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 Energy Ltd.'s ("NuVista") audited consolidated financial statements for the year ended December 31, 2011. The following MD&A of financial condition and results of operations was prepared at and is dated March 2, 2012. Our December 31, 2011 audited consolidated financial statements, Annual Information Form and other disclosure documents for 2011 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 *– Unless otherwise noted, the financial data presented below has been prepared in accordance with Canadian generally accepted accounting principles (GAAP) also known as International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). In 2010, NuVista prepared its interim and annual consolidated financial statements in accordance with Canadian generally accepted accounting principles in effect prior to January 1, 2011 ("Previous GAAP"). Comparative figures presented below pertaining to NuVista's 2010 results have been restated to be in accordance with IFRS. A reconciliation of comparative figures from Previous GAAP to IFRS is provided in the notes to the December 31, 2011 audited consolidated financial statements. The reporting and measurement currency is the Canadian dollar. Natural gas is converted to a barrel of oil equivalent ("Boe") using six thousand cubic feet of gas to one barrel of oil. In certain circumstances natural gas liquid volumes have been converted to a thousand cubic feet equivalent ("Mcfe") on the basis of one barrel of natural gas liquids to six thousand cubic feet of gas. 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. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion ratio on a 6:1 basis may be misleading as an indication of value.*

Advisory regarding forward-looking information and statements *– This MD&A contains forward-looking statements and forward-looking information (collectively, "forward-looking statements") within the meaning of applicable securities laws. The use of any of the words "will", "expects", "believe", "plans", "potential" and similar expressions are intended to identify forward-looking statements. More particularly and without limitation, this MD&A contains forward looking statements, including management's assessment of: NuVista's future focus, strategy, plans, opportunities and operations; financial risk management strategy; forecast production; production mix; drilling, development, completion and tie-in 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; NuVista's planned divesture program; the anticipated potential and growth opportunities associated with NuVista's asset base; forecast funds from operations; expectations regarding the review of NuVista's borrowing base; the source of funding of capital expenditures; the objectives and focus of NuVista's capital program and the allocation thereof; asset retirement obligations and the amount and timing of expenditures and the source of funding thereof; estimated tax pools; NuVista's risk management strategy; expectations regarding future commodity prices and netbacks; industry conditions; the costs to settle asset retirement obligations; anticipated accounting changes and the impact on NuVista's operations and financial position and the timing of filing NuVista's Annual Information Form.*

Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. By their nature, forward-looking statements are based upon certain assumptions and are subject to numerous risks and uncertainties, some of which are beyond NuVista's control, including the impact of general economic conditions, industry conditions, current and future commodity prices, currency and interest rates, anticipated production rates, borrowing, operating and other costs and funds from operations, the timing, allocation and amount of capital expenditures and the results therefrom, anticipated reserves and the imprecision of reserve estimates, the performance of existing wells, the success obtained in drilling new wells, the sufficiency of budgeted capital expenditures in carrying out *planned activities, competition from other industry participants, availability of qualified personnel or services and drilling and related equipment, stock market volatility, effects of regulation by governmental agencies including changes in environmental regulations, tax laws and royalties; the ability to access sufficient capital from internal sources and bank and equity markets; and including, without limitation, those risks considered under "Risk Factors" in our Annual Information Form. 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 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 GAAP and Previous 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 GAAP and Previous GAAP. All references to funds from operations throughout this MD&A are based on cash flow from operating activities before changes in non-cash working capital and asset retirement expenditures. Trailing twelve months funds from operations is calculated as cash flow from operating activities before changes in non-cash working capital and asset retirement expenditures for the preceding twelve month period. 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 revenues including realized commodity derivative gains/losses less royalties, transportation, operating costs, general and administrative, restricted stock unit, restricted share award, interest expense and cash taxes. Management also uses operating netbacks to analyze operating performance and adjusted working capital to analyze leverage. Adjusted net earnings (loss) is calculated as net earnings (loss) excluding non-recurring or non-cash items that management believes reduces the comparability of the NuVista's financial performance between periods. Thereafter tax items include, but are not limited to unrealized gains/losses on commodity derivatives, impairments and impairment reversals, goodwill impairments, gains/losses on divestures and the effect of changes in statutory income tax rate. Operating netbacks and adjusted working capital as presented, do not have any standardized meaning prescribed by GAAP and Previous GAAP and therefore, may not be comparable with the calculation of similar measures for other entities. Operating 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. Total Boe is calculated by multiplying the daily production by the number of days in the period.*

Description of business – NuVista is an oil and natural gas company actively engaged in the exploration for and the development and production of oil and natural gas reserves. NuVista's assets are concentrated within three core regions of the Western Canadian Sedimentary Basin – Alberta Deep Basin, Eastern Alberta and Saskatchewan, and Northwest Alberta and British Columbia. The common shares of NuVista trade on the Toronto Stock Exchange ("TSX") under the symbol NVA.

Operating activities – For the three months ended December 31, 2011, NuVista drilled 16 (11.9 net) wells resulting in seven (6.3 net) oil wells and nine (5.6 net) natural gas wells. NuVista drilled three (2.3 net) heavy oil wells at Hallam South in West Central Saskatchewan, four (4.0 net) oil wells in Provost, five (2.8 net) natural gas wells in Pembina, two (1.5 net) gas wells in Wapiti and one (1.0) gas well in Ferrier. NuVista operated 75% of the wells drilled and had an average working interest of 74% in the wells.

For the year ended December 31, 2011, NuVista drilled 56 (42.1 net) wells resulting in 38 (29.9 net) oil wells, 17 (11.2 net) natural gas wells and one dry hole. NuVista operated 47 of the wells and a total of 50 horizontal wells were drilled in the year.

Production

	Three months ended December 31,			Year ended December 31,		
	2011	2010	% Change	**2011**	2010	% Change
Natural gas (Mcf/d)	**101,327**	121,238	(16)	**104,250**	123,860	(16)
Liquids (Bbls/d)	**2,912**	3,024	(4)	**2,974**	3,053	(3)
Oil (Bbls/d)	**5,506**	4,935	12	**5,206**	4,647	12
Total oil equivalent (Boe/d)	**25,306**	28,165	(10)	**25,556**	28,343	(10)

For the three months ended December 31, 2011, NuVista's average production was 25,306 Boe/d, comprised of 101.3 MMcf/d of natural gas, 2,912 Bbls/d of associated natural gas liquids ("liquids") and 5,506 Bbls/d of oil, which is consistent compared to the third quarter of 2011 and a 10% decrease compared to the same period in 2010. The decrease in NuVista's production during the three months ended December 31, 2011 compared to the same period in 2010 was primarily due to the impact of muted levels of capital spending in 2011, in particular the first half of 2011. Oil and liquids weighting in the fourth quarter of 2011 increased to 33% from 28% in the same period in 2010. The increase in oil and liquids production and weighting reflects our increased focus on higher netback oil and liquids-rich natural gas projects.

NuVista's production for the year ended December 31, 2011 averaged 25,556 Boe/d comprised of 104.3 MMcf/d of natural gas, 2,974 Bbls/d of liquids and 5,206 Bbls/d of oil, which represents an overall 10% average decrease over the same period in 2010. The decrease in production for the year ended December 31, 2011 compared to the same period in 2010 is primarily due to lower capital spending, unplanned and planned third-party facility outages and a focus on drilling oil wells that add greater value but typically have lower average production additions.

Commodity prices

Benchmark pricing

	Three months ended December 31,			Year ended December 31,		
	2011	2010	% Change	**2011**	2010	% Change
Natural gas – AECO (daily) ($/GJ)	**3.01**	3.43	(12)	**3.43**	3.79	(10)
Natural gas – AECO (monthly) ($/GJ)	**3.29**	3.39	(3)	**3.48**	3.91	(11)
Oil – WTI (US$/Bbl)	**94.06**	85.17	10	**95.12**	79.53	20
Oil – Edmonton Par price (Cdn$/Bbl)	**97.57**	80.74	21	**94.04**	77.71	21
Exchange rate (Cdn$/US$)	**0.9774**	0.9873	(1)	**1.0114**	0.9710	4

Average selling prices [(1)]

	Three months ended December 31,			Year ended December 31,		
	2011	2010	% Change	**2011**	2010	% Change
Natural gas ($/Mcf)	**3.73**	3.86	(3)	**3.90**	4.47	(13)
Liquids ($/Bbl)	**68.82**	52.76	30	**64.31**	51.48	25
Oil ($/Bbl)	**85.68**	70.12	22	**79.41**	67.21	18

(1) Prices exclude price risk management realized and unrealized gains and losses on financial derivative commodity contracts and includes gains and losses on physical sale contracts.

NuVista markets its natural gas based on a mix of monthly and daily AECO pricing. The AECO daily index averaged $3.01/GJ for the quarter and the monthly index averaged $3.29/GJ. This compares to $3.43/GJ and $3.39/GJ respectively for the same period last year. NuVista's average selling price for gas in the quarter was $3.73/Mcf compared to $3.86/Mcf for the fourth quarter of 2010. The higher heat content of NuVista's gas stream is reflected in the higher realization on an Mcf basis. For the twelve months of 2011, the realized gas price includes price risk management gains of $2.0 million on physical sale contracts.

The price NuVista receives for its oil production is primarily driven by the price of WTI, less a discount to western Canada for heavier grades. NuVista's light oil sales closely match the Edmonton Par price and heavy oil sales closely match the Western Canadian Select ("WCS") heavy oil benchmark. WTI prices were 10% higher in the fourth quarter of 2011 compared to the fourth quarter of 2010. Stronger Edmonton Par prices and narrowing heavy oil differentials resulted in realized oil prices being up 22% in the fourth quarter of 2011 compared to the same period in 2010, higher than the 10% increase in WTI prices.

Natural gas liquids include ethane, propane, butane and condensate. Ethane prices are highly correlated to natural gas prices and condensate prices are highly correlated to light oil prices. Propane and butane trade at varying discounts to light oil prices depending on market conditions. NuVista realized an average price of $68.82/Bbl for liquids sales in the fourth quarter of 2011 representing approximately a 30% increase over the same period last year. This increase was due to NGL prices strengthening relative to WTI and a greater proportion of liquids production weighted toward condensate.

Revenues

	Three months ended December 31,					
($ thousands, except per unit amounts)	**2011**		2010		% Change	
Natural gas	$	$/Mcf	$	$/Mcf	$	$/Mcf
Revenue [(1)]	**34,736**	**3.73**	43,040	3.86	(19)	(3)
Realized gain (loss) on commodity derivatives	**(958)**	**(0.10)**	(80)	(0.01)	1,098	900
Total natural gas	**33,778**	**3.63**	42,960	3.85	(21)	(6)
Liquids	$	$/Bbl	$	$/Bbl	$	$/Bbl
Revenue	**18,435**	**68.82**	14,678	52.76	26	30
Realized gain (loss) on commodity derivatives	**-**	**-**	-	-	-	-
Total liquids	**18,435**	**68.82**	14,678	52.76	26	30
Oil	$	$/Bbl	$	$/Bbl	$	$/Bbl
Revenue	**43,407**	**85.68**	31,834	70.12	36	22
Realized gain (loss) on commodity derivatives	**(2,412)**	**(4.76)**	(2,605)	(5.74)	(7)	(17)
Total oil	**40,995**	**80.92**	29,229	64.38	40	26
Total	$	$/Boe	$	$/Boe	$	$/Boe
Revenue	**96,578**	**41.48**	89,552	34.56	8	20
Realized gain (loss) on commodity derivatives	**(3,370)**	**(1.45)**	(2,685)	(1.04)	26	39
Total revenue	**93,208**	**40.03**	86,867	33.52	7	19

[(1)] Natural gas revenue includes price risk management gains and losses on physical sale contracts. For the three months ended December 31, 2011, our physical sale contracts totaled a $1.2 million gain (2010 – $1.4 million gain).

($ thousands, except per unit amounts)	Year ended December 31, 2011		2010		% Change	
Natural gas	$	$/Mcf	$	$/Mcf	$	$/Mcf
Revenue [1]	**148,523**	**3.90**	201,969	4.47	(26)	(13)
Realized gain (loss) on commodity derivatives	**(1,286)**	**(0.03)**	779	0.02	(265)	(250)
Total natural gas	**147,237**	**3.87**	202,748	4.49	(27)	(14)
Liquids	$	$/Bbl	$	$/Bbl	$	$/Bbl
Revenue	**69,807**	**64.31**	57,357	51.48	22	25
Realized gain (loss) on commodity derivatives	**-**	**-**	-	-	-	-
Total liquids	**69,807**	**64.31**	57,357	51.48	22	25
Oil	$	$/Bbl	$	$/Bbl	$	$/Bbl
Revenue	**150,904**	**79.41**	114,001	67.21	32	18
Realized gain (loss) on commodity derivatives	**(9,477)**	**(4.99)**	(6,018)	(3.55)	57	41
Total oil	**141,427**	**74.42**	107,983	63.66	31	17
Total	$	$/Boe	$	$/Boe	$	$/Boe
Revenue	**369,234**	**39.58**	373,327	36.09	(1)	10
Realized gain (loss) on commodity derivatives	**(10,763)**	**(1.15)**	(5,239)	(0.51)	105	125
Total revenue	**358,471**	**38.43**	368,088	35.58	(3)	8

[1] Natural gas revenue includes price risk management gains and losses on physical sale contracts. For the year ended December 31, 2011, our physical sale contracts totaled a $2.0 million gain (2010 – $8.7 million gain).

For the three months ended December 31, 2011, revenues including realized commodity derivative gains and losses were $93.2 million, a 7% increase from $86.9 million for the same period in 2010. The increase in revenues for the three months ended December 31, 2011 compared to the same period of 2010 is primarily due to a 10% decrease in production volumes offset by a 19% increase in overall realized prices. Revenues were comprised of $33.8 million of natural gas revenue, $18.4 million of liquids revenue and $41.0 million of oil revenue. The increase in average realized commodity prices is comprised of a 6% decrease in the natural gas price to $3.63/Mcf from $3.85/Mcf, a 30% increase in the liquids price to $68.82/Bbl from $52.76/Bbl and a 26% increase in the oil price to $80.92/Bbl from $64.38/Bbl.

For the year ended December 31, 2011, revenues including realized commodity derivative gains and losses were $358.5 million, a 3% decrease from $368.1 million for the same period in 2010. The decrease in revenues for the twelve months of 2011 compared to the same period of 2010 is primarily due to a decrease in natural gas average production and natural gas pricing partially offset by the increase in liquids and oil prices and an increase in our oil and liquids production weighting. These revenues were comprised of $147.2 million of natural gas revenue, $69.8 million of liquids revenue and $141.4 million of oil revenue. The increase in average realized commodity prices is comprised of a 14% decrease in the natural gas price to $3.87/Mcf from $4.49/Mcf, a 25% increase in the liquids price to $64.31/Bbl from $51.48/Bbl and an increase of 17% in the oil price to $74.42/Bbl from $63.66/Bbl.

Commodity price risk management

($ thousands)	Three months ended December 31, 2011 Realized Gain (Loss)	2011 Unrealized Gain (Loss)	2011 Total Gain (Loss)	2010 Realized Gain (Loss)	2010 Unrealized Gain (Loss)	2010 Total Gain (Loss)
Natural gas	**(958)**	**(220)**	**(1,178)**	(80)	(1,048)	(1,128)
Oil	**(2,412)**	**(17,477)**	**(19,889)**	(2,605)	(5,028)	(7,633)
Total gain (loss)	**(3,370)**	**(17,697)**	**(21,067)**	(2,685)	(6,076)	(8,761)

($ thousands)	Year ended December 31, 2011			2010		
	Realized Gain (Loss)	**Unrealized Gain (Loss)**	**Total Gain (Loss)**	Realized Gain (Loss)	Unrealized Gain (Loss)	Total Gain (Loss)
Natural gas	**(1,286)**	**(3,275)**	**(4,561)**	779	1,906	2,685
Oil	**(9,477)**	**(7,005)**	**(16,482)**	(6,018)	(4,653)	(10,671)
Total gain (loss)	**(10,763)**	**(10,280)**	**(21,043)**	(5,239)	(2,747)	(7,986)

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 help 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, differential, 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 December 31, 2011, the commodity price risk management program resulted in a loss of $21.1 million, consisting of realized losses of $3.4 million and unrealized losses of $17.7 million on natural gas and oil contracts. For the year ended December 31, 2011, the commodity price risk management program consisted of realized losses of $10.8 million and unrealized losses of $10.3 million on natural gas and oil contracts. As at December 31, 2011, the mark-to-market value of our financial derivative commodity contracts was a net liability of $15.6 million.

There was $1.2 million and $2.0 million in price risk management gains on our physical sale contracts for the three and twelve months ended December 31, 2011 respectively. As at December 31, 2011, the mark-to-market value of our physical sale contracts was a gain of $2.0 million.

(a) Financial instruments

The following is a summary of financial instruments outstanding as at December 31, 2011:

	Volume	**Pricing**	**Premium**	**Remaining term**
WTI crude oil contracts				
Put option	2,000 Bbls/d	Cdn $88.55/Bbl	Cdn $9.43/Bbl	Jan 1, 2012 - Mar 31, 2012
Fixed price swap	2,000 Bbls/d	Cdn $89.93/Bbl		Jan 1, 2012 - Mar 31, 2012
Fixed price swap	3,000 Bbls/d	Cdn $87.62/Bbl		Apr 1, 2012 - Jun 30, 2012
Fixed price swap	2,000 Bbls/d	Cdn $82.68/Bbl		Jul 1, 2012 - Sep 30, 2012
Fixed price swap	2,000 Bbls/d	Cdn $82.68/Bbl		Oct 1, 2012 - Dec 31, 2012
Fixed price swap	1,000 Bbls/d	Cdn $83.00/Bbl		Jan 1, 2013 - Mar 31, 2013
WTI heavy oil differential contracts				
WCS differential	3,000 Bbls/d	US $(13.85)/Bbl		Jan 1, 2012 - Jun 30, 2012
NYMEX natural gas differential contracts				
AECO differential	30,000 MMbtu/d	US $(0.51)/MMbtu		Jan 1, 2012 - Mar 31, 2012
AECO differential	20,000 MMbtu/d	US $(0.59)/MMbtu		Apr 1, 2012 - Oct 31, 2012

Subsequent to December 31, 2011, the following financial instruments have been entered into:

	Volume	**Pricing**	**Premium**	**Remaining term**
WTI crude oil contracts				
Put option	250 Bbls/d	Cdn $108.70/Bbl	Cdn $6.58/Bbl	Apr 1, 2012 - Sep 30, 2012
Fixed price swap	250 Bbls/d	Cdn $101.10/Bbl		Apr 1, 2012 - Mar 31, 2013

(b) Physical purchase and sale contracts

The following is a summary of physical purchase and sale contracts outstanding as at December 31, 2011:

	Volume	Pricing	Remaining term
Natural gas contracts			
AECO fixed price swap	5,000 GJ/d	Cdn $3.41/GJ	Jan 1, 2012 - Nov 30, 2012
Electricity contracts			
Fixed price	4.0 Mwh	Cdn $65.64/Mwh	Jan 1, 2012 - Dec 31, 2013

These physical purchase and sale contracts are not considered financial instruments and are being accounted for as they settle.

Royalties

	Three months ended December 31,		Year ended December 31,	
(Percentage)	**2011**	2010	**2011**	2010
Natural gas and liquids	**6**	15	**11**	15
Oil	**8**	13	**13**	16
Weighted average rate	**7**	14	**12**	15

For the three months ended December 31, 2011, royalties were $6.5 million, 49% lower than the $12.7 million for the same period of 2010. Royalties for the year ended December 31, 2011 were $43.2 million compared to $57.3 million reported for the year ended December 31, 2010. The decrease in royalties for three and twelve months ended December 31, 2011 compared to the same period in 2010 is largely due to 2011 production additions being subject to crown royalty incentives and gas cost allowance adjustments.

Average royalty rates by product for the three months ended December 31, 2011 were 6% for natural gas and liquids and 8% for oil compared to 15% for natural gas and liquids and 13% for oil for the same period in 2010. Excluding the impact of gas cost allowance adjustments, the average royalty rate for natural gas and liquids for the three months ended December 31, 2011 was 17%. As a percentage of revenue, the reported average royalty rate for the three months ended December 31, 2011 was 7% compared to 14% for the comparative period of 2010. Average royalty rates by product for the year ended December 31, 2011 were 11% for natural gas and liquids and 13% for oil compared to 15% for natural gas and liquids and 16% for oil for the same period in 2010. As a percentage of revenue, the reported average royalty rate for the year ended December 31, 2011 was 12% compared to 15% for the comparative period of 2010.

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. For the year ended December 31, 2011 there were $2.0 million in physical price risk management gains included in revenue, compared to $8.7 million for the same period in 2010.

Transportation – Transportation costs were $3.0 million ($1.30/Boe) for the three months ended December 31, 2011 as compared to $1.8 million ($0.71/Boe) for the same period of 2010. Transportation costs were $10.5 million ($1.12/Boe) for the year ended December 31, 2011 compared to $8.6 million ($0.83/Boe) for the same period in 2010. The transportation costs for the three months ended December 31, 2011 were higher compared to the same period in 2010 due to higher transportation costs associated with increased oil production in West Central Saskatchewan and trucking costs incurred to mitigate the effect of pipeline outages in Northwest Alberta earlier in the year.

Operating – Operating expenses were $25.8 million ($11.06/Boe) for the three months ended December 31, 2011 as compared to $26.2 million ($10.09/Boe) for the three months ended December 31, 2010 and $24.4 million ($10.45/Boe) for the three months ended September 30, 2011. For the three months ended December 31, 2011, natural gas and liquids operating expenses averaged $1.69/Mcfe and oil operating expenses were $14.41/Bbl as compared to $1.37/Mcfe and $18.78/Bbl respectively for the same period of 2010. As compared to the third quarter of 2011, fourth quarter operating expenses increased due to the seasonality of the business and higher costs to operate in the winter months.

Operating expenses were $103.7 million ($11.12/Boe) for the year ended December 31, 2011 as compared to $94.2 million ($9.11/Boe) for the year ended December 31, 2010. The increase in operating costs is primarily due to higher first quarter costs associated with winter operations and increased maintenance expenditures. The increase on a per unit basis is primarily due to higher overall costs and the impact of the fixed cost nature of many of our costs and lower production volumes. Managing operating costs continues to be a key focus as we shift to typically higher value and higher cost oil and liquids-rich natural gas production. For the year ended December 31, 2011, natural gas and liquids operating expenses averaged $1.70/Mcfe and oil operating expenses were $14.63/Bbl as compared to $1.22/Mcfe and $18.26/Bbl respectively for the same period of 2010.

Operating netbacks – The table below summarizes operating netbacks by product for the three months ended December 31, 2011:

	Natural gas and liquids		Oil		Total	
($ thousands, except per unit amounts)	$	$/Mcfe	$	$/Bbl	$	$/Boe
Revenue	53,171	4.86	43,407	85.68	96,578	41.48
Realized gain (loss) on commodity derivatives	(958)	(0.09)	(2,412)	(4.76)	(3,370)	(1.45)
	52,213	4.77	40,995	80.92	93,208	40.03
Royalties	(3,035)	(0.28)	(3,466)	(6.84)	(6,501)	(2.79)
Transportation costs	(1,240)	(0.11)	(1,776)	(3.51)	(3,016)	(1.30)
Operating costs	(18,458)	(1.69)	(7,300)	(14.41)	(25,758)	(11.06)
Operating netback[1]	29,480	2.69	28,453	56.16	57,933	24.88

[1] Refer to "non-GAAP measurements".

The following table summarizes operating netbacks by product for the year ended December 31, 2011:

	Natural gas and liquids		Oil		Total	
($ thousands, except per unit amounts)	$	$/Mcfe	$	$/Bbl	$	$/Boe
Revenue	218,330	4.90	150,904	79.41	369,234	39.58
Realized gain (loss) on commodity derivatives	(1,286)	(0.03)	(9,477)	(4.99)	(10,763)	(1.15)
	217,044	4.87	141,427	74.42	358,471	38.43
Royalties	(23,336)	(0.52)	(19,859)	(10.45)	(43,195)	(4.63)
Transportation costs	(5,076)	(0.11)	(5,379)	(2.83)	(10,455)	(1.12)
Operating costs	(75,896)	(1.70)	(27,808)	(14.63)	(103,704)	(11.12)
Operating netback[1]	112,736	2.54	88,381	46.51	201,117	21.56

[1] Refer to "non-GAAP measurements".

General and administrative

	Three months ended December 31,		Year ended December 31,	
($ thousands, except per unit amounts)	**2011**	2010	**2011**	2010
Gross general and administrative expenses	**7,531**	7,013	**25,927**	25,640
Overhead recoveries	**(1,626)**	(1,966)	**(6,158)**	(6,467)
Net general and administrative expenses	**5,905**	5,047	**19,769**	19,173
Per Boe	**2.54**	1.95	**2.12**	1.85

General and administrative expenses, net of overhead recoveries, for the three months ended December 31, 2011 were $5.9 million ($2.54/Boe) compared to $5.0 million ($1.95/Boe) in the same period of 2010. General and administrative expenses, net of overhead recoveries, for the year ended December 31, 2011 were $19.8 million ($2.12/Boe) as compared to $19.2 million ($1.85/Boe) for the year ended December 31, 2010. The increase in general and administrative expenses for the three and twelve months ended December 31, 2011 compared to the same period in 2010 is primarily due to severance payments made to employees.

Share-based compensation

	Three months ended December 31,		Year ended December 31,	
($ thousands)	**2011**	2010	**2011**	2010
Stock options	**1,358**	1,879	**4,970**	6,556
Restricted stock units	**224**	220	**717**	1,039
Restricted share awards	**194**	-	**194**	-
Total	**1,776**	2,099	**5,881**	7,595

NuVista recorded a share-based compensation charge of $1.8 million for the three months ended December 31, 2011 compared to $2.1 million for the same period in 2010. For the year ended December 31, 2011, NuVista recorded a share-based compensation charge of $5.9 million compared to $7.6 million for the same period in 2010. The share-based compensation charge relates to the amortization of the fair value of stock option awards and restricted share awards and the accrual for future payments under the restricted stock unit incentive plan.

Interest – Interest expense for the three months ended December 31, 2011 was $3.3 million ($1.43/Boe) compared to $5.3 million ($2.04/Boe) for the same period of 2010. For the year ended December 31, 2011, interest expense was $16.6 million ($1.78/Boe) compared to $17.7 million ($1.71/Boe) in the same period of 2010. Interest expense for the year ended December 31, 2011 decreased compared to the same period in 2010 due to lower debt levels and decreased margins incurred in 2011. For the three months ended December 31, 2011, borrowing costs averaged 3.7% compared to 4.4% in the same period of 2010. Currently, NuVista's average borrowing rate is approximately 2.5%. Cash paid for interest for the three and twelve months ended December 31, 2011 was $3.4 million (2010 – $5.2 million) and $17.1 million (2010 – $17.9 million) respectively.

Depletion, depreciation, amortization ("DD&A") and impairment

	Three months ended December 31,		Year ended December 31,	
($ thousands, except per unit amounts)	**2011**	2010	**2011**	2010
Depletion of oil and gas assets(1)	**36,994**	38,273	**140,171**	145,248
Depreciation of fixed assets	**5,150**	4,263	**19,328**	15,746
Impairment charges (net of recoveries)	**147,707**	-	**147,707**	23,789
Total DD&A and impairment	**189,851**	42,536	**307,206**	184,783
DD&A rate per Boe, before impairment	**18.10**	16.42	**17.10**	15.56

(1) Includes depletion of the capitalized portion of the asset retirement obligations that were capitalized to the property, plant and equipment balance and are being depleted over the life of the reserves.

Depletion, depreciation and amortization ("DD&A") expenses excluding impairments were $42.1 million for the fourth quarter of 2011 as compared to $42.5 million for the same period in 2010. The average per unit cost was $18.10/Boe in the fourth quarter of 2011 as compared to $16.42/Boe for the same period in 2010. DD&A expenses, excluding impairments for the twelve months ended December 31, 2011 were $159.5 million as compared to $161.0 million for the same period in 2010. Per unit costs in the fourth quarter of 2011 increased from the same period in 2010 due primarily to higher finding and development costs incurred during 2011.

An impairment test was performed on NuVista's natural gas producing assets at December 31, 2011 due to a decrease in the forward price curve for natural gas at January 1, 2012 compared to the prior year. NuVista recognized an impairment charge (net of reversals) of $147.7 million (2010 – $23.8 million) related to four natural gas Cash Generating Units ("CGUs") in Northern and Eastern Alberta and in Saskatchewan, which has been included as depletion, depreciation, amortization and impairment expense on the statement of earnings. The recoverable amount was determined using a fair value less costs to sell methodology with the expected future cash flows based on proved and probable reserves using a pre-tax discount rate of 10% (2010 – 10%), based on the independent external reserves report.

Goodwill – Goodwill was recorded from various business acquisitions and was determined based on the excess of total consideration paid less the fair value of the assets and liabilities acquired. IFRS standards require that the goodwill balance be assessed for impairment at least annually or more frequently if events or changes in circumstances indicate that the balance might be impaired. An annual impairment test was performed on December 31, 2011. The carrying value of the CGU (including goodwill) was compared to the recoverable amount of the CGU determined to be fair value less costs to sell. Fair value less costs to sell was based on the discounted cash flows from oil and natural gas proved and probable reserves using third party forecast prices and a pre-tax discount rate of 10%. This methodology resulted in a goodwill impairment charge of $25.8 million to earnings for the year ended December 31, 2011 related to a natural gas CGU located in the deep basin area of Alberta.

Asset retirement obligations – Asset retirement obligations ("ARO") 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 December 31, 2011, NuVista recorded an ARO of $174.7 million as compared to $128.3 million as at December 31, 2010. The majority of the increase is due to a decrease in the risk free discount rate to 2.49% at December 31, 2011 from 3.52% at December 31, 2010 and also due to increases in cost estimates. At December 31, 2011, the estimated total undiscounted amount of cash flow required to settle NuVista's ARO is $267.3 million (2010 – $232.4 million), which is estimated to be incurred over the next 51 years. The majority of the costs are expected to be incurred between 2012 and 2030.

There are uncertainties related to asset retirement obligations and the impact on the financial statements could be material as the eventual timing and expected costs to settle these obligations could differ from our estimates. The main factors that could cause expected cash flows to differ are changes to laws, regulations, reserve estimates, costs and technology. Any reclamation or abandonment expenditures will generally be funded from cash flow from operating activities.

Income taxes – For the three months ended December 31, 2011, the provision for income and other taxes was a recovery of $42.6 million compared to a recovery of $6.4 million for the same period in 2010. For the year ended December 31, 2011, the provision for income and other taxes was a recovery of $36.4 million compared to a recovery of $10.7 million in the same period of 2010. The increase in recovery for the year ended December 31, 2011 compared to a recovery in 2010 is primarily attributable to an decrease in income after adjusting for non-deductible tax items in the periods.

Capital expenditures

	Three months ended December 31,		Year ended December 31,	
($ thousands)	**2011**	2010	**2011**	2010
Exploration and development				
Land and retention costs	**627**	420	**2,810**	19,118
Seismic	**3,016**	1,454	**7,369**	11,762
Drilling and completion	**40,592**	25,863	**120,106**	151,115
Facilities and equipment	**8,628**	7,241	**27,865**	42,022
Corporate and other	**256**	154	**434**	240
Subtotal	**53,119**	35,132	**158,584**	224,257
Alberta drilling incentive credits	**1,792**	(1,563)	**(1,278)**	(17,564)
Subtotal	**54,911**	33,569	**157,306**	206,693
Property acquisitions (dispositions)	**2,873**	(5,034)	**4,524**	18,357
Net capital expenditures	**57,784**	28,535	**161,830**	225,050

Capital expenditures were $57.8 million during the fourth quarter of 2011, consisting of $54.9 million of exploration and development spending and $2.9 million in minor property acquisitions. This compares to $28.5 million incurred for the same period of 2010, consisting of $33.6 million of exploration and development spending and a $5.0 million undeveloped land disposition. Capital expenditures for the twelve months ended December 31, 2011 were $161.8 million, consisting of $157.3 million (net of drilling credits) of exploration and development spending and $4.5 million of property acquisitions. This compares to $225.1 million incurred for the same period of 2010, consisting of $206.7 million of exploration and development spending and $18.4 million of net acquisitions of producing and non-producing properties. NuVista sold minor properties in the Pembina area of Alberta and in Northwest Saskatchewan for proceeds of $42.4 million resulting in a gain of $33.1 million during the year. The majority of the capital expenditures in the fourth quarter were spent on oil and liquids-rich natural gas projects.

Tax pools

	Available balance	Maximum annual deduction
($ thousands)	**2011**	%
Canadian exploration expense	**58,000**	100%
Canadian development expense	**263,000**	30% declining balance
Canadian oil and natural gas property expense	**321,000**	10% declining balance
Undepreciated capital cost	**191,000**	25% declining balance
Other	**3,000**	Various rates
Total federal tax pools	**836,000**	
Additional Alberta tax pools	**8,000**	100%

At December 31, 2011, NuVista had approximately $836 million (2010 – $900 million) of estimated tax pools available for deduction against future years' taxable income.

Net earnings – For the three months ended December 31, 2011, net loss totaled $158.5 million ($1.59/share, basic) compared to net loss of $21.0 million ($0.24/share, basic) for the same period in 2010. NuVista's net loss for year ended December 31, 2011 was $143.8 million ($1.47/share, basic) compared to a net loss of $59.7 million ($0.67/share, basic) in the same period in 2010. The net loss for the year ended December 31, 2011 is attributable to the oil and gas impairment charge of $147.7 million and goodwill impairment charge of $25.8 million recognized in 2011 as a result of lower natural gas prices offset by a gain on property dispositions of $33.1 million and deferred income tax recoveries of $36.4 million.

Adjusted net earnings (loss) – The table below summarizes adjusted net earnings (loss) for the three months ended and year ended December 31, 2011 compared December 31, 2010:

	Three months ended December 31,		Years ended December 31,	
($ thousands)	**2011**	2010	**2011**	2010
Net earnings (loss)	**(158,462)**	(20,965)	**(143,800)**	(59,655)
Deduct (add back):				
Unrealized gain (loss) on commodity derivatives, after tax	**(12,972)**	(4,356)	**(7,535)**	(1,970)
Impairment of property, plant and equipment, after tax	**(108,269)**	(17,057)	**(108,269)**	(17,057)
Goodwill impairments, after tax	**(18,903)**	(5,618)	**(18,903)**	(21,332)
Gain (loss) on divestitures, after tax	**1,647**	3,635	**24,273**	3,635
Adjusted net earnings (loss)(1)	**(19,965)**	2,431	**(33,366)**	(22,931)
Per basic share	**(0.20)**	0.03	**(0.34)**	(0.26)
Per diluted share	**(0.20)**	0.03	**(0.34)**	(0.26)

(1) Refer to "non-GAAP measurements".

Funds from operations – For the three months ended December 31, 2011, NuVista's funds from operations were $48.5 million ($0.49/share, basic), a 36% increase from $35.6 million ($0.40/share, basic) for the three months ended December 31, 2010. For the year ended December 31, 2011, NuVista's funds from operations were $164.0 million ($1.68/share, basic), a 4% decrease from $170.0 million ($1.92/share, basic) in the same period of 2010. Funds from operations for the three months ended December 31, 2011 were relatively consistent compared with the same period in 2010 as higher oil and liquids prices and lower royalty costs were offset by lower natural gas prices.

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

	Three months ended December 31,		Years ended December 31,	
($ thousands)	**2011**	2010	**2011**	2010
Cash provided by operating activities	**62,791**	42,717	**160,268**	167,455
Add back:				
Asset retirement expenditures	**2,491**	663	**7,120**	7,740
Change in non-cash working capital	**(16,815)**	(7,762)	**(3,369)**	(5,204)
Funds from operations(1)	**48,467**	35,618	**164,019**	169,991

(1) Refer to "non-GAAP measurements".

The table below summarizes funds from operations netbacks for the three months ended December 31, 2011 compared to the three months ended December 31, 2010:

($ thousands, except per unit amounts)	Three months ended December 31, 2011		2010		% Change	
	$	$/Boe	$	$/Boe	$	$/Boe
Revenue	**96,578**	**41.48**	89,552	34.56	8	20
Realized gain (loss) on commodity derivatives	**(3,370)**	**(1.45)**	(2,685)	(1.04)	26	39
	93,208	**40.03**	86,867	33.52	7	19
Royalties	**(6,501)**	**(2.79)**	(12,687)	(4.90)	(49)	(43)
Transportation	**(3,016)**	**(1.30)**	(1,848)	(0.71)	63	83
Operating costs	**(25,758)**	**(11.06)**	(26,154)	(10.09)	(2)	10
Operating netback	**57,933**	**24.88**	46,178	17.82	25	40
General and administrative	**(5,905)**	**(2.54)**	(5,047)	(1.95)	17	30
Restricted stock units	**(224)**	**(0.10)**	(220)	(0.08)	2	25
Interest	**(3,337)**	**(1.43)**	(5,293)	(2.04)	(37)	(30)
Funds from operations netback(1)	**48,467**	**20.81**	35,618	13.75	36	51

(1) Refer to "non-GAAP measurements".

The table below summarizes funds from operations netbacks for the year ended December 31, 2011 compared to the year ended December 31, 2010:

($ thousands, except per unit amounts)	Year ended December 31, 2011		2010		% Change	
	$	$/Boe	$	$/Boe	$	$/Boe
Revenue	**369,234**	**39.58**	373,327	36.09	(1)	10
Realized gain (loss) on commodity derivatives	**(10,763)**	**(1.15)**	(5,239)	(0.51)	105	125
	358,471	**38.43**	368,088	35.58	(3)	8
Royalties	**(43,195)**	**(4.63)**	(57,347)	(5.54)	(25)	(16)
Transportation	**(10,455)**	**(1.12)**	(8,588)	(0.83)	22	35
Operating costs	**(103,704)**	**(11.12)**	(94,237)	(9.11)	10	22
Operating netback	**201,117**	**21.56**	207,916	20.10	(3)	7
General and administrative	**(19,769)**	**(2.12)**	(19,173)	(1.85)	3	15
Restricted stock units	**(717)**	**(0.08)**	(1,039)	(0.10)	(31)	(20)
Interest	**(16,612)**	**(1.78)**	(17,713)	(1.71)	(6)	4
Funds from operations netback(1)	**164,019**	**17.58**	169,991	16.44	(4)	7

(1) Refer to "non-GAAP measurements".

Liquidity and capital resources

($ thousands)	2011	2010
Common shares outstanding	**99,513**	88,760
Share price(1)	**5.24**	9.25
Total market capitalization	**521,448**	821,030
Adjusted working capital (surplus) deficit(2)	**17,360**	5,477
Bank debt	**289,431**	438,566
Debt, net of adjusted working capital ("Net Debt")	**306,791**	444,043
Trailing 12 months funds from operations(2)	**164,019**	169,991
Net debt to trailing 12 months funds from operations	**1.9**	2.6
Net debt as a percentage of total capitalization	**59%**	54%

(1) Represents the closing price on the TSX on December 31.
(2) Refer to the "non-GAAP measurements".

As at December 31, 2011, debt net of adjusted working capital was $306.8 million, resulting in a net debt to the trailing twelve months funds from operations ratio of 1.9:1. NuVista's strategy is to maintain a net debt to trailing twelve months funds from operations of less than 2.0:1. The actual ratio may fluctuate on a quarterly basis above or below target due to a number of factors including timing of acquisitions, dispositions and commodity prices. At December 31, 2011, NuVista had an adjusted working capital deficit of $17.4 million. Adjusted working capital excludes the current portion of the fair value of the commodity derivative liabilities of $9.3 million. We believe it is appropriate to exclude this amount when assessing financial leverage. At December 31, 2011, NuVista had $150.6 million of unused bank borrowing capacity based on the current credit facility of $440 million.

As of December 31, 2011, NuVista had a $440 million extendible revolving term credit facility available from a syndicate of Canadian chartered banks. 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 borrowing margin. The credit facility is secured by a first floating charge debenture, general assignment of book debts and NuVista'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 approximately October 31. As part of the 2011 semi-annual review process, NuVista requested and was granted a reduction in its borrowing base from $470 million to $440 million. NuVista's bank borrowings have been significantly reduced following the issuance of equity and the dispositions of assets in the first half of 2011 and NuVista believes it can retain sufficient financial flexibility and reduce its financing costs by making this reduction. NuVista's annual review of its borrowing base is expected to be completed by the end of April 2012. During the term period, no principal payments would be required until April 29, 2013. As such, this credit facility is classified as long-term. As at December 31, 2011, NuVista had drawn $289.4 million on the facility.

At December 31, 2011, NuVista's bank debt net of adjusted working capital decreased to $306.8 million compared to $444.0 million at December 31, 2010. Improving NuVista's financial flexibility and reducing debt levels has been a priority in 2011. During the year, NuVista issued 10,614,000 common shares for gross proceeds of $100.8 million, terminated its dividend payments and constrained capital expenditures to ensure that 2011 capital expenditures would be lower than forecast cash flow. Also, NuVista completed a property dispositions for total cash consideration of $42.4 million during the year.

As at December 31, 2011, there were 99.5 million common shares outstanding. In addition, there were 7.3 million stock options outstanding, with an average exercise price of $10.51 per option. As of February 29, 2012, there were 99.5 million common shares outstanding.

Contractual obligations and commitments – NuVista enters into contract obligations as part of conducting business. The following is a summary of NuVista's contractual obligations and commitments as at December 31, 2011:

	Total	2012	2013	2014	2015	2016	Thereafter
Transportation	**$ 8,877**	$3,002	$ 2,429	$2,039	$1,190	$ 188	$ 29
Office lease	**15,211**	3,070	2,497	2,496	2,491	2,540	2,117
Purchase contracts	**277**	277	-	-	-	-	-
Physical power	**4,600**	2,300	2,300	-	-	-	-
Long-term debt (1)	**289,431**	-	289,431	-	-	-	-
Total commitments	**$318,396**	$8,649	$296,657	$ 4,535	$3,681	$2,728	$2,146

(1) Based on the new credit facility agreement entered into in May 2011 and renewed in November 2011, no principal payments would be required until April 29, 2013.

Off "balance sheet" arrangements – NuVista has certain lease arrangements, all of which are reflected in the contractual obligations and commitments table, which were entered into in the normal course of operations. All leases have been treated as operating leases whereby the lease payments are included in operating expenses or general and administrative expenses depending on the nature of the lease.

Annual financial information – The following table highlights selected annual financial information for the years ended December 31, 2011, 2010 and 2009:

($ thousands, except per share amounts)	**2011**	2010	2009[(1)]
Production revenue	**369,234**	373,327	345,272
Net earnings (loss)	**(143,800)**	(59,655)	2,476
Per share – basic	**(1.47)**	(0.67)	0.03
Per share – diluted	**(1.47)**	(0.67)	0.03
Balance sheet information			
Total assets	**1,373,705**	1,533,824	1,555,743
Long-term debt	**289,431**	438,566	384,623
Shareholders' equity	**755,548**	793,152	919,693

(1) Results are reported in accordance with Previous GAAP.

Quarterly financial information – The following table highlights NuVista's performance for the eight quarterly reporting periods from March 31, 2010 to December 31, 2011:

($ thousands, except	2011				2010			
per share amounts)	**Dec 31**	Sep 30	Jun 30	Mar 31	Dec 31	Sep 30	Jun 30	Mar 31
Production (Boe/d)	**25,306**	25,360	25,488	26,078	28,165	28,244	28,512	28,455
Revenue	**96,578**	88,700	95,719	88,237	89,552	88,733	89,524	105,519
Net earnings (loss)	**(158,462)**	1,807	22,445	(9,590)	(20,965)	(18,194)	(6,417)	(14,079)
Net earnings (loss)								
Per basic share	**(1.59)**	0.02	0.23	(0.10)	(0.24)	(0.21)	(0.07)	(0.16)
Per diluted share	**(1.59)**	0.02	0.23	(0.10)	(0.24)	(0.21)	(0.07)	(0.16)

NuVista has seen production volumes in a range of 25,306 Boe/d to 28,512 Boe/d for the last eight quarters. NuVista's production volumes have declined to 25,306 Boe/d due to lower capital expenditures in 2011, unplanned and planned third-party plant outages resulting in shut-in production and an increased emphasis on oil and liquids-rich natural gas projects which add more value but added Boe/d production more slowly. Over the prior eight quarters, quarterly revenue has been in a range of $88.2 million to $105.5 million with revenue primarily influenced by production volumes and commodity prices in the quarter. Net earnings have been in a range of a net loss of $158.5 million to net earnings of $22.4 million with earnings primarily influenced by impairments, production volumes, gains and losses from disposal of assets, commodity prices and realized and unrealized gains and losses on commodity derivatives.

Reserves – 2011 year end proved reserves were 69.8 MMBoe compared to 74.0 MMBoe at year end 2010. Proved plus probable year end reserves were 110.1 MMBoe compared to 113.1 MMBoe at year end 2010. The difference is primarily due to economic revisions of -2.7 MMBoe in dry gas production properties based on reduced natural gas price forecasts and -1.7 MMBoe of net divestitures, on a proved plus probable basis. Significant momentum is building in NuVista's W6 Montney and W5 Spirit River/Notikewin plays which are expected to result in material increases to proved and proved plus probable reserves bookings, however, year end cut-off phasing has pushed much of this benefit to 2012. In the Wapiti Montney alone, NuVista has only five proved drilling locations and eight probable drilling locations booked to date while resource estimates and well results continue to indicate the potential for over 400 future horizontal locations.

Overall finding and development costs, including revisions and future development capital, were $30.29/Boe for proved reserves and $27.89/Boe for proved plus probable reserves. Excluding revisions, the proved plus probable finding and development costs including future development capital was $20.37/Boe. This resulted in a corporate proved plus probable operating netback recycle ratio of 0.8x or 1.1x excluding revisions. One-time factors affecting these results include the phasing and economic revisions noted above and our corporate netback having a natural gas weighting while our new capital program focuses on oil and liquids-rich natural gas. 2011 play specific recycle ratios for all three key plays range from 1.8x to 2.4x despite the challenging natural gas price environment, illustrating our confidence in their finding and development costs and recycle ratio strength as we move through 2012 and beyond.

The following table outlines NuVista's finding, development and acquisition costs:

	3 Year-Average (1) (2)		**2011 (1) (2)**		2010 (1) (2)	
	Proved	Proved plus probable	**Proved**	**Proved plus probable**	Proved	Proved plus probable
After reserve revisions and including changes in future development capital ($/Boe)						
Finding, development and acquisition cost (3)	18.43	16.27	**27.80**	**28.79**	22.04	18.44
Finding and development costs	22.84	20.51	**30.29**	**27.89**	22.60	19.00
Acquisition/(disposition) costs	11.79	9.52	**(43.01)**	**(24.53)**	15.10	10.66

(1) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during the year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for the year.
(2) Drilling credits of $1.3 million were recorded during 2011 and $17.6 million were recorded in 2010.
(3) Finding, development and acquisition costs have been included in addition to finding and development costs, future acquisition costs can have a significant impact on reserves replacement costs.

Additional reserve disclosure tables, as required under National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101"), will be contained in the Annual Information Form to be filed on SEDAR on or before March 30, 2012. The reserves information set forth in this MD&A are "company interest" reserves. "Company interest" means, in relation to NuVista's interest in reserves, its working interest (operating or non-operating) share before deduction of royalties, plus NuVista's royalty interests in production or reserves. "Company interest" reserves of NuVista may not be comparable to similar measures presented by other issuers, and investors are cautioned that "company interest" reserves should not be construed as an alternative to "gross" or "net" reserves calculated in accordance with NI 51-101. All of NuVista's reserves, as at December 31, 2011, were evaluated by NuVista's independent engineering consultants, GLJ Petroleum Consultants Ltd ("GLJ").

The following table is a reconciliation of the 2011 year end reserves with the reserves reported in the 2010 year end report:

Reconciliation items (1)	Natural gas (Bcf)	Liquids (Mbbls)	Oil (Mbbls)	Total oil equivalent (MBoe)
Total proved				
Balance, December 31, 2010	319.0	8,758	12,077	73,989
Exploration and development	25.4	1,329	1,449	7,014
Technical revisions (including improved recovery)	8.2	469	2	1,843
Economic revisions	(15.0)	(243)	3	(2,739)
Acquisitions	10.9	29	155	1,999
Dispositions	(12.3)	(159)	(789)	(2,999)
Production	(38.1)	(1,086)	(1,900)	(9,328)
Balance, December 31, 2011	298.1	9,097	10,997	69,779
Total proved plus probable				
Balance, December 31, 2010	488.9	13,986	17,602	113,073
Exploration and development	40.1	2,272	2,034	10,995
Technical revisions (including improved recovery)	(0.6)	227	(365)	(250)
Economic revisions	(14.7)	(248)	(13)	(2,713)
Acquisitions	15.2	35	230	2,795
Dispositions	(18.8)	(203)	(1,156)	(4,487)
Production	(38.1)	(1,086)	(1,900)	(9,328)
Balance, December 31, 2011	472.0	14,983	16,432	110,085

(1) Numbers may not add due to rounding.

The estimated net present values of future net revenue before income taxes associated with NuVista's reserves effective December 31, 2011 and based on published GLJ future price forecast as at January 1, 2012 are summarized in the following table:

	Discount factor (%/year)			
Reserves category ($ millions) [1]	0%	5%	10%	15%
Proved:				
Developed producing	1,116	868	714	609
Developed non-producing	166	109	81	64
Undeveloped	265	163	106	72
Total proved	1,547	1,140	901	745
Probable	1,054	591	383	269
Total proved plus probable	2,601	1,731	1,284	1,014

[1] Estimated future net reserves do not represent the fair market value of reserves.

Commodity price forecasts

The following table is a summary of pricing and inflation rate assumptions based on published GLJ forecast prices and costs as at January 1, 2012:

	Natural Gas	Liquids		Oil					
Year	AECO Gas Price ($Cdn/ MMbtu)	Edmonton Propane ($Cdn/Bbl)	Edmonton Butane ($Cdn/Bbl)	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Par Price 40 API ($Cdn/ Bbl)	Hardisty Heavy 12 API ($Cdn/ Bbl)	Cromer Medium 29 API ($Cdn/ Bbl)	Inflation Rates %/ Year [1]	Exchange Rate ($US/$Cdn) [2]
Forecast									
2012	3.49	58.78	76.41	97.00	97.96	72.37	90.12	2.0	0.98
2013	4.13	60.61	78.80	100.00	101.02	73.60	92.94	2.0	0.98
2014	4.59	60.61	78.80	100.00	101.02	74.51	91.93	2.0	0.98
2015	5.05	60.61	78.80	100.00	101.02	74.51	91.93	2.0	0.98
2016	5.51	60.61	78.80	100.00	101.02	74.51	91.93	2.0	0.98
2017	5.97	60.61	78.80	100.00	101.02	74.51	91.93	2.0	0.98
2018	6.21	61.44	79.87	101.35	102.40	75.54	93.18	2.0	0.98
2019	6.33	62.68	81.49	103.38	104.47	77.09	95.07	2.0	0.98
2020	6.46	63.95	83.13	105.45	106.58	78.67	96.99	2.0	0.98
2021	6.58	65.24	84.81	107.56	108.73	80.28	98.85	2.0	0.98
2022	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.98

[1] Inflation rate for costs.
[2] Exchange rate used to generate the benchmark reference prices in this table.

Net asset value per share

($ thousands)	**2011**	2010
Net present value of oil and gas reserves, discounted at 10%, before tax (1) (2)	**$1,284,023**	$1,402,478
Undeveloped land (3)	**120,414**	123,575
Accounts receivable and prepaids	**50,350**	55,144
Accounts payable and accrued liabilities	**(67,710)**	(56,183)
Dividends payable	**-**	(4,438)
Long-term debt	**(289,431)**	(438,566)
Net asset value	**$1,097,646**	$1,082,010
Shares outstanding (000's)	**99,513**	88,760
Net asset value ($/share)	**$ 11.03**	$ 12.19

(1) Proved plus probable company interest reserves, as at December 31, 2011, as evaluated by GLJ.
(2) Estimated future net reserves do not represent the fair market value of reserves.
(3) Undeveloped land value is recorded at the carrying value.

Critical accounting estimates – Management is required to make judgements, assumptions and estimates in applying its accounting policies which have significant impact on the financial results of NuVista. The following outline the accounting policies involving the use of estimates that are critical to understanding the financial condition and results of operations of NuVista.

(a) ***Oil and natural gas reserves*** – 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 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 NuVista's development plans.

(b) ***Exploration and evaluation assets*** – The costs of drilling exploratory wells are initially capitalized as exploration and evaluation ("E&E") assets pending the evaluation of commercial reserves. Commercial reserves are defined as the existence of proved and probable reserves which are determined to be technically feasible and commercially viable to extract. Reserves may be considered commercially producible if management has the intention of developing and producing them based on factors such as project economics, quantities of reserves, expected production techniques, unsuccessful drilling results and estimated production costs and capital expenditures. Once a judgment is made that the reserves are commercially viable, an impairment test is performed prior to the transfer to property, plant and equipment.

(c) ***Development and production assets*** – Once an oil and gas property is transferred to property, plant and equipment, all subsequent development costs are capitalized.

(d) ***Depletion, depreciation, amortization and impairment*** – Property, plant and equipment is measured at cost less accumulated depletion, depreciation, amortization and impairment losses. The net carrying value of property, plant and equipment and estimated future development costs is depleted using the unit-of-production method based on estimated proved and probable reserves. Changes in estimated proved and probable reserves or future development costs have a direct impact in the calculation of depletion expense.

NuVista is required to use judgment when designating the nature of oil and gas activities as exploration and evaluation assets or development and production assets within property, plant and equipment. Exploration and evaluation assets and development and production assets are aggregated into CGUs based on their ability to generate largely independent cash flows. The allocation of NuVista's assets into CGUs requires significant judgment with respect to use of shared infrastructure, existence of active markets for NuVista's products and the way in which management monitors operations.

Exploration and evaluation expenditures relating to activities to explore and evaluate oil and natural gas properties are initially capitalized and include costs associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and testing, directly attributable overhead and administration expenses, and costs associated with retiring the assets. Exploration and evaluation assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined. Technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when proved and/or probable reserves are determined to exist. E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of CGUs, aggregated at the segment level. The determination of the fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and operating costs. Changes in any of these assumptions, such as a downward revision in reserves, decrease in commodity prices or increase in costs, could impact the fair value.

NuVista assesses property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. If any such indication of impairment exists, NuVista performs an impairment test related to the specific CGU. The determination of fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and operating costs. Changes in any of these assumptions, such as a downward revision in reserves, decrease in commodity prices or increase in costs, could impact the fair value.

(e) ***Asset retirement obligations*** – 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 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 expense charged to net 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 consolidated financial statements could be material.

(f) ***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.

(g) ***Financial instruments*** – NuVista utilizes financial instruments to manage the exposure to market risks relating to commodity prices. Fair values of derivative contracts fluctuate depending on the underlying estimate of future commodity prices and foreign currency exchange rates.

(h) ***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 allocated to the individual CGUs that are expected to benefit from the synergies of the business combination. Goodwill is not amortized, however it must be assessed for impairment at least annually or more frequently if events or changes in circumstances indicate that the carrying value may be impaired. To assess for impairment, the carrying amount of each CGU is compared to the recoverable amount. If the carrying amount exceeds the recoverable amount, the associated goodwill is written down with an impairment recognized in net earnings. Goodwill impairments are not reversed. The recoverable amount is the greater of the fair value less costs to sell and its value in use. Fair value less costs to sell is derived by estimating the discounted future net cash flows for the CGU. Discounted future net cash flows are based on forecasted commodity prices and costs over the expected economic life of the proved and probable reserves and discounted using market-based rates. A downward revision in reserves estimates could result in the recognition of a goodwill impairment charge to net earnings.

Update on regulatory matters

Environmental – The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of federal, provincial, and local laws and regulation. Environmental legislation provides for, among other things, restrictions and prohibitions on emissions, releases or spills of various substances produced in association with oil and natural gas operations. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, as well as larger fines and environmental liability. No assurance can be given that the application of environmental laws to the business and operations of NuVista will not result in a limitation of production or a material increase in the costs of operating, development, or exploration activities or otherwise adversely affect NuVista's financial condition, results of operations, or prospects.

NuVista utilizes monitoring and reporting programs, as well as inspections and audits for environmental, health, and safety performance that are designed to provide assurance that environmental and regulatory standards are met. In the event of unknown or unforeseeable environmental impacts arising from its operations, NuVista may be subject to remedial and litigation costs. Contingency plans are in place for a timely response to environmental events and for the utilization of remediation/reclamation strategies to restore the environment in the event of such impacts.

Given the evolving nature of climate change discussion, the regulation of greenhouse gases ("GHGs") and potential federal and provincial GHG commitments, NuVista is currently unable to predict the impact on its operations and financial condition at this time. It is possible that NuVista could face increases in operating and capital costs in order to comply with augmented greenhouse gas emissions legislation.

Further information regarding environmental and climate change regulations, current provincial royalty and incentive programs are contained in our Annual Information Form for the year ended December 31, 2011, to be filed on SEDAR by March 30, 2012, under the Industry Conditions section.

Update on financial reporting matters

Adoption of International Financial Reporting Standards ("IFRS") – NuVista has prepared its December 31, 2011 consolidated financial statements in accordance with IFRS and IFRS 1, "First-time Adoption of International Financial Reporting Standards" as issued by the International Accounting Standards Board. In 2010, NuVista prepared its financial statements in accordance with Previous GAAP. The adoption of IFRS has not had a material impact on NuVista's operations, strategic decisions or cash flows. NuVista's IFRS accounting policies are provided in note 3 to the consolidated financial statements. In addition, note 20 to the consolidated financial statements presents reconciliations between NuVista's 2010 Previous GAAP results and the 2010 IFRS results. The following provides summary reconciliations of NuVista's 2010 Previous GAAP and IFRS results, along with a discussion of the significant IFRS accounting policy changes.

Summary of consolidated statement of financial position reconciliations:

($ millions)	As at January 1, 2010 Previous GAAP	 Effect of transition to IFRS	 IFRS
Assets			
Current assets	$ 70	$ (1)	$ 69
Exploration and evaluation assets	-	128	128
Property, plant and equipment	1,402	(128)	1,274
Goodwill	83	(19)	64
Total assets	$1,555	$ (20)	$1,535
Liabilities and shareholders' equity			
Current liabilities	$ 55	$ -	$ 55
Long-term debt	385	-	385
Compensation liabilities	1	-	1
Asset retirement obligations	61	57	118
Deferred tax liabilities	134	(16)	118
Shareholders' equity	919	(61)	858
Total liabilities and shareholders' equity	$1,555	$ (20)	$1,535

($ millions)	As at December 31, 2010 Previous GAAP	 Effect of transition to IFRS	 IFRS
Assets			
Current assets	$ 56	$ (1)	$ 55
Exploration and evaluation assets	-	142	142
Property, plant and equipment	1,458	(155)	1,303
Goodwill	83	(49)	34
Total assets	$1,597	$ (63)	$1,534
Liabilities and shareholders' equity			
Current liabilities	$ 62	$ -	$ 62
Long-term debt	438	-	438
Commodity derivative liabilities	4	-	4
Compensation liabilities	1	-	1
Asset retirement obligations	63	65	128
Deferred tax liabilities	129	(21)	108
Shareholders' equity	900	(107)	793
Total liabilities and shareholders' equity	$1,597	$ (63)	$1,534

Summary of net earnings (loss) reconciliation:

	2010				
($ millions)	Annual	Q4	Q3	Q2	Q1
Net earnings (loss) as reported under Previous GAAP	$(14)	$(14)	$ (5)	$(1)	$ 6
Addition (deduction) to net earnings:					
Depletion, depreciation, amortization and impairment	(5)	5	(10)	(2)	2
Goodwill impairments	(29)	(8)	-	(1)	(20)
Exploration and evaluation	(17)	(8)	(6)	(2)	(1)
Gain on property dispositions	5	5	-	-	-
Accretion	(4)	(1)	(1)	(1)	(1)
Deferred income taxes	5	-	4	1	-
Net earnings (loss), as reported under IFRS	$(59)	$(21)	$(18)	$(6)	$(14)

Accounting policy changes

The following discussion explains the significant differences between NuVista's Previous GAAP accounting policies and those applied by NuVista under IFRS. IFRS policies have been retrospectively and consistently applied except where specific IFRS 1 optional and mandatory exemptions permitted an alternative treatment upon transition to IFRS for first-time adopters.

- Property, Plant and Equipment ("PP&E") – IFRS 1 provides the option to value PP&E assets in the Exploration and Evaluation ("E&E") phases and Development and Production ("D&P") phases at their deemed cost, defined as carrying amount assigned to these assets under Previous GAAP at the date of transition, January 1, 2010. This election is permissible for entities, such as NuVista, who currently follow the full cost accounting guideline, as established by the Canadian Institute of Chartered Accountants ("CICA"), which accumulates all oil and gas assets into one cost centre. Under IFRS, NuVista's PP&E assets in the D&P phases are allocated to the area level and CGUs. The deemed cost of NuVista's PP&E assets has been allocated to the CGUs based on proved and probable reserve values.

- Re-classification of E&E expenditures from PP&E – Under IFRS, E&E expenditures are those costs for an area where technical feasibility and commercial viability has not yet been determined. E&E expenditures were deemed to be $128.2 million as at January 1, 2010, representing the book value of undeveloped land that relates to exploration properties and other exploration related activities under Previous GAAP. This resulted in a reclassification of $128.2 million from PP&E to E&E assets in the January 1, 2010 opening statement of financial position prepared under IFRS. At December 31, 2010, the E&E asset balance was $141.9 million. E&E assets will not be depleted and must initially be assessed for impairment upon transition and subsequently when indicators suggest the possibility of impairment. Unsuccessful E&E costs and costs incurred prior to obtaining the legal right to explore are expensed to net earnings. Under Previous GAAP, exploration and evaluation costs were capitalized as property, plant and equipment in accordance with the CICA's full cost accounting guidelines where all costs directly associated with the acquisition of, the exploration for, and the development of oil and natural gas reserves were capitalized into one cost centre and depleted over the life of the reserves.

- Impairment of PP&E assets – Under IFRS, areas are aggregated into CGUs based on their ability to generate largely independent cash flows. If the carrying values of the CGU exceeds the recoverable amount, the CGU is written down with an impairment loss recognized in depletion, depreciation, amortization and impairment expense in net earnings. The recoverable amount is determined to be the higher of fair value less costs to sell and value in use. Impairments are reversed when there has been a subsequent increase in the recoverable amount. Impairment reversals are recognized in net earnings and the carrying amount of the CGUs is increased to its revised recoverable amount, net of any depletion that would have been charged as if no impairment loss had previously been recorded. Under Previous GAAP, an impairment was recognized if the carrying amount exceeded the sum of the undiscounted cash flows from proved reserves and the value of unproved properties. If impairment is indicated, then the discounted cash flows are prepared to quantify the amount of impairment. Impairments recognized under Previous GAAP were not reversed. For the year ended December 31, 2010, NuVista recognized an impairment loss of $23.8 million under IFRS. The carrying value exceeded the recoverable amount, determined to be fair value less costs to sell based on discounted future cash flows of proved and probable reserves using forecast prices and costs. Under Previous GAAP, these assets were included in one cost centre ceiling test, which was not impaired at December 31, 2010.

- Impairment of goodwill – Under IFRS, goodwill that arises from a business combination is allocated to the specific CGUs that are expected to benefit from the business combination. To test for impairment of goodwill, the carrying amount of the CGU including goodwill is compared to the recoverable amount of the CGU, which is determined to be the higher of fair value less costs to sell and value in use. The fair value less costs to sell was determined using discounted future cash flows of proved and probable reserves using forecast prices and costs. If the carrying value exceeds the recoverable amount, an impairment loss is recognized in net earnings. Impairments recognized on goodwill are not reversed. Under Previous GAAP, goodwill impairment was calculated at the operating segment level (being the company level). Goodwill was not impaired under the Previous GAAP at December 31, 2010. At January 1, 2010 and for the year ended December 31, 2010, NuVista recognized goodwill impairment loss of $19.4 million and $29.8 million respectively under IFRS.

- Depletion, depreciation, amortization and impairment expense – Under IFRS, development and production costs are depleted using the unit-of-production method calculated at the area level. The IFRS 1 exemption permitted NuVista to allocate development and production costs to the area level using proved and probable reserve values as at January 1, 2010. Depleting at an area level under IFRS resulted in an $18.7 million decrease to depletion, depreciation, amortization and impairment expense, for the year ended December 31, 2010.

- Asset retirement obligations – At transition to IFRS, as part of electing the IFRS 1 exemption, NuVista was required to remeasure its asset retirement obligation and recognize the difference in retained earnings. This resulted in a $57.0 million increase to the asset retirement obligation at January 1, 2010. Subsequent adjustments to the obligation are made to property, plant and equipment. Under IFRS, NuVista is required to revalue its entire asset retirement obligation at the end of each reporting period using a risk free rate. Under Previous GAAP, the obligation is initially discounted at a credit adjusted risk free rate. Once recorded, the asset retirement obligations were not adjusted for future changes in discount rate. As at December 31, 2010, NuVista's asset retirement obligation was $128.3 million under IFRS. An average risk free discount rate of 3.52% was used at December 31, 2010 based on the Government of Canada 30 year bond yield.

- Deferred income taxes – Deferred income taxes have been adjusted to reflect the tax effect arising from the differences between IFRS and Previous GAAP. For the year ended December 31, 2010, the application of the IFRS adjustments discussed above resulted in $5.6 million reduction in the deferred income tax expense with a corresponding decrease to the deferred income tax liability.

Future accounting changes

As of January 1, 2013, NuVista will be required to adopt the following standards as issued by the IASB ("International Accounting Standards Board"). NuVista is evaluating the impact that these standards may have on our results of operations and financial position.

- IFRS 10, "Consolidated Financial Statements" – In May 2011, the IASB issued IFRS 10 which is the IASB's project to replace Standing Interpretations Committee 12, "Consolidation – Special Purpose Entities" and the consolidation requirements of IAS 27, "Consolidated and Separate Financial Statements". The new standard eliminates the current risk and rewards approach and established control as the single basis for determining the consolidation of an entity.

- IFRS 11, "Joint Arrangements" – In May 2011, the IASB issued IFRS 11 to replace IAS 131, "Interest in Joint Ventures". The new standard redefines joint operations and joint ventures and requires joint operations to be proportionately consolidated and joint ventures to equity accounted. Under IAS 31, joint ventures could be proportionately accounted.

- IFRS 12, “Disclosure of Interests in Other Entities” – In May 2011, the IASB issued IFRS 12 which outlines the required disclosures for interests in subsidiaries and joint arrangements. The new disclosures require information that will assist financial statement users to evaluate the nature, risks and financial effects associated with an entity’s interests in subsidiaries and joint arrangements.

- IFRS 13, “Fair Value Measurement” – In May 2011, the IASB issued IFRS 13 which provides a common definition of fair value, establishes a framework for measuring fair value under IFRS and enhances the disclosures required for fair value measurements. The standard applies where fair value measurements are required and does not require new fair value measurements.

As of January 1, 2015, NuVista will be required to adopt IFRS 9, “Financial Instruments”. The IASB issued IFRS 9, which is the first phase of the IASB’s project to replace IAS 39, “Financial Instruments: Recognition and Measurement”. The new standard replaces the current multiple classification and measurement models for financial asset and liabilities with a single model that has only two classification categories: amortized cost and fair value. Portions of the standard remain in development and the full impact of the standard on the NuVista’s consolidated financial statements will not be known until the project is complete.

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 controls 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 required to be disclosed by NuVista in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by NuVista in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to NuVista’s management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure. The CEO and CFO have concluded, based on their evaluation as of the end of the period covered by the annual filings that the Company’s disclosure controls and procedures are effective to provide reasonable assurance that material information related to NuVista, is made known to them by others within the Company.

The CEO and CFO have also designed internal controls over financial reporting, or caused them to be designed under their supervision, to provide reasonable assurance regarding the reliability of NuVista’s financial reporting and the preparation of financial statements for external purposes in accordance with GAAP and includes those policies and procedures that: (a) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of NuVista; (b) are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of the consolidated financial statements in accordance with GAAP, and that receipts and expenditures of NuVista are being made only in accordance with authorizations of management and directors of NuVista; and (c) are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of NuVista’s assets that could have a material effect on the annual consolidated financial statements or interim consolidated financial statements. NuVista has designed its internal controls over financial reporting based on the framework in “Internal Control Over Financial Reporting – Guidance for Smaller Public Companies” issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). During the quarter and year ended December 31, 2011, there have been no changes to NuVista’s internal controls over financial reporting that have materially or are reasonably likely to materially affect the internal controls over financial reporting; the CEO and CFO have concluded that the internal controls over financial reporting are effective.

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 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;
- 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; and
- Labour risks related to availability, productivity and retention of qualified personnel.

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.

Information regarding risk factors associated with the business of NuVista and how NuVista seeks to mitigate these risks will be contained in our Annual Information Form under the Risk Factors Section for the year ended December 31, 2011.

OUTLOOK

In early 2012, we have seen natural gas prices continue to decline due to a warm winter and an oversupply of natural gas in North America. With the outlook for continued low natural gas prices over the near term, NuVista is carefully evaluating its business to preserve value and ensure a sustainable model without jeopardizing its financial flexibility and its advancement of long term growth opportunities in the W5 Spirit River/Notikewin and W6 Wapiti Montney plays. NuVista expects to limit 2012 capital spending to funds from operations and proceeds from non-core divestitures, however second half 2012 spending levels will be determined at the end of the second quarter of 2012 after reviewing the results of our Montney program and divestiture proceeds. As of the date of this press release, NuVista has disposed of non-core Pembina Cardium and other assets for approximately $14 million since December 2011 so this process is well advanced. NuVista will be pursuing additional non-core dispositions of assets throughout 2012 where retention values can be realized, creating additional financial flexibility to fund the areas of key focus for the company. NuVista will remain flexible to accelerate spending in areas where recent success has been realized subject to some of the various funding catalysts being contemplated.

For now, NuVista's operating and financial guidance for the first half of 2012 remains unchanged with a capital budget of between $70 million and $80 million and average production within the previous guidance range of 24,500 Boe/d to 25,500 Boe/d. Given the tremendous drilling results experienced over the past several months, NuVista expects that this range of production can be achieved. Funds from operations for the first half of 2012 are forecast at between $45 million and $50 million based on a forecast AECO natural gas price of $2.40/Mcf and WTI oil price of US$103/Bbl. The capital budget is planned to modestly exceed funds from operations in the first half of 2012 due to the busy winter drilling season however, as mentioned earlier, proceeds of asset dispositions are expected to make up any cash flow shortfall with $14 million already achieved to date.

Despite the weak natural gas price environment, NuVista is confident that its disciplined deployment of capital on its material key plays, while maintaining a prudent focus on the balance sheet, will result in shareholder value creation over the long term. With a talented and motivated workforce and a revised business strategy focused on discipline, execution and profitability, we look forward to updating you on the progress in this value creation process as we move through 2012.