THIRD QUARTER INTERIM REPORT
2009

Press Release November 12, 2009

Calgary – NuVista Energy Ltd. is pleased to announce its financial and operating results for the three and nine months ended September 30, 2009 as follows:

Corporate Highlights

	Three months ended September 30, 2009	2008	% Change	Nine months ended September 30, 2009	2008	% Change
Financial						
($ thousands, except per share)						
Production revenue	79,494	149,596	(47)	249,315	408,356	(39)
Funds from operations (1)	41,198	79,136	(48)	139,639	222,152	(37)
Per share – basic	0.48	1.00	(52)	1.72	3.05	(44)
Per share – diluted	0.48	1.00	(52)	1.72	3.02	(43)
Net earnings (loss)	(3,342)	53,699	(106)	(8,022)	63,753	(113)
Per share – basic	(0.04)	0.68	(106)	(0.10)	0.87	(111)
Per share – diluted	(0.04)	0.68	(106)	(0.10)	0.87	(111)
Total assets				1,572,124	1,387,517	13
Long-term debt, net of working capital				386,167	349,261	11
Long-term debt, net of adjusted working capital (1)				387,060	344,176	12
Shareholders' equity				906,993	784,557	16
Net capital expenditures	189,508	82,928	129	279,054	151,572	84
Corporate acquisition (non-cash)	-	-	-	-	594,944	-
Weighted average common shares outstanding (thousands)						
Basic	85,770	79,103	8	81,404	72,893	12
Diluted	85,770	79,270	8	81,404	73,619	11
Operating						
(boe conversion – 6:1 basis)						
Production						
Natural gas (mmcf/d)	121.0	111.4	9	114.3	103.3	11
Natural gas liquids (bbls/d)	3,181	2,942	8	3,153	2,221	42
Oil (bbls/d)	4,153	4,554	(9)	4,289	4,418	(3)
Total oil equivalent (boe/d)	27,505	26,065	6	26,490	23,860	11
Product prices (2)						
Natural gas ($/mcf)	3.99	8.35	(52)	4.99	8.60	(42)
Natural gas liquids ($/bbl)	39.58	81.95	(52)	36.86	81.23	(55)
Oil ($/bbl)	66.17	92.06	(28)	61.78	87.41	(29)
Operating expenses						
Natural gas and natural gas liquids ($/mcfe)	1.24	1.20	3	1.16	1.17	(1)
Oil ($/bbl)	16.32	14.70	11	16.31	13.18	24
Total oil equivalent ($/boe)	8.79	8.50	3	8.46	8.15	4
General and administrative expenses ($/boe)	1.49	1.33	12	1.45	1.37	6
Funds from operations netback ($/boe) (1)	16.29	33.00	(51)	19.30	33.98	(43)

NOTES:
(1) Funds from operations, funds from operations per share, funds from operations netback and adjusted working capital are not defined by GAAP in Canada and are referred to as non-GAAP measures. Funds from operations are based on cash flow from operating activities as per the statement of cash flows before changes in non-cash working capital and asset retirement expenditures. Funds from operations per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of net earnings (loss) per share. Funds from operations netback equals the total of revenues including realized commodity derivative gains/losses less royalties, transportation, general and administrative, restricted stock units, interest expenses and cash taxes calculated on a boe basis. Adjusted working capital excludes the current portions of the commodity derivative asset or liability and the future income tax asset or liability. Total boe is calculated by multiplying the daily production by the number of days in the period. For more details on non-GAAP measures, refer to "Management's Discussion and Analysis" section of this press release.
(2) Product prices include realized gains/losses on commodity derivatives.

MESSAGE TO SHAREHOLDERS

NuVista Energy Ltd. ("NuVista") is pleased to report to its shareholders the financial and operating results for the three and nine months ended September 30, 2009. NuVista reported record quarterly average production of 27,505 boe/d for the third quarter of 2009. In addition to record production, NuVista also closed and integrated a significant acquisition, adding a new core area in Northeast British Columbia and Northwest Alberta, and began a horizontal drilling program in our West of the Fifth Meridian and West of the Sixth Meridian ("W5/W6") core areas to test recovery concepts on four different scalable resource plays.

During the third quarter of 2009, natural gas prices continued to decline due to continued weakness in the North American economy and high natural gas storage levels. However, third quarter funds from operations were relatively unchanged from the second quarter of 2009 as lower natural gas prices were offset by $11 million of gains realized from our financial and physical sale price risk management program and the additional revenues associated with the acquisition of properties that closed on July 27, 2009.

Significant highlights for NuVista in the third quarter:

- Implemented a $16 million exploration and development capital program that was primarily directed towards our Oyen and Wapiti core areas. During the third quarter, we participated in 13 (11.4 net) wells with an 85% success factor. Our drilling program benefited from lower drilling and completion costs resulting from reduced industry activity levels and Alberta Drilling Incentive Credits;

- Completed the strategic acquisition and integration of properties located in the Martin Creek area of British Columbia and in Northwest Alberta for cash consideration of approximately $174 million. This acquisition closed on July 27, 2009;

- Issued 9.0 million shares for gross proceeds of $99 million to fund a significant portion of the acquisition with equity;

- Completed the 21 well shallow gas program in our Oyen Core Area that began in the second quarter of 2009 which added over 4 mmcf/d of natural gas production. Incorporating the impact of the Alberta Drilling Incentive Credits and the 5% first year royalty, our Oyen program added reserves at $9.00/boe with a payout of less than one year at a gas price of $5.00/gj;

- Drilled a 100% working interest multi-zone vertical well in our Wapiti Core Area, with the Falher C sand as the primary target. This zone tested at over 6.3 mmcf/d of liquid-rich natural gas production at a high flowing pressure. The well was completed in a total of three zones and tested at a combined rate of 10 mmcf/d. The Falher C sand is currently on production at a restricted rate of approximately 4 mmcf/d;

- Began the first of a series of horizontal wells focused on evaluating recovery technologies in four different scalable resource plays on NuVista lands. These tests will take place during the fourth quarter of 2009 and continue into the first quarter of 2010 and will target the Dunvegan, Montney, and Cardium zones; and

- Maintained financial flexibility by reducing net debt to approximately $387 million from a peak net debt level of approximately $410 million following the property acquisition in July 2009. NuVista is targeting net debt of $365 million by year end creating substantial financial flexibility on our existing credit facility.

We believe that we have positioned NuVista to create significant shareholder value when natural gas prices recover by taking this time to build our drilling inventory and adding strategic acquisitions which have lowered our corporate decline rate and created a stable platform for future growth. Although gas prices reached multi-year lows over the past few months, a significant rebound in the later part of October suggests that the cyclical bottom in gas prices may be behind us.

NuVista is now in a position to embark on the largest exploration and development program in our history for 2010. We find ourselves in the enviable position of being able to maintain our production and continue to build for the future by spending less than forecast cash flow. For the remainder of 2009, we will be prudently managing our business plan and continuing with our core capital program evaluating plays with potential for significant development in 2010 and beyond.

Evaluating Resource Plays for Development in 2010

Our 2009/2010 winter drilling capital program will include testing horizontal drilling and multi-stage fracing technology on several tight gas prospects and one tight oil prospect. In our Wapiti Core Area, we plan to investigate the thicker, tight gas charged, lower Dunvegan sands. One horizontal well was drilled in the third quarter and completion operations were carried out in October and November. Testing of this well will be carried out in the next two weeks. NuVista has approved and is moving forward with a second horizontal well and will use a different multi-stage frac technology. Based upon success from these wells, NuVista will plan a second half 2010 horizontal program in the thicker Dunvegan sands. NuVista will continue to follow up on the success of the upper Dunvegan vertical program by drilling two vertical wells prior to year end and two additional vertical wells in the first quarter of 2010.

Also in our Wapiti Core Area, we plan to drill our first horizontal well in the Montney formation during the first quarter of 2010 and monitor drilling and completion results for horizontal Montney wells drilled by other companies in the greater Wapiti area. A horizontal Montney well, drilled by another E&P company in the greater Wapiti Core Area has been on production for more than six months and continues to produce over 2.0 mmcf/d. Both the Dunvegan and Montney plays, if successful, possess the size and scope to dramatically impact NuVista's capital program and financial results over the next five years.

During the fourth quarter of 2009, a horizontal Montney well is planned to be drilled in our Fir/Kaybob Core Area where we have nine vertical Montney producing wells on seven and one-half sections of land. This project may ultimately result in five to 10 additional horizontal Montney wells, beginning in 2010. Several E&P companies have experienced significant horizontal drilling success within three miles of our lands, with initial production rates in excess of 4 mmcf/d per well.

During the first quarter of 2010, we plan to drill our first Cardium horizontal well in our Pembina Core Area. If successful, our current land position could ultimately yield 10 Cardium horizontal locations with drilling beginning after spring break-up in 2010.

NuVista is drilling four additional Birdbear horizontal oil wells in our West Central Saskatchewan Core Area prior to year end with additional drilling planned for the first quarter of 2010. The first two wells in this recent program have each been placed on production at approximately 140 bbl/d. Each well qualifies for a 2.5% crown royalty for the first 100,000 barrels of production.

Prudently Manage our Business Plan

During the second half of 2009, NuVista has experienced considerable unplanned production outages as third-party operators in our W5/W6 core areas used this period of low natural gas prices to accelerate the timing of facility turnarounds. In addition, during August 2009 NuVista decided to shut-in approximately 800 boe/d of high cost natural gas production and TCPL transportation constraints forced NuVista to shut-in approximately 500 boe/d of natural gas in our Northwest Alberta Core Area. The majority of the 800 boe/d of shut-in production should be back on-stream prior to November 15, 2009 and all of the production shut-in due to the TCPL outage is anticipated to return to production on or before December 1, 2009. Our current productive capability is in excess of 29,000 boe/d and production should return to this level in December when most shut-in volumes are brought back on-stream.

We will continue to invest capital on strategic projects and pursue acquisition opportunities available in this environment, while maintaining our financial flexibility. We believe natural gas prices will increase as supply and demand fundamentals adjust but the timing and pace of this increase is uncertain. NuVista is aware of approximately 200,000 boe/d of corporate and asset divestments planned in the next nine months. The uncertainty in the marketplace has made the timing of acquisitions difficult to predict. For 2010, less than 20% of our total capital program is forecast to come from smaller complementary acquisitions. Any significant acquisitions will result in an expansion of our capital program and a corresponding increase in forecast production guidance.

Through challenging and at times difficult industry conditions, we continue to maintain a disciplined approach to our business. We will continue to employ an "acquire and develop" business model focused on profitable reserves per share and production per share growth while maintaining our balance sheet strength. Due to low commodity prices and an uncertain economic environment, prudent financial management requires a responsive and flexible capital program. For the remainder of 2009, we will continue to closely manage capital spending levels and focus on maintaining financial flexibility. We pride ourselves on being able to make business decisions based on timely and accurate data during periods of rapidly changing economic and market conditions.

Craig W. Stewart, who joined our Board of Directors upon the completion of our business combination with Rider Resources Ltd., has resigned as a director of NuVista in order to pursue other business opportunities. We thank Craig for his wisdom, advice and support and wish him all the best in his future business endeavours.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") of financial conditions and results of operations should be read in conjunction with NuVista's unaudited consolidated financial statements for the three and nine months ended September 30, 2009, and the audited consolidated financial statements for the year ended December 31, 2008. The following MD&A of financial condition and results of operations was prepared at and is dated November 12, 2009. Our audited consolidated financial statements, Annual Report, Annual Information Form and other disclosure documents for 2008 are available through our filings on SEDAR at **www.sedar.com** or can be obtained from our website at **www.nuvistaenergy.com**.

Basis of presentation – *The financial data presented below has been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). The reporting and the measurement currency is the Canadian dollar. For the purpose of calculating unit costs, natural gas is converted to a barrel of oil equivalent ("boe") using six thousand cubic feet of natural gas equal to one barrel of oil, unless otherwise stated. In certain circumstances natural gas liquid volumes have been converted to thousand cubic feet equivalent ("mcfe") on the basis of one barrel of natural gas liquids to six thousand cubic feet. Boes and mcfes may be misleading, particularly if used in isolation. A conversion ratio of one barrel to six thousand cubic feet of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

Forward-looking statements – *Certain information set forth in this document contain forward-looking statements, including management's assessment of NuVista's future plans and operations, forecast production and growth and production and reserves, drilling plans and results, NuVista's planned capital budget, targeted debt level, the timing, allocation and efficiency of NuVista's capital program and the results therefrom, forecast funds from operations and targeted operating costs, benefits from the Alberta Government's announcement of royalty incentives, expectations regarding the payment of future taxes, expectations regarding future commodity prices, netbacks and industry conditions which are provided to allow investors to better understand our business. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond NuVista's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management and services, stock market volatility, changes in environmental regulations, tax laws and royalties and the ability to access sufficient capital from internal sources and bank and equity markets. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. NuVista's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements, or if any of them do so, what benefits that NuVista will derive therefrom. NuVista disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law.*

Non-GAAP measurements – *Within the MD&A, references are made to terms commonly used in the oil and natural gas industry. Management uses funds from operations to analyze operating performance and leverage. Funds from operations as presented, does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Funds from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, per the statement of cash flows, net earnings (loss) or other measures of financial performance calculated in accordance with Canadian GAAP. All references to funds from operations throughout this report are based on cash flow from operating activities before changes in non-cash working capital and asset retirement expenditures. Funds from operations per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of net earnings (loss) per share. Funds from operations netbacks equal total revenue including realized commodity derivative gains/losses less royalties, transportation, operating costs, general and administrative, restricted stock unit, interest expense and cash taxes. Management also uses field netbacks to analyze operating performance and adjusted working capital to analyze leverage. Field netbacks and adjusted working capital as presented, do not have any standardized meaning prescribed by Canadian GAAP and therefore, may not be comparable with the* *calculation of similar measures for other entities. Field netbacks equal the total of revenue including realized commodity derivative gains/losses less royalties, transportation and operating costs. Adjusted working capital equals working capital excluding the current portion of the commodity derivative asset or liability and the future income tax asset or liability. Total boe is calculated by multiplying the daily production by the number of days in the period.*

A reconciliation of funds from operations is presented in the following table:

	Three months ended September 30,		*Nine months ended September 30,*	
($ thousands)	*2009*	*2008*	*2009*	*2008*
Cash provided by operating activities	*32,852*	*84,582*	*130,792*	*187,201*
Add back:				
Asset retirement expenditures	*654*	*1,309*	*1,843*	*1,846*
Change in non-cash working capital	*7,692*	*(6,755)*	*7,004*	*33,105*
Funds from operations	*41,198*	*79,136*	*139,639*	*222,152*

Martin Creek and Northwest Alberta property acquisition – On July 27, 2009, NuVista closed the acquisition of certain properties in the Martin Creek area of Northeast British Columbia and in Northwest Alberta. The acquisition was financed through a combination of bank debt and net proceeds from two equity offerings. NuVista entered into an agreement to issue 7,500,000 subscription receipts at a price of $11.00 per subscription receipt on a bought deal basis for gross proceeds of $82.5 million. In addition, NuVista issued 1,500,000 subscription receipts at a price of $11.00 per subscription receipt, by way of a private placement, to Ontario Teachers' Pension Plan Board ("OTPP") for gross proceeds of $16.5 million. The subscription receipt offerings closed on July 7, 2009. Each subscription receipt was exchanged for one common share of NuVista for no additional consideration on July 27, 2009.

Plan of arrangement with Rider Resources Ltd. – On March 4, 2008, NuVista closed a business combination with Rider Resources Ltd. ("Rider" or the "Rider Acquisition") and a private placement financing with the OTPP. The Rider Acquisition resulted in the combination of NuVista and Rider, pursuant to which all of the issued and outstanding Rider shares were exchanged for common shares of NuVista. Rider shareholders received, for each Rider share held, 0.3540 of a NuVista share. The results of operations from the Rider assets have been included, effective March 4, 2008.

Operating activities – During the third quarter of 2009, NuVista participated in 13 (11.4 net) wells, all of which were operated wells, with an average working interest of 88%. Of these wells, nine were drilled in the Oyen core area and two wells in both the Pembina and Wapiti core areas. The success rate of 85% in this drilling program resulted in 11 natural gas wells and two dry holes. For the nine months ended September 30, 2009, NuVista drilled 36 (28.7 net) wells resulting in 24 natural gas wells, five oil wells and seven dry holes. NuVista has approximately 15 wells planned for the fourth quarter, primarily in our Central Saskatchewan, Wapiti and Waskahigan/Kaybob core areas.

Production

	Three months ended September 30,		
	2009	2008	% Change
Natural gas (mcf/d)	121,028	111,409	9
Liquids (bbls/d)	3,181	2,942	8
Oil (bbls/d)	4,153	4,554	(9)
Total oil equivalent (boe/d)	27,505	26,065	6

	Nine months ended September 30,		
	2009	2008	% Change
Natural gas (mcf/d)	114,293	103,325	11
Liquids (bbls/d)	3,153	2,221	42
Oil (bbls/d)	4,289	4,418	(3)
Total oil equivalent (boe/d)	26,490	23,860	11

For the three months ended September 30, 2009, NuVista's average production was 27,505 boe/d, comprised of 121.0 mmcf/d of natural gas, 3,181 bbls/d of associated natural gas liquids ("liquids") and 4,153 bbls/d of oil. This is a 6% increase compared to the same period in 2008 and a 7% increase compared to the three months ended June 30, 2009. The increase in NuVista's production during the three months ended September 30, 2009 was primarily due to the acquisition of properties located in Martin Creek and Northwest Alberta. Third quarter production volumes were negatively impacted by NuVista's decision to shut-in high operating cost production, unscheduled third-party outages and TCPL pipeline constraints.

NuVista's production for the nine months ended September 30, 2009 averaged 26,490 boe/d, comprised of 114.3 mmcf/d of natural gas, 3,153 bbls/d of liquids and 4,289 bbls/d of oil, which represents an 11% increase over the same period in 2008. Production increases for the nine month period compared to the same period in 2008 are primarily due to the inclusion of nine months of Rider properties in 2009 compared to seven months in 2008 and the Martin Creek and Northwest Alberta property acquisition.

Revenues

	Three months ended September 30,					
($ thousands, except per unit amounts)	2009		2008		% Change	
Natural gas	$	$/mcf	$	$/mcf	$	$/mcf
Production revenue[(1)]	44,440	3.99	84,595	8.25	(47)	(52)
Realized gain (loss) on commodity derivatives	-	-	988	0.10	-	-
Total	44,440	3.99	85,583	8.35	(48)	(52)
Liquids	$	$/bbl	$	$/bbl	$	$/bbl
Production revenue	11,583	39.58	22,184	81.95	(48)	(52)
Realized gain (loss) on commodity derivatives	-	-	-	-	-	-
Total	11,583	39.58	22,184	81.95	(48)	(52)
Oil	$	$/bbl	$	$/bbl	$	$/bbl
Production revenue	23,471	61.43	42,817	102.20	(45)	(40)
Realized gain (loss) on commodity derivatives	1,811	4.74	(4,249)	(10.14)	143	147
Total	25,282	66.17	38,568	92.06	(34)	(28)

	Nine months ended September 30,					
($ thousands, except per unit amounts)	2009		2008		% Change	
Natural gas	$	$/mcf	$	$/mcf	$	$/mcf
Production revenue[(1)]	154,054	4.94	243,490	8.61	(37)	(43)
Realized gain (loss) on commodity derivatives	1,421	0.05	(38)	(0.01)	3,839	600
Total	155,475	4.99	243,452	8.60	(36)	(42)
Liquids	$	$/bbl	$	$/bbl	$	$/bbl
Production revenue	31,723	36.86	49,439	81.23	(36)	(55)
Realized gain (loss) on commodity derivatives	-	-	-	-	-	-
Total	31,723	36.86	49,439	81.23	(36)	(55)
Oil	$	$/bbl	$	$/bbl	$	$/bbl
Production revenue	63,538	54.27	115,427	95.35	(45)	(43)
Realized gain (loss) on commodity derivatives	8,797	7.51	(9,617)	(7.94)	191	195
Total	72,335	61.78	105,810	87.41	(32)	(29)

(1) Natural gas revenue includes the impact of our physical sale contracts. See commodity price risk management.

For the three months ended September 30, 2009, revenues including realized commodity derivative gains and losses were $81.3 million, a 44% decrease from $146.3 million for the same period in 2008. The decrease in revenues for the three months ended September 30, 2009 compared to the same period of 2008 is due to the significant decrease in realized prices for all products and in particular natural gas. Revenues were comprised of $44.4 million of natural gas revenue, $11.6 million of liquids revenue, and $25.3 million of oil revenue. The decrease in average realized commodity prices is comprised of a 52% decrease in the natural gas price to $3.99/mcf from $8.35/mcf, a 52% decrease in the liquids price to $39.58/bbl from $81.95/bbl and a decrease of 28% in the oil price to $66.17/bbl from $92.06/bbl.

For the nine months ended September 30, 2009, revenues including realized commodity derivative gains and losses were $259.5 million, a 35% decrease from $398.7 million for the same period in 2008. The decrease in revenues for the first nine months of 2009 compared to the same period of 2008 is primarily due to the decline in commodity prices offset by the 11% increase in production. These revenues were comprised of $155.5 million of natural gas revenue, $31.7 million of liquids revenue, and $72.3 million of oil revenue. The decrease in average realized commodity prices is comprised of a 42% decrease in the natural gas price to $4.99/mcf from $8.60/mcf, a 55% decrease in the liquids price to $36.86/bbl from $81.23/bbl and a 29% decrease in the oil price to $61.78/bbl from $87.41/bbl.

Commodity price risk management

	Three months ended September 30,					
	2009			2008		
($ thousands)	Realized Gain(Loss)	Unrealized Gain (Loss)	Total Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)	Total Gain (Loss)
Natural gas	-	-	-	988	11,587	12,575
Oil	1,811	32	1,843	(4,249)	30,613	26,364
Total gain (loss)	1,811	32	1,843	(3,261)	42,200	38,939

	Nine months ended September 30,					
	2009			2008		
($ thousands)	Realized Gain(Loss)	Unrealized Gain (Loss)	Total Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)	Total Gain (Loss)
Natural gas	1,421	(1,093)	328	(38)	1,877	1,839
Oil	8,797	(14,194)	(5,397)	(9,617)	(9,452)	(19,069)
Total gain (loss)	10,218	(15,287)	(5,069)	(9,655)	(7,575)	(17,230)

As part of our financial risk management strategy, NuVista has adopted a disciplined commodity price risk management program. The purpose of this program is to reduce volatility in our financial results, protect acquisition economics and stabilize cash flow against the unpredictable commodity price environment. NuVista's Board of Directors has approved a price risk management limit of up to 60% of forecast production, net of royalties, using fixed price, put option and costless collar contracts. To achieve NuVista's price risk management objectives, we enter into both commodity derivative and physical sale contracts. For the three months ended September 30, 2009, the commodity derivative price risk management program resulted in a gain of $1.8 million consisting of realized gains from our oil derivative contracts. For the nine months ended September 30, 2009, the commodity derivative price risk management program resulted in a loss of $5.1 million consisting of realized gains of $10.2 million and an unrealized loss of $15.3 million.

For the three months ended September 30, 2009, the commodity physical price risk management program for natural gas resulted in a gain of $9.3 million. For the nine months ended September 30, 2009, price risk management gains on our physical sale contracts for natural gas totaled $27.3 million.

As at September 30, 2009, the mark-to-market value of our financial commodity derivative contracts was a gain of $1.2 million and the mark-to-market value of our physical sale contracts was a gain of $3.4 million.

The following is a summary of commodity price risk management contracts in place as at September 30, 2009:

(a) Financial instruments

As at September 30, 2009, NuVista has entered into the following crude oil contracts:

Volume	Average Price (CDN$/bbl)	Premium (CDN$/bbl)	Term
1,000 bbls/d	CDN $64.00 – Bow River	-	January 1, 2009 – December 31, 2009
1,000 bbls/d	CDN $95.01 – $110.01 – WTI(1)	-	January 1, 2009 – December 31, 2009
1,000 bbls/d	CDN $80.30 – WTI	$9.75(2)	October 1, 2009 – September 30, 2010
1,000 bbls/d	CDN $76.00 – WTI	$5.39(2)	October 1, 2009 – December 31, 2009
1,000 bbls/d	CDN $77.50 – WTI	$8.78(2)	January 1, 2010 – March 31, 2010

(1) This is a US$ denominated crude oil contract with an associated fixed price foreign exchange contract of 1.0262 US$/CDN$.
(2) The premiums are incurred monthly over the term of the contract and will be offset against revenues.

(b) Physical sale contracts

As at September 30, 2009, NuVista has entered into direct natural gas sale contracts as follows:

Volume	Average Price (CDN$/gj)	Premium (CDN$/gj)	Term
20,000 gj/d	CDN $7.45 – Fixed Price AECO	-	April 1, 2009 – October 31, 2009
5,000 gj/d	CDN $5.65 – AECO Floor	$0.82(1)	April 1, 2009 – October 31, 2009
20,000 gj/d	CDN $5.97 – $6.56 AECO	$0.30(1)	November 1, 2009 – October 31, 2010
20,000 gj/d	CDN $5.55 – AECO Floor	$0.97(1)	November 1, 2009 – March 31, 2010
20,000 gj/d	CDN $3.56 – Fixed Price AECO	-	November 1, 2009 – November 30, 2009
20,000 gj/d	CDN $4.50 – Fixed Price AECO	-	December 1, 2009 – December 31, 2009

(1) The premiums are incurred monthly over the term of the contract and will be offset against revenues.

These physical sale contracts are documented as normal purchase and sale transactions and as such are not considered derivative financial instruments.

Subsequent to September 30, 2009, the following financial commodity price risk management contracts have been entered into:

Volume	Average Price (CDN$/bbl)	Premium (CDN$/bbl)	Term
1,000 bbls/d	CDN $87.40 – WTI	$8.86(1)(3)	April 1, 2010 – June 30, 2010
1,000 bbls/d	CDN $89.40 – WTI	$12.60(2)(3)	October 1, 2010 – December 31, 2010

(1) The WTI put was purchased at a deferred cost of $8.86/bbl for a total cost of $0.8 million.
(2) The WTI put was purchased at a deferred cost of $12.60/bbl for a total cost of $1.2 million.
(3) The premiums are incurred monthly over the term of the contract and will be offset against revenues.

Royalties

	Three months ended September 30,		Nine months ended September 30,	
Royalty rates (%)	2009	2008	2009	2008
Natural gas and liquids	7	28	12	26
Oil	15	17	13	16
Weighted average rate	9	25	12	23

Royalties of $7.5 million for the three months ended September 30, 2009 were 80% lower than the $37.1 million for the same period of 2008. Royalties for the nine months ended September 30, 2009 were $31.0 million as compared to $95.2 million reported for the nine months ended September 30, 2008. The decrease in royalties are primarily due to lower revenues associated with low commodity prices in both the third quarter and first nine months of 2009 compared to the same periods in 2008.

As a percentage of production revenue, the average royalty rate for the third quarter of 2009 was 9% compared to 25% for the comparative period of 2008. Royalty rates by product for the three months ended September 30, 2009 were 7% for natural gas and liquids and 15% for oil compared to 28% for natural gas and liquids and 17% for oil for the same period in 2008. For the nine months ended September 30, 2009, the average royalty rate as a percentage of production revenue was 12% compared to 23% for the same period in 2008. Royalty rates by product were 12% for natural gas and liquids and 13% for oil compared to 26% for natural gas and liquids and 16% for oil for the same period in 2008.

The lower royalty rates are primarily due to the impact of the New Alberta Royalty Framework in a low commodity price environment and the impact of our physical price risk management activities on the reported royalty rates. Our physical price risk management activities impact reported royalty rates as royalties are based on government market reference prices and not our average realized prices that include price risk management activities. As a result, the gains from our physical price risk management activities included in revenue result in a lower royalty rate as a percentage of revenue than if no price risk management activities had taken place.

Netbacks – The table below summarizes field netback by product for the three months ended September 30, 2009:

	Natural gas and liquids		Oil		Total	
	140.1 mmcfe/d		4,153 bbl/d		27,505 boe/d	
($ thousands, except per unit amounts)	$	$/mcfe	$	$/bbl	$	$/boe
Production revenue	56,023	4.35	23,471	61.43	79,494	31.41
Realized gain on commodity derivatives	-	-	1,811	4.74	1,811	0.72
	56,023	4.35	25,282	66.17	81,305	32.13
Royalties	(3,998)	(0.31)	(3,495)	(9.15)	(7,493)	(2.96)
Transportation	(1,492)	(0.12)	(570)	(1.49)	(2,062)	(0.81)
Operating costs	(16,013)	(1.24)	(6,236)	(16.32)	(22,249)	(8.79)
Field netback	34,520	2.68	14,981	39.21	49,501	19.57

The following table summarizes field netback by product for the nine months ended September 30, 2009:

	Natural gas and liquids		Oil		Total	
	133.2 mmcfe/d		4,289 bbl/d		26,490 boe/d	
($ thousands, except per unit amounts)	$	$/mcfe	$	$/bbl	$	$/boe
Production revenue	185,777	5.11	63,538	54.27	249,315	34.47
Realized gain on commodity derivatives	1,421	0.04	8,797	7.51	10,218	1.41
	187,198	5.15	72,335	61.78	259,533	35.88
Royalties	(22,855)	(0.63)	(8,099)	(6.92)	(30,954)	(4.28)
Transportation	(4,585)	(0.13)	(1,636)	(1.40)	(6,221)	(0.86)
Operating costs	(42,049)	(1.16)	(19,100)	(16.31)	(61,149)	(8.46)
Field netback	117,709	3.23	43,500	37.15	161,209	22.28

The tables below summarize funds from operations netback for the three months ended September 30, 2009, compared to the three months ended September 30, 2008, and the nine months ended September 30, 2009, compared to the nine months ended September 30, 2008.

	Three months ended September 30,					
	2009		2008		% Change	
($ thousands, except per unit amounts)	$	$/boe	$	$/boe	$	$/boe
Production revenue	79,494	31.41	149,596	62.39	(47)	(50)
Realized gain (loss) on commodity derivatives	1,811	0.72	(3,261)	(1.36)	156	153
	81,305	32.13	146,335	61.03	(44)	(47)
Royalties	(7,493)	(2.96)	(37,051)	(15.45)	(80)	(81)
Transportation	(2,062)	(0.81)	(2,098)	(0.87)	(2)	(7)
Operating costs	(22,249)	(8.79)	(20,371)	(8.50)	9	3
Field netback	49,501	19.57	86,815	36.21	(43)	(46)
General and administrative	(3,768)	(1.49)	(3,178)	(1.33)	19	12
Restricted stock units	(617)	(0.24)	(110)	(0.05)	461	380
Interest	(3,918)	(1.55)	(4,391)	(1.83)	(11)	(15)
Funds from operations netback	41,198	16.29	79,136	33.00	(48)	(51)

	Nine months ended September 30,					
($ thousands, except per unit amounts)	2009		2008		% Change	
	$	$/boe	$	$/boe	$	$/boe
Production revenue	249,315	34.47	408,356	62.46	(39)	(45)
Realized gain (loss) on commodity derivatives	10,218	1.41	(9,655)	(1.48)	206	195
	259,533	35.88	398,701	60.98	(35)	(41)
Royalties	(30,954)	(4.28)	(95,204)	(14.56)	(67)	(71)
Transportation	(6,221)	(0.86)	(5,835)	(0.89)	7	(3)
Operating costs	(61,149)	(8.46)	(53,269)	(8.15)	15	4
Field netback	161,209	22.28	244,393	37.38	(34)	(40)
General and administrative	(10,496)	(1.45)	(8,989)	(1.37)	17	6
Restricted stock units	(1,215)	(0.17)	(1,228)	(0.19)	(1)	(11)
Interest	(9,859)	(1.36)	(12,024)	(1.84)	(18)	(26)
Funds from operations netback	139,639	19.30	222,152	33.98	(37)	(43)

***Transportation* –** Transportation costs were $2.1 million ($0.81/boe) for the three months ended September 30, 2009 as compared to $2.1 million ($0.87/boe) for the same period of 2008. Transportation costs were $6.2 million ($0.86/boe) for the nine months ended September 30, 2009 compared to $5.8 million ($0.89/boe) for the same period in 2008.

***Operating* –** Operating expenses were $22.2 million ($8.79/boe) for the three months ended September 30, 2009 as compared to $20.4 million ($8.50/boe) for the three months ended September 30, 2008 and $18.4 million ($7.84/boe) for the three months ended June 30, 2009. The increase in per unit costs resulted primarily from the inclusion of the acquired Northwest Alberta properties as these properties have a higher overall operating cost structure. For the three months ended September 30, 2009, natural gas and natural gas liquids operating costs averaged $1.24/mcfe and oil operating expenses were $16.32/bbl as compared to $1.20/mcfe and $14.70/bbl respectively for the same period in 2008.

Operating expenses were $61.1 million ($8.46/boe) for the nine months ended September 30, 2009 as compared to $53.3 million ($8.15/boe) for the nine months ended September 30, 2008. This increase resulted from the 11% increase in production volumes and a 4% increase in per unit costs. For the nine months ended September 30, 2009, natural gas and natural gas liquids operating expenses averaged $1.16/mcfe and oil operating expenses were $16.31/bbl as compared to $1.17/mcfe and $13.18/bbl respectively for the same period of 2008.

NuVista is forecasting our 2009 annual operating expenses to average approximately $8.75/boe. The increase in projected costs (on a per boe basis) is due primarily to the inclusion of the newly acquired Northwest Alberta properties for the last five months of 2009. These properties' cost structure is currently higher than NuVista's average operating costs per boe for 2009.

***General and administrative* –** General and administrative expenses, net of overhead recoveries, for the three months ended September 30, 2009 were $3.8 million ($1.49/boe) compared to $3.2 million ($1.33/boe) for the same period of 2008. General and administrative expenses, net of overhead recoveries, for the nine months ended September 30, 2009 were $10.5 million ($1.45/boe) as compared to $9.0 million ($1.37/boe) for the nine months ended September 30, 2008. This increase in general and administrative expenses is directly attributable to the higher production base in NuVista associated with the Rider Acquisition. Higher per unit costs reflect increased staffing costs and lower capital overhead recoveries. NuVista is forecasting 2009 general and administrative costs for the remainder of the year to average approximately $1.50/boe.

	Three months ended September 30,		Nine months ended September 30,	
($ thousands, except per unit amounts)	2009	2008	2009	2008
Gross general and administrative expenses	4,934	5,232	14,293	14,179
Overhead recoveries	(1,166)	(2,054)	(3,797)	(5,190)
Net general and administrative expenses	3,768	3,178	10,496	8,989
Per boe	1.49	1.33	1.45	1.37

Stock-based compensation

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2009	2008	2009	2008
Stock options	1,316	1,120	4,670	3,150
Restricted stock units	617	110	1,215	1,228
Total	1,933	1,230	5,885	4,378

NuVista recorded a stock-based compensation charge of $1.9 million for the three months ended September 30, 2009 compared to $1.2 million for the same period in 2008. For the nine months ended September 30, 2009, NuVista recorded a stock-based compensation charge of $5.9 million compared to $4.4 million for the same period in 2008. The stock-based compensation charge relates to the amortization of the value of stock option awards and the accrual for future payments under the Restricted Stock Unit ("RSU") Incentive Plan. The increase in the third quarter of 2009 relates primarily to an increase in the number of stock options outstanding. In January 2008, NuVista implemented an RSU Incentive Plan. Each RSU entitles participants to receive cash equal to the market value of the equivalent number of shares of NuVista. The RSUs become payable as they vest, typically over three years. The increase in RSU expense for the three and nine months ended 2009 was a result of the number of RSUs outstanding and movement in NuVista's share price.

Interest – Interest expense for the three months ended September 30, 2009 was $3.9 million ($1.55/boe) compared to $4.4 million ($1.83/boe) for the same period of 2008. For the nine months ended September 30, 2009, interest expense was $9.9 million ($1.36/boe) compared to $12.0 million ($1.84/boe) for the same period of 2008. For the three months ended September 30, 2009, borrowing costs averaged 3.25% compared to 4.5% for the same period of 2008. The revolving term of NuVista's credit facility was extended on March 3, 2009, as part of the terms of this extension NuVista's borrowing margin was increased to current market rates. Currently, NuVista's average borrowing rate is approximately 3.25%. Cash paid for interest for the three and nine months ended September 30, 2009 was $4.0 million (2008 - $3.9 million) and $9.5 million (2008 - $11.1 million) respectively.

Depreciation, depletion and accretion – Depreciation, depletion and accretion expenses were $43.8 million for the third quarter of 2009 as compared to $44.7 million for the same period in 2008. The average per unit cost was $17.31/boe in the third quarter of 2009 as compared to $18.65/boe for the same period in 2008. Third quarter depletion rates were positively impacted by the property acquisition completed in July 2009 as the metrics on the acquisition were significantly lower than NuVista's historical depletion rate. Depreciation, depletion and accretion expenses for the nine months ended September 30, 2009 were $128.7 million as compared to $120.5 million for the same period in 2008. The average per unit cost was $17.80/boe in the first nine months of 2009 as compared to $18.44/boe in the same period in 2008.

Income taxes – For the three months ended September 30, 2009, the provision for income taxes was a recovery of $0.5 million compared to an expense of $21.3 million for the same period in 2008. For the nine months ended September 30, 2009, the provision for income taxes was a recovery of $1.0 million compared to an expense of $26.0 million in the same period of 2008. The decrease in future tax expense in 2009 is consistent with the decrease in net earnings before taxes. The effective tax rate was 14% for the three months ended September 30, 2009.

Capital expenditures – Capital expenditures were $189.5 million during the third quarter of 2009 compared to $82.9 million in the same period of 2008, with $16.1 million of exploration and development spending (net of drilling credits) and $173.4 million spent on the Martin Creek and Northwest Alberta property acquisition. Third quarter capital is net of an estimated $3.2 million credit on drilling costs resulting from the Alberta government drilling incentive program. Capital expenditures for the nine months ended September 30, 2009 were $279.1 million, consisting of $51.6 million for exploration and development spending (net of drilling credits) and $227.5 million for acquisitions. This compares to $151.6 million incurred for the same period of 2008, consisting of $25.4 million of acquisitions and exploration and development spending of $126.2 million.

($ thousands, except per unit amounts)	Three months ended September 30, 2009	2008	Nine months ended September 30, 2009	2008
Exploration and development				
Land and retention costs	1,242	22,385	3,017	27,508
Seismic	2,300	4,169	6,790	8,852
Drilling and completion	12,473	40,039	30,001	61,159
Facilities and equipment	3,015	15,842	16,528	26,668
Corporate and other	316	493	807	1,987
Subtotal	19,346	82,928	57,143	126,174
Acquisitions				
Property	173,371	-	227,446	25,398
Subtotal	173,371	-	227,446	25,398
Total capital expenditures	192,717	82,928	284,589	151,572
Alberta drilling incentive credits	(3,209)	-	(5,535)	-
Net capital expenditures	189,508	82,928	279,054	151,572
Corporate acquisition – non-cash	-	-	-	594,944

Net earnings and funds from operations – For the three months ended September 30, 2009, there was a net loss of $3.3 million ($0.04/share, basic) compared to net earnings of $53.7 million ($0.68/share, basic) for the same period in 2008. Third quarter 2009 net earnings were lower when compared to the same period in 2008 primarily due to the impact of lower oil and natural gas prices. For the three months ended September 30, 2009, realized gains on our financial and physical sale price risk management programs totaled $11.1 million, partially mitigating the impact of lower oil and natural gas prices. Net earnings per share decreased due to the decrease in net earnings and increase in number of shares outstanding following the recent equity offerings related to the Martin Creek and Northwest Alberta property acquisition.

For the three months ended September 30, 2009, NuVista's funds from operations were $41.2 million ($0.48/share, basic), a 48% decrease from $79.1 million ($1.00/share, basic) for the three months ended September 30, 2008. Funds from operations for the three months ended September 30, 2009 were lower than the same period in 2008 primarily due to lower commodity prices, partially offset by higher production volumes, and increased operating and general and administrative costs. Funds from operations per share decreased 52% due to the decrease in funds from operations and an increase in number of shares outstanding following the two equity offerings related to the Martin Creek and Northwest Alberta property acquisition.

Liquidity and capital resources – As at September 30, 2009, debt net of adjusted working capital was $387.1 million, resulting in a net debt to annualized third quarter funds from operations ratio of 2.3:1. At September 30, 2009, NuVista had an adjusted working capital surplus of $23.5 million. Adjusted working capital excludes the current portion of the fair value of the commodity derivative asset of $1.2 million and the related current portion of future income tax liability of $0.3 million. We believe it is appropriate to exclude these amounts when assessing financial leverage. At September 30, 2009, NuVista had $99.5 million of unused bank borrowing capacity based on the current credit facility of $510.0 million.

On March 3, 2009, NuVista and the bank syndicate agreed to an extension of the revolving period from March 3, 2009 until April 30, 2009, in order for the bank syndicate to complete their annual review of NuVista's reserves and financial results. On April 3, 2009, NuVista's bank syndicate completed their annual review and extended the revolving period of the credit facility to April 29, 2010 and the term period to April 29, 2011. Under the term period, no principal payments would be required until April 29, 2011.

On July 27, 2009, NuVista's credit facility was increased to $510.0 million. NuVista has a credit facility from a syndicate of primarily Canadian banks with a maximum borrowing amount of $510.0 million. The credit facility is a 364-day revolving facility subject to an annual review by the bank syndicate, at which time a lender can extend the revolving period or can request conversion to a one year, term loan. During the revolving period, a determination of the maximum borrowing amount occurs semi-annually on or before April 30 and October 31.

NuVista is in the process of completing the semi-annual review of its borrowing base with its lenders and expects to complete the process by the end of November. In early November, NuVista made a formal request to its lenders for credit facilities totaling $510 million, comprised of a $480 million extendible revolving facility and a $30 million non-extendible, non-revolving acquisition facility. The acquisition facility is available subject to mutual approval of the lenders and NuVista.

NuVista anticipates that funds from operations will provide the flexibility to fund its planned 2009 capital program. In this period of volatile commodity prices and challenging economic environment, NuVista will place increased emphasis on maintaining its financial flexibility. NuVista plans to closely monitor its 2009 business plan and adjust capital programs in the context of commodity prices and access to bank and equity capital. NuVista has reduced its capital program for 2009. Net debt targeted for the end of the year is expected to be approximately $365 million.

As at September 30, 2009, there were 88.3 million common shares outstanding. There were 6.0 million stock options outstanding with an average exercise price of $13.48 per share.

Related party activities – NuVista and Bonavista Petroleum Ltd. ("Bonavista") are considered related as two directors of NuVista, one of whom is NuVista's chairman, are also directors and officers of Bonavista and a director and an officer of NuVista are also officers of Bonavista.

NuVista charges Bonavista management fees for jointly owned partnerships. For the three and nine months ended September 30, 2009, NuVista charged Bonavista management fees totaling $0.3 million (2008 – $0.3 million) and $1.0 million (2008 – $1.0 million) respectively. As at September 30, 2009, the amount receivable from Bonavista was $0.4 million (2008 – $1.0 million).

The above transactions are considered to be in the normal course of business and have been measured at their exchange amounts, being the amounts agreed to by both parties.

Contractual obligations and commitments – NuVista enters into contractual obligations as part of conducting business. The following is a summary of NuVista's contractual obligations and commitments as at September 30, 2009:

($ thousands)	Total	2009	2010	2011	2012	Thereafter
Transportation	14,311	1,396	4,695	3,036	1,888	3,296
Office lease	6,336	514	2,055	2,055	1,712	-
Physical sale contract premiums	5,247	1,677	3,570	-	-	-
Financial contract premiums	4,845	1,393	3,452	-	-	-
Physical power contract	6,900	-	-	2,300	2,300	2,300
Long-term debt	410,530	-	-	410,530	-	-
Total commitments	448,169	4,980	13,772	417,921	5,900	5,596

Quarterly financial information – The following table highlights NuVista's performance for the eight quarterly reporting periods from December 31, 2007 to September 30, 2009:

($ thousands,	2009			2008				2007
except per share amounts)	Sep 30	Jun 30	Mar 31	Dec 31	Sep 30	Jun 30	Mar 31	Dec 31
Production (boe/d)	27,505	25,777	26,175	25,688	26,065	26,153	19,339	14,251
Production revenue	79,494	78,092	91,729	106,982	149,596	161,794	97,064	53,790
Net earnings (loss)	(3,342)	(7,312)	2,632	24,443	53,699	2,905	7,150	11,063
Net earnings (loss)								
Per share – basic	(0.04)	(0.09)	0.03	0.31	0.68	0.04	0.12	0.21
Per share – diluted	(0.04)	(0.09)	0.03	0.31	0.68	0.04	0.12	0.21

NuVista has seen production volumes in a range of 25,688 boe/d to 27,505 boe/d for the last six quarters as NuVista reduced capital spending during this period in order to allocate cash flow to debt reduction following the acquisitions completed in 2008 and 2009 and in response to lower commodity prices. The increases in production during the third quarter of 2009 relate primarily to the Martin Creek and Northwest Alberta property acquisition that closed on July 27, 2009. Over the prior nine quarters, quarterly revenue has been in a range of $53.8 million to $161.8 million with revenue primarily influenced by production volumes, and oil and natural gas prices in the quarter. Net earnings (loss) have been in a range of a net loss of $7.3 million to net earnings of $53.7 million primarily influenced by production volumes, commodity prices and realized and unrealized gains and losses on commodity derivatives.

Critical accounting estimates – The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles. Certain accounting policies are critical to understanding the financial condition and results of operations of NuVista.

(a) ***Proved oil and natural gas reserves –*** Proved oil and natural gas reserves, as defined by the Canadian Securities Administrators in National Instrument 51-101 with reference to the Canadian Oil and Natural Gas Evaluation Handbook, are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

An independent reserve evaluator using all available geological and reservoir data as well as historical production data has prepared NuVista's oil and natural gas reserve estimates. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the Company's development plans. The effect of changes in proved oil and natural gas reserves on the financial results and position of the Company is described below.

(b) ***Depreciation, depletion and accretion expense –*** NuVista uses the full cost method of accounting for exploration and development activities whereby all costs associated with these activities are capitalized, whether successful or not. The aggregate of capitalized costs, net of certain costs related to unproved properties, and estimated future development costs is amortized using the unit-of-production method based on estimated proved reserves. Changes in estimated proved reserves or future development costs have a direct impact on depreciation and depletion expense.

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned, at which point they would be included in the depletion calculation, or for impairment, for which any write-down would be charged to depreciation and depletion expense.

(c) ***Full cost accounting ceiling test –*** The carrying value of property, plant and equipment is reviewed at least annually for impairment. Impairment occurs when the carrying value of the asset is not recoverable by the future undiscounted cash flows. The cost recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment would be charged as additional depletion and depreciation expense.

(d) ***Asset retirement obligation –*** The asset retirement obligations are estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonments and reclamations discounted at a credit adjusted risk free rate. The costs are included in property, plant and equipment and amortized over its useful life. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings and for revisions to the estimated future cash flows. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

(e) ***Income taxes –*** The determination of income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

(f) ***Goodwill –*** Goodwill is recorded on a business combination when the total purchase consideration exceeds the fair value of the net identifiable assets and liabilities of the acquired entity. The goodwill balance is not amortized, however, and must be assessed for impairment at least annually. Impairment is initially determined based on the fair value of a reporting unit compared to its book value. Any impairment must be charged to earnings in the period the impairment occurs. The Company has one reporting unit, being the entity as a whole, and as at September 30, 2009, we have determined there was no goodwill impairment.

Update on regulatory matters

(a) ***New Alberta Royalty Framework –*** On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" (the "NRF") containing the Government's proposals for Alberta's new royalty regime, which was followed by the Mines and Minerals (New Royalty Framework) Amendment Act, 2008, which was given Royal Assent on December 2, 2008. The NRF and the applicable new legislation became effective on January 1, 2009. The NRF establishes new royalty rates for conventional oil, natural gas and oil sands.

On April 10, 2008, the Government of Alberta introduced two new royalty programs that will encourage the development of deep oil and natural gas reserves, and these are: (a) a five-year oil program for exploration wells over 2,000 metres that will provide royalty adjustments to offset higher drilling costs and provide a greater incentive for producers to continue to pursue new, deeper oil plays (these oil wells will qualify for up to $1 million or 12 months of royalty offsets, whichever comes first); and (b) a five-year natural gas deep drilling program that will replace the existing program in order to encourage continued deep natural gas exploration for wells deeper than 2,500 metres (the program will create a sliding scale of royalty credit according to depth of up to $3,750 per metre). These new programs are to be implemented along with the NRF.

In response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced on November 19, 2008, the introduction of a five year program of transitional royalty rates with the intent of promoting new drilling. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) will be given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. In order to qualify for this program, wells must be drilled during the period starting on November 19, 2008, and ending on December 31, 2013. Following this period, all new wells drilled will automatically be subject to the NRF.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program, a $200 per metre royalty credit will be available on new conventional oil and natural gas wells drilled between April 1, 2009 and June 30, 2010, subject to certain maximum amounts. The maximum credits available will be determined by the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010. Based on NuVista's 2008 production, it will be entitled to a maximum credit of 50% of royalties payable in the period April 1, 2009 to March 31, 2010. The new well incentive program will apply to wells beginning production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels or 500 mmcf of natural gas. On June 25, 2009, the Government of Alberta extended this incentive program to March 31, 2011.

As royalties under the NRF are sensitive to both commodity prices and production levels, the estimated NRF Alberta and corporate royalty rates will fluctuate with commodity prices, well production rates, production decline of existing wells, and performance and location of new wells drilled.

(b) ***British Columbia Royalty Incentive Program –*** On August 6, 2009, the Government of British Columbia introduced a new royalty incentive program that provides for a 2% royalty rate for the first year of production from all wells drilled between September 2009 and June 2010. In addition, the existing royalty deductions available under the Deep Royalty Credit Program were increased by 15% and horizontal wells drilled between 1,900 and 2,300 metres now qualify for the Deep Royalty Credit Program.

Update on accounting policies and financial reporting matters

(a) ***Goodwill and intangible assets –*** Effective January 1, 2009, NuVista adopted Section 3064, Goodwill and Intangible Assets issued by the Canadian Institute of Chartered Accountants ("CICA"). Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. This new section has no current impact on NuVista's consolidated financial statements.

(b) ***Financial instruments – disclosures –*** In May 2009, the CICA issued amendments to Section 3862, Financial Instruments – Disclosures. The amendments include enhanced disclosures related to the fair value of financial instruments and the liquidity risk associated with financial instruments. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments are effective for NuVista on December 31, 2009.

(c) ***International Financial Reporting Standards –*** In February 2008, the Canadian Accounting Standards Board confirmed January 1, 2011 as the effective date for the requirement to report under International Financial Reporting Standards ("IFRS") with comparative 2010 periods converted as well. Canadian generally accepted accounting principles as we currently know them, will cease to exist for all public reporting entities. In

July 2009, the International Accounting Standards Board issued amendments to IFRS 1 – First-Time Adoption of International Financial Reporting Standards. This amendment allows first-time adopters using full cost accounting to elect to measure oil and natural gas assets at the date of transition to IFRS using amounts determined based on the entity's previous GAAP.

In order to meet the requirement to transition to IFRS, NuVista has appointed internal staff to lead the conversion project along with sponsorship from an executive steering committee. NuVista involves external auditors and external consultants, as required, during the conversion project. The conversion project consists of three main phases:

1. Assessment – this phase involved performing a high level preliminary analysis of the differences between Canadian GAAP and IFRS. Areas with the greatest potential impact to NuVista's consolidated financial statements, in terms of complexity and effort, were identified.
2. Evaluation – this phase involves an in-depth analysis of the accounting policy choices allowed under IFRS and their impact to NuVista's consolidated financial statements, business practices, information systems and internal control over financial reporting. Accounting policies will be finalized by management and their recommendations will be presented for review and approval by the Board of Directors.
3. Implementation – this phase includes implementing the required changes necessary for IFRS compliance and training of all staff impacted by the conversion.

NuVista has completed the assessment phase. During this phase, NuVista's preliminary analysis identified that accounting for property, plant and equipment, impairment testing, asset retirement obligation, stock-based compensation and income taxes may be significantly impacted by the conversion to IFRS. NuVista is currently in the second phase and is in the process of evaluating the impact of various accounting policy choices and drafting recommendations to the Board of Directors. The impact of IFRS on NuVista's consolidated financial statements is not reasonably determinable at this time.

Internal control reporting

NuVista's President and Chief Executive Officer ("CEO") and Vice President, Finance and Chief Financial Officer ("CFO") are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting as defined in National Instrument 52-109. NuVista's CEO and CFO have designed disclosure controls and procedures, or caused them to be designed under their supervision, to provide reasonable assurance that information to be disclosed by NuVista is accumulated and communicated to management as appropriate to allow timely decisions regarding the required disclosure. The CEO and CFO have also designed internal control over financial reporting, or caused them to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. During the quarter ended September 30, 2009, there have been no changes to NuVista's internal control over financial reporting that have materially or are reasonably likely to materially affect the internal control over financial reporting.

Because of their inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, error or fraud. Control systems, no matter how well conceived or operated, can provide only reasonable, not absolute assurance, that the objectives of the control system are met.

Assessment of business risks

The following are the primary risks associated with the business of NuVista. Most of these risks are similar to those affecting others in the conventional oil and natural gas sector. NuVista's financial position and results of operations are directly impacted by these factors:

- Operational risk associated with the production of oil and natural gas;
- Reserves risk with respect to the quantity and quality of recoverable reserves;
- Commodity risk as crude oil and natural gas prices fluctuate due to market forces;
- Financial risk such as volatility of the CDN/US dollar exchange rate, interest rates and debt service obligations;
- Risk associated with the current global financial crisis;
- Risk associated with the re-negotiation of NuVista's credit facility and the continued participation of NuVista's lenders;
- Market risk relating to the availability of transportation systems to move the product to market;
- Environmental and safety risk associated with well operations and production facilities; and
- Changing government regulations relating to royalty legislation, income tax laws, incentive programs, operating practices and environmental protection relating to the oil and natural gas industry.

NuVista seeks to mitigate these risks by:

- Acquiring properties with established production trends to reduce technical uncertainty as well as undeveloped land with development potential;
- Maintaining a low cost structure to maximize product netbacks and reduce impact of commodity price cycles;
- Diversifying properties to mitigate individual property and well risk;
- Maintaining product mix to balance exposure to commodity prices;
- Conducting rigorous reviews of all property acquisitions;
- Monitoring pricing trends and developing a mix of contractual arrangements for the marketing of products with creditworthy counterparties;
- Maintaining a price risk management program to manage commodity prices and foreign exchange currency rates risk and transacting with creditworthy counterparties;
- Ensuring strong third-party operators for non-operated properties;
- Adhering to NuVista's safety program and keeping abreast of current operating best practices;
- Keeping informed of proposed changes in regulations and laws to properly respond to and plan for the effects that these changes may have on our operations;
- Carrying industry standard insurance to cover losses;
- Establishing and maintaining adequate cash resources to fund future abandonment and site restoration costs;
- Closely monitoring commodity prices and capital programs to manage financial leverage; and
- Monitoring the bank and equity markets to understand how changes in the capital market may impact NuVista's business plan.

OUTLOOK

NuVista continues to believe in the favourable outlook for commodity prices over the long term. We believe natural gas prices will increase as supply and demand fundamentals adjust but the timing and pace of this increase is uncertain. By focusing on production and reserves per share growth, while maintaining financial flexibility, NuVista expects to continue to turn short term adversity into opportunities and emerge stronger. NuVista continues to prudently manage our business through careful planning. We will continue to invest capital on strategic projects and pursue acquisition opportunities while maintaining our financial flexibility. Looking forward to the remainder of 2009, we will be focused on continuing with our core capital program focused on evaluating plays with potential for significant development opportunities in 2010 and beyond.

Fourth Quarter 2009 Guidance

For 2009, NuVista's Board of Directors has approved a capital budget of $320 million with approximately $35 million planned for the fourth quarter. This capital program will see NuVista participate in approximately 52 wells for the year including approximately 15 wells expected to be drilled in the fourth quarter. Based on 2009 pricing assumption of $4.10/mcf for AECO natural gas, US$62/bbl for WTI crude oil, a foreign exchange of 0.87 CDN/USD, and including price risk management contracts, NuVista is forecasting funds from operations for 2009 of approximately $190 million. NuVista is currently forecasting 2009 production to average approximately 27,000 boe/d.

2010 Guidance

Despite an uncertain natural gas pricing environment, for 2010 NuVista is positioned to embark on its largest exploration and development program in our history. NuVista's Board of Directors has approved a preliminary 2010 capital program of $240 to $280 million with over 80% of expenditures allocated to exploration and development activities. 2010 forecast funds from operations of approximately $270 million are based on forecast pricing of $5.75/mcf for AECO gas, US$78/bbl for WTI crude oil, a foreign exchange rate of 0.97 CDN/USD, and including price risk management contracts. The 2010 capital program will continue to build upon our 2009 capital program with further testing of resource concepts in our core regions. This program anticipates the drilling of approximately 130 wells. The successful implementation of our capital program should allow NuVista's production to average between 29,500 boe/d and 30,500 boe/d in 2010.

The 2010 capital budget will be reviewed after our first quarter drilling program and adjusted in response to changes in commodity prices and opportunities. NuVista will continue to be focused on maintaining financial flexibility in an uncertain commodity price environment. Acquisitions will continue to be a key component of NuVista's growth strategy. With over 200,000 boe/d of production anticipated to be sold in early 2010, NuVista will continue to prudently evaluate these opportunities as they are presented. Any significant acquisitions will result in an expansion of our capital program and a corresponding increase in forecast production.

NuVista will continue to focus on its core strategy of cost control and applying the expertise of its technical staff to its current operating regions, through both its exploration and development program and strategic acquisitions. The execution of these strategies is expected to allow NuVista to grow its production and reserves on a per share basis, consistently and profitably. NuVista is poised for continued growth and is well positioned to post strong operational and financial results for the balance of 2009 and beyond. NuVista remains unwavering in its commitment to enhance shareholder value over the long-term in a diligent and prudent manner by accessing the broad depth and expertise of its team.

Sincerely,

Alex G. Verge
President & CEO
November 12, 2009

Robert F. Froese
Vice President, Finance & CFO

NUVISTA ENERGY LTD.

Consolidated Balance Sheets

($ thousands)	September 30, 2009	December 31, 2008
(unaudited)		
Assets		
Current assets		
Cash and cash equivalents	**$ -**	$ 139
Accounts receivable and prepaids	**71,588**	64,712
Commodity derivative asset (note 7)	**1,225**	16,513
	72,813	81,364
Oil and natural gas properties and equipment (note 3)	**1,415,595**	1,242,216
Goodwill	**83,716**	83,716
	$ 1,572,124	$ 1,407,296
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 48,118**	$ 50,710
Future income taxes	**332**	4,954
	48,450	55,664
Long-term debt (note 5)	**410,530**	355,407
Compensation liability (note 6)	**440**	850
Asset retirement obligations (note 4)	**64,721**	46,296
Future income taxes	**140,990**	137,779
Shareholders' equity		
Share capital, warrants and contributed surplus (note 6)	**701,757**	598,042
Retained earnings	**205,236**	213,258
	906,993	811,300
	$ 1,572,124	$ 1,407,296

Commitments (note 9)

See accompanying notes to consolidated financial statements.

NUVISTA ENERGY LTD.

Consolidated Statements of Earnings (Loss), Comprehensive Income (Loss) and Retained Earnings

($ thousands)	Three months ended September 30, 2009	Three months ended September 30, 2008	Nine months ended September 30, 2009	Nine months ended September 30, 2008
(unaudited)				
Revenues				
Production	**$ 79,494**	$ 149,596	**$ 249,315**	$ 408,356
Royalties	**(7,493)**	(37,051)	**(30,954)**	(95,204)
Realized gain (loss) on commodity derivatives	**1,811**	(3,261)	**10,218**	(9,655)
Unrealized gain (loss) on commodity derivatives	**32**	42,200	**(15,287)**	(7,575)
	73,844	151,484	**213,292**	295,922
Expenses				
Operating	**22,249**	20,371	**61,149**	53,269
Transportation	**2,062**	2,098	**6,221**	5,835
General and administrative	**3,768**	3,178	**10,496**	8,989
Bad debt provision	**-**	466	**-**	1,127
Interest	**3,918**	4,391	**9,859**	12,024
Stock-based compensation (note 6)	**1,933**	1,230	**5,885**	4,378
Depreciation, depletion and accretion	**43,796**	44,734	**128,714**	120,526
	77,726	76,468	**222,324**	206,148
Earnings (loss) before income taxes	**(3,882)**	75,016	**(9,032)**	89,774
Future income tax expense (recovery)	**(540)**	21,317	**(1,010)**	26,021
Net earnings (loss)	**(3,342)**	53,699	**(8,022)**	63,753
Other comprehensive income				
Amortization of fair value of financial instruments	**-**	-	**-**	(17)
Comprehensive income (loss)	**(3,342)**	53,699	**(8,022)**	63,736
Retained earnings, beginning of period	**208,578**	135,117	**213,258**	125,063
Retained earnings, end of period	**$ 205,236**	$ 188,816	**$ 205,236**	$ 188,816
Net earnings per share – basic	**$ (0.04)**	$ 0.68	**$ (0.10)**	$ 0.87
Net earnings per share – diluted	**$ (0.04)**	$ 0.68	**$ (0.10)**	$ 0.87

See accompanying notes to the consolidated financial statements.

NUVISTA ENERGY LTD.

Consolidated Statement of Cash Flows

($ thousands)	Three months ended September 30, 2009	Three months ended September 30, 2008	Nine months ended September 30, 2009	Nine months ended September 30, 2008
(unaudited)				
Cash provided by (used in)				
Operating Activities				
Net earnings (loss)	**$ (3,342)**	$ 53,699	**$ (8,022)**	$ 63,753
Items not requiring cash from operations				
Depreciation, depletion and accretion	**43,796**	44,734	**128,714**	120,526
Stock-based compensation	**1,316**	1,120	**4,670**	3,150
Bad debt provision	**-**	466	**-**	1,127
Unrealized loss (gain) on commodity derivatives	**(32)**	(42,200)	**15,287**	7,575
Future income tax expense (recovery)	**(540)**	21,317	**(1,010)**	26,021
Asset retirement expenditures	**(654)**	(1,309)	**(1,843)**	(1,846)
Decrease (increase) in non-cash working capital items	**(7,692)**	6,755	**(7,004)**	(33,105)
	32,852	84,582	**130,792**	187,201
Financing Activities				
Issue of share capital and warrants, net of share issuance costs	**95,271**	711	**96,072**	89,785
Increase in long-term debt	**34,225**	-	**55,123**	168,036
Repayment of long-term debt	**-**	(18,877)	**-**	(305,584)
	129,496	(18,166)	**151,195**	(47,763)
Investing Activities				
Oil and natural gas properties and equipment	**(16,137)**	(82,912)	**(51,608)**	(124,628)
Transaction costs on Rider acquisition	**-**	(16)	**-**	(4,146)
Property acquisition	**(173,371)**	-	**(227,446)**	(22,798)
Deposit applied on property acquisition (note 3)	**18,084**	-	**-**	-
Decrease (increase) in non-cash working capital items	**9,076**	16,294	**(3,072)**	17,509
	(162,348)	(66,634)	**(282,126)**	(134,063)
Increase (decrease) in cash and cash equivalents	**-**	(218)	**(139)**	5,375
Cash and cash equivalents, beginning of period	**-**	5,593	**139**	-
Cash and cash equivalents, end of period	**$ -**	$ 5,375	**$ -**	$ 5,375

See accompanying notes to consolidated financial statements.

Three and nine months ended September 30, 2009.

The unaudited interim consolidated financial statements of NuVista Energy Ltd. ("Nuvista" or "the Company") have been prepared by management in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"), using the same accounting policies as those set out in note 1 to the consolidated financial statements for the year ended December 31, 2008, except as noted below in note 1. These interim consolidated financial statements for the three and nine months ended September 30, 2009 should be read in conjunction with the annual audited consolidated financial statements for the year ended December 31, 2008. Certain amounts have been reclassified to conform with the current year's presentation. All tabular amounts are in thousands, except per share amounts, unless otherwise stated.

1. Adoption of new accounting policies

Goodwill and intangible assets

Effective January 1, 2009, the Company adopted Section 3064, Goodwill and Intangible Assets issued by the Canadian Institute of Chartered Accountants ("CICA"). Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. This new section has no current impact on the Company's consolidated financial statements.

2. Future accounting changes

(a) Financial instruments – disclosures

In May 2009, the CICA issued amendments to Section 3862, Financial Instruments – Disclosures. The amendments include enhanced disclosures related to the fair value of financial instruments and the liquidity risk associated with financial instruments. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments are effective for the Company on December 31, 2009.

(b) International Financial Reporting Standards

In February 2008, the Canadian Accounting Standards Board confirmed January 1, 2011 as the effective date for the requirement to report under International Financial Reporting Standards ("IFRS") with comparative 2010 periods converted as well. Canadian GAAP as we currently know them will cease to exist for all public reporting entities. In July 2009, the International Accounting Standards Board issued amendments to IFRS 1 – First-Time Adoption of International Financial Reporting Standards. This amendment allows first-time adopters using full cost accounting to elect to measure oil and natural gas assets at the date of transition to IFRS using amounts determined based on the entity's previous GAAP.

3. Property acquisitions

(a) Ferrier, Sunchild, Wapiti and Northwest Saskatchewan properties

On January 29, 2009, the Company acquired certain natural gas properties and related facilities in the Ferrier/Sunchild, Wapiti and Northwest Saskatchewan core areas. The purchase price was approximately $55.6 million, net of asset retirement obligations. The acquisition was financed through bank borrowings. The results of operations of these properties have been included in the consolidated financial statements of the Company since the acquisition date.

(b) Northeast British Columbia and Northwest Alberta properties

On July 27, 2009, the Company acquired certain natural gas properties and related facilities in the Martin Creek area of Northeast British Columbia and in Northwest Alberta for a purchase price of $174 million, net of asset retirement obligations. The purchase price is subject to change as a result of any final closing adjustments. A cash deposit of $18 million was paid in June 2009, and was subsequently applied against the purchase price. The results of operations of these properties have been included in the consolidated financial statements of the Company since the acquisition date.

4. Asset retirement obligations

Total asset retirement obligations are based on estimated costs to reclaim and abandon ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. At September 30, 2009, the estimated total undiscounted amount of cash flows required to settle the Company's asset retirement obligations is $276.8 million (2008 – $187.9 million), which will be incurred over the next 51 years. The majority of the costs will be incurred between 2010 and 2036. A credit-adjusted risk-free rate of 8% (2008 – 8%) and an inflation rate of 2% (2008 – 2%) were used to calculate the fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below:

	September 30, 2009	December 31, 2008
Balance, beginning of period	$ 46,296	$ 26,574
Accretion expense	3,132	3,026
Liabilities incurred	7,151	7,203
Liabilities acquired	9,985	8,505
Change in assumptions	-	3,504
Liabilities settled	(1,843)	(2,516)
Balance, end of period	$ 64,721	$ 46,296

5. Long-term debt

In July 2009, the Company's credit facility was increased to a maximum borrowing amount of $510.0 million (2008 – $450.0 million). Borrowing under the credit facility may be made by prime loans, bankers' acceptances and/or US libor advances. These advances bear interest at the bank's prime rate and/or at money market rates plus a stamping fee. The credit facility is secured by a first floating charge debenture, general assignment of book debts and the Company's oil and natural gas properties and equipment. The credit facility has a 364-day revolving period and is subject to an annual review by the lenders, at which time a lender can extend the revolving period or can request conversion to a one year, term loan. During the revolving period, a determination of the maximum borrowing amount occurs semi-annually on or before April 30 and October 31. During the term period, no principal payments would be required until April 29, 2011. As such, this credit facility is classified as long-term.

The Company is in the process of completing the semi-annual review of its borrowing base with its lenders and expects to complete the process by the end of November. In early November, the Company made a formal request to its lenders for credit facilities totaling $510 million, comprised of a $480 million extendible revolving facility and a $30 million non-extendible, non-revolving acquisition facility. The acquisition facility is available subject to mutual approval of the lenders and the Company.

Cash paid for interest expense for the three months ended September 30, 2009 was $4.0 million (2008 – $3.9 million) and for the nine months ended September 30, 2009 was $9.5 million (2008 – $11.1 million).

6. Shareholders' equity

(a) Share capital, warrants and contributed surplus

	September 30, 2009	December 31, 2008
Share capital	$ 684,980	$ 587,460
Warrants	-	3,454
Contributed surplus	16,777	7,128
Total	$ 701,757	$ 598,042

(b) Authorized

Unlimited number of voting Common Shares and 1,200,000 Class B Performance Shares.

(c) Common shares issued

	September 30, 2009		December 31, 2008	
	Number	Amount	Number	Amount
Balance, beginning of period	79,164	$ 587,460	52,704	$ 240,245
Issued for cash	9,000	99,016	6,000	80,546
Issued on Rider acquisition	-	-	19,844	256,195
Exercise of stock options	165	1,108	616	6,545
Stock-based compensation	-	351	-	4,144
Cost associated with shares issued, net of future tax benefit of $1.1 million (2008 - $84)	-	(2,955)	-	(215)
Balance, end of period	88,329	$ 684,980	79,164	$ 587,460

On July 27, 2009, the Company closed the acquisition of certain properties in the Martin Creek area of Northeast British Columbia and in Northwest Alberta. The acquisition was financed through a combination of bank debt and net proceeds from two equity offerings. The Company entered into an agreement to issue 7,500,000 subscription receipts at a price of $11.00 per subscription receipt on a bought deal basis for gross proceeds of $82.5 million. In addition, the Company issued 1,500,000 subscription receipts at a price of $11.00 per subscription receipt, by way of a private placement, to Ontario Teachers' Pension Plan Board for gross proceeds of $16.5 million. The subscription receipt offerings closed on July 7, 2009. Each subscription receipt was exchanged for one common share of NuVista for no additional consideration on July 27, 2009.

(d) Warrants

	September 30, 2009		December 31, 2008	
	Number	Amount	Number	Amount
Balance, beginning of period	3,000	$ 3,454	-	$ -
Issued	-	-	3,000	3,454
Transferred to contributed surplus on expiry	(3,000)	(3,454)	-	-
Balance, end of period	-	$ -	3,000	$ 3,454

At December 31, 2008, there were 3.0 million common share purchase warrants outstanding. Each warrant entitled the holder thereof to acquire, subject to adjustment, one common share for $15.50, prior to March 4, 2009. As of March 5, 2009, these warrants expired unexercised.

(e) Contributed surplus

	September 30, 2009	December 31, 2008
Balance, beginning of period	$ 7,128	$ 4,967
Stock-based compensation	6,546	6,305
Exercise of stock options	(351)	(4,144)
Expired warrants	3,454	-
Balance, end of period	$ 16,777	$ 7,128

(f) Per share amounts

During the three months ended September 30, 2009, there were 85,770,428 (2008 – 79,102,721) weighted average shares outstanding. On a diluted basis, if any there were 85,770,428 (2008 – 79,269,886) weighted average shares outstanding after giving effect for dilutive stock options. For the nine months ended September 30, 2009, there were 81,404,296 (2008 – 72,892,750) weighted average shares outstanding and 81,404,296 (2008 – 73,619,230) weighted average shares outstanding on a dilutive basis. The number of anti-dilutive options totaled 5,128,722 at September 30, 2009 (2008 – 6,748,497).

(g) Stock options

The Company has established a stock option plan whereby officers, directors, employees and service providers may be granted options to purchase common shares. Options granted prior to December 2008 vest at the rate of 25% per year and expire two years from the vest date. The terms of future stock option grants were amended in December 2008. Pursuant to the amendment, options subsequently granted will vest at the rate of 33% per year and expire 2.5 years after the vest date. The total stock options outstanding plus the Class B Performance Shares cannot exceed 10% of the outstanding common shares. The summary of stock option transactions is as follows:

	September 30, 2009		December 31, 2008	
	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
Balance, beginning of period	6,111,945	$ 13.69	4,046,400	$ 13.46
Granted	800,966	10.80	3,263,260	13.64
Exercised	(164,650)	6.73	(615,675)	10.63
Forfeited	(432,750)	14.12	(508,715)	14.63
Expired	(303,300)	13.51	(73,325)	17.64
Balance, end of period	6,012,211	$ 13.48	6,111,945	$ 13.69

The Company uses the fair value based method for the determination of the stock-based compensation costs. The fair value of each option granted during the nine months ended September 30, 2009 was estimated on the date of grant using the Black-Scholes option pricing model. In the pricing model, the risk-free interest rate used was 2% (2008 – 4%); volatility of 52% (2008 – 33%); an average expected life of 4.5 years (2008 – 4.5 years); an estimated forfeiture rate of 10% (2008 – 10%); and dividends of nil (2008 – nil). The weighted average fair value of stock options granted during the nine months ended September 30, 2009 was $4.75 per option (2008 – $5.30 per option). For the nine months ended September 30, 2009, the Company capitalized $1.9 million (2008 – $1.3 million) in stock-based compensation.

(h) Restricted stock units

In January 2008, the Board of Directors approved a Restricted Stock Unit ("RSU") Incentive Plan for employees and officers. Each RSU entitles participants to receive cash equal to the market value of the equivalent number of shares of the Company. The RSUs become payable as they vest over their lives, typically three years.

For the nine months ended September 30, 2009, the Company recorded an RSU stock-based compensation expense of $0.6 million (2008 – $1.3 million) and capitalized $0.2 million (2008 – $0.4 million) to property, plant and equipment with a corresponding offset recorded in compensation liability. The stock-based compensation expense was based on the trading price of the Company's shares on September 30, 2009.

The following table summarizes the change in RSUs:

	September 30, 2009	December 31, 2008
	Number	Number
Balance, beginning of period	351,543	-
Vested	(110,838)	-
Granted	107,124	390,163
Forfeited	(19,987)	(38,620)
Balance, end of period	327,842	351,543

The following table summarizes the change in compensation liability relating to the RSUs:

	September 30, 2009 Amount	December 31, 2008 Amount
Balance, beginning of period	$ 1,461	$ -
Change in accrued compensation liability	1,632	1,461
Cash payments	(813)	-
Balance, end of period	$ 2,280	$ 1,461
Compensation liability – current (included in accounts payable and accrued liabilities)	$ 1,840	$ 611
Compensation liability – long-term	$ 440	$ 850

For the nine months ended September 30, 2009, cash payments of $0.8 million (2008 – $nil) were made relating to the RSU Incentive Plan.

7. Risk management activities

(a) Financial instruments

The Company's financial instruments recognized in the consolidated balance sheet consists of cash and cash equivalents, accounts receivable, commodity derivative contracts, accounts payable and accrued liabilities, and long-term debt. Unless otherwise noted, carrying values reflect the current fair value of the Company's financial instruments due to their short-term maturities. The estimated fair values of recognized financial instruments have been determined based on the Company's assessment of available market information and appropriate methodologies, through comparisons to similar instruments or third party quotes.

As at September 30, 2009, the Company has entered into the following crude oil contracts:

Volume	Average Price (CDN$/bbl)	Premium (CDN$/bbl)	Term
1,000 bbls/d	CDN $64.00 – Bow River	-	January 1, 2009 – December 31, 2009
1,000 bbls/d	CDN $95.01 – $110.01 – WTI(1)	-	January 1, 2009 – December 31, 2009
1,000 bbls/d	CDN $80.30 – WTI	$9.75(2)	October 1, 2009 – September 30, 2010
1,000 bbls/d	CDN $76.00 – WTI	$5.39(2)	October 1, 2009 – December 31, 2009
1,000 bbls/d	CDN $77.50 – WTI	$8.78(2)	January 1, 2010 – March 31, 2010

(1) This is a US$ denominated crude oil contract with an associated fixed price foreign exchange contract of 1.0262 US$/CDN$.
(2) The premiums are incurred monthly over the term of the contract and will be offset against revenues.

As at September 30, 2009, the mark-to-market value of the financial commodity contracts was an asset of $1.2 million.

(b) Physical sale contracts

As at September 30, 2009, the Company has entered into direct natural gas sale contracts as follows:

Volume	Average Price (CDN$/gj)	Premium (CDN$/gj)	Term
20,000 gj/d	CDN $7.45 – Fixed Price AECO	-	April 1, 2009 – October 31, 2009
5,000 gj/d	CDN $5.65 – AECO Floor	$0.82(1)	April 1, 2009 – October 31, 2009
20,000 gj/d	CDN $5.97 – $6.56 AECO	$0.30(1)	November 1, 2009 – October 31, 2010
20,000 gj/d	CDN $5.55 – AECO Floor	$0.97(1)	November 1, 2009 – March 31, 2010
20,000 gj/d	CDN $3.56 – Fixed Price AECO	-	November 1, 2009 – November 30, 2009
20,000 gj/d	CDN $4.50 – Fixed Price AECO	-	December 1, 2009 – December 31, 2009

(1) The premiums are incurred monthly over the term of the contract and will be offset against revenues.

These physical sale contracts are documented as normal purchase and sale transactions and as such are not considered derivative financial instruments.

Subsequent to September 30, 2009, the following financial commodity price risk management contracts have been entered into:

Volume	Average Price (CDN$/bbl)	Premium (CDN$/bbl)	Term
1,000 bbls/d	CDN $87.40 – WTI	$8.86(1)(3)	April 1, 2010 – June 30, 2010
1,000 bbls/d	CDN $89.40 – WTI	$12.60(2)(3)	October 1, 2010 – December 31, 2010

(1) The WTI put was purchased at a deferred cost of $8.86/bbl for a total cost of $0.8 million.
(2) The WTI put was purchased at a deferred cost of $12.60/bbl for a total cost of $1.2 million.
(3) The premiums are incurred monthly over the term of the contract and will be offset against revenues.

8. Relationship with Bonavista Petroleum Ltd.

NuVista and Bonavista Petroleum Ltd. ("Bonavista") are considered related as two directors of NuVista, one of whom is NuVista's chairman, are also directors and officers of Bonavista and a director and an officer of NuVista are also officers of Bonavista.

NuVista charges Bonavista management fees for jointly owned partnerships. For the three and nine months ended September 30, 2009, NuVista charged Bonavista management fees totaling $0.3 million (2008 – $0.3 million) and $1.0 million (2008 – $1.0 million) respectively. As at September 30, 2009, the amount receivable from Bonavista was $0.4 million (2008 – $1.0 million).

The above transactions are considered to be in the normal course of business and have been measured at their exchange amounts, being the amounts agreed to by both parties.

9. Commitments

The following is a summary of the Company's contractual obligations and commitments as at September 30, 2009:

	Total	2009	2010	2011	2012	Thereafter
Transportation	$ 14,311	$ 1,396	$ 4,695	$ 3,036	$ 1,888	$ 3,296
Office lease	6,336	514	2,055	2,055	1,712	-
Physical sale contract premiums	5,247	1,677	3,570	-	-	-
Financial contract premiums	4,845	1,393	3,452	-	-	-
Physical power contract	6,900	-	-	2,300	2,300	2,300
Long-term debt	410,530	-	-	410,530	-	-
Total commitments	$ 448,169	$ 4,980	$ 13,772	$ 417,921	$ 5,900	$ 5,596

Corporate Information

Directors
Keith A. MacPhail, Chairman
W. Peter Comber, Barrantagh Investment Management Inc.
Pentti O. Karkkainen, KERN Partners
Ronald J. Poelzer, Bonavista Energy Trust
Alex G. Verge, President and CEO
Clayton H. Woitas, Range Royalty Management Ltd.
Grant A. Zawalsky, Burnet, Duckworth & Palmer LLP

Officers
Keith A. MacPhail, Chairman
Alex G. Verge, President and CEO
Robert F. Froese, Vice President, Finance and CFO
Ross L. Andreachuk, Vice President and Controller
Kevin J. Christie, Vice President, Exploration
Steven J. Dalman, Vice President, Business Development
D. Chris McDavid, Vice President, Operations
Daniel B. McKinnon, Vice President, Engineering
Joshua T. Truba, Vice President, Land
Glenn A. Hamilton, Corporate Secretary

Auditors
KPMG LLP
Chartered Accountants
Calgary, Alberta

Bankers
Canadian Imperial Bank of Commerce
Bank of Montreal
Royal Bank of Canada
Toronto Dominion Bank
Bank of Nova Scotia
Alberta Treasury Branches
Union Bank of California, Canada Branch

Engineering Consultants
GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Legal Counsel
Burnet, Duckworth & Palmer LLP
Calgary, Alberta

Registrar and Transfer Agent
Valiant Trust Company
Calgary, Alberta

Stock Exchange Listing
Toronto Stock Exchange
Trading Symbol "NVA"

For further information, please contact:

Alex G. Verge
President and CEO
(403) 538-8501

Robert F. Froese
Vice President, Finance and CFO
(403) 538-8530

NuVista Energy Ltd.
Suite 3500, 700 – 2nd Street SW
Calgary, Alberta T2P 2W2
Telephone: (403) 538-8500
Facsimile: (403) 538-8505

Website: www.nuvistaenergy.com
Email: inv_rel@nuvistaenergy.com

NUVISTA ENERGY LTD