition, this permits them to visit and inspect any of our properties and facilities. These services are provided in the normal course of operations and are measured at the value of consideration established and agreed to by the related parties.

Internal Systems and Processes

Overview of information systems

We currently use JDE (Enterprise One) as our Enterprise Resource Planning (ERP) tool and deploy the financial system, payroll, procurement, job-costing and equipment maintenance modules from this tool. We supplement this functionality with either third-party software (for our estimating system) or in-house developed tools (for project management).

The proper identification of costs is a critical part of our ability to recognize revenues and provide accurate management information for decision-making. We continue to focus resources to address this in our ERP system through the automation of transactional activities. We continue to work on improving the process for tracking and reporting equipment and maintenance costs. We have seen some improvements in the identification and tracking of our procurement costs.

During the year ended March 31, 2009, we completed a user-needs analysis and compared this to the functionality of our ERP system. As part of this analysis, we determined if we could implement additional

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

modules in JDE or whether we needed to commence a review of industry-specific software to supplement our existing ERP functionality. We have started plans for the implementation of specific JDE modules based on this analysis.

Evaluation of disclosure controls and procedures

Management has evaluated whether there were changes in our Internal Controls over Financial Reporting (ICFR) during the three and six month periods ended September 30, 2009 that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting. No material changes were identified.

As of March 31, 2009, we assessed the effectiveness of the Company s ICFR. In making this assessment, we used the criteria set forth in the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). During this process we identified a material weakness in internal controls over financial reporting described below and as a result we concluded that the Company s ICFR is ineffective as of March 31, 2009.

We did not maintain effective processes and controls specific to revenue recognition. We did not effectively develop, communicate and implement an appropriate revenue recognition policy, a formal process to track claims and unapproved change orders and sufficient monitoring controls over the completeness and accuracy of forecasts, including the consideration of project changes subsequent to the end of each reporting period. The accounts that could be affected by these deficiencies are revenue, project costs, unbilled revenue and billings in excess of costs incurred and estimated earnings on uncompleted contracts. This material weakness in ICFR, which is pervasive in nature, resulted in material errors in the financial statements that were corrected prior to release of the financial statements. Further, there is a reasonable possibility that a material misstatement of our financial statements will not be prevented or detected on a timely basis.

In response to the material weakness identified above, during the three months ended and subsequent to March 31, 2009, we formalized our revenue recognition policy to assist in the understanding and consistent application of GAAP, initiated the development of a procedural manual to assist with applying the revenue recognition policy, designed new process-level controls and conducted staff training. As of September 30, 2009, significant progress has been made on our remediation plans but this material weakness has not been fully remediated. We will evaluate the effectiveness of these controls during the balance of the fiscal year to determine if they adequately address our ability to recognize revenue in accordance with GAAP. For a discussion of the risks associated with such weakness, please see our most recent annual Management s Discussion and Analysis.

Significant Accounting Policies

In our audited consolidated financial statements for the year ended March 31, 2009 and our most recent annual Management s Discussion and Analysis, we have identified the accounting policies and estimates that are critical to the understanding of our business operations and our results of operations. For the three and six months ended September 30, 2009, there are no changes to the critical accounting policies and estimates.

Recently Adopted Accounting Policies (Canadian GAAP)

Goodwill and intangible assets

Effective April 1, 2009, we adopted, on a retrospective basis, CICA Handbook Section 3064, Goodwill and Intangible Assets , which replaces Section 3062, Goodwill and Other Intangible Assets , and Section 3450,

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

Research and Development Costs and establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The provisions relating to the definition and initial recognition of intangible assets, including internally generated intangible assets, are equivalent to the corresponding provisions of International Accounting Standard IAS 38, Intangible Assets. The adoption of this standard did not have a material impact on our interim consolidated financial statements.

Business combinations

Effective July 1, 2009, we early adopted CICA Handbook Section 1582, Business Combinations , which replaces the existing standard. This section establishes standards for the accounting of business combinations, and states that all assets and liabilities of an acquired business will be recorded at fair value. Obligations for contingent considerations and contingencies will also be recorded at fair value at the acquisition date. The standard also states that acquisition related costs will be expensed as incurred, that restructuring charges will be expensed in periods after the acquisition date and that non-controlling interests should be measured at fair value at the date of acquisition. This standard is to be applied prospectively to business combinations with acquisition dates on or after July 1, 2009. We applied this new standard to the August 1, 2009 acquisition of DF Investments Ltd. and its subsidiary Drillco Foundation Co. Ltd.

Consolidated financial statements

Effective July 1, 2009, we early adopted CICA Handbook Section 1601, Consolidated Financial Statements , which replaces Section 1600, Consolidated Financial Statements . This Section carries forward existing Canadian guidance for preparing consolidated financial statements other than guidance for non-controlling interests. The adoption of this standard did not have a material impact on our interim consolidated financial statements.

Non-controlling interests

Effective July 1, 2009, we early adopted CICA Handbook Section 1602, Non-Controlling Interests , which establishes standards for the accounting of non-controlling interests of a subsidiary in the preparation of consolidated financial statements subsequent to a business combination. The adoption of this standard did not have a material impact on our interim consolidated financial statements.

Equity

In August 2009, the CICA amended presentation requirements of Handbook Section 3251, Equity as a result of issuing Section 1602, Non-Controlling Interests . The amendments apply only to entities that have adopted Section 1602. We early adopted this standard on July 1, 2009. The adoption of this standard did not have a material impact on our interim consolidated financial statements.

Financial instruments recognition and measurement

Effective July 1, 2009 we adopted CICA amendments to Handbook Section 3855, Financial Instruments Recognition and Measurement , which added guidance concerning the assessment of embedded derivatives upon reclassification of a financial asset out of the held-for-trading category. These amendments apply to reclassifications made on or after July 1, 2009. The adoption of these amendments did not have a material impact on our interim consolidated financial statements.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

Recent Accounting Pronouncements Not Yet Adopted (Canadian GAAP)

Accounting changes

In June 2009, the CICA amended Handbook Section 1506, Accounting Changes , to exclude from its scope changes in accounting policies arising from the complete replacement of an entity s primary basis of accounting. The amendment applies to interim and annual financial statements relating to fiscal years beginning on or after July 1, 2009. We are currently evaluating the impact of this standard.

Financial instruments recognition and measurement

In June 2009, the CICA amended Handbook Section 3855, Financial Instruments Recognition and Measurement , to clarify the application of the effective interest method after a debt instrument has been impaired. The Section has also been amended to clarify when an embedded prepayment option is separated from its host instrument for accounting purposes. The amendments apply to interim and annual financial statements relating to fiscal years beginning on or after May 1, 2009 for the amendments relating to the effective interest method and on or after January 1, 2011 for the amendments relating to embedded prepayment options. We are currently evaluating the impact of the amendments to the standard.

Financial instruments disclosure

In June 2009, the CICA amended Handbook Section 3862, Financial Instruments Disclosures , to include additional disclosure requirements about fair value measurements of financial instruments and to enhance liquidity risk disclosure requirements. The amendments apply to annual financial statements relating to fiscal years ending after September 30, 2009. We are currently evaluating the impact of the amendments to the standard.

Comprehensive revaluation of assets and liabilities

In August 2009, the CICA amended Handbook section 1625 Comprehensive Revaluation of Assets and Liabilities as a result of issuing Section 1582, Business Combinations , Section 1601, Consolidated Financial Statements , and Section 1602, Non-Controlling Interests in January 2009. The amendments apply prospectively to comprehensive revaluations of assets and liabilities occurring in fiscal years beginning on or after January 1, 2011. Earlier adoption is permitted as of the beginning of a fiscal year, provided that Section 1582 is also adopted. We are currently evaluating the impact of the amendments to the standard.

Transition to International Financial Reporting Standards (IFRS)

In 2006, the Canadian Accounting Standards Board (AcSB) published a new strategic plan that significantly affects financial reporting requirements for Canadian public companies. The AcSB strategic plan outlines the convergence of Canadian GAAP with IFRS over an expected five-year transitional period.

In February 2008, the AcSB confirmed that IFRS will be mandatory in Canada for profit-oriented publicly accountable entities for fiscal periods beginning on or after January 1, 2011, unless, as permitted by Canadian securities regulations, we were to adopt US GAAP on or before this date. Should we decide to adopt IFRS, our first annual IFRS financial statements would be for the year ending March 31, 2012 and would include the comparative period of the year ending March 31, 2011. Starting for the three months ending June 30, 2011, we would provide unaudited consolidated financial statements in accordance with IFRS including comparative figures for the three month period ending June 30, 2010.

28

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

We have completed our gap analysis of the accounting and reporting differences under IFRS, Canadian GAAP and US GAAP, however, we have not yet finalized our determination of the impact of these differences on our consolidated financial statements. This analysis will, in part, determine whether we adopt IFRS or US GAAP once Canadian GAAP ceases to exist. We are also closely monitoring standard-setting activity and regulatory developments in Canada, the United States and internationally that may affect the timing of our adoption of either IFRS or US GAAP in future periods.

G. Forward-Looking Information and Risk Factors

Forward-Looking Information

This document contains forward-looking information that is based on expectations and estimates as of the date of this document. Our forward-looking information is information that is subject to known and unknown risks and other factors that may cause future actions, conditions or events to differ materially from the anticipated actions, conditions or events expressed or implied by such forward-looking information. Forward-looking information is information that does not relate strictly to historical or current facts, and can be identified by the use of the future tense or other forward-looking words such as believe , expect , anticipate , intend , plan , estimate , should , may , cou target , objective , projection , forecast , continue , strategy , intend , position or the negative of those terms or other variations of them o terminology.

Examples of such forward-looking information in this document include, but are not limited to, statements with respect to the following, each of which is subject to significant risks and uncertainties and is based on a number of assumptions which may prove to be incorrect:

(a) the amount of our backlog expected to be performed and realized in the twelve months ending September 30, 2010;

(b) that our expectations for the second half of fiscal 2010 are for continued strong operating performance in a more competitive market environment;

(c) the increased pressure on revenue growth and profit margins due to weaker industrial and commercial construction market conditions, a more moderate pace of development in the oil sands and increasing competition for contracts;

(d) the merger between Suncor and Petro-Canada will have a positive impact on oil sands investment;

(e) we will experience continued sustainable growth in the services we provide to Canadian Natural;

(f) we will experience more stability in our recurring revenue as the result of our recently signed 3 year services agreement with Shell Albian Sands Muskeg River Mine;

(g)

that reductions in project costs and gradual strengthening of oil prices are creating a more attractive environment for investment;

(h) the demand for our recurring oil sands services will see the resumption of growth in the second half of fiscal 2010 and the return of volumes on the Horizon project over the next six months;

(i) the construction of the 37-kilometer, 24 inch pipeline related to the North Maxhamish Loop will be completed by the end of fiscal 2010;

(j) current commercial and industrial construction activity is not expected to improve this year, negatively affecting our Piling division;

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

(k) the expected benefits to our Piling division from the announced federal and provincial government spending in Ontario;

(l) the expected renewal agreement between our employees party to the collective bargaining agreement which expired October 31, 2009 and us;

(m) our estimated capital needs in fiscal 2010 and further potential growth capital required for fiscal 2010 is accurate;

(n) our operating and lease facilities and cash flow from operations will be sufficient to meet our capital requirements;

(o) we will generate a net cash surplus through December 31, 2009;

(p) the seasonality of our business results may result in an increase in working capital requirements; and

(q) any additional funding required by us will be satisfied by the credit facility.

Some of the risks and other factors which could cause results to differ materially from those expressed in the forward-looking information contained in this Management s Discussion and Analysis include, but are not limited to:

The forward-looking information in paragraphs (a), (b), (c), (d), (e), (f), (g), (h), (i), (j), (k), (m), (n), (o), (p) and (q) rely on certain market conditions and demand for our services and are based on the assumptions that: despite the slow down in the global economy and tightening of credit conditions we still expect to see strong demand for our recurring services as the oil sands continue to be an economically viable source of energy, our customers and potential customers continue to invest in the oil sands and other natural resources developments; our customers and potential customers will continue to outsource the type of activities for which we are capable of providing service; and the Western Canadian economy continues to develop with additional investment in public construction; and are subject to the following risks and uncertainties that:

anticipated new major capital projects in the oil sands may not materialize;

demand for our services may be adversely impacted by regulations affecting the energy industry;

failure by our customers to obtain required permits and licenses may affect the demand for our services;

changes in our customers perception of oil prices over the long-term could cause our customers to defer, reduce or stop their capital investment in oil sands projects, which would, in turn, reduce our revenue from those customers;

reduced financing as a result of the tightening credit markets may affect our customers decisions to invest in infrastructure projects;

insufficient pipeline, upgrading and refining capacity or lack of sufficient governmental infrastructure to support growth in the oil sands region could cause our customers to delay, reduce or cancel plans to construct new oil sands projects or expand existing projects, which would, in turn, reduce our revenue from those customers;

a change in strategy by our customers to reduce outsourcing could adversely affect our results;

cost overruns by our customers on their projects may cause our customers to terminate future projects or expansions which could adversely affect the amount of work we receive from those customers;

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

- because most of our customers are Canadian energy companies, a further downturn in the Canadian energy industry could result in a decrease in the demand for our services;

- shortages of qualified personnel or significant labour disputes could adversely affect our business; and

- unanticipated short term shutdowns of our customers operating facilities may result in temporary cessation or cancellation of projects in which we are participating.

The forward-looking information in paragraphs (a), (b), (c), (e), (f), (g), (h), (i), (j), (k), (l), (m), (n), (o) and (q) rely on our ability to execute our growth strategy and are based on the assumptions that the management team can successfully manage the business; we can maintain and develop our relationships with our current customers; we will be successful in developing relationships with new customers; we will be successful in the competitive bidding process to secure new projects; we will identify and implement improvements in our maintenance and fleet management practices; we will be able to benefit from increased recurring revenue base tied to the operational activities of the oil sands; we will be able to access sufficient funds to finance our capital growth; and are subject to the risks and uncertainties that:

- continued reduced demand for oil and other commodities as a result of slowing market conditions in the global economy may result in reduced oil production and a decline in oil prices;

- if we are unable to obtain surety bonds or letters of credit required by some of our customers, our business could be impaired;

- we are dependent on our ability to lease equipment, and a tightening of this form of credit could adversely affect our ability to bid for new work and/or supply some of our existing contracts;

- our business is highly competitive and competitors may outbid us on major projects that are awarded based on bid proposals;

- our customer base is concentrated, and the loss of or a significant reduction in business from a major customer could adversely impact our financial condition;

- lump-sum and unit-price contracts expose us to losses when our estimates of project costs are lower than actual costs;

- our operations are subject to weather-related factors that may cause delays in our project work; and

- environmental laws and regulations may expose us to liability arising out of our operations or the operations of our customers.

While we anticipate that subsequent events and developments may cause our views to change, we do not have an intention to update this forward-looking information, except as required by applicable securities laws. This forward-looking information represents our views as of the date of this document and such information should not be relied upon as representing our views as of any date subsequent to the date of this document. We have attempted to identify important factors that could cause actual results, performance or achievements to vary from those current expectations or estimates expressed or implied by the forward-looking information. However, there may be other factors that cause results, performance or achievements not to be as expected or estimated and that could cause actual results, performance or achievements to differ materially from current expectations. **There can be no assurance that forward-looking information will prove to be accurate, as actual results and future events could differ materially from those expected or estimated in such statements. Accordingly, readers should not place undue reliance on forward-looking information.** These factors are not intended to represent a complete list of the factors that could affect us. See Risk Factors below and risk factors

31

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

highlighted in materials filed with the securities regulatory authorities filed in the United States and Canada from time to time, including, but not limited to, our most recent annual information form.

Risk Factors

For the three and six months ended September 30, 2009, other than noted below, there has been no significant change in our risk factors discussed in our most recent annual Management s Discussion and Analysis, which was current as of June 9, 2009. The risk factors discussed in our most recent annual Management s Discussion and Analysis should be reviewed in conjunction with this interim Management s Discussion and Analysis. Significant developments since June 9, 2009 are as follows:

Reduced availability or increased cost of leasing our equipment fleet could adversely affect our results

A portion of our equipment fleet is currently leased from third parties. Further, we anticipate leasing substantial amounts of equipment to meet equipment acquisition commitments related to our long-term overburden removal contract in the upcoming year. Other future projects may require us to lease additional equipment. If equipment lessors are unable or unwilling to provide us with reasonable lease terms within our expectations, it will significantly increase the cost of leasing equipment or may result in more restrictive lease terms that require recognition of the lease as a capital lease. We are actively pursuing new lessor relationships to dilute our exposure to the loss of one or more of our lessors.

A change in strategy by our customers to reduce outsourcing could adversely affect our results.

Outsourced Heavy Construction and Mining segment services constitute a large portion of the work we perform for our customers. For example, our mining and site preparation project revenues constituted approximately 74%, 63% and 75% of our revenues in each of fiscal years 2009, 2008 and 2007, respectively. The election by one or more of our customers to perform some or all of these services themselves, rather than outsourcing the work to us, could have a material adverse impact on our business and results of operations. Certain customers perform some of this work internally and may choose to expand on the use of internal resources to complete this work. Additionally, the recent tightening of the credit market and worldwide economic downturn may result in our customers reducing their spending on outsourced mining and site preparation services if they believe they can perform this work in a more cost effective and efficient manner using their internal resources.

We may not be able to achieve the expected benefits from any future acquisitions, which would adversely affect our financial condition and results of operations.

We intend to pursue selective acquisitions as a method of expanding our business. However, we may not be able to identify or successfully bid on businesses that we might find attractive. If we do find attractive acquisition opportunities, we might not be able to acquire these businesses at a reasonable price. If we do acquire other businesses, we might not be able to successfully integrate these businesses into our then-existing business. We might not be able to maintain the levels of operating efficiency that acquired companies will have achieved or might achieve separately. Successful integration of acquired operations will depend upon our ability to manage those operations and to eliminate redundant and excess costs. Because of difficulties in combining operations, we may not be able to achieve the cost savings and other size-related benefits that we hoped to achieve through these acquisitions. Any of these factors could harm our financial condition and results of operations.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

Quantitative and Qualitative Disclosures about Market Risk

Foreign exchange risk

Foreign exchange risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to changes in foreign exchange rates. We have 8 $^{3}/4$% senior notes denominated in US dollars in the amount of US $200.0 million. In order to reduce our exposure to changes in the United States to Canadian dollar exchange rate, we entered into a cross-currency swap agreement to manage this foreign currency exposure for both the principal balance due on December 1, 2011 as well as the semi-annual interest payments from the issue date to the maturity date. In conjunction with the cross-currency swap agreement, we also entered into a US dollar interest rate swap and a Canadian dollar interest rate swap. These derivative financial instruments were not designated as hedges for accounting purposes. At September 30, 2009 and March 31, 2009, the notional principal amount of the cross-currency swap was US $200.0 million and Canadian $263.0 million.

On December 17, 2008, we received notice that all three swap counterparties had exercised the cancellation option on the US dollar interest rate swap and, effective February 2, 2009, the US dollar interest rate swap was terminated.

Our Canadian dollar interest rate swap and cross-currency swap agreements are not cancellable at the option of the counterparties and remain in effect. We will continue to pay the counterparties an average fixed rate of 9.889% on the notional amount of Canadian $263.0 million or Canadian $13.0 million semi-annually until December 1, 2011. Beginning March 1, 2009, we received quarterly floating rate payments in US dollars on the cross-currency swap agreement at the prevailing 3-month US LIBOR rate plus a spread of 4.2% on the notional amount of US $200.0 million.

As a result of the cancellation of the US dollar interest rate swap, we are exposed to changes in the value of the Canadian dollar versus the US dollar. To the extent that the 3-month US LIBOR rate is less than 4.6% (the difference between the 8 $^{3}/4$% senior notes coupon and the 4.2% spread over 3-month US LIBOR on the cross- currency swap agreement), we will have to acquire US dollars to fund a portion of our semi-annual coupon payment on our 8 $^{3}/4$% senior notes. At the 3-month US LIBOR rate of 0.298% at September 30, 2009, a $0.01 increase (decrease) in exchange rates in the Canadian dollar would result in an insignificant decrease (increase) in the amount of Canadian dollars required to fund each semi-annual coupon payment.

We also regularly transact in foreign currencies when purchasing equipment, spare parts as well as certain general and administrative goods and services. These exposures are generally of a short-term nature and the impact of changes in exchange rates has not been significant in the past. We may fix our exposure in either the Canadian dollar or the US dollar for these short-term transactions, if material.

At September 30, 2009, with other variables unchanged, a $0.01 increase (decrease) in exchange rates of the Canadian dollar to the US dollar related to the US dollar denominated 8 $^{3}/4$% senior notes would decrease (increase) net income and decrease (increase) equity by approximately $1.7 million, net of tax. With other variables unchanged, a $0.01 increase (decrease) in exchange rates in the Canadian to the US dollar related to the cross-currency swap would increase (decrease) net income and increase (decrease) equity by approximately $1.7 million, net of tax. The impact of similar exchange rate changes on short-term exposures would be insignificant and there would be no impact to other comprehensive income.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

Interest rate risk

We are exposed to interest rate risk from the possibility that changes in interest rates will affect future cash flows or the fair values of our financial instruments. Amounts outstanding under our amended credit facilities are subject to a floating rate. Our 8 $^{3}/4$% senior notes are subject to a fixed rate. Our interest risk arises from long-term borrowings issued at fixed rates that create fair value interest rate risk and variable rate borrowings that create cash flow interest rate risk. Changes in market interest rates cause the fair value of long-term debt with fixed interest rates to fluctuate but do not affect earnings, as our debt is carried at amortized cost and the carrying value does not change as interest rates change.

In some circumstances, floating rate funding may be used for short-term borrowings and other liquidity requirements. We may use derivative instruments to manage interest rate risk. We manage our interest rate risk exposure by using a mix of fixed and variable rate debt and may use derivative instruments to achieve the desired proportion of variable to fixed-rate debt.

We also entered into a US dollar interest rate swap and a Canadian dollar interest rate swap with the net effect of economically converting the 8.75% rate payable on the 8 $^{3}/4$% senior notes into a fixed rate of 9.889% for the duration that the 8 $^{3}/4$% senior notes are outstanding. These derivative financial instruments were not designated as hedges for accounting purposes. As a result of the US dollar interest swap cancellation, we are exposed to changes in interest rates. We have a fixed semi-annual coupon payment of 8 $^{3}/4$% on our US $200.0 million senior notes. With the termination of the US dollar interest rate swap, we will no longer receive fixed US dollar payments from the counterparties to offset the coupon payment on our 8 $^{3}/4$% senior notes. As a result of this termination, our annual interest expense at the current US LIBOR rate will increase US $8.5 million. In addition, we are now exposed to interest rate risk where a 100 basis point increase (decrease) in the 3-month US LIBOR rate will result in a US $2.0 million decrease (increase) in annual interest expense.

As at September 30, 2009, holding all other variables constant, a 100 basis point increase (decrease) to Canadian interest rates would impact the fair value of the interest rate swaps by $3.9 million, net of tax, with this change in fair value being recorded in net income. As at September 30, 2009, holding all other variables constant, a 100 basis point increase (decrease) to U.S. interest rates would impact the fair value of the interest rate swaps by $0.1 million, net of tax, with this change in fair value being recorded in net income. As at September 30, 2009, holding all other variables constant, a 100 basis point increase (decrease) of Canadian to US interest rate volatility would impact the fair value of the interest rate swaps by $nil million, net of tax, with this change in fair value being recorded in net income.

At September 30, 2009, we held $33.0 million of floating rate debt pertaining to our term facility within our amended and restated credit facility (March 31, 2009 $nil). As at September 30, 2009, holding all other variables constant, a 100 basis point increase (decrease) to interest rates on floating rate debt would result in a $0.3 million increase (decrease) in annual interest expense. This assumes that the amount of floating rate debt remains unchanged from that which was held at September 30, 2009.

H. General Matters

Our executive head office is located at Suite 2400, 500 4th Avenue SW, Calgary, Alberta, T2P 2V6. Our executive head office telephone and facsimile numbers are 403-767-4825 and 403-767-4849, respectively.

Our corporate office is located at Zone 3, Acheson Industrial Area, #2, 53016 Hwy 60, Acheson, Alberta, T7X 5A7. Our corporate office telephone and facsimile numbers are 780-960-7171 and 780-960-7103, respectively.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Management s Discussion and Analysis

For the three and six months ended September 30, 2009

Additional Information

Additional information relating to us, including our Annual Information Form dated June 9, 2009, can be found on the Canadian Securities Administrators System for Electronic Document Analysis and Retrieval (SEDAR) database at www.sedar.com and the Securities and Exchange Commission s website at www.sec.gov.

Table of Contents

FORM 52-109F2

CERTIFICATION OF INTERIM FILINGS

I, Rodney J. Ruston, the Chief Executive Officer of North American Energy Partners Inc., certify the following:

1. ***Review:*** I have reviewed the interim financial statements and interim MD&A (together, the interim filings) of North American Partners Inc. (the issuer) for the interim period ended September 30, 2009.

2. ***No misrepresentations:*** Based on my knowledge, having exercised reasonable diligence, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings.

3. ***Fair presentation:*** Based on my knowledge, having exercised reasonable diligence, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date of and for the periods presented in the interim filings.

4. ***Responsibility:*** The issuer s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (DC&P) and internal control over financial reporting (ICFR), as those terms are defined in National Instrument 52-109 *Certification of Disclosure in Issuers Annual and Interim Filings*, for the issuer.

5. ***Design:*** Subject to the limitations, if any, described in paragraphs 5.2 and 5.3, the issuer s other certifying officer(s) and I have, as at the end of the period covered by the interim filings

   (a) designed DC&P, or caused it to be designed under our supervision, to provide reasonable assurance that

      (i) material information relating to the issuer is made known to us by others, particularly during the period in which the interim filings are being prepared; and

      (ii) information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation; and

   (b) designed ICFR, or caused it 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 the issuer s GAAP.

5.1 ***Control framework:*** The control framework the issuer s other certifying officer(s) and I used to design the issuer s ICFR is COSO and COBIT.

5.2 ***ICFR material weakness relating to design:*** The issuer has disclosed in its interim MD&A for each material weakness relating to design existing at the end of the interim period

(a) a description of the material weakness;

(b) the impact of the material weakness on the issuer s financial reporting and its ICFR; and

(c) the issuer s current plans, if any, or any actions already undertaken, for remediating the material weakness.

5.3 **Limitation on scope of design: N/A**

6. ***Reporting changes in ICFR:*** The issuer has disclosed in its interim MD&A any change in the issuer s ICFR that occurred during the period beginning on July1, 2009 and ended on September 30, 2009 that has materially affected, or is reasonably likely to materially affect, the issuer s ICFR.

Date: November 3, 2009

/s/ Rodney J. Ruston
Chief Executive Officer

Table of Contents

FORM 52-109F2

CERTIFICATION OF INTERIM FILINGS

I, David Blackley, the Chief Financial Officer of North American Energy Partners Inc., certify the following:

1. ***Review:*** I have reviewed the interim financial statements and interim MD&A (together, the interim filings) of North American Partners Inc. (the issuer) for the interim period ended September 30, 2009.

2. ***No misrepresentations:*** Based on my knowledge, having exercised reasonable diligence, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings.

3. ***Fair presentation:*** Based on my knowledge, having exercised reasonable diligence, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date of and for the periods presented in the interim filings.

4. ***Responsibility:*** The issuer s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (DC&P) and internal control over financial reporting (ICFR), as those terms are defined in National Instrument 52-109 *Certification of Disclosure in Issuers Annual and Interim Filings*, for the issuer.

5. ***Design:*** Subject to the limitations, if any, described in paragraphs 5.2 and 5.3, the issuer s other certifying officer(s) and I have, as at the end of the period covered by the interim filings

   (a) designed DC&P, or caused it to be designed under our supervision, to provide reasonable assurance that

      (i) material information relating to the issuer is made known to us by others, particularly during the period in which the interim filings are being prepared; and

      (ii) information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation; and

   (b) designed ICFR, or caused it 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 the issuer s GAAP.

5.1 ***Control framework:*** The control framework the issuer s other certifying officer(s) and I used to design the issuer s ICFR is COSO and COBIT.

5.2 ***ICFR material weakness relating to design:*** The issuer has disclosed in its interim MD&A for each material weakness relating to design existing at the end of the interim period

(a) a description of the material weakness;

(b) the impact of the material weakness on the issuer s financial reporting and its ICFR; and

(c) the issuer s current plans, if any, or any actions already undertaken, for remediating the material weakness.

5.3 **Limitation on scope of design: N/A**

6. ***Reporting changes in ICFR:*** The issuer has disclosed in its interim MD&A any change in the issuer s ICFR that occurred during the period beginning on July 1, 2009 and ended on September 30, 2009 that has materially affected, or is reasonably likely to materially affect, the issuer s ICFR.

Date: November 3, 2009

/s/ David Blackley
Chief Financial Officer