UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 6-K

Report of Foreign Private Issuer

Pursuant to Rule 13a-16 or 15d-16

under the Securities Exchange Act of 1934

For the month of February 2009

Commission File Number 001-33161

NORTH AMERICAN ENERGY PARTNERS INC.

Zone 3 Acheson Industrial Area

2-53016 Highway 60

Acheson, Alberta

Canada T7X 5A7

(Address of principal executive offices)

Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F.

Form 20-F ____ Form 40-F _X_

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1): ____

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7): ____

Table of Contents

Documents Included as Part of this Report

1. Interim consolidated financial statements of North American Energy Partners Inc. for the three and nine months ended December 31, 2008.

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

Table of Contents

SIGNATURES

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

NORTH AMERICAN ENERGY PARTNERS INC.

By: /s/ Peter Dodd
Name: Peter Dodd
Title: Chief Financial Officer

Date: February 5, 2009

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Expressed in thousands of Canadian dollars)

(Unaudited)

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Interim Consolidated Balance Sheets

(In thousands of Canadian dollars)	**December 31, 2008 (Unaudited)**	**March 31, 2008**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 42,309	$ 32,871
Accounts receivable	143,248	166,002
Unbilled revenue	60,657	70,883
Inventory (note 3(c))	15,210	110
Prepaid expenses and deposits	6,817	9,300
Other assets (note 3(c))		3,703
Future income taxes	2,488	8,217
	270,729	291,086
Future income taxes	13,317	18,199
Assets held for sale	1,206	1,074
Plant and equipment (note 6)	338,749	281,039
Goodwill (note 4)	167,319	200,072
Intangible assets, net of accumulated amortization of $2,927 (March 31, 2008 $2,105)	1,306	2,128
	$ 792,626	**$ 793,598**
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 93,321	$ 113,143
Accrued liabilities	29,872	45,078
Billings in excess of costs incurred and estimated earnings on uncompleted contracts	6,842	4,772
Current portion of capital lease obligations	10,202	4,733
Current portion of derivative financial instruments (note 11(a))	12,226	4,720
Future income taxes	10,387	10,907
	162,850	183,353
Deferred lease inducements	862	941
Capital lease obligations	12,962	10,043
Director deferred stock unit liability	380	190
Senior notes (note 7(b))	244,214	198,245
Derivative financial instruments (note 11(a))	55,774	93,019
Asset retirement obligation (note 8)	470	
Future income taxes	25,269	24,443
	502,781	510,234
Shareholders equity:		
Common shares (authorized unlimited number of voting and non-voting common shares; issued and outstanding 36,038,476 voting common shares (March 31, 2008 35,929,476 voting common shares) (note 9(a))	299,973	298,436
Contributed surplus (note 9(b))	4,993	4,215
Deficit	(15,121)	(19,287)
	289,845	283,364

Revolving credit facility (note 7(a))		
	$ 792,626	**$ 793,598**

See accompanying notes to unaudited interim consolidated financial statements.

2

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

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

(In thousands of Canadian dollars, except per share amounts)	Three Months Ended December 31,		Nine Months Ended December 31,	
	2008	2007	2008	2007
(Unaudited)		Restated (See note 5)		Restated (See note 5)
Revenue	**$ 258,565**	**$ 274,894**	**$ 797,836**	**$ 666,096**
Project costs	129,912	167,323	433,504	397,262
Equipment costs	55,549	44,231	162,146	131,582
Equipment operating lease expense	11,934	4,825	30,317	12,329
Depreciation	10,178	7,885	29,004	24,179
Gross profit	**50,992**	**50,630**	**142,865**	**100,744**
General and administrative costs	19,156	17,009	57,717	48,996
Loss on disposal of plant and equipment	1,022	5	3,778	850
Loss on disposal of asset held for sale			24	316
Amortization of intangible assets	268	443	822	766
Impairment of goodwill (note 4)	32,753		32,753	
Operating (loss) income before the undernoted	**(2,207)**	**33,173**	**47,771**	**49,816**
Interest expense (note 10)	6,774	7,399	19,663	20,333
Foreign exchange loss/(gain)	32,504	(1,784)	39,099	(33,136)
Realized and unrealized (gain)/loss on derivative financial instruments (note 11(a))	(26,523)	(4,510)	(21,171)	36,690
Other income (note 11(b))	(5,343)	(115)	(5,364)	(351)
(Loss) income before income taxes	**(9,619)**	**32,183**	**15,544**	**26,280**
Income taxes (note 13(c)):				
Current income taxes	1,779	8	1,842	29
Future income taxes	3,301	7,469	10,527	6,951
Net (loss) income and comprehensive (loss) income for the period	**(14,699)**	**24,706**	**3,175**	**19,300**
Deficit, beginning of period as previously reported	(422)	(64,477)	(19,287)	(55,526)
Change in accounting policy related to financial instruments (note 5)				(3,545)
Change in accounting policy related to inventory (note 3(c))			991	
Deficit, end of period	**$ (15,121)**	**$ (39,771)**	**$ (15,121)**	**$ (39,771)**
Net (loss) income per share basic (note 9(c))	**$ (0.41)**	**$ 0.69**	**$ 0.09**	**$ 0.54**
Net (loss) income per share diluted (note 9(c))	**$ (0.41)**	**$ 0.67**	**$ 0.09**	**$ 0.52**

See accompanying notes to unaudited interim consolidated financial statements.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Interim Consolidated Statements of Cash Flows

(In thousands of Canadian dollars)	Three Months Ended December 31,		Nine Months Ended December 31,	
(Unaudited)	2008	2007 Restated (See note 5)	2008	2007 Restated (See note 5)
Cash provided by (used in):				
Operating activities:				
Net (loss) income for the period	$ (14,699)	$ 24,706	$ 3,175	$ 19,300
Items not affecting cash:				
Depreciation	10,178	7,885	29,004	24,179
Write-down of other assets to replacement cost				1,848
Amortization of intangible assets	268	443	822	766
Amortization of deferred lease inducements	(26)	(26)	(79)	(78)
Loss on disposal of plant and equipment	1,022	5	3,778	850
Loss on disposal of assets held for sale			24	316
Impairment of goodwill (note 4)	32,753		32,753	
Unrealized foreign exchange loss/(gain) on senior notes	32,509	(1,612)	38,825	(32,626)
Amortization of bond issue costs, premiums and financing costs	219	162	577	669
Unrealized change in the fair value of derivative financial instruments	(27,189)	(5,177)	(23,172)	34,688
Stock-based compensation expense (note 15)	497	276	1,803	1,023
Accretion expense asset retirement obligation (note 8)	53		159	
Future income taxes	3,301	7,469	10,527	6,951
Net changes in non-cash working capital (note 13(b))	24,377	(1,294)	(10,702)	3,531
	63,263	**32,837**	**87,494**	**61,417**
Investing activities:				
Acquisition, net of cash acquired				(1,581)
Purchase of plant and equipment	(9,369)	(8,021)	(84,895)	(51,566)
Additions to assets held for sale	(350)		(350)	(2,248)
Proceeds on disposal of plant and equipment	3,173	120	7,821	4,036
Proceeds on disposal of assets held for sale			194	10,200
Net changes in non-cash working capital (note 13(b))	(2,068)	(18,976)	3,191	(4,727)
	(8,614)	**(26,877)**	**(74,039)**	**(45,886)**
Financing activities:				
Cheques issued in excess of cash deposits	(311)			
(Decrease) increase in revolving credit facility	(10,000)	20,000		(500)
Repayment of capital lease obligations	(2,029)	(900)	(4,719)	(2,508)
Issue of common shares		859		1,599
Stock options exercised (note 9(a))			702	
Financing costs		(7)		(774)
	(12,340)	**19,952**	**(4,017)**	**(2,183)**
Increase in cash and cash equivalents	**42,309**	**25,912**	**9,438**	**13,348**
Cash and cash equivalents, beginning of period		(4,669)	32,871	7,895
Cash and cash equivalents, end of period	**$ 42,309**	**$ 21,243**	**$ 42,309**	**$ 21,243**

Supplemental cash flow information (note 13(a))

See accompanying notes to unaudited interim consolidated financial statements.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

1. Nature of operations

North American Energy Partners Inc. was incorporated under the Canada Business Corporations Act on October 17, 2003. On November 26, 2003, North American Energy Partners Inc. (the Company) purchased all of 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 and substantially all of the plant and equipment, prepaids and accounts payable of North American Equipment Ltd. The Company had no operations prior to November 26, 2003.

The Company undertakes several types of projects including heavy construction, industrial and commercial site development, 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, 2008 and should be read in conjunction with those consolidated financial statements.

These financial statements include the accounts of the Company, its wholly-owned subsidiaries, NACGI and NACG Finance LLC, the Company s joint venture, Noramac Ventures Inc. and the following 100% owned subsidiaries of NACGI:

North American Caisson Ltd.	North American Pipeline Inc.
North American Construction Ltd.	North American Road Inc.
North American Engineering Ltd.	North American Services Inc.
North American Enterprises Ltd.	North American Site Development Ltd.
North American Industries Inc.	North American Site Services Inc.
North American Mining Inc.	North American Pile Driving Inc.
North American Maintenance Ltd.	

3. Recently adopted Canadian accounting pronouncements

a) Financial instruments disclosure and presentation

Effective April 1, 2008, the Company prospectively adopted the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3862, Financial Instruments Disclosures , which replaces disclosure guidance in CICA Handbook Section 3861 and provides expanded disclosure requirements that enable users to evaluate the significance of financial instruments on the entity s financial position and its performance and the nature and extent of risks arising from financial instruments to which the entity is exposed during the period and at the balance sheet date, and how the entity manages those risks. This standard harmonizes

5

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

disclosures with International Financial Reporting Standards. The Company has provided the required disclosures in note 11 to its interim consolidated financial statements for the three and nine months ended December 31, 2008.

Effective April 1, 2008, the Company adopted CICA Handbook Section 3863, Financial Instruments Presentation , which carries forward presentation guidance in CICA Handbook Section 3861. This Section establishes standards for presentation of financial instruments and non-financial derivatives. It deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, gains and losses, and the circumstances in which financial assets and financial liabilities are offset. The adoption of this standard did not have a material impact on the presentation of financial instruments in the Company s financial statements.

b) Capital disclosures

Effective April 1, 2008, the Company prospectively adopted CICA Handbook Section 1535, Capital Disclosures , which requires disclosure of qualitative and quantitative information that enables users to evaluate the Company s objectives, policies and process for managing capital. The Company has provided the required disclosures in note 12 to its interim consolidated financial statements for the three and nine months ended December 31, 2008.

c) Inventories

Effective April 1, 2008, the Company retrospectively adopted CICA Handbook Section 3031, Inventories without restatement of prior periods. This standard requires inventories to be measured at the lower of cost and net realizable value and provides guidance on the determination of cost, including the allocation of overheads and other costs to inventories, the requirement for an entity to use a consistent cost formula for inventory of a similar nature and use, and the reversal of previous write-downs to net realizable value when there is subsequent increases in the value of inventories. This new standard also clarifies that spare component parts that do not qualify for recognition as property, plant and equipment should be classified as inventory. To adopt the new standard, the Company reversed a tire impairment that was previously recorded at March 31, 2008 in other assets of $1,383 with a corresponding decrease to opening deficit of $991 net of future taxes of $392. The Company then reclassified $5,086 of tires and spare component parts from Other assets to Inventory . As at December 31, 2008, inventory is comprised of tires and spare component parts of $13,152 and job materials of $2,058. The Company carries inventory at the lower of weighted average cost and net realizable value. The carrying amount of inventory pledged as security for borrowings under the revolving credit facility (note 7 (a)) is approximately $15,210 as at December 31, 2008. The adoption of this standard did not have a significant impact on net (loss) income for the three and nine months ended December 31, 2008.

d) Recent Canadian accounting pronouncements not yet adopted

i. Goodwill and intangible assets

In February 2008, the CICA issued Handbook Section 3064, Goodwill and Intangible Assets , which replaces Section 3062, Goodwill and Intangible Assets, and Section 3450, Research and Development Costs, 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

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

intangible assets, are equivalent to the corresponding provisions of International Accounting Standard IAS 38, Intangible Assets. This new standard is effective for the Company s interim and annual consolidated financial statements commencing April 1, 2009. The Company is currently evaluating the impact of this standard.

4. Goodwill

In accordance with the Company s accounting policy, a goodwill impairment test is completed annually on October 1 of each fiscal year or whenever events or changes in circumstances indicate that an impairment may exist. The Company conducted its annual goodwill impairment test on October 1, 2008 and concluded that the fair value of each of its reporting segments exceeded carrying amount. However, at December 31, 2008, based on adverse changes in the Company s principal markets, the recent decline in the Company s market capitalization and updated long-term financial forecasts, which resulted in lower near-term and longer-term revenues and cash flows for each reporting unit, the Company concluded that an interim test for impairment of goodwill was appropriate.

In performing the goodwill assessment at December 31, 2008, the Company considered discounted cash flows, market capitalization and other factors, including observable market data to determine the fair value of each reporting unit. Although implied market comparable valuation multiples and transaction premiums were considered in the analysis, there are significant differences in the products, services, and operating characteristics of the reporting units as compared to a set of selected comparable companies. As a result, the Company relied primarily on the discounted cash flow method, using management projections for each reporting unit and risk-adjusted discount rates to determine fair value. Expected cash flows of each of the reporting units were discounted using estimated discount rates ranging from 18.0% to 27.0% to calculate fair value. As a result of this analysis, the Company concluded that the carrying value of the Pipeline Operating Segment (also a separate reporting unit) exceeded its fair value and the Company recorded an impairment charge of $32,753, calculated as the difference between the carrying value of goodwill of the Pipeline Operating Segment and its implied fair value of the Pipeline Operating Segment of $nil at December 31, 2008. The implied fair value of goodwill was determined in the same manner as the value of goodwill is determined in a business combination. The impairment charge is included in the caption Impairment of goodwill in the Consolidated Statement of Operations, Comprehensive (Loss) Income and Deficit during the three and nine months period ended December 31, 2008.

At December 31, 2008, the Company determined that there was no impairment to any other reporting units as their fair values exceeded their carrying values. However, given conditions in the financial markets and the global economic downturn and their current impact on the Company s principal markets, events or changes on circumstances could occur in the future, which may cause actual performance in the near-term and/or longer-term to be materially different from current forecasts and may result in further impairment of goodwill. Circumstances that would require us to perform an interim test for impairment of goodwill include further updates to our long-term financial forecasts resulting in lower near-term and longer-term revenue and cash flow forecasts for all our operating segments, actual performance being materially different from our forecasts, continued adverse changes in our principal market; and a continuing weakness and/or declines in our market capitalization.

The change in goodwill during the nine months ended is as follows:

For the nine months ended	**December 31, 2008**
Balance, beginning of period	$ 200,072
Impairment of goodwill	(32,753)

Balance, end of period	$	167,319

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

5. Restatement

In preparing the financial statements for the year ended March 31, 2008, the Company determined that its previously issued interim unaudited consolidated financial statements for the three and nine months ended December 31, 2007 did not properly account for an embedded derivative that is not closely related to the host contract with respect to price escalation features in a supplier maintenance contract. As disclosed in the annual consolidated statements, the Company has restated its original transition adjustment on adoption of CICA Handbook Section 3855, Financial Instruments Recognition and Measurement disclosed in the financial statements for the three and nine months ended December 31, 2007 and recorded the fair value of this embedded derivative liability of $2,474 on April 1, 2007, with a corresponding increase in the opening deficit of $1,769, net of future income taxes of $705.

The embedded derivative is measured at fair value and included in derivative financial instruments on the consolidated balance sheet with changes in fair value recognized in net income since April 1, 2007 and the comparative figures for the three and nine months ended December 31, 2007 have been restated to account for this embedded derivative.

The impact of this restatement on the Interim Consolidated Statements of Operations, Comprehensive (Loss) Income and Deficit is as follows:

Three Months Ended December 31, 2007	**As Previously Reported**	**Adjustments**	**As Restated**
Realized and unrealized gain on derivative financial instruments	$ (5,419)	$ 909	$ (4,510)
Future income taxes	7,707	(238)	7,469
Net income	25,377	(671)	24,706
Deficit, beginning of period	(65,557)	1,080	(64,477)
Deficit, end of period	(40,180)	409	(39,771)
Basic net income per share	0.71	(0.02)	0.69
Diluted net income per share	0.69	(0.02)	0.67

Nine Months Ended December 31, 2007	**As Previously Reported**	**Adjustments**	**As Restated**
Realized and unrealized loss on derivative financial instruments	$ 39,766	$ (3,076)	$ 36,690
Future income taxes	6,053	898	6,951
Net income	17,122	2,178	19,300
Change in accounting policy related to financial instruments	(1,776)	(1,769)	(3,545)
Deficit, end of period	(40,180)	409	(39,771)
Basic net income per share	0.48	0.06	0.54
Diluted net income per share	0.46	0.06	0.52

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

The impact of this restatement on the Interim Consolidated Balance Sheets is as follows:

As at December 31, 2007	As Previously Reported	Adjustments	As Restated
Derivative financial instruments	$ 101,316	$ (602)	$ 100,714
Future income taxes (long-term asset)	30,059	(193)	29,866
Deficit	(40,180)	409	(39,771)

The impact of this restatement on the Interim Consolidated Statements of Cash Flows is as follows:

Three Months Ended December 31, 2007	As Previously Reported	Adjustments	As Restated
Net income	$ 25,377	$ (671)	$ 24,706
Unrealized change in fair value of derivative financial instruments	(6,086)	909	(5,177)
Future income taxes	7,707	(238)	7,469

Nine Months Ended December 31, 2007	As Previously Reported	Adjustments	As Restated
Net income	$ 17,122	$ 2,178	$ 19,300
Unrealized change in fair value of derivative financial instruments	37,764	(3,076)	34,688
Future income taxes	6,053	898	6,951

6. Plant and equipment

December 31, 2008	Cost	Accumulated Depreciation	Net Book Value
Heavy equipment	$ 324,660	$ 72,749	$ 251,911
Major component parts in use	21,283	2,178	19,105
Other equipment	21,442	7,692	13,750
Licensed motor vehicles	11,549	7,002	4,547
Office and computer equipment	12,083	4,959	7,124
Buildings	20,128	4,557	15,571
Leasehold improvements	6,475	1,640	4,835
Assets under capital lease	33,338	11,432	21,906
	$ 450,958	$ 112,209	$ 338,749

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

March 31, 2008	Cost	Accumulated Depreciation	Net Book Value
Heavy equipment	$ 281,975	$ 62,539	$ 219,436
Major component parts in use	12,291	4,797	7,494
Other equipment	17,086	6,232	10,854
Licensed motor vehicles	8,981	6,110	2,871
Office and computer equipment	9,016	3,479	5,537
Buildings	19,530	3,443	16,087
Leasehold improvements	6,272	1,107	5,165
Assets under capital lease	23,271	9,676	13,595
	$ 378,422	$ 97,383	$ 281,039

During the three and nine months ended December 31, 2008, additions of plant and equipment included $7,991 and $13,107, respectively, for capital leases (three and nine months ended December 31, 2007 $4,255 and $4,553 respectively). Depreciation of equipment under capital leases of $1,337 and $3,570 for the three and nine months ended December 31, 2008, respectively is included in depreciation expense (three and nine months ended December 31, 2007 $783 and $1,929 respectively).

7. Debt

a) Revolving credit facility

On June 7, 2007, the Company modified its amended and restated credit agreement to provide for borrowings of up to $125.0 million (previously $55.0 million) under which revolving loans and letters of credit may be issued. This facility matures on June 7, 2010. Advances under the revolving credit facility may be repaid from time to time at the option of the Company. Based upon the Company s current credit rating, prime rate revolving loans under the agreement will bear interest at the Canadian prime rate plus 0.25% per annum, Canadian bankers acceptances have stamping fees equal to 1.75% per annum and letters of credit are subject to a fee of 1.25% per annum.

This credit facility is secured by a first priority lien on substantially all 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.

As of December 31, 2008, the Company had outstanding borrowings of $nil (March 31, 2008 $nil) under the revolving credit facility and had issued $20.8 million in letters of credit to support performance guarantees associated with customer contracts. The funds available under the revolving credit facility are reduced for any outstanding letters of credit. The Company s borrowing availability under the facility was $104.2 million at December 31, 2008.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

b) Senior notes

	December 31, 2008	March 31, 2008
Principal outstanding of 8 3/4% senior unsecured notes due in 2011 ($US)	$ 200,000	$ 200,000
Unrealized foreign exchange	44,920	5,574
Unamortized bond issue costs, financing costs and premiums, net	(3,003)	(3,059)
Fair value of embedded prepayment and early redemption options	2,297	(4,270)
	$ 244,214	$ 198,245

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 December 31, 2008, 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%.

8. Asset retirement obligation

During the quarter ended June 30, 2008, the Company recorded an asset retirement obligation related to the future retirement of a facility on leased land. Accretion expense associated with this obligation is included in equipment costs in the Interim Consolidated Statements of Operations, Comprehensive (Loss) Income and Deficit.

The following table presents the reconciliation of the liability for the asset retirement obligation:

At December 31, 2008	Amount
Balance, beginning of period	$

Obligation relating to the future retirement of a facility on leased land		311
Accretion expense		159
Balance, end of period	$	470

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

At December 31, 2008, estimated undiscounted cash flows required to settle the obligation were $1,454. The credit adjusted risk-free rate assumed in measuring the asset retirement obligation was 8.94%. The Company expects to settle this obligation in 2021.

9. Shares

a) Common shares

Authorized:

Unlimited number of common voting shares

Unlimited number of common non-voting shares

Issued:

	Number of Shares	Amount
Common voting shares		
Outstanding at March 31, 2008	35,929,476	$ 298,436
Issued on exercise of options	109,000	702
Transferred from contributed surplus on exercise of options		835
Outstanding at December 31, 2008	36,038,476	$ 299,973

b) Contributed surplus

Balance, March 31, 2008	$ 4,215
Stock-based compensation (note 15)	1,391
Deferred performance share unit plan (note 15)	222
Transferred to common shares on exercise of options	(835)
Balance, December 31, 2008	$ 4,993

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

c) Net (loss) income per share

	Three Months Ended December 31, 2008	Three Months Ended December 31, 2007 (Restated note 5)	Nine Months Ended December 31, 2008	Nine Months Ended December 31, 2007 (Restated note 5)
Basic net (loss) income per share				
Net (loss) income available to common shareholders	$ (14,699)	$ 24,706	$ 3,175	$ 19,300
Weighted average number of common shares	36,038,476	35,809,141	36,015,172	35,744,406
Basic net (loss) income per share	$ (0.41)	$ 0.69	$ 0.09	$ 0.54
Diluted net (loss) income per share				
Net (loss) income available to common shareholders	$ (14,699)	$ 24,706	$ 3,175	$ 19,300
Weighted average number of common shares	36,038,476	35,809,141	36,015,172	35,744,406
Dilutive effect of:				
Stock options		919,297	668,687	1,110,011
Weighted average number of diluted common shares	36,038,476	36,728,438	36,683,859	36,854,417
Diluted net (loss) income per share	$ (0.41)	$ 0.67	$ 0.09	$ 0.52

For the three months ended December 31, 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.

10. Interest expense

	Three Months Ended December 31, 2008	Three Months Ended December 31, 2007	Nine Months Ended December 31, 2008	Nine Months Ended December 31, 2007
Interest on senior notes	$ 5,834	$ 5,834	$ 17,503	$ 17,503
Amortization of bond issue costs and premiums	219	162	577	669
Interest on revolving credit facility	116	270	206	457
Interest on capital lease obligations	341	165	887	497

Interest on long-term debt	6,510	6,431	19,173	19,126
Other interest	264	968	490	1,207
	$ 6,774	$ 7,399	$ 19,663	$ 20,333

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

11. Financial instruments and risk management

a) Fair value and classification of financial instruments

Based on the measurement categories set out in CICA Handbook Section 3855, Financial Instruments Recognition and Measurement , the Company s financial instruments are classified as follows:

Cash and cash equivalents are classified as financial assets held for trading and are recorded at fair value, with realized and unrealized gains and losses reported in net income;

Accounts receivable and unbilled revenue are classified as loans and receivables and are initially recorded at fair value and subsequent to initial recognition are accounted for at amortized cost using the effective interest method;

The Company has classified cheques issued in excess of cash deposits, amounts due under its revolving credit facility, accounts payable, accrued liabilities, and senior notes as other financial liabilities. Other financial liabilities are accounted for on initial recognition at fair value and subsequent to initial recognition at amortized cost using the effective interest method with gains and losses reported in net income in the period that the liability is derecognized; and

Derivative financial instruments, including non-financial derivatives, are classified as held-for-trading and are measured at fair value with realized and unrealized gains and losses recognized in the Consolidated Statement of Operations, Comprehensive Income (Loss) and Deficit, unless exempted from derivative treatment as a normal purchase or sale.

In determining the fair value of financial instruments, the Company uses a variety of methods and assumptions that are based on market conditions and risks existing on each reporting date. Counterparty confirmations and standard market conventions and techniques, such as discounted cash flow analysis and option pricing models, are used to determine the fair value of the Company s financial instruments, including derivatives. All methods of fair value measurement result in a general approximation of value and such value may never actually be realized.

The fair values of the Company s accounts receivable, unbilled revenue, cheques issued in excess of cash deposits, accounts payable and accrued liabilities approximate their carrying amounts due to the relatively short periods to maturity for the instruments.

The fair values of amounts due under the revolving credit facility are based on management estimates which are determined by discounting cash flows required under the instruments at the interest rate currently estimated to be available for loans with similar terms. Based on these estimates and by using the outstanding balance of $nil at December 31, 2008 and March 31, 2008, the fair value of amounts due under the revolving credit facility as at December 31, 2008 and March 31, 2008 are not significantly different than their carrying value.

The fair values of the Company s cross-currency and interest rate swap agreements and the Company s embedded derivatives are based on appropriate price modeling commonly used by market participants to estimate fair value. Such modeling includes option pricing models and discounted cash flow analysis, using observable market based inputs to estimate fair value. Fair value determined using valuation models requires the use of assumptions concerning the amount and timing of future cash flows. Fair value amounts reflect management s best estimates using external readily observable market data such as future prices, interest rate yield curves, foreign exchange rates and discount rates for time value. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

	December 31, 2008		March 31, 2008	
Asset (Liability)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Senior notes(i)	$ (244,214)	$ (198,385)	$ (198,245)	$ (209,178)
Capital lease obligations(ii)	(23,164)	(22,542)	(14,776)	(14,776)

(i) The fair value of the $US denominated 8 3/4 % senior notes is based upon their period end closing market price translated into Canadian dollars at period end exchange rates as at December 31, 2008 and March 31, 2008.

(ii) The fair values of amounts due under capital leases are based on management estimates which are determined by discounting cash flows required under the instruments at the interest rates currently estimated to be available for loans with similar terms.

Derivative financial instruments that are used for risk management purposes, as described in Note 11(b) under Risk Management consist of the following:

December 31, 2008	**Derivative Financial Instruments**	**Senior Notes**
Cross-currency and interest rate swaps	$ 45,338	
Embedded price escalation features in a long-term revenue construction contract	1,894	
Embedded price escalation features in long-term supplier contracts	20,768	
Embedded prepayment and early redemption options on senior notes		2,296
Total fair value of derivative financial instruments	68,000	2,296
Less: current portion	12,226	
	$ 55,774	2,296

March 31, 2008	**Derivative Financial Instruments**	**Senior Notes**
Cross-currency and interest rate swaps	$ 81,649	
Embedded price escalation features in a long-term revenue construction contract	14,821	
Embedded price escalation features in a long-term supplier contract	1,269	
Embedded prepayment and early redemption options on senior notes		(4,270)
Total fair value of derivative financial instruments	97,739	(4,270)
Less: current portion	4,720	
	$ 93,019	(4,270)

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

The realized and unrealized (gain)/loss on derivative financial instruments is as follows:

	Three Months Ended December 31		Nine months Ended December 31	
	2008	2007 (Restated note 5)	2008	2007 (Restated note 5)
Realized and unrealized (gain)/loss on cross-currency and interest rate swaps	$ (28,087)	$ (3,925)	$ (34,309)	$ 26,248
Unrealized (gain)/loss on embedded price escalation features in a long-term revenue construction contract	(8,424)	(2,630)	(12,927)	8,961
Unrealized loss/(gain) on embedded price escalation features in long-term supplier contracts	10,346	909	19,499	(3,076)
Unrealized (gain)/loss on embedded prepayment and early redemption options on senior notes	(358)	1,136	6,566	4,557
	$ (26,523)	$ (4,510)	$ (21,171)	$ 36,690

b) Risk Management

The Company is exposed to market, credit and liquidity risks associated with its financial instruments. The Company will from time to time use various financial instruments to reduce market risk exposures from changes in foreign currency exchange rates and interest rates. The Company does not hold or use any derivative instruments for trading or speculative purposes.

Overall, the Company s Board of Directors has responsibility for the establishment and approval of the Company s risk management policies. Management performs a risk assessment on a continual basis to ensure that all significant risks related to the Company and its operations have been reviewed and assessed to reflect changes in market conditions and the Company s operating activities.

Market Risk

Market risk is the risk of loss that results from changes in market factors such as foreign currency exchange rates and interest rates. The level of market risk to which the Company is exposed at any point in time varies depending on market conditions, expectations of future price or market rate movements and composition of the Company s financial assets and liabilities held, non-trading physical assets and contract portfolios.

To manage the exposure related to changes in market risk, the Company uses various risk management techniques including the use of derivative instruments. Such instruments may be used to establish a fixed price for a commodity, an interest-bearing obligation or a cash flow denominated in a foreign currency. Market risk exposures are monitored regularly and tolerances and control processes are in place to monitor that only authorized activities are undertaken.

The sensitivities provided below are hypothetical and should not be considered to be predictive of future performance or indicative of earnings on these contracts.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

i. Foreign exchange risk

The Company has 8 3/4 % Senior Notes denominated in U.S. dollars in the amount of U.S. $200.0 million. In order to reduce its exposure to changes in the U.S. to Canadian dollar exchange rate, the Company 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, the Company also entered into a U.S. dollar interest rate swap and a Canadian dollar interest rate swap as discussed in note 11(b)(ii) below. These derivative financial instruments were not designated as hedges for accounting purposes. At December 31, 2008 and March 31, 2008, the notional principal amount of the cross-currency swaps was U.S. $200.0 million and Canadian $263.0 million.

On December 17, 2008, the Company received notice that all three swap counterparties had exercised the cancelation option on the U.S. dollar interest rate swap and, effective February 2, 2009, the U.S. dollar interest rate swap was terminated. In addition to net accrued interest to the termination date of U.S. $0.7 million, the counterparties will pay a cancellation premium of 2.2% on the notional amount of U.S. $200.0 million or U.S. $4.4 million (equivalent to Canadian $5.3 million), which is included in the caption Other income in the Consolidated Statement of Operations, Comprehensive (Loss) Income and Deficit for the three and nine months ended December 31, 2008.

The Company s Canadian dollar interest rate swap and cross-currency swap agreement are not cancellable at the option of the counterparties and remain in effect. The Company 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, the Company will receive quarterly floating rate payments in U.S. dollars on the cross-currency swap agreement at the prevailing 3-month LIBOR rate plus a spread of 4.2% on the notional amount of U.S. $200.0 million.

As a result of the cancellation of the U.S. dollar interest rate swap, the Company is exposed to changes in the value of the Canadian dollar versus the U.S. dollar. To the extent that 3-month 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 LIBOR on the cross-currency swap agreement), the Company will have to acquire U.S. dollars to fund a portion of its semi-annual coupon payment on its Senior Notes. At the 3-month U.S. LIBOR rate of 1.4% at December 31, 2008, a $0.01 increase (decrease) in exchange rates in the Canadian dollar would result in a Canadian $0.03 million decrease (increase) in the amount of Canadian dollars required to fund each semi-annual coupon payment.

The Company also regularly transacts 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. The Company may fix its exposure in either the Canadian dollar or the U.S. dollar for these short-term transactions, if material.

At December 31, 2008, with other variables unchanged, a $0.01 increase (decrease) in exchange rates of the Canadian dollar to the U.S. dollar related to the U.S. dollar denominated senior notes would decrease (increase) net income by approximately $1.7 million. With other variables unchanged, a $0.01 increase (decrease) in exchange rates in the Canadian to the U.S. dollar related to the cross-currency swap would increase (decrease) net income by approximately $2.0 million. The impact of similar exchange rate changes on short-term exposures would be insignificant and there would be no impact to other comprehensive income.

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

ii. Interest rate risk

The Company is exposed to interest rate risk from the possibility that changes in interest rates will affect future cash flows or the fair values of its financial instruments. Amounts outstanding under the Company s revolving credit facility are subject to a floating rate. The Company s senior notes are subject to a fixed rate.

In some circumstances, floating rate funding may be used for short-term borrowings and other liquidity requirements. The Company may use derivative instruments to manage interest rate risk.

In conjunction with the cross-currency swap agreement discussed in note 11(b)(i) above, the Company also entered into a U.S. dollar interest rate swap and a Canadian dollar interest rate swap with the net effect of economically converting the 8 $^{3}/4$% rate payable on the 8 $^{3}/4$% senior notes into a fixed rate of 9.765% for the duration that the 8 $^{3}/4$% senior notes are outstanding. On May 19, 2005, in connection with the Company s new revolving credit facility at that time, this fixed rate was increased to 9.889%. These derivative financial instruments were not designated as a hedge for accounting purposes.

As a result of the U.S. dollar interest swap cancelation described in note 11(b)(i), the Company is exposed to changes in interest rates. The Company has a fixed semi-annual coupon payment of 8 $^{3}/4$% on its U.S. $200.0 million Senior Notes. With the termination of the U.S. dollar interest rate swap, the Company will no longer receive fixed U.S. dollar payments from the counterparties to offset the coupon payment on its Senior Notes. As a result of this termination, our annual interest expense at current LIBOR rate will increase U.S. $6.3 million. In addition, we are now exposed to interest rate risk where a 100 basis point increase (decrease) in the 3-month U.S. LIBOR rate will result in a U.S. $2.0 million decrease (increase) in annual interest expense.

At December 31, 2008 and March 31, 2008, the notional principal amounts of the interest rate swaps were U.S. $200.0 million and Canadian $263.0 million.

As at December 31, 2008, 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 $5.8 million with this change in fair value being recorded in net income. As at December 31, 2008, 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 $0.8 million with this change in fair value being recorded in net income. As at December 31, 2008, holding all other variables constant, a 100 basis point increase (decrease) of Canadian to U.S. interest rate volatility would impact the fair value of the interest rate swaps by $nil million with this change in fair value being recorded in net income.

At December 31, 2008, the Company held $nil of floating rate debt pertaining to its revolving credit facility (March 31, 2008 $nil). As at December 31, 2008, holding all other variables constant, a 100 basis point increase (decrease) to interest rates would not have a significant impact on net income or equity. This assumes that the amount of floating rate debt remains unchanged from that which was held at December 31, 2008.

Credit Risk

Credit risk is the financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company manages the credit risk associated with its cash by holding its funds with reputable financial institutions. The Company is exposed to credit risk through its accounts receivable and unbilled revenue. Credit risk for trade and other accounts receivables, and unbilled revenue are managed through established credit monitoring activities.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

The Company has a concentration of customers in the oil and gas sector. The concentration risk is mitigated primarily by the customers being large investment grade organizations. The credit worthiness of new customers is subject to review by management through consideration of the type of customer and the size of the contract.

At December 31, 2008 and March 31, 2008, the following customers represented 10% or more of accounts receivable and unbilled revenue:

	December 31, 2008	March 31, 2008
Customer A	23%	19%
Customer B	13%	8%
Customer C	13%	9%
Customer D	9%	11%
Customer E	1%	11%
Customer F	0%	18%

The Company reviews its accounts receivable amounts regularly and amounts are written down to their expected realizable value when outstanding amounts are determined not to be fully collectible. This generally occurs when the customer has indicated an inability to pay, the Company is unable to communicate with the customer over an extended period of time, and other methods to obtain payment have been considered and have not been successful. Bad debt expense is charged to net income in the period that the account is determined to be doubtful. Estimates of the allowance for doubtful accounts are determined on a customer-by-customer evaluation of collectability at each reporting date taking into consideration the following factors: the length of time the receivable has been outstanding, specific knowledge of each customer s financial condition and historical experience.

The Company s maximum exposure to credit risk for trade accounts receivable is the carrying value of $136,352 as at December 31, 2008 (March 31, 2008 $157,237), other receivables is the carrying value of $6,896 (March 31, 2008 $8,765) and unbilled revenue is the carrying value of $60,657 as at December 31, 2008 (March 31, 2008 $70,883). On a geographic basis as at December 31, 2008, approximately 99% (March 31, 2008 89%) of the balance of trade accounts receivable (before considering the allowance for doubtful accounts) was due from customers based in Western Canada.

Payment terms are generally net 30 days. As at December 31, 2008 and March 31, 2008 trade receivables are aged as follows:

	December 31, 2008	March 31, 2008
Not past due	$ 96,562	$ 124,211
Past due 1-30 days	11,190	19,790
Past due 31-60 days	10,286	1,896
More than 61 days	18,314	11,340
Total	$ 136,352	$ 157,237

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

As at December 31, 2008, the Company has recorded an allowance for doubtful accounts of $3,259 (March 31, 2008 $742) of which 87% relates to amounts that are more than 61 days past due.

The allowance is an estimate of the December 31, 2008 trade receivable balances that are considered uncollectible. Changes to the allowance during the three and nine months ended December 31, 2008 consisted of payments received on outstanding balances of $nil and $100 respectively (three and nine months ended December 31, 2007 $nil and $nil, respectively), bad debt expense of $1,225 and $2,625 for the three and nine months ended December 31, 2008 (three and nine months ended December 31, 2007 $nil and $nil, respectively) and write off of $8 and $8 for the three and nine months ended December 31, 2008 (three and nine months ended December 31, 2007 $nil and $nil, respectively).

Credit risk on cross-currency and interest rate swap agreements arises from the possibility that the counterparties to the agreements may default on their respective obligations under the agreements. This credit risk only arises in instances where these agreements have positive fair value for the Company.

Liquidity Risks

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company manages liquidity risk through management of its capital structure and financial leverage, as outlined in note 12 to the unaudited interim consolidated financial statements. It also manages liquidity risk by continuously monitoring actual and projected cash flows to ensure that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Company s reputation. The Company believes that forecasted cash flows from operating activities, along with the available lines of credit, will provide sufficient cash requirements to cover the Company s forecasted normal operating and budgeted capital expenditures.

The Company s principal sources of cash are funds from operations and borrowings under our revolving credit facility.

The Company s revolving credit facility contains covenants that restrict its activities, including, but not limited to, incurring additional debt, transferring or selling assets and making investments including acquisitions. Under the revolving credit agreement, Consolidated Capital Expenditures during any applicable period cannot exceed 120.0% of the amount in the capital expenditure plan. In addition, the Company is required to satisfy certain financial covenants, including a minimum interest coverage ratio and a maximum senior leverage ratio, both of which are calculated using Consolidated EBITDA as defined in the revolving credit agreement, as well as a minimum current ratio.

At December 31, 2008, the Company was in compliance with its senior leverage, its interest coverage, and working capital covenants.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

The following are the undiscounted contractual cash flows of financial liabilities and other contractual cash flows measured at period end exchange rates:

				Fiscal Year				
	Carrying Amount	Contractual Cash Flows	Remaining 2009	2010	2011	2012	2013	2014 and Thereafter
Accounts payable and accrued liabilities	$ 121,026	$ 121,026	$ 121,026	$	$	$	$	$
Capital lease obligations (including interest)	23,164	24,930	6,352	6,188	5,233	4,629	2,369	159
Senior notes(i)	244,214	244,920				244,920		
Interest on senior notes	2,167	69,039		23,013	23,013	23,013		
Cross-currency and interest rate swaps(i)	45,338	71,988		2,996	2,996	65,996		

(i) The contractual cash flows of the Senior Notes represents the gross loan commitments of U.S. $200.0 million translated at the exchange rate of 1.2246 as at December 31, 2008, which reflects an unrealized foreign exchange commitment of $44,920. However, as disclosed in note 11(b), the Company entered into a cross currency swap agreement which fixes this obligation related to the Senior Notes and cross currency and interest swaps contracts at $263.0 million payable at the December 1, 2011 maturity date.

12. Capital disclosures

The Company s objectives in managing capital are to ensure sufficient liquidity to pursue its strategy of organic growth combined with strategic acquisitions and to provide returns to its shareholders. The Company defines capital that it manages as the aggregate of its shareholders equity, which is comprised of issued capital, contributed surplus, accumulated other comprehensive income (loss) and deficit. The Company manages its capital structure and makes adjustments to it in light of general economic conditions, the risk characteristics of the underlying assets and the Company s working capital requirements. In order to maintain or adjust its capital structure, the Company, upon approval from its Board of Directors, may issue or repay long-term debt, issue shares, repurchase shares through a normal course issuer bid, pay dividends or undertake other activities as deemed appropriate under the specific circumstances. The Board of Directors reviews and approves any material transactions out of the ordinary course of business, including proposals on acquisitions or other major investments or divestitures, as well as capital and operating budgets.

The Company monitors debt leverage ratios as part of the management of liquidity and shareholders return and to sustain future development of the business. The Company is also subject to externally imposed capital requirements under its revolving credit facility and indenture agreement governing the U.S. dollar denominated $8\,^{3}/4\%$ senior notes, which 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 s overall strategy with respect to capital risk management remains unchanged from the year ended March 31, 2008.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

The Company is subject to restrictive covenants under its banking agreements with its principal lenders related to its revolving credit facility (note 7(a)), its capital lease obligations and senior notes (note 7(b)) that are measured on a quarterly basis. These covenants include, but are not limited to, a current ratio, senior leverage ratio, and interest coverage ratio. As at December 31, 2008, the Company was in compliance with all externally imposed covenant requirements.

13. Other information

a) Supplemental cash flow information

	Three Months Ended December 31,		Nine Months Ended December 31,	
	2008	**2007**	**2008**	**2007**
Cash paid during the period for:				
Interest	$ 13,736	$ 13,787	$ 27,558	$ 27,551
Income taxes		8		29
Cash received during the period for:				
Interest	8	97	(2)	282
Income taxes	4		67	
Non-cash transactions:				
Acquisition of plant and equipment by means of capital leases	7,991	4,255	13,107	4,553
Lease inducements				1,045

b) Net change in non-cash working capital

	Three Months Ended December 31,		Nine Months Ended December 31,	
	2008	**2007**	**2008**	**2007**
Operating activities:				
Accounts receivable	$ (5,821)	$ 8,454	$ 20,237	$ (22,374)
Allowance for doubtful accounts	1,217	82	2,517	82
Unbilled revenue	49,503	(758)	10,226	9,386
Inventory	(5,808)	40	(10,016)	42
Prepaid expenses and deposits	1,570	212	2,483	4,957
Other assets		2,092		4,940
Accounts payable	(422)	(8,086)	(23,013)	13,174
Accrued liabilities	(9,111)	(4,970)	(15,206)	(7,296)
Billings in excess of costs incurred and estimated earnings on uncompleted contracts	(6,751)	1,640	2,070	620
	$ 24,377	$ (1,294)	$ (10,702)	$ 3,531

Investing activities:				
Accounts payable	$ (2,068)	$ (18,976)	$ 3,191	$ (4,727)

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

c) Income taxes

Income tax expense as a percentage of income before income taxes for the three and nine months ended December 31, 2008 differs from the statutory rate of 29.38% primarily due to the impact of changes in enacted tax rates, the benefit from changes in the timing of the reversal of temporary differences and a permanent difference related to the $32.8 million non-deductible impairment discussed in note 4. Income tax as a percentage of income before income taxes for the three and nine months ended December 31, 2007 differed from the statutory rate of 31.47% primarily due to the impact of the enacted rate changes during the period and the impact of new accounting standards for the recognition and measurement of financial instruments as certain embedded derivatives are considered capital in nature for income tax purposes.

14. Segmented information

a) General overview

The Company operates in the following reportable business 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.

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

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.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

b) Results by business segment

Three Months Ended December 31, 2008	Heavy Construction and Mining	Piling	Pipeline	Total
Revenues from external customers	$ 198,620	$ 41,565	$ 18,380	$ 258,565
Depreciation of plant and equipment	5,701	1,117	2	6,820
Segment profits	38,489	12,740	5,589	56,818
Impairment of goodwill			(32,753)	(32,753)
Transfer of plant and equipment between segments	8,231	338	(8,569)	
Segment assets	553,083	121,692	7,785	682,560
Expenditures for segment plant and equipment	14,629	479	87	15,195

Three Months Ended December 31, 2007	Heavy Construction and Mining	Piling	Pipeline	Total
Revenues from external customers	$ 154,402	$ 43,751	$ 76,741	$ 274,894
Depreciation of plant and equipment	5,563	817	419	6,799
Segment profits	28,097	11,386	12,934	52,417
Segment assets	439,487	116,195	98,473	654,155
Expenditures for segment plant and equipment	5,462	1,890	44	7,396

Nine Months Ended December 31, 2008	Heavy Construction and Mining	Piling	Pipeline	Total
Revenues from external customers	$ 564,101	$ 132,709	$ 101,026	$ 797,836
Depreciation of plant and equipment	18,438	2,811	567	21,816
Segment profits	86,416	32,445	22,464	141,325
Impairment of goodwill			(32,753)	(32,753)
Transfer of plant and equipment between segments	8,231	338	(8,569)	
Segment assets	553,083	121,692	7,785	682,560
Expenditures for segment plant and equipment	81,510	7,634	5,157	94,301

Nine Months Ended December 31, 2007	Heavy Construction and Mining	Piling	Pipeline	Total
Revenues from external customers	$ 431,140	$ 121,698	$ 113,258	$ 666,096
Depreciation of plant and equipment	16,676	2,534	721	19,931
Segment profits	68,631	31,725	14,154	114,510
Segment assets	439,487	116,195	98,473	654,155

Expenditures for segment plant and equipment	30,210	10,878	4,923	46,011

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

c) Reconciliations

i. (Loss) income before income taxes

	Three Months Ended December 31, 2008	Three Months Ended December 31, 2007 (Restated note 5)	Nine Months Ended December 31, 2008	Nine Months Ended December 31, 2007 (Restated note 5)
Total profit for reportable segments	$ 56,818	$ 52,417	$ 141,325	$ 114,510
Unallocated corporate expenses:				
General and administrative expense	(19,156)	(17,009)	(57,717)	(48,996)
Loss on disposal of plant and equipment	(1,022)	(5)	(3,778)	(850)
Loss on disposal of assets held for sale			(24)	(316)
Amortization of intangibles	(268)	(443)	(822)	(766)
Impairment of goodwill (note 4)	(32,753)		(32,753)	
Interest expense	(6,774)	(7,399)	(19,663)	(20,333)
Foreign exchange (loss) / gain	(32,504)	1,784	(39,099)	33,136
Realized and unrealized gain / (loss) on derivative financial instruments	26,523	4,510	21,171	(36,690)
Other income (note 11(b))	5,343	115	5,364	351
Unallocated equipment (costs) recovery(1)	(5,826)	(1,787)	1,540	(13,766)
(Loss) income before income taxes	$ (9,619)	$ 32,183	$ 15,544	$ 26,280

(1) 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

	December 31, 2008	March 31, 2008
Total assets for reportable segments	$ 682,560	$ 698,966
Corporate assets:		
Cash and cash equivalents	42,309	32,871
Plant and equipment	37,615	26,785
Future income taxes	15,805	26,416

Other	14,337	8,560
Total corporate assets	110,066	94,632
Total assets	$ 792,626	$ 793,598

All of the Company s assets are located in Canada and the activities are carried out throughout the year.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

iii. Depreciation of plant and equipment

	Three Months Ended December 31,		Nine Months Ended December 31,	
	2008	2007	2008	2007
Total depreciation for reportable segments	$ 6,820	$ 6,799	$ 21,816	$ 19,931
Depreciation for corporate assets	3,358	1,086	7,188	4,248
Total depreciation	$ 10,178	$ 7,885	$ 29,004	$ 24,179

d) Customers

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

	Three Months Ended December 31,		Nine Months Ended December 31,	
	2008	2007	2008	2007
Customer A	34%	24%	28%	31%
Customer B	22%	14%	19%	13%
Customer C	15%	11%	15%	12%
Customer D	7%	27%	12%	14%
Customer E	7%	12%	10%	13%

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

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

15. Stock-based compensation

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 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 December 31,			
	2008		2007	
	Number of Options	Weighted Average Exercise Price ($ per share)	Number of Options	Weighted Average Exercise Price ($ per share)
Outstanding, beginning of period	1,934,164	$ 7.93	1,927,440	$ 6.14
Granted	219,800	3.69	315,100	13.50
Exercised			(199,624)	(5.00)
Forfeited	(29,400)	6.27	(75,000)	(17.53)
Outstanding, end of period	2,124,564	$ 7.52	1,967,916	$ 7.00

	Nine Months Ended December 31,			
	2008		2007	
	Number of Options	Weighted Average Exercise Price ($ per share)	Number of Options	Weighted Average Exercise Price ($ per share)
Outstanding, beginning of period	2,036,364	$ 7.54	2,146,840	$ 6.03
Granted	344,800	8.22	315,100	13.50
Exercised	(109,000)	(6.45)	(347,024)	(5.00)
Forfeited	(147,600)	(10.20)	(147,000)	(11.39)
Outstanding, end of period	2,124,564	$ 7.52	1,967,916	$ 7.00

At December 31, 2008, the weighted average remaining contractual life of outstanding options is 7.2 years (March 31, 2008 7.6 years). At December 31, 2008, the Company had 1,010,552 exercisable options (March 31, 2008 804,192) with a weighted average exercise price of $5.60 (March 31, 2008 $5.30).

The Company recorded $458 and $1,391 of compensation expense related to the stock options in the three and nine months ended December 31, 2008, respectively (three and nine months ended December 31, 2007 $276 and $1,023 respectively), with such amount being credited to contributed surplus.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

The fair value of each unit under the Stock Option 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 share options issued under the Stock Option Plan are as follows:

	Three Months Ended December 31,		Nine Months Ended December 31,	
	2008	2007	2008	2007
Number of options granted	219,800	315,100	344,800	315,100
Weighted average fair value per option granted ($)	2.35	6.42	4.53	6.42
Weighted average assumptions:				
Dividend yield	nil%	nil%	nil%	nil%
Expected volatility	65.70%	40.90%	59.01%	40.90%
Risk-free interest rate	3.05%	4.00%	3.24%	4.00%
Expected life (years)	6.5	6.5	6.5	6.5

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 on operating income and 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 voting 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, subject to shareholder approval.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts 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 share options issued under the DPSU Plan at April 1, 2008 are as follows:

Number of units granted	111,020
Weighted average fair value per option granted ($)	12.34
Weighted average assumptions:	
Dividend yield	
Expected volatility	56.25%
Risk-free interest rate	2.83%
Expected life (years)	3.00

	Three Months Ended December 31, 2008		Nine Months Ended December 31, 2008	
	Number of Units	Weighted Average Exercise Price ($ per share)	Number of Units	Weighted Average Exercise Price ($ per share)
Outstanding, beginning of period	101,636			
Granted			111,020	
Exercised				
Forfeited	(2,464)		(11,848)	
Outstanding, end of period	99,172		99,172	

At December 31, 2008, the weighted average remaining contractual life of outstanding DPSUs is 2.25 years. For the three and nine months ended December 31, 2008, respectively, the Company granted nil and 111,020 units under the Plan and recorded compensation expense of $80 and $222 respectively which is included in general and administrative costs. As at December 31, 2008, there was approximately $661 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 2.25 years.

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

Directors 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-employee or 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 (Loss) Income 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 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 days 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. For the three and nine months ended December 31, 2008, the Company recorded a (recovery)/expense of $(41) and $190 respectively (three and nine months ended December 31, 2007 $nil and $nil).

	Three Months Ended December 31, 2008 Number of Units	Nine Months Ended December 31, 2008 Number of Units
Outstanding, beginning of period	38,261	11,822
Granted	54,444	80,883
Exercised		
Forfeited		
Outstanding, end of period	92,705	92,705

At December 31, 2008, the redemption value of these units were $4.10/unit (March 31, 2008 $16.01/unit).

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.

17. Claims revenue

On June 25, 2008, the Company reached an agreement with a customer to settle all outstanding claims arising from a pipeline project completed in fiscal 2008 for $8,000. The Company had previously recognized claims revenue of $2,744 related to such outstanding claims as at March 31, 2008 and it has recognized the

Table of Contents

NORTH AMERICAN ENERGY PARTNERS INC.

Notes to the Interim Consolidated Financial Statements

For the three and nine months ended December 31, 2008

(Amounts in thousands of Canadian dollars, except per share amounts or unless otherwise specified)

(Unaudited)

excess of the settlement over previously recognized claims revenue of $5,256 as revenue in the three months ended June 30, 2008. In December 2008, the Pipeline segment successfully settled a claim related to the TMX project completed this fiscal year. The claim was settled for $16,167 which had previously been recognized as revenue in the three months ended September 30, 2008. Additionally, our Heavy Construction and Mining segment had $5,264 of claims revenue for the three months ended December 31, 2008 while our Piling segment had $2,948 of claims revenue for the same period. Both segments claims revenue related to unsigned change orders.

18. Comparative figures

The comparative consolidated financial statements have been reclassified from statements previously presented to conform to the presentation of the current year consolidated financial statements.

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

The following discussion and analysis is as of February 5, 2009 and should be read in conjunction with the unaudited interim consolidated financial statements for the three and nine months ended December 31, 2008, the audited consolidated financial statements for the fiscal year ended March 31, 2008, 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) and, 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 are available on the Canadian Securities Administrators SEDAR System at www.sedar.com and the Securities and Exchange Commission s IDEA System at www.sec.gov.

February 5, 2009

Table of Contents

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

Prior Year Comparisons

In preparing the financial statements for the year ended March 31, 2008, we determined that the previously issued interim unaudited consolidated financial statements for the three and nine months ended December 31, 2007 did not properly account for an embedded derivative with respect to price escalation features in a supplier maintenance contract.

The embedded derivative has been measured at fair value and included in derivative financial instruments on the consolidated balance sheet with changes in fair value recognized in net income. The impact of this restatement on the Interim Consolidated Balance Sheet as at December 31, 2007 is a $0.2 million reduction to future income taxes (long-term assets), a $0.6 million reduction to derivative financial instruments and a $0.4 million improvement to deficit. The impact on the Interim Consolidated Statement of Operations and Comprehensive (Loss) Income and Deficit for the three and nine months ended December 31, 2007 is an adjustment to unrealized income on derivative financial instruments and income tax expense. For the three months ended December 31, 2007, this resulted in a reduction to net income of $0.7 million (restated as net income of $24.7 million) and a reduction to basic earnings per share of $0.02 per share (restated as $0.69 earnings per share) and a reduction to diluted earnings per share of $0.02 per share (restated as $0.67 earnings per share). For the nine months ended December 31, 2007, this resulted in an increase to net income of $2.2 million (restated as net income of $19.3 million) and an increase to basic earnings per share of $0.06 per share (restated as $0.54 earnings per share) and an increase to diluted earnings per share of $0.06 per share (restated as $0.52 earnings per share).

A. Business Overview and Strategy

Business Overview

We provide a wide range of heavy construction and mining, piling and pipeline installation services to customers in the Canadian oil sands, mineral mining, commercial and public construction and conventional oil and gas markets. Our primary market is the Alberta oil sands, where we support our customers mining operations and capital projects, with our core focus on providing recurring services, such as contract mining services, during the operational phase. On a trailing 12-months basis to December 31, 2008, recurring services represented 60% of our oil sands business. Our principal oil sands customers include all three of the producers that are currently mining bitumen in Alberta: Syncrude Canada Ltd.[1] (Syncrude), Suncor Energy Inc. (Suncor) and Albian Sands Energy Inc.[2] (Albian) as well as two large customers that are currently in the development phase of their projects: Canadian Natural Resources Limited (Canadian Natural) and Fort Hills[3]. We have long-term relationships with most of our customers. For example, we have been providing services to Syncrude and Suncor since they pioneered oil sands development over 30 years ago.

We believe that we operate the largest fleet of equipment of any contract resource services provider in the oil sands. Our total fleet includes over 776 pieces of diversified heavy construction equipment supported by over 925 ancillary vehicles. While our expertise covers mining, heavy construction, underground services (fire lines,

[1] Joint venture amongst Canadian Oil Sands Limited (37%), Imperial Oil Resources (25%), Petro-Canada Oil and Gas (12%), ConocoPhillips Oil Sands Partnership II (9%), Nexen Oil Sands Partnership (7%), Murphy Oil Company Ltd (5%) and Mocal Energy Limited (5%).

[2] Joint venture amongst Shell Canada Limited (60%), Chevron Canada Limited (20%) and Marathon Oil Canada Corporation (20%).

[3] Joint venture among between UTS Energy, Teck Cominco and Petro-Canada.

2

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

sewer, water etc) for industrial projects, piling and pipeline installation in any location, we have a specific capability operating in the harsh climate and difficult terrain of northern Canada generally and specifically in the oil sands in Alberta.

We believe that our significant oil sands knowledge, experience, long-term customer relationships, equipment capacity and scale of operations differentiate us from our competition. In addition, we believe that these capabilities will enable us to support the anticipated increase in demand for recurring services.*

While our mining services have been primarily focused on the oil sands, we believe that we have demonstrated our ability to successfully export knowledge and technology gained in the oil sands and put it to work in other resource development projects across Canada. As an example, in fiscal 2008 we successfully completed the development of a diamond mine site in Northern Ontario. This three-year project required us to operate effectively in a remote location in the extreme weather conditions prevalent in northern Canada. As a result of our successful work on this and other similar projects, we believe we have attracted the attention of resource developers. While development of resources has been affected by the current economic environment we remain committed to expanding our operations to other potential projects, including those in the high Arctic regions.

Operations Overview

Our business is organized into three interrelated, yet distinct, operating segments: (i) Heavy Construction and Mining, (ii) Piling and (iii) Pipeline. The table below shows the revenues generated by each operating segment for the three and nine month periods ended December 31, 2008 and December 31, 2007:

	Three Months Ended December 31,				**Nine Months Ended December 31,**			
(Dollars in thousands)	**2008**	**% of Total**	**2007**	**% of Total**	**2008**	**% of Total**	**2007**	**% of Total**
Revenue by operating segment:								
Heavy Construction and Mining	$ 198,620	*76.8%*	$ 154,402	*56.2%*	$ 564,101	*70.7%*	$ 431,140	*64.7%*
Piling	41,565	*16.1%*	43,751	*15.9%*	132,709	*16.6%*	121,698	*18.3%*
Pipeline	18,380	*7.1%*	76,741	*27.9%*	101,026	*12.7%*	113,258	*17.0%*
Total[(1)]	$ 258,565	*100.0%*	$ 274,894	*100.0%*	$ 797,836	*100.0%*	$ 666,096	*100.0%*
Segment profit:								
Heavy Construction and Mining	$ 38,489	*67.7%*	$ 28,097	*53.6%*	$ 86,416	*61.1%*	$ 68,631	*59.9%*
Piling	12,740	*22.4%*	11,386	*21.7%*	32,445	*23.0%*	31,725	*27.7%*
Pipeline	5,589	*9.8%*	12,934	*24.7%*	22,464	*15.9%*	14,154	*12.4%*
Total[(1)]	$ 56,818	*100.0%*	$ 52,417	*100.0%*	$ 141,325	*100.0%*	$ 114,510	*100.0%*

(1) Please refer to Analysis of Results for a discussion on segment results.

Our Heavy Construction and Mining segment focuses primarily on providing support for surface mining for oil sands and other natural resources. This includes activities such as:

land clearing, stripping, muskeg removal and overburden removal to expose the mining area;

*This paragraph contains forward looking statements. 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 nine months ended December 31, 2008

- the supply of labour and equipment to be operated within the customers mining fleet directly supporting the mining of ore;
- general support services including road building, repair and maintenance for both mine and treatment plant operations, hauling of sand and gravel and relocation of plant;
- construction related to the expansion of the operations including site development and construction of infrastructure; and
- reclamation of completed mining to stringent environmental standards.

Most of these services are classified as recurring services and represent the majority of services provided by our Heavy Construction and Mining business. We also provide industrial site construction for mega-projects and underground utility installation for plant, refinery and commercial building construction.

Our Piling segment installs all types of driven, drilled and screw piles, caissons, earth retention and stabilization systems. Operating throughout Western Canada, this segment has a solid record of performance on both small and large-scale projects. Our Piling segment also has experience with industrial projects in the oil sands and related petrochemical and refinery complexes and has been involved in the development of commercial and community infrastructure projects.

Our Pipeline segment installs transmission, distribution and gathering systems made of steel, fiberglass and/or plastic pipe in sizes up to 52 in diameter. Penstock installation services are also provided. This segment has successfully completed jobs of varying magnitude for some of Canada s largest energy companies. Recent projects include Kinder Morgan s Trans Mountain Expansion (TMX) Anchor Loop pipeline, which included installation of 160 km of large-diameter pipe through extremely challenging and ecologically sensitive terrain. The project, which runs from Hinton, Alberta through Jasper National Park, across the Rocky Mountains and through to Mt. Robson Provincial Park in British Columbia was successfully completed with minimal impact to the environment.

Current Business Environment

Business conditions in each of our key markets have been affected by the financial crisis and global economic downturn, which have brought tighter credit markets and lower demand and prices for many commodities, including oil. The following discusses our view of the impact of these conditions on the various industries we serve, as well as our outlook for these sectors.

Oil Sands Business Conditions

Oil sands customers utilize the type of services we provide at various stages of their projects. The one-to-four year mine development phase creates demand for capital-intense project development services, such as site preparation and facilities construction services. As mines move into their 30-40 year operational phase, demand shifts to recurring services such as operational surface mining, overburden removal, labour and equipment supply, mine infrastructure development and maintenance and land reclamation. Approximately 60% of our oil sands-related revenue (on a trailing 12-months basis) comes from the provision of recurring services to existing oil sands projects, with the balance coming from project development.

- *Recurring Services:* Recently, oil prices have dropped significantly from the record highs set in 2008 and construction costs have risen sharply, leading to a view that oil sands projects could become less viable. Contrary to some market views, existing oil sands mining operations are less sensitive to

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

short-term changes in oil prices due to their immense up front capital investment and relatively low operating costs. Furthermore, these projects need to be operated at full capacity in order to maintain their low operating costs. As a result, we believe that operational oil sands projects are unlikely to make any significant reduction in their production activity as a result of a short term decline in oil price.*

In addition, as oil sands projects move through their typical 30-40 year life cycle, easy-to-access bitumen deposits are depleted and operators must go greater distances and move more material to access their ore reserves. Over this period, haulage distances progressively extend and the amount of overburden to be removed per cubic meter of exposed oil sand progressively increases. As a result, the total capacity of digging and hauling equipment must increase and consequently, the amount of ancillary equipment and services to run this equipment must also increase. As a result, we believe that demand for recurring oil sands services will continue to grow even if no new oil sand mines are built because the geographical footprint of existing mines must continue to expand under normal operation. We also believe that further expansion of our accessible market will occur as new mines nearing production, such as Canadian Natural s Horizon mine and Albian s Jackpine mine, come on-line. As an example of this growth, mining production from the Alberta oil sands has increased from 0.3 million barrels per day to 0.7 million barrels per day since 2001 and is expected to increase to 1.0 million barrels per day by 2012[4]*.

Project Development: In previously filed Management s Discussion and Analysis we indicated that we expected the continued development of the oil sands as a driver of a significant portion of our fiscal 2009 revenue and that we expected continued rapid growth of operations in the oil sands business and their planned projects. However, several oil sands producers have recently updated their near-term capital spending plans in response to the current commodity, equity and credit market conditions. Last quarter, Petro-Canada announced a halt to the development of the Fort Hills project in order to re-evaluate their project and several customers have announced they were deferring decisions about upgrader projects. More recently, Suncor has announced a further reduction in spending on both the Voyageur and Firebag developments. In contrast, Albian continues to push forward with the development of its Jackpine mine and Exxon has indicated it intends to move forward with its Kearl project. Although short-term oil prices may impact the ability of some companies to fund the development of new projects out of cash flow, the major producers continue to reiterate that their investment in the oil sands is driven by expected long-term demand and prices for oil and not by short-term oil prices. This is consistent with the minimum three-to-four year development lead time required to build oil sands mines and the 30-40 year operating life of these projects.

Pricing in the oil sands: Oil sands producers are becoming more focused on input costs and seeking cost reduction strategies to counter the effects of lower oil prices. In response, we are working closely with our customers and suppliers to identify and implement project efficiencies and cost-saving strategies to benefit our customers and maintain our position in the oil sands.

[4] Canadian Association of Petroleum Producers (CAPP) Canadian Crude Oil Production Forecast December 2008

*This paragraph contains forward looking statements. 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 nine months ended December 31, 2008

Mineral Mining Business Conditions

The effects of the global economic downturn have weakened demand for base metals and minerals in recent months, causing prices to drop significantly. This devaluation of commodities, together with limited access to capital, has had a negative impact on new mine development. Projects in British Columbia that were slated to start construction in 2009 have been deferred. Additionally, in previously filed Management s Discussion and Analysis, we had indicated that we expected an increased level of involvement with Baffinland Iron Mines Corp. However, the financial crisis has impacted Baffinland Iron Mines plans for a new iron ore mine in the Arctic, as it has been unable to secure a strategic financial partner. It is anticipated that commodity prices will remain low until the world economy improves and as such, investment in new mine development is expected to remain below normal levels which may constrain our growth into these new areas.*

Commercial and Public Construction Business Conditions

We supply the commercial and public construction industry with a range of piling and construction services. In previously filed Management s Discussion and Analysis we had indicated that we expected the demand for our piling services to remain strong in fiscal 2009. Currently, commercial construction activity is experiencing a rapid slowdown in Western Canada, reflecting tighter credit markets, declining real estate values and other impacts of the economic recession.

While we expect that the number of commercial construction projects will continue to decline in 2009, government-sponsored infrastructure projects could help to offset some of this impact as federal and provincial governments invest in shovel ready projects to stimulate the economy. Canada s federal government recently unveiled a budget which includes $12 billion of infrastructure spending over the next two years.*

Conventional Oil and Gas Business Conditions

Although oil and gas prices have decreased, companies involved in the transmission of oil and gas do not appear to be delaying investment in new pipeline development. With current pipelines at capacity and new pipeline projects taking several years to complete, several new projects appear to be proceeding on plan.

Revenue Source Trends

Revenue by Category

We have experienced steady growth in recurring revenue from operating oil sands projects over the past few years. Project development revenue, by contrast, has recently declined reflecting the impact of economic conditions on large-scale capital projects. Future growth in our recurring revenue will be reflective of the expansion of activities at current operational mines along with the start-up of new operational mines as oil sands projects move from the capital development stage into the operational phase.

*This paragraph contains forward looking statements. 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 nine months ended December 31, 2008

The following trailing 12-months graph displays the breakdown between recurring services revenue and project development revenue:

Recurring Services Revenue: Recurring services revenue is derived from long-term contracts and master services agreements as described below:

Long-term contracts. This category of revenue consists of revenue generated from long-term contracts (greater than one year) with total contract values greater than $20 million. These contracts are for work that supports the operations of our customers and include long-term contracts for overburden removal and reclamation. Revenue in this category is typically generated under unit-price contracts and is included in our calculation of backlog. This work is generally funded from our customers operating budgets.

Master Services Agreements. This category of revenue is generated from the master services agreements in place with Syncrude and Albian. This revenue is typically generated by supporting the operations of our customers and is therefore considered to be recurring. This revenue is not guaranteed under contract and is not included in our calculation of backlog. This revenue is primarily generated under time-and-materials contracts. This work is generally funded from our customers operating or maintenance capital budgets.

Project Development Revenue: Project development revenue is typically generated during the support of capital construction projects and is therefore considered to be non-recurring. This revenue can be generated under lump-sum, unit-price, time-and-materials and cost-plus contracts. It can be included in backlog if generated under lump-sum, unit price or time-and-materials contracts and scope is defined. This work is generally funded from our customer s capital budgets.

7

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

Revenue by End Market

Growth in both recurring services and capital projects increased our oil sands work volumes during 2007 and 2008. The pipeline installation project for Kinder Morgan increased our revenues in the conventional oil and gas sector. The declining contribution of minerals mining revenue reflects the completion of the DeBeers diamond mine project in early 2008.

Our Strategy

Our strategy is to be an integrated service provider for the developers and operators of resource-based industries in a broad and often challenging range of environments. To help us manage successfully through the current business environment, we are focused on:

- working with our customers and suppliers to establish the most efficient and cost effective way for us to deliver services to meet all of our customers project needs;

- cash conservation to ensure liquidity for operational circumstances;

- timely invoicing and accounts receivable collection to minimize working capital;

- strategic prioritization of our capital expenditures to minimize cash outflows while maintaining the flexibility to take advantage of profitable opportunities; and

- careful and thorough evaluation of all opportunities to ensure we maintain reasonable levels of profitability in the current economic environment.

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

More generally, our strategy continues to be the following:

- *Increase our recurring revenue base:* It is our intention to continue expanding our recurring services business to provide a larger base of stable revenue.*
- *Leverage our long-term relationships with customers:* We intend to continue to build on our relationships with existing oil sands customers to win a substantial share of the heavy construction and mining, piling and pipeline services outsourced in connection with their projects.*
- *Leverage and expand our complementary services:* Our complementary service segments, Heavy Construction and Mining, Pipeline and Piling allow us to compete for many different forms of business. We intend to build on our first-in position to cross-sell our other services and pursue selective acquisition opportunities that expand our complementary service offerings.*
- *Enhance operating efficiencies to improve revenues and margins:* We aim to increase the availability and efficiency of our equipment through enhanced maintenance, providing the opportunity for improved revenue, margins and profitability.*
- *Position for growth:* We intend to build on our market leadership position and successful track record with our customers to benefit from future oil sands development. We intend to use our fleet size and management capability to respond to new opportunities as they occur.*
- *Increase our presence outside the oil sands:* We intend to increase our presence outside the oil sands and extend our services to other resource industries across Canada. Canada has significant natural resources and we believe that we have the equipment and the experience to assist with developing those natural resources.*

*This paragraph contains forward looking statements. 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 nine months ended December 31, 2008

B. Financial Results

Consolidated Results (Three and Nine Months)

(Dollars in thousands, except per share information)	Three Months Ended December 31, 2008	% of Revenue	2007	% of Revenue	Nine Months Ended December 31, 2008	% of Revenue	2007	% of Revenue
Revenue	$ 258,565	*100.0%*	$ 274,894	*100.0%*	$ 797,836	*100.0%*	$ 666,096	*100.0%*
Project costs	129,912	*50.2%*	167,323	*60.9%*	433,504	*54.3%*	397,262	*59.6%*
Equipment costs	55,549	*21.5%*	44,231	*16.1%*	162,146	*20.3%*	131,582	*19.8%*
Equipment operating lease expense	11,934	*4.6%*	4,825	*1.8%*	30,317	*3.8%*	12,329	*1.9%*
Depreciation	10,178	*3.9%*	7,885	*2.9%*	29,004	*3.6%*	24,179	*3.6%*
Gross profit	50,992	*19.7%*	50,630	*18.4%*	142,865	*17.9%*	100,744	*15.1%*
General & administrative costs	19,156	*7.4%*	17,009	*6.2%*	57,717	*7.2%*	48,996	*7.4%*
Operating (loss) income	(2,207)	*-0.9%*	33,173	*12.1%*	47,771	*6.0%*	49,816	*7.5%*
Net (loss) income	(14,699)	*-5.7%*	24,706	*9.0%*	3,175	*0.4%*	19,300	*2.9%*
Per share information								
Net (loss) income - basic	$ (0.41)		$ 0.69		$ 0.09		$ 0.54	
Net (loss) income - diluted	(0.41)		0.67		0.09		0.52	
EBITDA[(1)]	$ 7,601	*2.9%*	$ 47,910	*17.4%*	$ 65,033	*8.2%*	$ 71,558	*10.7%*
Consolidated EBITDA[(1)] (as defined within the revolving credit agreement)	47,900	*18.5%*	42,069	*15.3%*	120,855	*15.1%*	79,659	*12.0%*

[(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 (loss) before interest expense, income taxes, depreciation and amortization. Consolidated EBITDA (as defined within the revolving credit agreement) is a measure defined by our revolving credit facility. 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 plant and equipment and certain other non-cash items included in the calculation of net income (loss). 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 revolving 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 revolving 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

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

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 U.S. GAAP. For example, EBITDA and Consolidated EBITDA:

do not reflect our cash expenditures or requirements for capital expenditures or capital commitments;

do not reflect changes in our cash requirements for our working capital needs;

do not reflect the interest expense or the cash requirements necessary to service interest or principal payments on our debt;

do not include tax payments that represent a reduction in cash available to us; and

do not 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. Our use of the term, Consolidated EBITDA (as defined within the revolving credit agreement) , replaces the term Consolidated EBITDA (per bank) used in prior filings but the definition of Consolidated EBITDA has not changed.

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

(Dollars in thousands)	Three Months Ended December 31, 2008	Three Months Ended December 31, 2007 (Restated)	Nine Months Ended December 31, 2008	Nine Months Ended December 31, 2007 (Restated)
Net (loss) income	$ (14,699)	$ 24,706	$ 3,175	$ 19,300
Adjustments:				
Interest expense	6,774	7,399	19,663	20,333
Income taxes	5,080	7,477	12,369	6,980
Depreciation	10,178	7,885	29,004	24,179
Amortization of intangible assets	268	443	822	766
EBITDA	**$ 7,601**	**$ 47,910**	**$ 65,033**	**$ 71,558**
Adjustments:				
Unrealized foreign exchange loss (gain) on senior notes	32,509	(1,612)	38,825	(32,626)
Realized and unrealized (gain) loss on derivative financial instruments	(26,523)	(4,510)	(21,171)	36,690
Loss on disposal of plant and equipment and assets held for sale	1,022	5	3,802	1,166
Stock-based compensation	538	276	1,613	1,023
Write-down of other assets to replacement cost				1,848

Impairment of goodwill	32,753		32,753	
Consolidated EBITDA	**$ 47,900**	**$ 42,069**	**$ 120,855**	**$ 79,659**
(as defined within the revolving credit agreement)				

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

Analysis of Results

Revenue

Revenues of $258.6 million for the three months ended December 31, 2008 were $16.3 million or 5.9% lower than in the same period last year. The completion of work on oil sands capital projects at Petro-Canada s Fort Hills site and Suncor s Voyageur site along with continued growth in recurring services revenues in the oil sands helped to offset the impact of the TMX pipeline project winding down and the slow down in commercial construction markets. For the nine months ended December 31, 2008, revenues of $797.8 million were $131.7 million higher, up 19.8%, from the prior year period. Strong construction activity during the current nine-month period and continued growth in oil sands-related recurring services revenues were the key factors in this increase.

Gross Profit

Gross profit for the three months ended December 31, 2008 increased to $51.0 million or 19.7% of revenue compared to $50.6 million or 18.4% of revenue last year. The higher revenues in Heavy Construction and Mining combined with the processing of change orders in both the Heavy Construction and Mining and the Piling segments were key factors in this improvement. In addition, project costs were lower during the quarter as a result of a different project mix, however this was largely offset by higher equipment-related costs reflecting the increased proportion of Heavy Construction and Mining revenue. Equipment costs were also higher for the three months ended December 31, 2008 due to the timing of maintenance work. Increased activity in the Heavy Construction and Mining segment combined with additional lease costs related to equipment on the long-term overburden contract raised both depreciation and leased equipment costs compared to last year. Included in the current period depreciation was a charge of $0.8 million for accelerated depreciation of equipment that was removed from service.

For the nine months ended December 31, 2008, gross profit increased to $142.9 million or 17.9% of revenue from $100.7 million or 15.1% of revenue, reflecting higher revenue in the Heavy Construction and Mining segment and improved project margins in the Pipeline segment. The improvement in Pipeline gross profit reflects the segment s return to profitability in the current period after incurring losses on specific projects the year before, as well as the partial recovery of some of the prior year losses through our claims process. Improvements in the management and purchasing of tires led to an 18.2%, or $4.2 million, year-over-year reduction in tire expense. Partially offsetting these factors was higher equipment leasing expense as a result of the March 2008 commissioning of a new electric cable shovel for a long-term overburden removal contract along with higher costs related to the year-over-year growth in the size of our leased equipment fleet. We commissioned a second electric cable shovel for this contract in December 2008. Increased Heavy Construction and Mining activity resulted in higher equipment depreciation for the nine months ended December 31, 2008 compared to the previous year, but as a percent of revenue, depreciation was 3.6%, consistent with the previous year. Included in the current nine month period was a $2.1 million charge for the accelerated depreciation of equipment that was being prepared for sale during the current year. This compares to a $3.0 million charge last year.

Operating (loss) income

We recorded an operating loss of $2.2 million for the three months ended December 31, 2008, compared to operating income of $33.2 million during the same period last year. The change from last year reflects the non-cash impact of a $32.8 million impairment of goodwill in the Pipeline segment, as discussed in more detail later in this section. Excluding this impairment, operating income would have been $30.6 million for the current three month period. General and administrative (G&A) expense increased $2.1 million this year as a result of the

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

higher staffing levels that were needed to support higher operations activity. We are focused on reducing costs and are already starting to benefit from process improvements implemented earlier in the year. For the nine months ended December 31, 2008 operating income was $47.8 million compared to $49.8 million during the same period last year. Excluding the impact of the goodwill impairment, the current nine month operating income would have been $80.5 million, 61.6% higher than in the prior year period. This improvement reflects higher gross profit and declining G&A expense as a percentage of revenue on a year to date basis.

Net (loss) income

We recorded a net loss of $14.7 million (basic loss per share of $0.41) for the three months ended December 31, 2008, compared to net income of $24.7 million (basic net income per share of $0.69) for the same period last year. The net loss includes other income related to recognition of a cancellation premium as a result of the cancellation of a swap by the counterparties to the swap (more details on the cancelation can be found in our Foreign currency risk discussion in Quantitative and Qualitative Disclosures about Market Risk). Non-cash items negatively affecting net loss include the impact of goodwill impairment (no tax effect), the negative impact of a depreciating Canadian dollar on our 8 3/4% senior notes and non-cash losses on embedded derivatives. This was partially mitigated by a gain in the cross currency and interest rate swaps along with a gain in the embedded price escalation features in a long-term revenue contract. Excluding these non-cash items, net income would have been $21.4 million resulting in, basic earnings per share of $0.59 per share and diluted earnings per share of $0.59 per share, up from $0.51 per share and $0.50 per share, respectively, for the same period a year ago.

For the nine months ended December 31, 2008, we reported net income of $3.2 million (basic earnings per share of $0.09), compared to net income of $19.3 million (basic earnings per share of $0.54) in the prior year. This $16.1 million reduction in net income or per share reduction of $0.45 mainly reflects the non-cash impacts of the goodwill impairment (no effect on tax) and an unrealized foreign exchange loss compared to unrealized foreign exchange gains, net of tax, during the same period last year. These negative impacts were partially mitigated by non-cash gains on derivative financial instruments, this year, compared to a non-cash loss last year. Excluding these non-cash items, basic earnings per share would have been $1.31 per share and diluted earnings of $1.29 per share for the nine months this year. This compares to $0.57 per share and $0.55, respectively, per share for the same period a year ago.

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

Impairment of Goodwill

As discussed in our analysis of operating loss, we recognized a $32.8 million impairment of goodwill in the three months ended December 31, 2008. In accordance with our accounting policy, a goodwill impairment test is completed annually on October 1 of each year or whenever events or changes in circumstances indicate that goodwill impairment may exist. We conducted our annual goodwill impairment test on October 1, 2008 and concluded that the fair value of each of our reporting units exceeded their carrying amounts. However, at December 31, 2008, based on adverse changes in our principal markets, the recent decline in our market capitalization and updated long-term financial forecasts, which resulted in lower forecasted near-term and longer-term revenues and lower forecasted cash flows for all our operating segments, we concluded that an interim test for impairment of goodwill was appropriate.

In performing the goodwill assessment on December 31, 2008, we considered discounted cash flows, market capitalization and other factors including observable market data to determine fair value. Although implied market comparable valuation multiples and transaction premiums from a set of selected comparable companies were considered in our analysis we concluded that there are significant differences in the services and operating characteristics of our reporting units as compared to these companies. As a result, we relied primarily on the discounted cash flow method, using our projections for each of our reporting units and risk adjusted discount rates. Expected cash flows of each of our reporting units were discounted using estimated discount rates ranging from 18% to 27% to calculate fair value. We considered this method to be most reflective of a market participant s view of fair value given the current market conditions.

As a result of our analysis, we concluded that the carrying value of goodwill assigned to the Pipeline operating segment (also a separate reporting unit) exceeded its fair value and we recorded an impairment charge of $32.8 million. The goodwill impairment charge was calculated as the difference between the carrying value of goodwill of the Pipeline operating segment and its implied fair value of $nil at December 31, 2008. The implied fair value of the goodwill for the Pipeline operating segment was determined in the same manner as the value of goodwill is determined in a business combination. The impairment charge is included in the caption Impairment of goodwill in the Consolidated Statement of Operations, Comprehensive (Loss) Income and Deficit for the three and nine month periods ended December 31, 2008.

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

At December 31, 2008, we determined that there was no impairment to any other reporting units as their fair values exceeded their carrying values. However, given conditions in the financial markets and the global economic downturn and their current impact on our principal markets, events or changes in circumstances could occur in the future, which may result in further impairment of goodwill. Circumstances that would require us to perform an interim test for impairment of goodwill include further updates to our long-term financial forecasts resulting in lower near-term and longer-term revenue and cash flow forecasts for all our operating segments, actual performance being materially different from our forecasts, continued adverse changes in our principal market; and a continuing weakness and/or declines in our market capitalization.

The goodwill impairment charge reduced our carrying value for goodwill from $200.1 million to $167.3 million as at December 31, 2008.

Segment Results (Three and Nine Months)

Segment profits include revenue earned from the performance of our projects, including amounts arising from approved change orders and claims that have met the appropriate accounting criteria for recognition, less all direct project expenses, including direct labour, short-term equipment rentals and materials, payments to subcontractors, indirect job costs and internal charges for use of capital equipment.

Segment results for the three and nine months ended December 31, 2008 compared to the three and nine months ended December 31, 2007 are summarized below:

Heavy Construction and Mining

	Three Months Ended December 31,				Nine Months Ended December 31,			
(Dollars in thousands)	**2008**	**% of Revenue**	**2007**	**% of Revenue**	**2008**	**% of Revenue**	**2007**	**% of Revenue**
Segment revenue	$ 198,620		$ 154,402		$ 564,101		$ 431,140	
Segment profit:	$ 38,489	*19.4%*	$ 28,097	*18.2%*	$ 86,416	*15.3%*	$ 68,631	*15.9%*

For the three months ended December 31, 2008 the Heavy Construction and Mining segment achieved revenues of $198.6 million, a $44.2 million improvement over last year. Project closeout activities at the Petro-Canada Fort Hills site preparation project and Suncor s Voyageur and Millennium Naphtha Unit projects, combined with strong demand for recurring site services work, including master services work at Albian s Jackpine Mine and Muskeg River Mine, were the primary factors in this revenue growth. Recurring services have become an increasingly significant contributor to our revenues as more oil sands projects move into the stable, operational phase of their lifecycles. Ongoing operational work represented 66% of Heavy Construction and Mining s revenues in the three-month period and 68% in the nine month period ended December 31, 2008 compared to 62% and 59%, respectively, during the same periods a year ago. For the nine months ended December 31, 2008, Heavy Construction and Mining segment revenues of $564.1 million were $133.0 million higher than last year. Project closeout activities and significant activity at the Suncor and Albian sites were the primary factors in this revenue growth.

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

Segment margins for the three months ended December 31, 2008 were 19.4%, higher than the 18.2% achieved during the same period last year. A redeployment of equipment from the overburden project to other sites combined with change orders associated with project close-outs led to the improvement in margins. Margins for the nine months ended December 31, 2008 declined to 15.3% from 15.9% last year primarily reflecting the negative impact of first quarter production challenges on a single project.

Piling

	Three Months Ended December 31,				Nine Months Ended December 31,			
(Dollars in thousands)	**2008**	**% of Revenue**	**2007**	**% of Revenue**	**2008**	**% of Revenue**	**2007**	**% of Revenue**
Segment revenue	$ 41,565		$ 43,751		$ 132,709		$ 121,698	
Segment profit:	$ 12,740	*30.7%*	$ 11,386	*26.0%*	$ 32,445	*24.4%*	$ 31,725	*26.1%*

The Piling segment achieved revenues of $41.6 million in the three months ended December 31, 2008, a decrease of $2.2 million compared to a year ago. The change in Piling revenues reflects declining activity levels in the commercial construction market resulting from the general economic slowdown. For the nine months ended December 31, 2008 Piling revenues climbed to $132.7 million, representing an $11.0 million increase over last year. Work on a major oil sands-related plant and upgrader project was a significant contributor to the revenue growth in the current nine month period.

For the three months ended December 31, 2008, project close-out activities and the processing of change orders increased segment margins to 30.7%, from 26.0% last year. For the nine months ended December 31, 2008, segment margin declined to 24.4% from 26.1% reflecting an increased number of lower margin time-and-materials oil sands projects in our project mix.

Pipeline

	Three Months Ended December 31,				Nine Months Ended December 31,			
(Dollars in thousands)	**2008**	**% of Revenue**	**2007**	**% of Revenue**	**2008**	**% of Revenue**	**2007**	**% of Revenue**
Segment revenue	$ 18,380		$ 76,741		$ 101,026		$ 113,258	
Segment profit:	$ 5,589	*30.4%*	$ 12,934	*16.9%*	$ 22,464	*22.2%*	$ 14,154	*12.5%*

Pipeline revenues for the three months ended December 31, 2008 declined to $18.4 million from $76.7 million a year ago, reflecting the successful and on-schedule completion of the TMX project during the quarter. Pipeline revenues for the nine months ended December 31, 2008 were $101.0 million compared to $113.3 million during the same period last year again reflecting completion of the TMX project.

Although Pipeline profit for the three months ended December 31, 2008 decreased as a result of the lower revenue, margins increased sharply to 30.4%, from 16.9% as closeout activities and final change orders for the TMX project were processed. Margins for the nine-month period ended December 31, 2008 also improved, increasing to 22.2% from 12.5% last year. Margins for the current nine month period benefited from $5.3 million in claims revenue, while margins in the nine month period last year were negatively affected by $2.0 million in additional costs related to a fixed-priced contract. Excluding these impacts in both years nine month margins would have been 17.9% compared to 14.3% a year ago.

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

Non-Operating Income and Expense

(Dollars in thousands)	Three Months Ended December 31, 2008	Three Months Ended December 31, 2007	Nine Months Ended December 31, 2008	Nine Months Ended December 31, 2007
Interest expense				
Interest on senior debt	$ 5,834	$ 5,834	$ 17,503	$ 17,503
Interest on revolving credit facility and other interest	380	1,238	696	1,664
Interest on capital lease obligations	341	165	887	497
Amortization of deferred bond issue costs	219	162	577	669
Total Interest expense	$ 6,774	$ 7,399	$ 19,663	$ 20,333
Foreign exchange loss (gain) on senior notes	$ 32,504	$ (1,784)	$ 39,099	$ (33,136)
Realized and unrealized loss (gain) on derivative financial instruments	(26,523)	(4,510)	(21,171)	36,690
Other income	(5,343)	(115)	(5,364)	(351)
Income tax expense	5,080	7,477	12,369	6,980

Interest expense

Total interest expense of $6.8 million for the three months ended December 31, 2008 and $19.7 million for the nine months ended December 31, 2008 decreased $0.6 million and $0.7 million, respectively, from the same prior year periods. Reduced use of the revolving credit facility together with a decline in deferred finance costs offset the small increases in the amortization of bond issue costs and interest on capital lease obligations leading to the decrease in interest expense. As described in more detail under Qualitative and Quantitative Disclosures about Market Risk *Interest rate risk* , we are now exposed to interest rate risk as a result of our counterparty cancellation of the US dollar interest rate swap. Our three swap counterparties under the swap exercised this cancellation option effective February 2, 2009. As a result of this termination, our annual interest expense at current LIBOR rates will increase by US$6.3 million. In addition, we are now exposed to interest rate risk where a 100 basis point increase (decrease) in the 3-month LIBOR rate will result in a US$2.0 million (decrease) increase in annual interest expense.

Foreign exchange loss (gain) on senior notes

The foreign exchange gains and losses recognized in the current and prior-year 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 decline in the value of the Canadian dollar, which dropped from 0.9435 CAN/US to 0.8166 CAN/US, in the three months ended December 31, 2008 resulted in a significant unrealized exchange loss. The depreciation of the Canadian dollar relative to the US dollar offset previous quarter gains and resulted in an unrealized loss of $39.1 million for the nine months ended December 31, 2008.

Realized and unrealized (loss) gain on derivative financial instruments

The realized and unrealized gains and losses on derivative financial instruments reflect 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. 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 foreign 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.

17

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

Due to our April 1, 2007 adoption of the CICA standards regarding financial instruments, realized and unrealized gains and losses on derivative financial instruments for the three and nine month periods ended December 31, 2007 and 2008 include changes in the fair value of derivatives embedded in our US dollar denominated 8 3/4% senior notes, in a long-term construction contract and in supplier maintenance agreements. The change in the realized and unrealized gain / loss of the cross-currency and interest swaps resulted in a gain of $28.1 million in the three months ended December 31, 2008 compared to a gain of $3.9 million in the same period of last year. For the nine months ended December 31, 2008, the change in realized and unrealized value of the cross-currency and interest swaps resulted in a gain of $34.3 million this year compared to a loss of $26.2 million in the prior year. The balance of the realized and unrealized gains and losses on derivative financial instruments resulted from gains and losses on derivatives embedded in our 8 3/4% senior notes, in a long-term construction contract and in supplier maintenance agreements.

With respect to the early redemption provision in the 8 3/4% senior notes, the process to determine the fair value of the implied derivative was to compare the rate on the notes to the best financial alternative. The fair value determined as at April 1, 2007 resulted in a positive adjustment to opening deficit. The change in fair value in future periods is recognized as a charge to earnings. Changes in fair value result from changes in long-term bond interest rates during a 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 long-term construction contract, there is a provision that requires an adjustment to billings to our customer to reflect actual exchange rate and price index changes as against the contract amount. 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.

With respect to the supplier maintenance contracts, there are provisions that require a price adjustment to reflect actual Canadian versus US dollar exchange rate and the Unites States government published Producers Price Index for Mining Machinery and Equipment (US-PPI) changes versus the contract amount. The embedded derivative instrument takes into account the impact of fluctuations in these measures on costs.

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

Other income

On December 17, 2008, we received notice that all three swap counterparties had exercised the cancellation option on the US dollar interest rate swap. Effective February 2, 2009, the US dollar interest rate swap was terminated. The counterparties paid a cancellation premium of 2.1875% on the notional amount of US$200.0 million or US$4.4 million (equivalent to $5.3 million). As the cancellation is irrevocable we recognized the premium as other income in the three months ended December 31, 2008.

Income tax expense (recovery)

For the three months ended December 31, 2008, we recorded current income tax expense of $1.8 million and future income tax expense of $3.3 million for a combined income tax expense of $5.1 million compared to

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

combined income tax expense of $7.5 million (restated) last year. For the nine months ended December 31, 2008, we recorded current income tax expense of $1.8 million along with future income tax expense of $10.5 million for a combined income tax expense of $12.3 million. This compares to a combined income tax expense of $7.0 million (restated) last year.

For the three and nine month periods ended December 31, 2008, income tax expense as a percentage of income before income taxes differs from the statutory rate of 29.38% primarily due to the impact of the impairment of goodwill of $32.8 million (a non-deductible item), the impact of changes in enacted tax rates and the impact of the benefit from changes in the timing of the reversal of temporary differences during the period. For the three and nine month periods ended December 31, 2007, income tax expense as a percentage of income before income taxes differed from the statutory rate of 31.47% primarily due to the impact of enacted rate changes during the period and the impact of new accounting standards for the recognition and measurement of financial instruments. Under the new accounting standards, certain embedded derivatives are considered capital in nature for income tax purposes.

Summary of Quarterly Results

	Fiscal 2009			Fiscal 2008				Fiscal 2007
Three months ending,	**31-Dec-08**	**30-Sep-08**	**30-Jun-08**	**31-Mar-08**	**31-Dec-07 (Restated)**	**30-Sep-07 (Restated)**	**30-Jun-07 (Restated)**	**31-Mar-07**
(Dollars in millions, except per share amounts)								
Revenue	$ 258.6	$ 280.3	$ 259.0	$ 323.6	$ 274.9	$ 223.6	$ 167.6	$ 205.4
Gross profit	51.0	44.3	47.6	62.6	50.6	35.2	14.9	13.6
Operating (loss) income	(2.2)	23.0	26.9	42.6	33.2	17.1	(0.4)	4.5
Net (loss) income	(14.7)	(1.2)	19.1	22.7	24.7	3.2	(8.6)	1.3
EPS - Basic[1]	$ (0.41)	$ (0.03)	$ 0.53	$ 0.63	$ 0.69	$ 0.09	$ (0.24)	$ 0.04
EPS - Diluted[1]	(0.41)	(0.03)	0.52	0.62	0.67	0.09	(0.24)	0.04

(1) Net (loss) income 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.

As discussed previously, a number of factors have the potential to contribute to variations in our quarterly results between periods, 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 and the strength of the Western Canadian economy. For a more detailed discussion regarding seasonality and its impact on our business see Key Trends .

The timing of large projects can influence quarterly revenues. For example, Pipeline segment revenues were $76.7 million in the third quarter of fiscal 2008 (up $61.5 million compared to the same period in fiscal 2007), $87.5 million in the fourth quarter of 2008 (up $62.0 million compared to the same period in fiscal 2007), $27.1 million in the first quarter of fiscal 2009 (up $21.9 million compared to the same period in fiscal 2008), $55.6 million in the second quarter of fiscal 2009 (up $24.2 million compared to the same period in fiscal 2008) and $18.4 million in the third quarter of fiscal 2009 (down $58.4 million compared to the same period in fiscal 2008). The Heavy Construction and Mining segment experienced increased revenues from the second quarter of fiscal 2008 through the first quarter of fiscal 2009 related to the execution of work at Suncor Millennium Naphtha Unit project under our five-year site services agreement, the construction of an aerodrome for Albian during the third and fourth quarters of fiscal 2008 and increased demand under our master service agreements with Albian and Syncrude. Timing of work under the site services agreements can vary based on our customers production and project activities.

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

In addition to revenue variability, gross margins can be negatively impacted by the timing of maintenance costs. Timing of these costs is dependant on when management can make the equipment available for service without adversely affecting billable equipment hours.

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. During the first quarter of fiscal 2009, a $5.3 million claim was recognized causing gross margins for the Pipeline segment to increase above what they would otherwise have been. The additional costs relating to the claim were incurred in fiscal 2007 and in the first quarter of fiscal 2008.

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 income as certain costs, which are generally fixed, including general and administrative expenses, are spread over higher revenue levels. Net income and earnings per share are also subject to operating leverage as provided by fixed interest expense.

We have experienced earnings variability in all periods due to the recognition of 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. The current period non-cash goodwill impairment charge has added to the earnings variability between periods.

Consolidated Financial Position

(Dollars in thousands)	As of December 31, 2008	As of March 31, 2008	% Change
Current assets	$ 270,729	$ 291,086	-7.0%
Current liabilities	(162,850)	(183,353)	-11.2%
Net working capital	107,879	107,733	0.1%
Plant and equipment	338,749	281,039	20.5%
Total assets	792,626	793,598	-0.1%
Capital Lease obligations (including current portion)	23,164	14,776	56.8%
Total long-term financial liabilities[1]	(313,330)	(301,497)	3.9%

[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 taxes balances.

At December 31, 2008, net working capital (current assets less current liabilities) was $107.9 million compared to $107.7 million at March 31, 2008, a decrease of $0.2 million. Positive cash flow increased our overall cash balance from $32.9 million to $42.3 million. Collections improved on both trade receivables and holdbacks (reduced by $22.8 million since March 31, 2008) and unbilled revenue (reduced by $10.2 million since March 31, 2008) offset by decreased accounts payable (down by $19.8 million since March 31, 2008) and accrued liabilities (down by $15.2 million since March 31, 2008). Inventory has increased $15.1 million since March 31, 2008. The inventory increase is as a result of the new Canadian GAAP standard for inventory which requires that tires now be reported as inventory (tires valued at $5.1 million were moved from other assets as at April 1, 2008) and tire requirements for new leased haul trucks (haul trucks do not arrive with tires included).

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

Unbilled revenue relates to delays by some of our large customers in processing change orders and progress payment certificates. We are continuing to work with our customers to address these delays and during the three months ended December 31, 2008 unbilled revenue improved by $49.5 million compared to the three months ended September 30, 2008. Equipment purchases of $8.3 million, which are scheduled to be paid after the quarter end, are included in accounts payable as of December 31, 2008.

Plant and equipment, net of depreciation, increased by $57.7 between December 31, 2008 and March 31, 2008. This reflects the capital investment of $98.3 million during the period, offset by equipment disposals of $12.2 million (net book value) and depreciation.

Total long-term financial liabilities increased by $11.8 million between December 31, 2008 and March 31, 2008 due largely to a $46.0 million increase in the carrying amount of our 8 $^{3}/4$% senior notes and a $19.5 million increase related to the derivative financial instruments from long-term supplier contracts. This was partially offset by a reduction of $36.3 million related to the cross-currency and interest rate swap agreement and a reduction of $12.9 million in the value of the derivative financial instruments from the long-term revenue construction contract.

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 December 31, 2008, we had approximately $1.9 million in costs for claims and unsigned change orders from project inception, with no associated increase in contract value or revenue. Due to the timing of receipt of signed change orders we also had approximately $8.2 million in revenue recognized to the extent of costs incurred. 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.

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

In December 2008, the Pipeline segment successfully settled a claim related to the TMX project completed this fiscal year. The claim was settled for $16.2 million which had previously been recognized as revenue in the three months ended September 30, 2008. Additionally, our Heavy Construction and Mining segment had $5.3 million of claims revenue for the three months ended December 31, 2008 while our Piling segment had $2.9 million of claims revenue for the same period. Both segment s claims revenue related to unsigned change-orders.

In June 2008, the Pipeline segment successfully settled a claim related to a project completed in the last fiscal year. The claim was settled for $8.0 million, of which $5.3 million was recognized as revenue in the three months ended June 30, 2008. The balance of $2.7 million was previously recognized as revenue in the three months ended September 30, 2007.

C. Key Trends

Seasonality

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 and the strength of the Western Canadian economy.

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. Profitability also varies from period-to-period due to claims and change orders. Claims and change orders are a normal aspect of the contracting business but can cause variability in profit margin between quarters due to the unmatched recognition of costs in one quarter and revenues in a subsequent quarter. For further explanation see Claims and Change Orders.

During the higher activity periods we have experienced improvements in operating income due to operating leverage. General and administrative costs are generally fixed and we see these costs decrease as a percentage of revenue when our project volume increases. Net income and earnings per share are also subject to operating leverage as provided by fixed interest expense. However, 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. The non-cash goodwill impairment charge, recognized in the current period, has added to the earnings variability.

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.

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.

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

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, the work scope and value are not clearly defined. For the three months ended December 31, 2008, the total amount of revenue earned under our master services agreements was approximately $101.1 million and for the nine months ended December 31, 2008 was $281.7 million.

Our estimated backlog by segment and contract type as at December 31, 2008 and 2007 was:

By Segment	As at December 31, 2008	2007
Heavy Construction & Mining	$ 651.1	$ 760.0
Piling	14.1	19.6
Pipeline		88.9
Total	$ 665.2	$ 868.5

By Contract Type	As at December 31, 2008	2007
Unit-Price	$ 658.8	$ 681.8
Lump-Sum	6.4	7.3
Time-and-Material and Cost-Plus		179.4
Total	$ 665.2	$ 868.5

A contract with a single customer represented approximately $611.6 million of the December 31, 2008 backlog compared to $621.4 million reported as backlog in our MD&A for the three and six months ended September 30, 2008. The reduction in contract value is due to a short-term halt in overburden removal, at the request of this customer, to align our overburden removal activity with the client s production schedule. To reduce costs to the customer and to lessen the effect of this decline in our revenue we are actively looking to redeploy equipment to other sites.

We expect that approximately $152.3 million of total backlog will be performed and realized in the 12 months ending December 31, 2009. *

Major Suppliers

We have long-term relationships with the following equipment suppliers: Finning International Inc. (45 years), Wajax Income Fund (20 years) and Brandt Tractor Ltd. (30 years). Finning is a major Caterpillar heavy equipment dealer for Canada. Wajax is a major Hitachi equipment supplier to us for both mining and construction equipment. We purchase or rent John Deere equipment, including excavators, loaders and small bulldozers, from Brandt Tractor. In addition to the supply of new equipment, each of these companies is a major supplier for equipment rentals, parts and service labor. We are seeing a significant reduction in lead time required for placing heavy equipment orders which allows us to react quickly to increased demand for our services from

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

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

our customers. We are also actively working with these suppliers to identify cost saving opportunities such as reducing our rental fleet and focusing on parts management.

Tire supply has been a challenge for our haul truck fleet over the past few years. We prefer to use radial tires from proven manufacturers but the shortage of supply has forced us to use bias tires and source radial tires from new manufacturers. Bias tires have a shorter usage life and are of a lower quality than radial tires. This affects operations as we are forced to reduce operating speeds and loads to compensate for the quality of the tires. Tire supply has improved significantly over the last few months with increased allocations in our five-year contract with Bridgestone Firestone Canada Inc. and improved availability and pricing from non-dealer sources. The reduction in demand for tires has resulted in a decline in the premium pricing from these non-dealer sources. Given this reduction in price combined with the improved tire supply, we will reduce our inventory levels over the coming months, including reducing or eliminating the purchase of any additional bias tires. This is expected to improve our near-term cash management of purchases while we draw down on our inventory of higher-cost tire inventory.*

Contracts

We complete work under the following types of contracts: cost-plus, time-and-materials, unit-price and lump-sum. Each type of contract contains a different level of risk associated with its formation and execution. The following table demonstrates our revenue by contract type:

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Time-and-materials. A time-and-materials contract involves using the components of a cost-plus job to calculate rates for the supply of labour and equipment. In this regard, all components of the rates are fixed and we are compensated for each hour of labour and equipment supplied. The risk associated with this type of contract is the estimation of the rates and incurrence of expenses in excess of a specific component of the agreed-upon rate. Any cost overrun in this type of contract must come out of the fixed margin included in the rates.

Unit-price. A unit-price contract is utilized in the execution of projects with large repetitive quantities of work and is commonly used for site preparation, mining and pipeline work. We are compensated for each unit of work we perform (for example, cubic meters of earth moved, lineal meters of pipe installed or completed piles). Within the unit-price contract, there is an allowance for labor, equipment, materials and subcontractors costs. Once these costs are calculated, we add any site and corporate overhead costs along with an allowance for the margin we want to achieve. The risk associated with this type of contract is in the calculation of the unit costs with respect to completing the required work.

Lump-sum. A lump-sum contract is utilized when a detailed scope of work is known for a specific project. Thus, the associated costs can be readily calculated and a firm price provided to the customer for the execution of the work. The risk lies in the fact that there is no escalation of the price if the work takes longer or more resources are required than were estimated in the established price, as the price is fixed regardless of the amount of work required to complete the project.

Cost-plus. A cost-plus contract is a contract in which all the work is completed based on actual costs incurred to complete the work. These costs include all labour, equipment, materials and any subcontractors costs. In addition to these direct costs, all site and corporate overhead costs are charged to the job. An agreed-upon fee in the form of a fixed percentage is then applied to all costs charged to the project. This type of contract is utilized where the project involves a large amount of risk or the scope of the project cannot be readily determined.

Competition

Our industry is highly competitive in each of our markets and in the current weaker economic conditions, competition has increased. Historically, the majority of our new business was awarded to us based on past client relationships without a formal bidding process, in which, typically, a small number of pre-qualified firms submit bids for the project work. In order to generate new business with new customers, we have had to participate in formal bidding processes. As new major projects arise, we expect to have to participate in bidding processes on a meaningful portion of the work available to us on these projects. Factors that impact competition include price, safety, reliability, scale of operations, equipment and labour availability and quality of service. Most of our clients and potential clients in the oil sands area operate their own heavy mining equipment fleet. However, these operators have historically outsourced a significant portion of their mining and site preparation operations and other construction services.*

Our principal competitors in the Heavy Construction and Mining segment include Klemke Mining Corporation, Cow Harbour Construction Ltd., Cross Construction Ltd., Ledcor Construction Limited, Peter Kiewit and Sons Co., Tercon Contractors Ltd., Sureway Construction Ltd. and Thompson Bros. (Construction) Ltd. In underground utilities installation (a part of our Heavy Construction and Mining segment), Voice

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North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

Construction Ltd., Ledcor Construction Limited and I.G.L. Industrial Services are our major competitors. The main competition to our deep foundation piling operations comes from Agra Foundations Limited, Double Star Co. and Ruskin Construction Ltd. The primary competitors in the pipeline installation business include Ledcor Construction Limited, Washcuk Pipe Line Construction Ltd. and Willbros.

In the public sector, we compete against national firms and there is usually more than one competitor in each local market. Most of our public sector customers are local governments that are focused on serving only their local regions. Competition in the public sector continues to increase and we typically choose to compete on projects only where we can utilize our equipment and operating strengths to secure profitable business.

D. Outlook

Our customers have been impacted by the current extraordinary economic environment and have responded by controlling costs in both their capital and operating budgets. A number of large oil sands projects in the planning and early development phases have been delayed, including Suncor s Voyageur expansion and Petro-Canada s Fort Hills project. While our piling and industrial construction work on the Voyageur project was largely complete, the postponement of the Fort Hills project will likely have a negative impact on heavy construction and piling revenues going forward.*

Oil sands projects in the operating or late development phases have been less affected by the current economic challenges. Unlike conventional oil operations, existing oil sands mining operations are less sensitive to changes in oil prices due to their immense up-front capital investment and relatively low operating costs. These projects need to be operated at full capacity in order to defray the high fixed cost and maintain low unit costs. Accordingly, we do not expect that long-term demand for recurring services provided in support of the ongoing efficient operation of oil sands mines will be negatively impacted by the current economic environment. These recurring services, which include overburden removal, equipment and labor supply, mine infrastructure development and maintenance and land reclamation, are the core of our business and represented approximately 60% of oil sands revenue and 45% of consolidated revenues on a trailing 12-month basis to December 31, 2008. This was up from 50% of oil sands revenue and 37% of consolidated revenues during the same period last year.*

We expect that long-term demand for recurring services will remain strong and continue to grow over time. However, we do anticipate increased variability in recurring services revenues throughout 2009 as customers balance production requirements with the need to achieve operational efficiencies. In addition, a near-term reduction in overburden removal revenues will result from a customer s request to re-align our overburden removal schedule with its own project start-up schedule. The temporary overburden removal shutdown, which will be in effect until April 2009, is not associated with the current economic climate but relates specifically to the timing of the customer s start-up program.*

We have redeployed equipment from this project to service other oil sands customers to lessen the impact to both parties. We believe our excellent customer relationships with the major oil sands producers and strong position on every site enabled us to undertake this type of redeployment quickly and effectively.

Commercial and industrial construction activity in Western Canada is expected to remain weak over the coming quarters, reducing demand for construction and piling services. Infrastructure-related construction activity is

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26

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

expected to be significantly stronger and could help to mitigate some of this impact. Canada s federal government has recently earmarked $12 billion for shovel-ready infrastructure projects over the next two years, while the Province of Alberta has committed $120 billion to infrastructure improvements over the next 20 years.*

Pipeline segment revenues are expected to decline in the next quarter as the TMX project has now been successfully completed. We are looking at several new pipeline opportunities to replace this revenue but we do not expect to be involved in a major pipeline project in the near term.*

As we work through these challenging market conditions, we are continuing to leverage our strong market position, high quality equipment fleet and experienced management team to secure profitable business. Concurrently, we are enhancing our competitive position by working proactively with suppliers and reviewing our internal cost structures to realize additional cost savings. Overall, we believe these actions, coupled with the opportunities for recurring services, will enable us to manage effectively through the current economic uncertainty.*

E. 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.

We believe we have all material required permits and licenses to conduct our operations and are in substantial compliance with applicable regulatory requirements relating to our operations. Our failure to comply with the applicable regulations could result in substantial fines or revocation of our operating permits.

Our operations are subject to numerous federal, provincial and municipal environmental laws and regulations, including those governing the release of substances, the remediation of contaminated soil and groundwater, vehicle emissions and air and water emissions. These laws and regulations are administered by federal, provincial and municipal authorities, such as Alberta Environment, Saskatchewan Environment, the British Columbia Ministry of Environment and other governmental agencies. The requirements of these laws and regulations are becoming increasingly complex and stringent and meeting these requirements can be expensive.

The nature of our operations and our ownership or operation of property exposes us to the risk of claims with respect to environmental matters and there can be no assurance that material costs or liabilities will not be incurred with such claims. For example, some laws can impose strict, joint and several liability on past and present owners or operators of facilities at, from or to which a release of hazardous substances has occurred, on parties who generated hazardous substances that were released at such facilities and on parties who arranged for

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North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

the transportation of hazardous substances to such facilities. If we were found to be a responsible party under these statutes, we could be held liable for all investigative and remedial costs associated with addressing such contamination, even though the releases were caused by a prior owner or operator or third party. We are not currently named as a responsible party for any environmental liabilities on any of the properties on which we currently perform or have performed services. However, our leases typically include covenants which obligate us to comply with all applicable environmental regulations and to remediate any environmental damage caused by us to the leased premises. In addition, claims alleging personal injury or property damage may be brought against us if we cause the release of or any exposure to, harmful substances.

Our construction contracts require us to comply with all environmental and safety standards set by our customers. These requirements cover such areas as safety training for new hires, equipment use on site, visitor access on site and procedures for dealing with hazardous substances.

Capital expenditures relating to environmental matters during the fiscal years ended March 31, 2006, 2007 and 2008 were not material. We do not currently anticipate any material adverse effect on our business or financial position as a result of future compliance with applicable environmental laws and regulations. Future events, however, such as changes in existing laws and regulations or their interpretation, more vigorous enforcement policies of regulatory agencies or stricter or different interpretations of existing laws and regulations may require us to make additional expenditures which may or may not be material.*

Employees and Labour Relations

As of December 31, 2008, we had over 320 salaried employees and over 1,600 hourly employees. Our hourly workforce will fluctuate according to the seasonality of our business and the staging and timing of projects by our customers. The hourly workforce is estimated at a low of 1,000 employees to a high of 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 1,200 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 expires on October 31, 2009. A small portion of our employees work under an industrial collective bargaining agreement with the Alberta Road Builders and Heavy Construction Association and the International Union of Operating Engineers Local 955, the primary term of which expires February 28, 2009. In June 2008, we signed an agreement with the International Union of Operating Engineers Local 955 covering the small group of employees working in our Acheson shop, which will expire June 30, 2011. 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 satisfactory. We have not experienced a strike or lockout.

F. Resources and Systems

Outstanding Share Data

We are authorized to issue an unlimited number of common voting shares and an unlimited number of common non-voting shares. As at February 5, 2009, there were 36,038,476 common voting shares outstanding

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28

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

(36,038,476 as at December 31, 2008). In comparison, 35,929,476 common voting shares were outstanding as at March 31, 2008. We had no non-voting common shares outstanding on any of the foregoing dates.

Liquidity

Liquidity requirements

Our primary uses of cash are for 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. We typically finance approximately 30% to 50% of our total capital requirements through our operating lease facilities, 5% to 10% through our capital lease facilities and the remainder out of 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 is currently split between owned (48%), leased (44%) and rented equipment (8%). This equipment mix is a change from the mix reported in previous periods as a result of the closeout of projects that operated with significant amounts of rental equipment. This mix allows us to respond to variations in construction activity and still maintain positive cash flow from operations. Approximately 42% of our leased fleet is specific to one long-term overburden removal project. We are currently evaluating our capital needs given the rapid decline in capital projects by our major customers. We have already cancelled orders for equipment due for delivery towards the end of calendar 2009. We are monitoring equipment lead times and working closely with suppliers to ensure that we limit our capital spending going forward.*

As at December 31, 2008 we received lease financing for the second cable shovel that was commissioned for the long-term overburden removal project. We continue to receive interest from finance companies to support our current lease requirements and we have availability under one of our supplier s 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 next two quarters.

Our long-term debt includes US$200 million of 8 $^{3}/4$% senior notes due in December 2011. As at December 31, 2008 the foreign currency risk relating to both the principal and interest portions of these 8 $^{3}/4$% senior notes is managed with a cross-currency swap and interest rate swaps, which went into effect concurrent with the issuance of the notes on November 26, 2003. The swap agreements are an economic hedge but have not been designated as hedges for accounting purposes. Interest totaling C$13.0 million on the 8 $^{3}/4$% senior notes

* This paragraph contains forward looking statements. 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 nine months ended December 31, 2008

and 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 hedged at C$1.315=US$1.000, resulting in a principal repayment of $263 million due on December 1, 2011. There are no principal repayments required on the 8 3/4% senior notes until maturity.

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. As of February 2, 2009 our interest expense will increase by US$6.3 million per annum (based on current LIBOR rates) for the remaining life of the 8 3/4% senior notes. 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 million in letters of credit. As at December 31, 2008, we had $20.0 million in letters of credit outstanding in connection with this contract. 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.

Sources of liquidity

Our principal sources of cash are funds from operations and borrowings under our $125 million revolving credit facility. As of December 31, 2008, we had approximately $104.2 million of available borrowings under the revolving credit facility after taking into account $20.8 million of outstanding and undrawn letters of credit to support performance guarantees associated with customer contracts.

As at December 31, 2008 we had $28.6 million in trade receivables that were more than 30 days past due compared to $13.3 million as at March 31, 2008. We have currently provided for $3.3 million ($0.7 million at March 31, 2008) through our allowance for doubtful accounts and we have subsequently collected $8.1 million from customers to apply against the past due outstanding balances. 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 status of developers of condominiums and high rise developments.

As of December 31, 2008, our cash balance of $42.3 million was $9.4 million higher than our cash balance on March 31, 2008, as a result of the timing of capital expenditures and the timing of processing change orders and payment certificates. We anticipate that we will continue to generate a net cash surplus through March 31, 2009 from cash generated from operations. In the event that we require additional funding, we believe that any such funding requirements would be satisfied by the funds available from our revolving credit facility, described immediately below.*

Revolving credit facility

We entered into an amended and restated credit agreement on June 7, 2007 with a syndicate of lenders that provides us with a $125.0 million revolving credit facility. Our revolving credit facility provides for an original principal amount of up to $125.0 million under which revolving loans may be made and under which letters of

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

30

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

credit may be issued. The facility will mature on June 7, 2010, subject to possible extension. The credit facility is secured by a first priority lien on substantially all of our and our subsidiaries existing and after-acquired property (tangible and intangible) including, without limitation, accounts receivable, inventory, equipment, intellectual property and other personal property and real property, whether owned or leased, and a pledge of the shares of our subsidiaries, subject to various exceptions.

The facility bears interest on each prime loan at variable rates based on the Canadian prime rate plus the applicable pricing margin (as defined within the revolving credit agreement). Interest on U.S. base rate loans is paid at a rate per annum equal to the U.S. base rate plus the applicable pricing margin. Interest on prime and U.S. base rate loans is payable monthly in arrears and computed on the basis of a 365-day or 366-day year, as the case may be. Interest on LIBOR loans is paid during each interest period at a rate per annum, calculated on a 360-day year, equal to the LIBOR rate with respect to such interest period plus the applicable pricing margin.

Our revolving credit facility contains covenants that restrict our activities including, but not limited to: incurring additional debt that doesn t qualify as Permitted Debt ; transferring or selling assets other than Permitted Dispositions ; and making investments, including acquisitions. Permitted Debt includes, but is not limited to, debt in respect to capital leases aggregating not in excess of $30.0 million as well as an additional $30.0 million in permitted debt that may also be in the form of capital leases. Permitted Dispositions include the sale or disposition of assets in the ordinary course of business and in accordance with sound industry practice but are limited such that the disposition does not result in a material adverse affect in our business.

Under the revolving credit facility, Consolidated Capital Expenditures (as defined within the revolving credit agreement) during any applicable period cannot exceed 120% of the amount in the capital expenditure plan. In addition, we are required to satisfy certain financial covenants, including a minimum interest coverage ratio and a maximum senior leverage ratio, both of which are calculated using Consolidated EBITDA as well as a minimum current ratio.

Consolidated EBITDA is defined in the credit facility as the sum, without duplication, of (1) consolidated net income, (2) consolidated interest expense, (3) provision for taxes based on income, (4) total depreciation expense, (5) total amortization expense, (6) costs and expenses incurred by us in entering into the credit facility, (7) accrual of stock-based compensation expense to the extent not paid in cash or if satisfied by the issue of new equity and (8) other non-cash items (other than any such non-cash item to the extent it represents an accrual of or reserve for cash expenditure in any future period) but only, in the case of clauses (2)-(8), to the extent deducted in the calculation of consolidated net income, less 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 for us in conformity with Canadian GAAP.

Interest coverage is determined based on a ratio of Consolidated EBITDA to consolidated cash interest expense and the senior leverage is determined as a ratio of senior debt to Consolidated EBITDA. Measured as of the last day of each fiscal quarter on a trailing four-quarter basis, Consolidated EBITDA shall not be less than 2.5 times consolidated cash interest expense (2.35 times at June 30, 2007). Also, measured as of the last day of each fiscal quarter on a trailing four-quarter basis, senior leverage shall not exceed 2 times Consolidated EBITDA. We believe Consolidated EBITDA is an important measure of our performance and liquidity.

The credit facility may be prepaid in whole or in part without penalty, except for bankers acceptances, which will not be pre-payable 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

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

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.

Working capital fluctuations effect on cash

The seasonality of our work may result in a slow down in cash collections between December and early February, 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 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. We are only entitled to collect payment on holdbacks once substantial completion of the contract is performed, 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). As at December 31, 2008, holdbacks totaled $17.6 million, down from $35.0 million as at March 31, 2008. Holdbacks represent 12.1% of our total accounts receivable as at December 31, 2008 (21.0% as at March 31, 2008). This decrease is attributable to the seasonal reduction of revenue compared to the previous two quarters and the collection of holdbacks outstanding as at March 31, 2008, including the DeBeers holdback for $11.0 million. As at December 31, 2008, we carried $13.9 million in holdbacks for three large customers.

Debt Ratings

Our debt ratings were last assessed in December 2007 by Standard & Poor s who upgraded our debt rating to B+ from B with a stable outlook and Moody s who maintained rating at B2 with a stable outlook. Standard & Poor s rated our 8 3/4% senior notes at B+ with a recovery rating of 4 indicating an expectation for an average of (30% 50%) recovery in the event of a payment default. Moody s rates our 8 3/4% senior notes at B3 with a loss given default rating of 5. A securities rating is not a recommendation to buy, sell or hold a security, may be subject to revision or withdrawal at any time by the issuing ratings agency in its sole discretion and should be evaluated independently of any other rating.

Cash Flow and Capital Resources

	Three Months Ended December 31,		Nine Months Ended December 31,	
(Dollars in thousands)	**2008**	**2007**	**2008**	**2007**
Cash provided by (used in) operating activities	$ 63,263	$ 32,837	$ 87,494	$ 61,417
Cash (used in) investing activities	(8,614)	(26,877)	(74,039)	(45,886)
Cash (used in) provided by financing activities	(12,340)	19,952	(4,017)	(2,183)
Net increase in cash and cash equivalents	$ 42,309	$ 25,912	$ 9,438	$ 13,348

Operating activities

Cash provided by operating activities for the three months ended December 31, 2008 was an inflow of $63.3 million compared to an inflow of $32.8 million last year. For the nine months ended December 31, 2008, cash provided by operating activities was an inflow of $87.5 million compared to a cash inflow of $61.4 million last year. Operating activities in the three month period ended December 31, 2008 benefited from improved collections as we worked with our customers in processing change orders and progress payment certificates. We continue to work with our customers to address delays so that we can stay current with change orders and progress payment certificates.

Investing activities

Sustaining capital expenditures are those that are required to keep our existing fleet of equipment at its optimal useful life through capital maintenance or replacement. Growth capital expenditures relate to equipment additions required to perform larger or a greater number of projects.

During the three months ended December 31, 2008, we invested $3.9 million in sustaining capital expenditures, compared with $3.9 million last year, and invested $5.2 million in growth capital expenditures compared with $4.1 million in the prior year, for total capital expenditures of $9.1 million this year compared with $8.0 million last year. The $2.1 million net reduction in accounts payable related to timing of capital expenditures disbursements for the period ended December 31, 2008. Proceeds of $3.2 million from asset disposals in the current quarter, compared with $0.1 million in the same quarter last year, lessened the effect of capital purchases resulting in net cash invested of $8.6 million for the three months ended December 31, 2008, compared with $26.9 million in the prior year.

Capital expenditures funded by capital leases, not included in Cash (used in) investing activities , added $7.8 million to the reported growth capital expenditures and $0.2 million to sustaining capital for the three months ended December 31, 2008. This compares to an addition of $2.6 million in capital leases in growth capital expenditures and $1.7 million capital leases in sustaining capital expenditures last year. Operating leases used to fund equipment purchases added $52.2 million in the three months ended December 31, 2008 (not reflected in capital expenditures) compared to $31.4 million last year.

For the nine months ended December 31, 2008, we invested $16.6 million in sustaining capital expenditures, compared with $19.8 million in the prior year and invested $67.7 million in growth capital expenditures, compared with $31.7 million last year, for total capital expenditures of $84.3 million, compared with $51.6 million a year ago. Proceeds from asset disposals of $8.0 million and net inflow from non-cash working capital of $3.2 million in the nine months ended December 31, 2008, compared with $14.2 million and an outflow of $4.7 million respectively last year lessened the effect of capital purchases. Net investment activities were an outflow of $74.0 million for the nine months ended December 31, 2008, compared with an outflow of $45.9 million a year ago.

Capital expenditures funded by capital leases, not included in Cash (used in) investing activities , added $3.0 million to the reported sustaining capital expenditures and $10.1 million to the reported growth capital expenditures for the nine months ended December 31, 2008. This compares to an addition of $2.9 million in capital leases in growth capital expenditures and $1.7 million in capital leases in sustaining capital expenditure last year. Operating leases used to fund equipment purchases added $85.2 million for the nine months ended December 31, 2008 (not reflected in capital expenditures) compared to $44.6 million in the last year.

Financing activities

Financing activities in the three months ended December 31, 2008 resulted in a cash outflow of $12.3 million due to a $10.0 million repayment on the revolving credit facility combined with a repayment of

capital leases. Cash inflow in the three months ended December 31, 2007 of $20.0 million was largely a result of

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

a $20.0 million drawdown on the revolving credit facility and share issues related to the exercise of stock options.

Financing activities for the nine months ended December 31, 2008 resulted in a cash outflow of $4.0 million due to a repayment of capital lease obligations partially offset by share issues related to the exercise of stock options. Cash outflow for the nine months ended December 31, 2007 of $2.2 million was a result of a $0.5 million repayment to the revolving credit facility, repayment of capital lease obligations and financing costs partially offset by the issue of common shares.

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 December 31, 2008.

		Payments due by fiscal year				
(in millions)	**Total**	**2009**	**2010**	**2011**	**2012**	**2013 and after**
Senior notes[1]	$ 263.0	$	$	$	$ 263.0	$
Capital leases (including interest)[2]	24.9	6.4	6.2	5.2	4.6	2.5
Operating leases	144.9	11.6	42.1	32.5	25.1	33.6
Supplier contracts	32.3	1.3	5.9	8.1	9.7	7.3
Total contractual obligations	**$ 465.1**	**$ 19.3**	**$ 54.2**	**$ 45.8**	**$ 302.4**	**$ 43.4**

(1) We have entered into cross-currency and interest rate swaps, which represent an economic hedge of the 8 3/4% senior notes (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 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. At December 31, 2008, the carrying value of the derivative financial instruments was $45.3 million, inclusive of the interest components

(2) Capital lease obligation for the remaining period of fiscal 2009 includes $4.7 million related to a 320 ton haul truck lease payment. We entered into a short-term capital lease to secure this asset until such time as we were able to negotiate a longer term operating lease that is not restricted by our Revolving Credit Facility debt covenants (see our discussion on the *Revolving Credit Facility* in the Liquidity section for more detail on debt restrictions related to capital leases)

Off-Balance Sheet Arrangements

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

34

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

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. Throughout fiscal 2008 we concentrated on the development of better cost tracking tools through the implementation of a procure-to-pay process in our ERP system. We continue to work on improving the process for tracking and reporting equipment and maintenance costs. We are seeing some improvements in the identification and tracking of our procurement costs.

During the three months ended December 31, 2008 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 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 implementations based on the recommendations.

During the three months ended December 31, 2008 we started to realize the benefits from new staff hires in the corporate finance group. Additional procedures were developed and implemented during the quarter to address the material weaknesses in the financial close and reporting. We are currently evaluating the effectiveness of these new controls and will continue to implement improvements to our financial reporting process.*

Evaluation of Disclosure Controls and Procedures

Management has evaluated whether there were changes in our internal controls over financial reporting during the three and nine month periods ended December 31, 2008 that have materially affected or reasonably likely to materially affect our internal controls over financial reporting. No material changes were identified.

As of March 31, 2008, we identified material weaknesses in internal controls over financial reporting as described below. We did not maintain effective processes and controls related to the following:

Specific to complex and non routine transactions and period end controls: There was a lack of sufficient accounting and finance personnel with an appropriate level of technical accounting knowledge and training commensurate with the complexity of our financial accounting and reporting requirements. Complex and non routine financial reporting matters that would be affected by this deficiency include the identification of embedded derivatives and preparation of our US GAAP reconciliation note. Additionally, we did not adequately perform period end controls related to the review and approval of account analysis, verification of inputs and reconciliations. The accounts that would be affected by these deficiencies are cash, senior notes, contributed surplus, stock-based compensation expense, foreign exchange and related financial statement disclosures.

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

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

Specific to revenue recognition: 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, were not effectively implemented. The accounts that would be affected by these deficiencies are revenue, project costs, unbilled revenue and billings in excess of costs incurred and estimated earnings on uncompleted contracts.

Specific to accounts payable and procurement: We did not have an effectively implemented procurement process to track purchase commitments, reconcile vendor accounts and accurately accrue costs not invoiced by vendors at each reporting date. The accounts that would be affected by these deficiencies are accounts payable, accrued liabilities, unbilled revenue, billings in excess of costs incurred and estimated earnings on uncompleted contracts, revenue, project costs, equipment costs, general and administrative costs and other expenses.

As of December 31, 2008, significant progress has been made on our remediation plans but these material weaknesses have not been fully remediated. For a discussion of our remediation plans, which are ongoing, and for a discussion of the risks associated with such weaknesses, please see our most recent annual Management s Discussion and Analysis.

Significant Accounting Policies

Critical Accounting Estimates

Certain accounting policies require management to make significant estimates and assumptions about future events that affect the amounts reported in our financial statements and the accompanying notes. Therefore, the determination of estimates requires the exercise of management s judgment. Actual results could differ from those estimates and any differences may be material to our financial statements.

Revenue recognition

Our contracts with customers fall under the following contract types: cost-plus, time-and-materials, unit-price and lump-sum. While contracts are generally less than one year in duration, we do have several long-term contracts. The mix of contract types varies year-by-year. For the three months ended December 31, 2008, our revenue mix was made up of 70.6% time-and-materials contracts, 23.8% unit-price contracts and 5.6% lump-sum contracts.

Profit for each type of contract is included in revenue when its realization is reasonably assured. Estimated contract losses are recognized in full when determined. Claims and unapproved change orders are included in total estimated contract revenue only to the extent that contract costs related to the claim or unapproved change order have been incurred, when it is probable that the claim or unapproved change order will result in a bona fide addition to contract value and the amount of revenue can be reliably estimated.

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Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

The accuracy of our revenue and profit recognition in a given period is dependent, in part, on the accuracy of our estimates of the cost to complete each unit-price and lump-sum project. Our cost estimates use a detailed bottom-up approach, using inputs such as labour and equipment hours, detailed drawings and material lists. These estimates are updated monthly. We have noted a material weakness related to our procurement processes as previously identified in the fiscal year-end March 31, 2008 Management s Discussion and Analysis. To address these weaknesses we implemented monitoring and review controls to assist with the determination of our cost estimates. These controls require a significant review of our payable activities after the month-end to ensure that we have identified project costs in the correct period. Given the time delay in identifying costs, we may misstate revenues. However, we believe our experience allows us to produce materially reliable estimates. Our projects can be highly complex and in almost every case, the profit margin estimates for a project will either increase or decrease to some extent from the amount that was originally estimated at the time of the related bid. Because we have many projects of varying levels of complexity and size in process at any given time, these changes in estimates can offset each other without materially impacting our profitability. However, sizable changes in cost estimates, particularly in larger, more complex projects, can have a significant effect on profitability. Factors that can contribute to changes in estimates of contract cost and profitability include, without limitation:*

- changes in site conditions that differ from those assumed in the original bid, to the extent that contract remedies are unavailable;
- changes in identification and evaluation of scope modifications during the execution of the project;
- changes in the availability and cost of skilled workers in the geographic location of the project;
- changes in the availability and proximity of materials;
- changes in unfavorable weather conditions hindering productivity;
- changes in equipment productivity and timing differences resulting from project construction not starting on time; and
- changes in general coordination of work inherent in all large projects we undertake.

The foregoing factors, as well as the stage of completion of contracts in process and the mix of contracts at different margins, may cause fluctuations in gross profit between periods and these fluctuations may be significant. These changes in cost estimates and revenue recognition impact all three business segments.

Once contract performance is underway, we will often experience changes in conditions, client requirements, specifications, designs, materials and work schedule. Generally, a change order will be negotiated with the customer to modify the original contract to approve both the scope and price of the change. Occasionally, however, disagreements arise regarding changes, their nature, measurement, timing and other characteristics that impact costs and revenue under the contract. When a change becomes a point of dispute between a customer and us, we will then consider it as a claim.

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North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

Costs related to change orders and claims are recognized when they are incurred. Change orders are included in total estimated contract revenue when it is probable that the change order will result in a bona fide addition to contract value and can be reliably estimated. Claims are included in total estimated contract revenue only to the extent that contract costs related to the claim have been incurred and when it is probable that the claim will result in a bona fide addition to contract value and can be reliably estimated. Those two conditions are satisfied when (1) the contract or other evidence provides a legal basis for the claim or a legal opinion is obtained providing a reasonable basis to support the claim, (2) additional costs incurred were caused by unforeseen circumstances and are not the result of deficiencies in our performance, (3) costs associated with the claim are identifiable and reasonable in view of the work performed and (4) evidence supporting the claim is objective and verifiable. No profit is recognized on claims until final settlement occurs. This can lead to a situation where costs are recognized in one period and revenue is recognized when customer agreement is obtained or claim resolution occurs, which can be in subsequent periods. Historical claim recoveries should not be considered indicative of future claim recoveries.

Plant and equipment

The most significant estimates in accounting for plant and equipment are the expected useful life of the asset and the expected residual value. Most of our property, plant and equipment have long lives that can exceed 20 years with proper repair work and preventative maintenance. Useful life is measured in operating hours, excluding idle hours and a depreciation rate is calculated for each type of unit. Depreciation expense is determined monthly based on daily actual operating hours. In determining the estimates of these useful lives, we take into account industry trends and company-specific factors, including changing technologies and expectations for the in-service period of certain assets. On an annual basis, we re-assess our existing estimates of useful lives to ensure they match the anticipated life of the equipment from a revenue-producing perspective. If technological change happens more quickly or in a different way than anticipated, we might have to reduce the estimated life of plant and equipment, which could result in a higher depreciation expense in future periods or we may record an impairment charge to write down the value of plant and equipment.

Another key estimate is the expected cash flows from the use of an asset and the expected disposal proceeds in applying CICA Section 3063 Impairment of Long-Lived Assets and Section 3475 Disposal of Long-Lived Assets and Discontinued Operations . These standards require the recognition of an impairment loss for a long-lived asset when changes in circumstances cause its carrying value to exceed the total undiscounted cash flows expected from its use. An impairment loss, if any, is determined as the excess of the carrying value of the asset over its fair value. The valuation of long-lived assets requires us to exercise judgment in the determination of an asset group and in making assumptions about future results, including revenue and cash flow projections for an asset group.

Allowance for doubtful accounts receivable

We regularly review our accounts receivable balances for each of our customers and we write down these balances to their expected realizable value when outstanding amounts are determined not to be fully collectible. This generally occurs when our customer has indicated an inability to pay, we were unable to communicate with our customer over an extended period of time and we have considered other methods to obtain payment without success. We determine estimates of the allowance for doubtful accounts on a customer-by-customer evaluation of collectability at each reporting date, taking into consideration the following factors: the length of time the receivable has been outstanding, specific knowledge of each customer s financial condition and historical experience.

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

Goodwill impairment

Impairment is tested at the reporting unit level by comparing the reporting unit s carrying amount to its fair value. The process of determining fair value is subjective and requires us to exercise judgment in making assumptions about future results, including revenue and cash flow projections at the reporting unit level and discount rates. We previously tested goodwill annually on December 31. Starting in fiscal year 2008 we complete the annual goodwill impairment testing on October 1. This change in timing was made to reduce conflict between the impairment testing and our financial reporting close process for the fiscal period ending December 31 of each calendar year. It is our intention to continue to complete subsequent goodwill impairment testing on October 1 going forward or whenever events or changes in circumstances indicate that impairment may exist. This change in accounting policy was applied on a retrospective basis and had no impact on the consolidated financial statements. We completed our most recent annual goodwill impairment testing on October 1, 2008. On December 31, 2008 we performed an interim goodwill impairment test due to recent economic events which adversely affected the value of our Pipeline reporting unit. We concluded that neither the fair value of our Heavy Construction and Mining reporting unit nor our Piling reporting unit had fallen below their carrying values as a result of the interim testing. We will continue to monitor economic events as they relate to each of our reporting units to determine if further impairment exists. For a more detailed discussion on our goodwill impairment testing as at October 1, 2008 and as at December 31, 2008 see Impairment of goodwill in the Analysis of Results discussion, above.

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.

Recently Adopted Accounting Policies

Financial Instruments Disclosure and Presentation

Effective April 1, 2008, we prospectively adopted the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3862, Financial Instruments Disclosures , which replaces disclosure guidance in CICA Handbook Section 3861 and provides expanded disclosure requirements that enable users to evaluate the significance of financial instruments on our financial position and our performance and the nature and extent of risks arising from financial instruments to which we are exposed during the period and at the balance sheet date, and how we manage those risks. This standard harmonizes disclosures with International Financial Reporting Standards. We have provided the required disclosures in note 11 to our interim consolidated financial statements for the three and nine months ended December 31, 2008.

Effective April 1, 2008, we adopted CICA Handbook Section 3863, Financial Instruments Presentation , which carries forward presentation guidance in CICA Handbook Section 3861. This Section establishes standards

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

for presentation of financial instruments and non-financial derivatives. It deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, gains and losses, and the circumstances in which financial assets and financial liabilities are offset. The adoption of this standard did not have a material impact on the presentation of financial instruments in our financial statements.

Capital Disclosures

Effective April 1, 2008, we prospectively adopted CICA Handbook Section 1535, Capital Disclosures , which requires disclosure of qualitative and quantitative information that enables users to evaluate our objectives, policies and processes for managing capital. We have provided the required disclosures in note 12 to our interim consolidated financial statements for the three and nine months ended December 31, 2008.

Inventories

Effective April 1, 2008, we retrospectively adopted CICA Handbook Section 3031, Inventories without restatement of prior periods. This standard requires inventories to be measured at the lower of cost and net realizable value and provides guidance on the determination of cost, including the allocation of overheads and other costs to inventories, the requirement for an entity to use a consistent cost formula for inventory of a similar nature and use, and the reversal of previous write-downs to net realizable value when there are subsequent increases in the value of inventories. This new standard also clarifies that spare component parts that do not qualify for recognition as property, plant and equipment should be classified as inventory. To adopt this new standard we reversed a tire impairment of $1.4 million that was previously recorded at March 31, 2008 in other assets with a corresponding decrease to opening deficit of $1.0 million net of future taxes of $0.4 million. We then reclassified $5.1 million of tires and spare component parts from other assets to inventory . As at December 31, 2008, inventory is comprised of tires of $13.1 million and job materials of $2.1 million. We carry inventory at the lower of weighted average cost and net realizable value. The carrying amount of inventories pledged as security for borrowings under the revolving credit facility is $15.2 million as at December 31, 2008. The adoption of this standard did not have a significant impact on net income (loss) for the three and nine months ended December 31, 2008.

Recent Accounting Pronouncements Not Yet Adopted

Goodwill and Other Intangible Assets

In February 2008, the CICA issued Section 3064, Goodwill and Other Intangible Assets , replacing Section 3062, Goodwill and Other Intangible Assets and Section 3450, Research and Development Costs . The new pronouncement establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. This new standard will be effective for our interim and annual consolidated financial statements commencing April 1, 2009. We are currently evaluating the impact of adopting the standard.

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

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

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 , could , would , target , objective , projection , forecast , position or the negative of those terms or other variations of them or comparable 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 operational spending throughout the 30-40 year life of a mine and our ability to provide services through such period;

(b) the market for our recurring services will expand due to new mines nearing production coming on-line and the expansion of activities at current operational mines;

(c) existing oil sands projects will continue to be less sensitive than conventional oil operations to changes in oil prices;

(d) commodity prices will continue to remain low and mine development in the minerals mining sector will continue to remain below normal levels;

(e) our intention to use our fleet size to respond to new opportunities;

(f) our intention to pursue selective acquisition opportunities will materialize that will expand our complementary service offerings which we will be able to cross-sell with our existing services;

(g) our intention to build on our relationships with our existing oil sands customers to win a substantial share of the heavy construction and mining, piling and pipeline services outsourced in connection with these projects;

(h) our intention to increase our presence outside the oil sands and extend our services to other resource industries across Canada;

(i) the success of the enhancements to maintenance practices resulting in improved availability through reduced repair time and increased utilization of our equipment with a consequent improvement in our revenue, margins and profitability;

(j) the amount of our backlog expected to be performed and realized in the twelve months ending December 31, 2009;

(k) that infrastructure spending will remain robust;

(l) the arrival of new major projects and our required participation in the bidding process for work on these projects;

(m) the increased variability in recurring services revenue in 2009;

(n) the anticipated reduction in our pipeline segment revenues, the anticipated reduction in our heavy construction, mining and piling operating segment revenues, the anticipated resumption of work in overburden removal by April 30, 2009, with a return to full production by June 30, 2009 and the significant long-term opportunities for these segments;

(o) our expectation of being able to implement improvements to our financial reporting process;

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

(p) our operating and capital lease facilities and cash flow from operations are sufficient to meet capital expenditure requirements;

(q) our ability to produce materially reliable estimates;

(r) the demand for our recurring oil sands services remaining strong and continuing to grow;

(s) the expansion of our accessible market will occur as new mines near production;

(t) the expected improvement in our near-term cash management, our draw down of our inventory of higher-cost tire inventory and a reduction in our tire inventory over the coming months;

(u) our ability to manage effectively through the current economic uncertainty; and

(v) the decline in commercial construction projects will be offset by an expected increase in infrastructure-related construction activity infrastructure projects.

The forward-looking information in paragraphs (a), (b), (d), (e), (f), (k), (l), (m), (n), (r), (s), (u) and (v) 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 combined with short term declines in oil prices, which will slow capital development of Canada s natural resources, in particular the oil sands, 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 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;

because most of our customers are Canadian energy companies, a further decline 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

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

- 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), (m), (o), (p), (q), (r), (s), (t) and (u) 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; that 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 be able to access sufficient funds to finance our capital growth; and are subject to the risks and uncertainties that:

- our ability to grow our operations in the future may be hampered by our inability to obtain equipment and tires;
- 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 further 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;
- environmental laws and regulations may expose us to liability arising out of our operations or the operations of our customers; and
- many of our senior officers have either recently joined the company or have just been promoted and have only worked together as a management team for a short period of time.

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

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

list of the factors that could affect us. See Risk Factors below and risk factors 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 Management s Discussion and Analysis.

Risk Factors

For the three and nine months ended December 31, 2008, other than noted below, there has been no significant change in our risk factors from those described in our Management s Discussion and Analysis for the fiscal year ended March 31, 2008. For a detailed discussion of these risk factors, see Risk Factors in our Management s Discussion and Analysis for the fiscal year ended March 31, 2008.

Anticipated new major capital projects in the oil sands may not materialize.

Notwithstanding the National Energy Board s estimates regarding new capital investment and growth in the Canadian oil sands, planned and anticipated capital projects in the oil sands may not materialize. The underlying assumptions on which the capital projects are based are subject to significant uncertainties, and actual capital investments in the oil sands could be significantly less than estimated. Projected investments in new capital projects may be postponed or cancelled for any number of reasons, including among others:

- reductions in available credit for customers to fund capital projects;
- changes in the perception of the economic viability of these projects;
- shortage of pipeline capacity to transport production to major markets;
- lack of sufficient governmental infrastructure funding to support growth;
- delays in issuing environmental permits or refusal to grant such permits;
- shortage of skilled workers in this remote region of Canada; and
- cost overruns on announced projects.

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

Due to the amount of capital investment required to build an oil sands project, or construct a significant capital expansion to an existing project, investment decisions by oil sands operators are based upon long-term views of the economic viability of the project. Economic viability is dependent upon the anticipated revenues the capital project will produce, the anticipated amount of capital investment required and the anticipated fixed cost of operating the project. The most important consideration is the customer s view of the long-term price of oil which is influenced by many factors, including the condition of developed and developing economies and the resulting demand for oil and gas, the level of supply of oil and gas, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political conditions in oil producing nations, including those in the Middle East, war or the threat of war in oil producing regions and the availability of fuel from alternate sources. If our customers believe the long-term outlook for the price of oil is not favorable, or believe oil-sands projects are not viable for any other reason, they may delay, reduce or cancel plans to construct new oil sands capital projects or capital expansions to existing projects. Recently, the market price of oil decreased significantly. In addition, the slowing world economy is leading to lower international demand for oil, which could continue to suppress oil prices. As a result of these developments, many of our customers have decided to

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

scale back their capital development plans and are significantly reducing their capital expenditures on oil sands projects. Delays, reductions or cancellations of major oil sands projects would adversely affect our prospects for revenues from capital projects and could have an adverse impact on our financial condition and results of operations.

Because most of our customers are Canadian energy companies, a downturn in the Canadian energy industry could result in a decrease in the demand for our services.

Most of our customers are Canadian energy companies. A downturn in the Canadian energy industry is leading our customers to slow down or curtail their future capital expansion which, in turn, has reduced our revenue from those customers on their capital projects. Such a delay or curtailment could have an adverse impact on our financial condition and results of operations. In addition, a reduction in the number of new oil sands capital projects by customers would also likely result in increased competition among oil sands service providers, which could also reduce our ability to successfully bid for new capital projects.

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

Outsourced mining and site preparation services constitute a large portion of the work we perform for our customers. For example, our mining and site preparation project revenues constituted approximately 63%, 75% and 74% of our revenues in each of fiscal years 2008, 2007 and 2006 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.

Quantitative and Qualitative Disclosures about Market Risk

Foreign currency risk

We are subject to currency exchange risk as our 8 $^{3}/4$% senior notes are denominated in US dollars and all of our revenues and most of our expenses are denominated in Canadian dollars. To manage the foreign currency risk and potential cash flow impact on our $200 million in US dollar-denominated notes, we have entered into currency swap and interest rate swap agreements. These financial instruments consist of three components: a US dollar interest rate swap; a US dollar-Canadian dollar cross-currency basis swap; and a Canadian dollar interest rate swap. Of the three components, only the US dollar interest rate swap could be cancelled at the counterparty s option at any time after December 1, 2007 if the counterparty pays a cancellation premium.

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 will be terminated. In addition to net accrued interest to the termination date of US$0.7 million, the counterparties will pay a cancellation premium of 2.1875% on the notional amount of US$200.0 million or US$4.4 million (equivalent to C$5.3 million).

As a result of this 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 3-month LIBOR is less than 4.57% (the difference between the 8.75% coupon on our 8 $^{3}/4$% senior notes and the 4.18% spread over 3-month LIBOR on the cross currency basis swap), we will have to acquire US dollars to fund a portion of the semi-annual coupon payment on

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

our 8 $^{3}/4$% senior notes. At the 3-month LIBOR rate of 1.43% at December 31, 2008, a $0.01 increase (decrease) in the Canadian dollar would result in a C$0.03 million decrease (increase) in the amount of Canadian dollars required to fund each semi-annual coupon payment.

Exchange rate fluctuations may also cause the price of goods to increase or decrease for us. For example, a decrease in the value of the Canadian dollar compared to the US dollar would proportionately increase the cost of equipment and parts which are sold to us or priced in US dollars.

The impact of the exchange rate fluctuation may also affect any embedded derivatives included in our revenue or parts and maintenance contracts with price escalators tied to either foreign exchange rates or foreign cost indices.

Interest rate risk

We are exposed to interest rate risk on the revolving credit facility, capital lease obligations and certain operating leases with a variable payment that is tied to prime rates. We do not use derivative financial instruments to reduce our exposure to these risks. The estimated financial impact as a result of fluctuations in interest rates is not significant for the revolving credit facility, capital lease obligations and certain operating leases.

In conjunction with the cross-currency swap agreement we 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 9.765% for the duration that the 8 $^{3}/4$% senior notes are outstanding. On May 19, 2005 in connection with our new revolving credit facility at that time, this fixed rate was increased to 9.889%. These derivative financial instruments were not designated as a hedge for accounting purposes.

As a result of the US dollar interest swap cancelation described in Foreign currency risk , above, we are exposed to changes in interest rates. We have a fixed semi-annual coupon payment of 8.75% on our US$200.0 million 8 $^{3}/4$% 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, we have interest rate exposure to changes in the 3-month LIBOR rate (1.43% at December 31, 2008). As at the effective date of the cancellation, at the current LIBOR rate, our interest expense will increase by US$6.3 million per annum over the remaining term of the 8 $^{3}/4$ % senior notes. A 100 basis point increase (decrease) in the 3-month LIBOR rate will result in a US$2.0 million increase (decrease) in the annual floating rate payment received from the swap counterparties

At December 31, 2008 and March 31, 2008, the notional principal amounts of the interest rate swaps were US$200 million and Canadian $263 million, respectively.

As at December 31, 2008, 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 $5.8 million, net of tax, with this change in fair value being recorded in net income. As at December 31, 2008, holding all other variables constant, a 100 basis point increase (decrease) to US interest rates would impact the fair value of the interest rate swaps by $0.8 million, net of tax, with this change in fair value being recorded in net income. As at December 31, 2008, holding all other variables constant, a 100 basis point increase (decrease) to Canadian to US interest rate volatility would impact the fair value of the interest rate swaps by $nil with this change in fair value being recorded in net income.

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

Inflation

Inflation can have a material impact on our operations due to increasing parts, equipment replacement and labour costs; however, many of our contracts contain provisions for annual price increases. Inflation can have a material impact on our operations if the rate of inflation and cost increases remains above levels that we are able to pass to our customers.

Credit risk

Credit risk is the risk of financial loss to us if a customer or counterparty to a financial instrument fails to meet its contractual obligations. We are exposed to credit risk through our cash and cash equivalents, accounts receivable and unbilled revenue. We manage the credit risk associated with our cash and cash equivalents by holding our funds with reputable financial institutions. Credit risk for trade and other accounts receivables and unbilled revenue are managed through established credit monitoring activities. We review our trade receivable accounts regularly for collectability and payment performance.

We have a concentration of customers in the oil and gas sector. The concentration risk is mitigated by the customers being large investment grade organizations. The key risk related to oil and gas customers is the effect the economic conditions and tightening credit market have on their cash flows. Lower revenues from a declining per-barrel price of oil; increasing per-barrel operating costs and fixed debt commitments for capital projects can have an adverse effect on their operating cash flows.

Customers outside of the oil and gas sector include both developers and general contractors. Developers are more vulnerable to changes in economic conditions and tightening credit markets as they rely heavily on financing to complete their commercial property projects. General contractors are vulnerable to their customer s ability to pay. Both developers and general contractors are more closely monitored for changes in their payment behavior and credit worthiness.

Losses related to trade accounts receivable for oil and gas customers have historically been insignificant. Losses related to trade accounts receivable for developers or general contractors have historically been more pronounced, depending on the change in economic conditions. Decisions to extend credit to new customers are approved by management.

In the event that recent economic conditions adversely impact our customers or counterparties cash flows or their credit worthiness generally resulting in such parties failing to meet their payment obligations to us, such failure could have a material adverse effect on our business and our results of operations.

Availability or increased cost of leasing

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. To mitigate this risk we have secured an increased leasing facility with one of our existing equipment lessors, expanding our leasing capacity by approximately 30%. Our current lease commitments with this supplier now represent 78% of the total capacity available. We are actively pursuing new lessor relationships to dilute our exposure to the loss of one or more of our lessors.

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

H. General Matters

History and Development of the Company

NACG Holdings Inc. (Holdings) was formed in October 2003 in connection with the Acquisition discussed below. Prior to the Acquisition, Holdings had no operations or significant assets and the Acquisition was primarily a change of ownership of the businesses acquired.

On October 31, 2003, two wholly owned subsidiaries of Holdings, as the buyers, entered into a purchase and sale agreement with Norama Ltd. and one of its subsidiaries, as the sellers. On November 26, 2003, pursuant to the purchase and sale agreement, Norama Ltd. sold to the buyers the businesses comprising North American Construction Group in exchange for total consideration of approximately $405.5 million, net of cash received and including the impact of certain post-closing adjustments (the Acquisition). The businesses we acquired from Norama Ltd. have been in operation since 1953. Subsequent to the Acquisition, we have operated the businesses in substantially the same manner as prior to the Acquisition.

On November 28, 2006, prior to the consummation of the initial public offering (IPO) discussed below, Holdings amalgamated with its wholly-owned subsidiaries, NACG Preferred Corp and North American Energy Partners Inc. The amalgamated entity continued under the name North American Energy Partners Inc. The voting common shares of the new entity, North American Energy Partners Inc., were the shares sold in the IPO and related secondary offering. On November 28, 2006, we completed the IPO in the United States and Canada of 8,750,000 voting common shares and a secondary offering of 3,750,000 voting common shares for $18.38 per share (U.S. $16.00 per share).

On November 22, 2006, our common shares commenced trading on the New York Stock Exchange and on the Toronto Stock Exchange on an if, as and when issued basis. On November 28, 2006, our common shares became fully tradable on the Toronto Stock Exchange.

Net proceeds from the IPO were $140.9 million (gross proceeds of $158.5 million, less underwriting discounts and costs and offering expenses of $17.6 million). On December 6, 2006, the underwriters exercised their option to purchase an additional 687,500 common shares from us. The net proceeds from the exercise of the underwriters option were $11.7 million (gross proceeds of $12.6 million, less underwriting fees of $0.9 million). Total net proceeds were $152.6 million (total gross proceeds of $171.1 million less total underwriting discounts and costs and offering expenses of $18.5 million).

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

Transition to International Financial Reporting Standards (IFRS)

The Canadian Accounting Standards Board announced in February 2008 that 2011 is the changeover date for publicly-listed companies to use IFRS, replacing Canadian GAAP. The date is for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. Our first financial statement reported under IFRS will be our interim statements for the three months ended June 30, 2011. Prior year comparatives restated under IFRS will be included in these statements.

In order to meet the requirement to transition to IFRS, we have established an enterprise-wide project and formed an executive steering committee. We are following a transition plan comprised of four phases: IFRS

Table of Contents

North American Energy Partners Inc.

Management s Discussion and Analysis

For the three and nine months ended December 31, 2008

diagnostic assessment; policy decisions; implementation and education; and completion of all integration systems and process changes. We are on track, having completed the diagnostic phase of our project, and we have entered the early stages of the policy decision phase of our plan. Due to anticipated changes in International Accounting Standards prior to our transition to IFRS, we are not yet in a position to determine the impact on our financial results.

Additional Information

Additional information relating to us, including our Annual Information Form dated June 20, 2008, 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 Interactive Data Electronics Application (IDEA) system 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 December 31, 2008.

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 frameworks the issuer s other certifying officer(s) and I used to design the issuer s ICFR are as follows:

(a) the Committee of Sponsoring Organizations of the Treadway Commission (COSO) framework; and

(b) the Control Objectives for Information and related Technology (COBIT) framework created by the Information Systems Audit and Control Association and the IT Governance Institute.

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 October 1, 2008 and ended on December 31, 2008 that has materially affected, or is reasonably likely to materially affect, the issuer s ICFR.

Date: February 5, 2009

/s/ Rodney J. Ruston

Chief Executive Officer

Table of Contents

FORM 52-109F2

CERTIFICATION OF INTERIM FILINGS

I, Peter Dodd, 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 December 31, 2008.

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 frameworks the issuer s other certifying officer(s) and I used to design the issuer s ICFR are as follows:

   (a) the Committee of Sponsoring Organizations of the Treadway Commission (COSO) framework; and

(b) the Control Objectives for Information and related Technology (COBIT) framework created by the Information Systems Audit and Control Association and the IT Governance Institute.

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 October 1, 2008 and ended on December 31, 2008 that has materially affected, or is reasonably likely to materially affect, the issuer s ICFR.

Date: February 5, 2009

/s/ Peter Dodd

Chief Financial Officer