

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

The following discussion and analysis ("MD&A") should be read in conjunction with the Company's Annual Report on Form 10-K ("Annual Report") filed with the United States Securities and Exchange Commission and our historical consolidated financial statements and the accompanying notes included elsewhere in the Annual Report.

In this MD&A, unless otherwise specified, all dollar amounts are expressed in US Dollars ("\$").

BOE Presentation

Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas ("mcf"): one barrel of oil ("bbl") is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Overview

NiMin Energy Corp. ("NiMin", "we" or the "Company") is an oil and gas company engaged in the acquisition, development and production of oil and gas properties in the United States. We have operated as an exploration and production company since late 2006 and have principal operations in the Bighorn Basin, Wyoming and the San Joaquin Basin, California.

Oil and Gas Sales Report

Average daily production sold by region ⁽¹⁾

	Year Ended December 31, 2011	Year Ended December 31, 2010	Year Ended December 31, 2009
<i>Louisiana</i> ⁽²⁾			
Oil - Bbl/d	59	66	81
Gas - Mcf/d	439	795	1173
Total Louisiana (boe/d)	133	199	277
<i>California</i>			
Oil - Bbl/d	201	218	239
Gas - Mcf/d	0	-	-
Total California (boe/d)	201	218	239
<i>Wyoming</i> ⁽³⁾			
Oil - Bbl/d	700	426	29
Gas - Mcf/d	-	-	-
Total Wyoming (boe/d)	700	426	29
Total Oil (Bbl/d)	960	710	350
Total Gas (Mcf)	439	795	1,173
Total (boe/d)	1,033	842	546

Notes:

(1) These numbers are net to NiMin's working interest for the relevant properties.

(2) The Louisiana properties were sold on December 1, 2011 (see "Liquidity and Capital Resources").

(3) Wyoming average volumes in 2009 are based on 14 days of production and averaged over the entire applicable period.

Crude oil and natural gas sales

For the year ended December 31, 2011, we recorded gross revenues of \$30.95 million, as compared to \$18.75 million for the year ended December 31, 2010. Oil sales as a percentage of total revenue during the year ended December 31, 2011 as compared to the same period in 2010 increased from 93% to 98%. Oil volumes increased by 35% to 960 barrels of oil per day (“Bopd”) and the price received increased by 28% to \$86.44 during the year ended December 31, 2011 as compared to the same period in 2010. Natural gas sales as a percentage of total revenue during the year ended December 31, 2011 as compared to the same period in 2010 decreased from 7% to 2%. Natural gas volumes decreased by 45% to 439 thousand cubic feet of natural gas per day (“Mcf/d”) and the price received decreased by 10% to \$4.09 during the year ended December 31, 2011 as compared to the same period in 2010. The increase in gross revenues for the year ended December 31, 2011 as compared to the same period during 2010, is mainly due to successful drilling and work-overs in Wyoming.

For the year ended December 31, 2010, we recorded gross revenues of \$18.75 million, as compared to \$8.71 million for the year ended December 31, 2009. Oil sales as a percentage of total revenue during the year ended December 31, 2010 as compared to the same period in 2009 increased from 80% to 93%. Oil volumes increased by 103% to 710 Bopd and the price received increased by 24% to \$67.30 during the year ended December 31, 2010 as compared to the same period in 2009. Natural gas sales as a percentage of total revenue during the year ended December 31, 2010 as compared to the same period in 2009 decreased from 20% to 7%. Natural gas volumes decreased by 32% to 795 Mcf/d and the price received increased by 9% to \$4.55 during the year ended December 31, 2010 as compared to the same period in 2009. The increase in gross revenues for the year ended December 31, 2010 as compared to the same period during 2009, is attributable to higher realized commodity prices, the acquisition of producing fields in the state of Wyoming in December 2009, new drilling and work-overs in Wyoming.

Crude Oil Derivative Contracts

On November 11, 2011, we entered into a swap contract to minimize the variability in cash flows due to price movements in crude oil. We agreed to economically hedge the future sales of 100 barrels of NYMEX WTI crude oil per day at a fixed price of \$96.75 starting January 1, 2012 for a period of 12 months.

On December 20, 2010, we agreed to economically hedge the future sales of 125 barrels of NYMEX WTI crude oil per day at a fixed price of \$90.40 starting January 1, 2011 for a period of 12 months and 250 barrels of NYMEX WTI crude oil per day at a fixed price of \$90.40 starting January 1, 2012 for a period of 12 months.

On January 4, 2010, we agreed to economically hedge the future sale of 7,500 barrels of NYMEX WTI crude oil per month at a fixed price of \$85.10 per barrel for a period of 24 months.

On April 1, 2009, we agreed to economically hedge the future sale of 3,000 barrels of NYMEX WTI crude oil per month at a fixed price of \$56.85 per barrel for a period of 9 months.

We do not designate our derivative financial instruments as hedging instruments for accounting purposes and, as a result, we recognize the current change in a derivative’s fair value in earnings. At December 31, 2011, we recognized \$976,929 as a derivative liability on crude oil derivative contracts.

For the year ended December 31, 2011, the change in derivative contracts included a realized loss of \$1.12 million and an unrealized gain of \$365,109. For the year ended December 31, 2010, the change in derivative contracts included a realized gain of \$501,255 and an unrealized loss of \$1.21 million. For the year ended December 31, 2009, the change in derivative contracts included a realized gain of \$300,778.

Royalties and Production Taxes

California

For the years ended December 31, 2011, 2010 and 2009, we paid royalties on oil production sold from the Pleito Creek Field located in Kern County, California. Royalties for production extracted below 3,000 feet subsea are 25%

and for production extracted from above 3,000 feet subsea are 20%. During the same periods, we also paid a production fee consisting of 635.10 barrels of oil per month which commenced in 2008 and declines at a rate of 5.5% each year. For the year ended December 31, 2011, the production fee rate was 535.90 barrels of oil per month. For the year ended December 31, 2010, the production fee rate was 567.10 barrels of oil per month. For the year ended December 31, 2009, the production fee rate was 600.10 barrels of oil per month.

For the year ended December 31, 2011, we recorded royalties in California in the amount of \$2.19 million as compared to \$1.68 million for the same period in 2010. The increase in royalties for the year ended December 31, 2011 is mainly due to higher realized commodity prices.

For the year ended December 31, 2010, we recorded royalties in California in the amount of \$1.68 million as compared to \$1.29 million for the same period in 2009. The increase in royalties for the year ended December 31, 2010 is mainly due to higher realized commodity prices.

Louisiana

Royalties on our Louisiana production varied by property. For the year ended December 31, 2011, we recorded \$842,900 in royalties representing an average rate of 29.56%, as compared to \$870,564 representing an average rate of 26.88% for the year ended December 31, 2010. The increase in royalties is mainly due to higher realized commodity prices.

For the year ended December 31, 2010, we recorded \$870,564 in royalties representing an average rate of 26.88%, as compared to \$784,472 representing an average rate of 22.37% for the year ended December 31, 2009. The increase in royalties is mainly due to higher realized commodity prices.

On December 1, 2011, we sold our Louisiana properties (see “*Liquidity and Capital Resources*”).

Wyoming

For the year ended December 31, 2011, we recorded \$3.62 million in royalties in Wyoming representing an average rate of 17.67%, as compared to \$2.12 million or 20.51% for the same period in 2010. The increase in royalties is mainly due to higher realized commodity prices.

For the year ended December 31, 2010, we recorded \$2.12 million in royalties in Wyoming representing an average rate of 20.51%, as compared to \$143,261 or 21.42% for the same period in 2009. Royalties during 2009 represent 14 days of expense as the properties were acquired in December 2009.

Operating Costs

Average Operating costs per BOE

	Year ended December 31, 2011	Year ended December 31, 2010	Year ended December 31, 2009
	(\$)	(\$)	(\$)
Operating costs	11,565,565	9,116,563	5,162,936
Average operating costs per boe	30.66	29.66	25.93

For the year ended December 31, 2011, we incurred operating costs in the amount of \$11.57 million, as compared to \$9.12 million for the same period in 2010. During the year ended December 31, 2011, we incurred increased operating costs as compared to the same period in 2010 mainly due to: (i) higher production volumes in 2011, (ii) higher severance taxes paid in 2011 resulting from a 65% increase in oil and gas revenues for the year ended December 31, 2011, (iii) workovers performed in Wyoming during the year ended December 31, 2011, (iv)

temporary production equipment rentals and contract labor expense; and (v) costs associated with the Krotz Springs Field and its maintenance due to the south Louisiana flooding.

For the year ended December 31, 2010, we incurred operating costs in the amount of \$9.12 million, as compared to \$5.16 million for the same period in 2009. During the year ended December 31, 2010, we incurred increased operating costs as compared to the same period in 2009 mainly due to: (i) our newly acquired oil and gas properties in Wyoming (“Wyoming Assets”) which added a total of \$1.23 million during the three months ended December 31, 2009 and \$2.80 million during the year ended December 30, 2010 to the overall total increase in operational costs; and (ii) increased operating costs in California associated with the Company’s Combined Miscible Drive patented process (“CMD”).

Operating costs included severance taxes paid in Louisiana and Wyoming. There is no severance tax in the state of California. Severance taxes in Louisiana consist of 12.5% on gross oil sales and \$0.164 per Mcf of gas sales. For the year ended December 31, 2011, we recorded \$2.36 million in severance taxes, as compared to \$1.32 million for the same period in 2010. The increase in severance taxes is mainly due to higher production volumes and commodity prices.

For the year ended December 31, 2010, we recorded \$1.32 million in severance taxes, as compared to \$422,786 for the same period in 2009. The increase in severance taxes in 2010 is mainly due to the Wyoming Assets in December 2009.

General and Administrative Expenses (“G&A”)

Average G&A per BOE

	Year ended December 31, 2011	Year ended December 31, 2010	Year ended December 31, 2009
	(\$)	(\$)	(\$)
G&A expense before stock-based compensation	5,288,587	5,172,115	3,881,464
Average per boe	14.02	16.83	19.49
Stock-based compensation (“SBC”)	2,605,892	2,716,621	2,945,197
Average per boe	6.91	8.84	14.79
G&A	<u>7,894,479</u>	<u>7,888,736</u>	<u>6,826,661</u>
Average per boe	20.93	25.67	34.29

For the year ended December 31, 2011, we recorded G&A expense, excluding SBC of \$5.29 million, as compared to \$5.17 million for the same period in 2010. This increase during the year ended December 31, 2011 is due to higher accounting and personnel expense, as compared to the same period in 2010.

For the year ended December 31, 2010, we recorded G&A expense, excluding SBC of \$5.17 million, as compared to \$3.88 million for the same period in 2009. This increase during the year ended December 31, 2010, is mainly due to: (i) higher personnel expense; (ii) additional expenses related to preparation of the Registration Statement; and (iii) higher accounting and legal services associated with being a U.S. and Canadian registered public company.

We use the grant date fair-value-based method of accounting for SBC and recognizes compensation cost using the straight-line method over the requisite service period for the entire award for stock options.

For the year ended December 31, 2011, we recorded SBC in the amount of \$2.61 million, as compared to \$2.72 million for the same period in 2010. The decrease in SBC for the year ended December 31, 2011 as compared to the previous year is due to forfeiture of options during 2011.

For the year ended December 31, 2010, we recorded SBC in the amount of \$2.72 million, as compared to \$2.95 million for the same period in 2009. The decrease in SBC for the year ended December 31, 2010 as compared to the previous year is due to the immediate recognition of expected future costs on cancelled options and additional grants during 2009.

Depreciation, Depletion, Amortization and Accretion Expense (“DD&A”)

Average DD&A per BOE

	Year ended December 31, 2011	Year ended December 31, 2010	Year ended December 31, 2009
	(\$)	(\$)	(\$)
DD&A expense	3,507,669	3,190,905	3,351,753
Average per boe	9.30	10.38	16.83

We follow the full-cost method of accounting and all costs included in proved properties and all future development costs along with our total proved reserves determine the period’s depletion cost.

For the year ended December 31, 2011, we recorded DD&A in the amount of \$3.51 million, as compared to \$3.19 million for the same period in 2010. The decrease in the DD&A rate per boe for the year ended December 31, 2011, is due to an increase in our proved reserves at December 31, 2011 (15,923 thousand boe (“Mboe”) in 2011, as compared to 13,717 Mboe in 2010).

For the year ended December 31, 2010, we recorded DD&A in the amount of \$3.19 million, as compared to \$3.35 million for the same period in 2009. The decrease in DD&A rate per boe for the year ended December 31, 2010, as compared to the same period in 2009, is due to an increase in the total proved reserves due to (i) conversion of probable reserves to proved reserves in Wyoming as a result of our successful 2010 development program; and (ii) positive results from the CMD project in California.

Change in Fair Value of Warrants and Options

The exercise price of certain warrants is denominated in Canadian dollar which is not the functional currency of the Company. As a result, these warrants are classified as a liability on the balance sheet and recorded at their fair value at the end of each period and the change in fair value recognized in earnings.

During the year ended December 31, 2011, 5,354,800 warrants were exercised. At December 31, 2011, the fair value of the warrant liability was \$235,134, with a gain of \$1.06 million recognized in earnings during the year ended December 31, 2011. At December 31, 2010, the fair value of the outstanding warrants was \$5.63 million, with a gain of \$1.67 million recognized in earnings during the year ended December 31, 2010. At December 31, 2009, the fair value of the outstanding warrants was \$7.38 million, with a charge of \$3.52 million recognized in earnings during the year ended December 31, 2009. The fair value of the warrants is calculated using the Black-Scholes Merton Model (“Black-Scholes Model”).

We continue to classify the remaining balance of warrants issued prior to September 4, 2009, as additional paid in capital warrants where the issue date fair value of the original equity classified warrant is greater than the fair value of the liability of the underlying warrant at the balance sheet date.

The exercise price of 1.5 million stock options relating to former employees that transitioned to a consulting role is denominated in Canadian dollars, which is not the functional currency of the Company (which is the U.S. dollar). As a result, the applicable 999,998 vested options are classified as a liability on the balance sheet and recorded at their fair value at the end of each period and the change in fair value is recognized in earnings.

At December 31, 2011, the fair value of the options liability was \$136,773 with a gain of \$707,513 recognized in earnings during the year ended December 31, 2011. The fair value of the options is calculated using the Black-Scholes Model.

Reduction of Carrying Value of Proved Oil and Natural Gas Properties

Under the full cost method of accounting, capitalized oil and gas property costs less accumulated depletion and net of deferred income taxes may not exceed an amount equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and gas reserves plus the cost of unproved properties not subject to amortization (without regard to estimates of fair value) or estimated fair value, if lower of unproved properties that are subject to amortization. During 2009, we reduced the carrying values of certain of our proved oil and natural gas properties by \$6.31 million due to full-cost ceiling limitations. This reduction was recognized in the first quarter of 2009 and resulted from a significant decrease in the full cost ceiling. The lower ceiling value largely resulted from the effects of sharp declines in oil, natural gas, and natural gas liquids (“NGL”) prices compared to prices in previous periods. There were no impairments to our proved oil and natural gas properties during 2011 or 2010.

Interest Income and Expense

For the year ended December 31, 2011, we recorded interest expense of \$5.41 million (\$906,569 non-cash) related to the Senior Loan (as define herein, see “*Liquidity and Capital Resources*”), as compared to \$7.11 million (\$3.46 million non-cash) for the same period in 2010 related to: (i) the Short-term Loan (as define herein, see “*Liquidity and Capital Resources*”); (ii) and the Senior Loan. The amortization of debt issuance cost related to the Short-term Loan and Senior Loan is included in interest expense. For the year ended December 31, 2009, we recorded interest expense of \$228,131. Interest expense recorded in 2009 was due to the Short-term Loan.

For the year ended December 31, 2011, we recorded interest income in the amount of \$44,595 as compared to \$54,070 for the same period in 2010. For the year ended December 31, 2010, we recorded interest income in the amount of \$54,070 as compared to \$78,127 for the same period in 2009. Lower interest income for the years ended December 31, 2011 and 2010 is due to a reduction in average interest-bearing cash balances and lower interest rates.

Income Tax

At December 31, 2011, we had estimated non capital losses of approximately \$96.48 million available to reduce future taxable income. The benefit of these losses has not been recognized as a full valuation allowance has been taken. As a result of available deductions and our planned capital expenditures for 2011, we do not expect to pay income taxes in 2011. At December 31, 2010, we had estimated non capital losses of approximately \$76.6 million available to reduce future taxable income. At December 31, 2009, we had estimated non capital losses of approximately \$54.90 million available to reduce future taxable income.

Foreign Currency Exchange

Our foreign exchange expense is derived from our cash balances denominated in Canadian dollars. For the year ended December 31, 2011, we recorded a foreign exchange loss of \$26,101. For the year ended December 31, 2010, we recorded a foreign exchange gain of \$6,617. For the year ended December 31, 2009, the Company recorded a loss in foreign exchange of \$385,626.

Capital Expenditures

The following tables provide information regarding our capital expenditures incurred during the periods presented:

	Capital Expenditures		
	Incurred during December 31, 2011 (\$000s)	Incurred during December 31, 2010 (\$000s)	Incurred during December 31, 2009 (\$000s)
Property Costs			
- Louisiana	19	68	827
- California	102	244	273
- Wyoming	128	361	27,040
Total Property Costs	249	673	28,140
Drilling/Workover	-	-	-
- Louisiana	144	49	3,809
- California	4,100	421	3,201
- Wyoming	11,770	9,647	-
Total Drilling/Workover	16,014	10,117	7,010
Facilities	-	-	-
- Louisiana	-	-	-
- California	560	253	2,790
- Wyoming	1,698	304	-
Total Facilities	2,258	556	2,790
Total Capital Expenditures ⁽¹⁾	18,521	11,347	37,940

Note:

(1) The Louisiana properties were sold on December 1, 2011 (see "Liquidity and Capital Resources").

Our drilling and work-over capital expenditures during 2011 were focused primarily on the Wyoming Assets and secondarily on the Pleito Creek Field in California. Additional capital costs for oil and gas properties include legal fees associated with the Wyoming properties, geological and geophysical data acquisition, and lease acquisition and rental expenses.

Capital expenditures associated with Louisiana properties during December 31, 2011, included the recompletion of the Jeffers well in Acadia Parish.

Capital expenditures associated with California properties during December 31, 2011, included the drilling and completion of two new wells and capital workovers on two existing wells.

Capital expenditures associated with Wyoming properties during December 31, 2011, included the drilling and completion of three wells at Hunt Field, three wells at Sheep Point Field and two wells at Willow Draw Field, facility expansion at Willow Draw Field and waterflood implementation at Ferguson Ranch Field. In addition, 2011 capital expenditures included: (i) completion costs associated with four wells at Willow Draw Field and one well at Ferguson Ranch Field which were drilled in the fourth quarter of 2010 and (ii) the implementation of polymer treatments at Willow Draw Field and (iii) facility expansion at Willow Draw Field and waterflood construction at Ferguson Ranch Field.

Additional capital expenditures for oil and gas properties include geological and geophysical data acquisition and lease acquisition and rental expenses.

Our drilling and work-over capital expenditures during 2010 were focused primarily on the Wyoming Assets and secondarily on the Pleito Creek Field in California. The majority of expenditures in Wyoming were at the Ferguson Ranch Field for drilling. Expenditures in California were for a work-over performed at the Pleito Creek Field. Additional capital costs for oil and gas properties include legal fees associated with the acquisition of the Wyoming properties, geological and geophysical data acquisition, and lease acquisition and rental expenses.

During the year ended December 31, 2010, operational activity in Wyoming included; (i) ten new wells drilled (six on production at December 31, 2010 and four wells awaiting production); (ii) two work-overs; and (iii) three polymer treatments.

During 2009, we spent \$827,453 in property costs required to generate, evaluate and acquire new projects in Louisiana. Property costs also include leasehold costs generated by our existing properties.

Drilling costs in Louisiana during the year ended December 31, 2009, included the completion of two additional producing wells, the Trahan and the Jeffers.

In 2009, we designed, implemented and initiated the CMD project on our Pleito Creek Field located in Kern County, California.

During 2009, we completed the construction of an injection facility and it is currently operational for the CMD process. Five horizontal gravel packed wells and one injection well were drilled in conjunction with the CMD Project.

Significant Acquisition

On December 17, 2009, we acquired the Wyoming Assets. The purchase price for the Wyoming Assets was \$27.17 million of which \$22 million was funded by a loan syndicated by a private lending company (“PLC”), and the remainder from our working capital. The effective date for the acquisition was December 1, 2009.

The following table details the purchase price allocation for the Wyoming Assets:

Net Value of Wyoming Assets

Fair value of assets acquired:		
Inventory	\$	78,763
Equipment		50,000
Crude oil and natural gas properties		27,472,671
Asset retirement obligations		(428,326)
Total net assets acquired	\$	<u>27,173,108</u>

2012 Capital Expenditure Budget

The following table provides information regarding our 2012 capital expenditure budget:

2012 Capital Expenditure Budget

	2012 Capital Expenditures Budget (\$000s)
Drilling/Workovers	
- California	11,120
- Wyoming	21,954
Total Drilling/Workovers	33,074
Facilities	
- Wyoming	940
Total Facilities	940
Total Capital Budget	34,014

Highlights for the planned 2012 Capital Expenditure Budget include:

- Eighteen new wells in Wyoming
- Nine workovers on existing well in Wyoming
- Eight new wells in California
- Facility upgrades in Wyoming

We have engaged in a broad review of strategic alternatives (“Strategic Review”) aimed at maximizing shareholders’ value. To assist in this review process, we have engaged Macquarie Capital as our financial advisor. We expect to consider and evaluate several alternatives, including strategic financing opportunities, asset divestitures, technology licensing agreements, joint ventures and/or a corporate sale, merger or other business combination. There can be no assurance that this Strategic Review will result in a significant transaction.

Subject to the results of the Strategic Review, and access to the capital markets, we plan to invest a total of \$34.01 million in capital expenditures during 2012.

All capital program expenditures are discretionary and are restricted by the Senior Loan including compliance with any covenants or receiving waivers therefrom (see “*Liquidity and Capital Resources*”). We review all capital expenditure programs on a regular basis and adjust spending based on factors such as changes in commodity prices, drilling and production results, and availability of funding. While we believe we have sufficient capital and liquidity to finance current operations through the next twelve months, our long-term liquidity depends on our ability to access the capital markets. There can be no assurance that we will be successful with any of these initiatives (See *ITEM 1.A - “Risk Factors”* on the Company’s Annual Report).

Liquidity and Capital Resources

The following table summarizes our cash flows for the periods presented.

Cash Flows Summary

	Year ended December 31, 2011⁽¹⁾ (\$)	Year ended December 31, 2010⁽¹⁾ (\$)	Year ended December 31, 2009⁽¹⁾ (\$)
Cash flows (used in) provided by operating activities	(713,122)	(984,623)	(2,461,948)
Cash flows (used in) investing activities	(17,094,341)	(11,829,708)	(37,947,610)
Cash flows provided by financing activities	12,128,486	19,162,118	33,016,558
Increase (decrease) in cash and cash equivalents	(5,678,977)	6,347,787	(7,393,000)
Cash and cash equivalents at beginning of year	9,490,005	3,142,218	10,535,218
Cash and cash equivalents at end of year	3,811,028	9,490,005	3,142,218

Note:

(1) Audited.

During the year ended December 31, 2011, our cash balance decreased by \$5.68 million, primarily due to \$18.52 million invested in oil and natural gas properties and equipment offset by the proceeds of \$1 million received for the divestiture of oil and gas properties in Louisiana and a decrease in restrictive investments of \$19,208. Cash flows from financing activities of \$12.13 million were from the exercise of warrants and the sale of the Company's common shares ("Common Shares") during the period.

In September 2011, we completed the Private Placement of 2,758,620 Units of the Company at a purchase price of CDN\$1.45 per Unit for gross proceeds of CDN\$3,999,999 or USD \$4,010,545, net of CDN \$267,224 or USD \$267,928 of agents fees.

Effective December 1, 2011, we completed the divestiture of the Company's non-operated and non-core interests in producing oil and gas properties located in the southern onshore region of Louisiana for a total of \$1 million.

During the year ended December 31, 2010, our cash balance increased by \$6.35 million, primarily due to \$10.07 million from the sale of Common Shares and net proceeds of \$31.11 million from long-term borrowings, \$11.83 million of investment in oil and natural gas properties and \$22.02 million of short-term debt repayments.

On June 30, 2010, we entered into a credit agreement ("Senior Loan) with CLG Corp., an administrative agent, and Beal Bank Nevada as lender (the "Lender") in the amount of \$36 million. We borrowed \$36 million from the Lender subject to an original issue discount of 7.5%, a commitment fee of 1%, a placement fee of 1% and a transaction fee of 3%. At our request and subject to approval by the Lender, the Senior Loan availability may be increased by \$39 million, up to \$75 million, to provide additional development capital.

The Senior Loan has a 12.5% fixed interest rate and a term of five years. Interest is payable quarterly beginning September 30, 2010. Principal is payable quarterly beginning June 29, 2012 in the following annual amounts:

Senior Loan Principal Repayments

2012	\$	4,050,000
2013		5,400,000
2014		6,750,000
2015		<u>19,800,000</u>
	\$	<u>36,000,000</u>

The Senior Loan is secured by all of our assets. The loan may be repaid after June 30, 2013 without a pre-payment penalty or make whole provision. Prior to June 30, 2012, in the event of prepayment, we will be required to pay a make whole provision compensating the Lender for all unpaid interest. From July 1, 2012 to June 30, 2013, a 2% prepayment premium will be assessed on any outstanding principal being repaid in excess of the scheduled repayments noted above.

We used the net proceeds of the Senior Loan to repay the existing short-term loan of \$22 million (“Short-term Loan”) and the remaining proceeds are to be utilized for the capital expenditure program at the Company’s properties in Wyoming and California. We are required to meet certain financial based covenants under the terms of this facility including: (i) total capital expenditures were limited to an amount no greater than \$12 million from the date of the loan until December 31, 2010; (ii) total capital expenditures are limited to an amount no greater than \$25 million for the year ended December 31, 2011. (iii) total capital expenditures are limited to an amount no greater than \$25 million for the year ended December 31, 2012. The facility has a material adverse change clause relating to financial stability and for which the lender can ultimately demand immediate repayment in the event of default. At December 31, 2011, we were in compliance with all financial based covenants.

On May 16, 2010, we completed a public offering of Common Shares (the “Short Form Prospectus Offering”) at an offering price of CDN \$1.25 per share. The Company issued 9,200,000 Common Shares for aggregate gross proceeds of CDN \$11,500,000 or USD \$11,018,492, net of CDN \$989,260 or USD \$947,840 of offering costs.

During the year ended December 31, 2009, our cash balance declined by \$7.39 million primarily due to the acquisition of the Wyoming Assets for \$27.17 million funded partially from the Short-term Loan of \$22 million, and \$10.85 million invested in oil and natural gas properties and equipment and \$11.02 million received from the issuance of Common Shares. On December 17, 2009, we entered into the Short-term Loan with a private lending company, whereby the PLC syndicated a loan to the Company in an aggregate amount of US\$5,500,000 and Cdn\$17,534,550 (US\$ 16,713,738) for the acquisition of the Wyoming Assets. Concurrent with the advances, the Company issued 2,566,666 Common Shares at an attributed price of Cdn \$1.15 (US\$1.07) per share which was recorded as prepaid interest expense, to be amortized over the term of the loan. We also paid a structuring fee in cash in the amount of US\$120,000. Interest on the outstanding principal amount was calculated daily and compounded monthly and payable on a monthly basis at 12% per annum. The principal amount, together with all accrued unpaid interest was due December 17, 2010. The loan was able to be repaid at any time without pre-payment penalty. The loan was secured by a fixed and floating charge debenture which provided the PLC a security interest in all of our present and after-acquired real and personal property. The PLC loan was paid in full on June 30, 2010 from borrowings under the Senior Loan.

In September 2009, we completed a public offering of units (“Units”), each consisting of one Common Share and one warrant to acquire one Common Share for an offering price of Cdn \$1.25 per Unit (USD \$1.13). The Company issued 11,324,900 Units for aggregate gross proceeds of Cdn \$14,156,125 or USD \$13,078,573, net of Cdn \$2,265,671 or USD \$2,085,777 of offering costs. The Warrants had a term of two years from the date of issuance, and each Warrant was exercisable into one common share at a price of CDN \$1.55 per share. NiMin issued 11.44 million of these warrants and 5.35 million were exercised during the two year term for gross proceeds of Cdn\$8.3 million. The remaining 6.09 million warrants expired without being exercised. Offering costs include a fee of 4.5% on Cdn \$3,273,625 of Units sold by a sub-agent, payable in 117,851 Units issued on the same terms and conditions as the Units issued pursuant to this offering.

Since inception, we have financed our operations from public and private sales of equity and debt, and revenues from sales of oil and gas reserves. While we believe we have sufficient capital and liquidity to finance current

operations through the next twelve months, our long-term liquidity depends on our ability to access the capital markets. Our ability to develop proved reserves is contingent upon our cash flow from operations and obtaining adequate financing. However, if we are unable to obtain financing and do not believe we can develop these reserves pursuant to our plan, then these reserves will be reclassified to probable (See *ITEM 1.A – “Risk Factors”* on the Company’s Annual Report).

Research and development, patents and licenses, etc.

In December, 2010, the U.S. Patent and Trademark Office issued a patent to NiMin for its CMD process for enhanced oil recovery. As reported in the third quarter of 2010, our CMD technology has been successful in significantly increasing production in California's Pleito Creek Field. Our patent covers the process of the injection of oxygen and water as foam to create carbon dioxide (“CO₂”) and steam in the reservoir through wet combustion. The CO₂ and steam increase reservoir pressure and significantly reduce oil viscosity making the oil substantially more mobile allowing it to flow rapidly into production wells. The CMD process is currently being used on the Santa Margarita Formation at the Pleito Creek Field.

Trend information

Over the past few years, the prices for crude oil and natural gas have been increasingly volatile and we expect this volatility to continue. Prolonged increases or decreases in the price of oil could significantly impact us. There is a strong relationship between energy commodity prices and access to both equipment and personnel. High commodity prices also affect the cost structure of services which may impact our ability to accomplish drilling, completion and equipping goals.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements during the years ended December 31, 2011, 2010 and 2009 except for the office lease obligations noted below.

Tabular disclosure of contractual obligations

Contractual Obligations as of December 31, 2011

	Total	Less than 1	1-3 years	4 -5 years	More than 5
	(\$)	year	(\$)	(\$)	years
	(\$)	(\$)	(\$)	(\$)	(\$)
Accounts payable and accrued liabilities	5,005,515	5,005,515	-	-	-
Commodity derivative liability	976,929	976,929	-	-	-
Office lease obligations	155,808	117,778	37,230	800	-
Interest payable on long-term debt	12,304,459	4,372,746	6,760,480	1,171,233	-
Long-term debt (principal)	36,000,000	4,050,000	12,150,000	19,800,000	-
Total contractual obligations	54,442,711	14,522,968	18,947,710	20,972,033	-

Critical Accounting Policies and Estimates

In preparing financial statements, we make informed judgments and estimates that affect the reported amounts of assets and liabilities as of the date of the financial statements and affect the reported amounts of revenues and expenses during the reporting period.

The amounts recorded for depletion and depreciation of property and equipment, the accretion expense associated with the asset retirement obligation and the cost recovery assessments for property and equipment are based on

estimates of proved reserves, production and discount rates, oil and natural gas prices, future costs and other relevant assumptions. The amount recorded for the unrealized gain or loss on financial instruments is based on estimates of future commodity prices and volatility. The recognition of amounts in relation to stock-based compensation requires estimates related to valuation of stock options at the time of issuance or modification. Future taxes require estimates as to the realization of future tax assets and the timing of reversal of tax assets and liabilities. By their nature, these estimates are subject to measurement uncertainty and the effect on the consolidated financial statements from changes in such estimates in future years could be significant.

On an ongoing basis, we review estimates, including those related to the impairment of long-lived assets, contingencies and income taxes. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates.

Crude Oil and Natural Gas Properties

We account for our crude oil and natural gas producing activities under the full-cost method of accounting. Accordingly, all costs incurred in the acquisition, exploration, and development of proved crude oil and natural gas properties, including the costs of abandoned properties, dry holes, geological and geophysical costs, and annual lease rentals, are capitalized. All general corporate costs are expensed as incurred. Sales or other dispositions of crude oil and natural gas properties are accounted for as adjustments to capitalized costs with no gain or loss recorded unless such sale would alter the relationship between pool cost and reserves.

Depletion and Depreciation

Depletion of crude oil and natural gas properties is computed under the unit-of-production method where by the ratio of production to proved reserves, after royalties, determines the proportion of depletable costs to be expensed in each period. Costs associated with unevaluated properties are excluded from the full-cost pool until a determination is made whether proved reserves can be attributable to the related properties. Unevaluated properties are evaluated at least annually to determine whether the costs incurred should be classified to the full-cost pool and thereby subject to amortization. A significant reduction in our proved reserves may result in an accelerated depletion rate.

Reserves are determined by an independent reserves engineering firm. Volumes are converted to equivalent units using the ratio of one barrel of oil to six thousand cubic feet of natural gas.

Depreciation of equipment is provided for on a straight-line basis over the useful life (5 to 10 years) of the asset.

Impairment of oil and gas properties

We perform a full-cost ceiling test on proved crude oil and natural gas properties in which the capitalized costs are not allowed to exceed their related estimated future net revenues of proved reserves discounted at 10%, net of tax considerations. Costs associated with unevaluated properties are excluded from the full-cost pool until a determination is made whether proved reserves can be attributable to the related properties. Unevaluated properties are evaluated at least annually to determine whether the costs incurred should be classified to the full-cost pool and thereby subject to amortization. A significant reduction in our proved reserves may result in a full cost ceiling limitation.

Equipment is reviewed for impairment whenever events or changes in circumstances indicate such impairment may have occurred. An impairment is recognized when the estimated undiscounted future net cash flows of an asset are less than its carrying value. If an impairment occurs, the carrying value of the impaired asset is reduced to fair value.

Asset Retirement Obligations

We recognize a liability for the present value of all legal obligations associated with the retirement of tangible, long-lived assets and capitalizes an equal amount as a cost of the asset. The cost associated with the abandonment obligation is included in the computation of depreciation, depletion, amortization and accretion. The liability

accretes until we settle the obligation. We use a credit-adjusted risk-free interest rate in its calculation of asset retirement obligations (“ARO”).

Revisions to the original estimated liability would result in an increase or decrease to the ARO liability and related capitalized costs. Actual costs incurred upon settlement of the asset retirement obligation are charged against the obligation to the extent of the liability recorded.

Estimates for future abandonment and reclamation costs are based on historical costs to abandon and reclaim similar sites, taking into consideration current costs. The liability is based on our net interest in the respective sites.

Income Tax

Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in enacted tax rates is recognized in income in the period that includes the enactment date.

We do not have any unrecognized tax benefits other than those for which a valuation allowance has been provided thereon. Our policy is that we recognize interest and penalties accrued on any unrecognized tax benefits as a component of income tax expense. We did not have any accrued interest or penalties associated with any unrecognized tax benefits, nor were any tax-related interest expense recognized during 2011, 2010 or 2009.

Commodity and Derivative Instruments

Derivative instruments are recognized as either assets or liabilities in the balance sheet at fair value. The accounting for changes in the fair value of derivative instruments depends on their intended use and resulting hedge designation. For derivative instruments designated as hedges, the changes in fair value are recorded in the balance sheet as a component of accumulated other comprehensive income (loss). Changes in the fair value of derivative instruments not designated as hedges are recorded as a gain or loss on derivative contracts in the consolidated statements of operations. We do not designate its derivative financial instruments as hedging instruments and, as a result, recognizes the change in a derivative’s fair value currently in earnings.

Fair value measurements

We categorize our assets and liabilities that are measured at fair value, based on the priority of the inputs to the valuation techniques. The three levels of the fair value measurement hierarchy are as follows:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities.

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

Level 3: Measured based on prices or valuation models that required inputs that are both significant to the fair value measurement and less observable for objective sources (i.e. supported by little or no market activity).

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The Company considers active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis. For assets and liabilities carried at fair value, the Company measures fair value under the following levels:

Financial Instrument	Level
Cash and cash equivalents	Level 1
Restricted investments	Level 1
Long-term debt	Level 2
Commodity derivative	Level 2
Warrants and options	Level 3

Stock-Based Compensation

We measure and recognize compensation expense for all share-based payment awards, including employee stock options, based on estimated fair values. The value of the portion of the award that is ultimately expected to vest is recognized as an expense on a straight-line basis over the requisite vesting period. We estimate the fair value of stock option awards on the date of grant using an option-pricing model. We use the Black-Scholes Model as its method of valuation for share-based awards. Our determination of fair value of share-based payment awards on the date of grant using the Black-Scholes Model is affected by NiMin's stock price, as well as assumptions regarding a number of subjective variables. These variables include, but are not limited to, our expectation of NiMin's stock price volatility over the term of the awards, as well as actual and projected exercise and forfeiture activity. The fair value of options granted to consultants, to the extent unvested due to required services not having been fully performed, is determined on subsequent reporting dates.

Foreign Currency Transactions

These consolidated financial statements are presented and measured in U.S. dollars, as substantially all of our operations are located in the United States of America. Transactions and balances using Canadian dollars are expressed in U.S. dollars whereby monetary assets and liabilities are expressed at the period end exchange rate, non-monetary assets and liabilities are expressed at historical exchange rates, and revenue and expenses are expressed at the average exchange rate for the period. Foreign exchange gains and losses are included in the consolidated statements of operations.

Business combinations

We record identifiable assets, liabilities, non-controlling interests, and goodwill acquired in a business combination at "fair value" by applying the acquisition method. Accordingly, transaction costs related to acquisitions are recorded as a reduction of earnings in the period they are incurred and costs related to issuing debt or equity securities that are related to the transaction are recognized in accordance with other applicable rules under U.S. GAAP. Non-controlling interests (previously referred to as minority interests) are treated as a separate component of equity, not as a liability or other item outside of permanent equity.

Recently Issued Accounting Pronouncements

In June 2011, the Financial Accounting Standards Board issued ASU No. 2011-05, "Comprehensive Income (Topic 220): Presentation of Comprehensive Income" ("ASU No. 2011-05"). In ASU No. 2011-05, an entity has the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with total net income, each component of other comprehensive income along with a total for other comprehensive income, and a total amount for comprehensive income. The amendments in ASU No. 2011-05 do not change the items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income. They also do not change the presentation of related tax effects, before related tax effects, or the portrayal or calculation of earnings per share. The amendments in ASU No. 2011-05 should be applied retrospectively. The amendment is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. The amendments do not require any transition disclosures. This update is not expected to have a material impact on our consolidated financial statements.