BONAVISTA ENERGY TRUST

ANNUAL REPORT 2009

Highlights

	Three months ended December 31, 2009	Three months ended December 31, 2008	Years ended December 31, 2009	Years ended December 31, 2008
Financial				
($ thousands, except per unit)				
Production revenues	232,870	221,782	759,423	1,234,391
Funds from operations (1)	135,534	131,741	447,743	643,876
Per unit (1) (2)	0.93	1.12	3.46	5.64
Distributions declared	59,783	85,824	217,965	332,540
Per unit	0.48	0.90	2.00	3.60
Percentage of funds from operations (1)	44%	65%	49%	52%
Net income	39,647	129,192	106,606	438,366
Per unit (2)	0.27	1.09	0.82	3.84
Adjusted net income (3)	56,588	61,326	169,767	351,252
Per unit (2)	0.39	0.52	1.31	3.08
Total assets			3,092,129	2,543,240
Long-term debt, including working capital deficiency(4)			881,169	600,518
Long-term debt, net of adjusted working capital (3)(4)			874,409	654,500
Unitholders' equity			1,723,583	1,411,972
Capital expenditures:				
Exploration and development	62,044	60,236	203,845	305,514
Acquisitions, net	13,172	(105)	629,999	176,783
Weighted average outstanding equivalent trust units: (thousands) (2)				
Basic	146,019	118,065	129,263	114,190
Diluted	148,035	119,905	131,233	116,468
Operating				
(boe conversion – 6:1 basis)				
Production:				
Natural gas (mmcf/day)	222	171	191	175
Oil and liquids (bbls/day)	24,849	24,733	23,484	24,079
Total oil equivalent (boe/day)	61,832	53,288	55,299	53,190
Product prices: (5)				
Natural gas ($/mcf)	4.84	7.52	4.78	8.30
Oil and liquids ($/bbl)	62.79	53.05	58.18	70.68
Operating expenses ($/boe)	9.04	9.91	9.80	9.45
General and administrative expenses ($/boe)	0.92	0.78	0.89	0.74
Cash costs ($/boe) (6)	10.74	11.87	11.38	11.87
Operating netback ($/boe) (7)	25.53	28.83	23.77	35.49

Highlights (cont'd)	December 31, 2009	2008
Drilling (gross wells)	114	200
Natural gas	57	84
Oil	55	106
Average success rate	98%	95%
Reserves: [8]		
Proved:		
Natural gas (bcf)	732.2	462.6
Oil and liquids (mbbls)	71,722	65,044
Total oil equivalent (mboe)	193,750	142,150
Proved and probable:		
Natural gas (bcf)	1,039.2	613.7
Oil and liquids (mbbls)	99,419	88,817
Total oil equivalent (mboe)	272,617	191,095
% Proved producing	46%	59%
% Proved	71%	74%
% Probable	29%	26%
Net present value of future cash flow before income taxes ($ millions):		
0% discount rate	9,676	7,465
5% discount rate	6,497	4,804
10% discount rate	4,876	3,555
Reserve life index (years):		
Proved	8.6	7.4
Proved and probable	11.5	9.4
Finding, development and acquisition costs – proved and probable ($/boe):		
Including changes in future development expenditures	12.01	19.11
Excluding changes in future development expenditures	8.20	15.50
Recycle ratio – proved and probable: [9]		
Including changes in future development expenditures	2.0	1.9
Excluding changes in future development expenditures	2.9	2.3

Trust Unit Trading Statistics	Three months ended December 31, 2009	September 30, 2009	June 30, 2009	March 31, 2009
($ per unit, except volume)				
High	24.00	21.89	19.95	18.93
Low	19.86	16.64	14.84	11.74
Close	22.30	20.42	18.04	15.30
Average Daily Volume - Units	314,701	566,846	231,577	306,298

NOTES:

(1) Management uses funds from operations to analyze operating performance, distribution coverage and leverage. Funds from operations as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculations 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, net income 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 unit is calculated based on the weighted average number of units outstanding consistent with the calculation of net income per unit.

(2) Basic per unit calculations include exchangeable shares which are convertible into trust units on certain terms and conditions.

(3) Amounts have been adjusted to exclude unrealized gains or losses on financial instruments and its related tax impact.

(4) Amounts exclude convertible debentures.

(5) Product prices include realized gains or losses on financial instruments.

(6) Cash costs equal the total of operating, general and administrative, and financing expenses.

(7) Operating netback equals production revenues including realized gains or losses on financial instruments, less royalties, transportation and operating expenses, calculated on a boe basis.

(8) Company interest reserves are working interest reserves prior to deduction of royalties and includes any royalty interests of the Company.

(9) Recycle ratio is calculated using operating netback per boe divided by finding, development and acquisitions costs per boe.

MESSAGE TO UNITHOLDERS

Bonavista Energy Trust ("Bonavista" or the "Trust") is pleased to report to its unitholders (the "Unitholders") its consolidated financial and operating results for the year ended December 31, 2009. Throughout the year, Bonavista continued its transition towards 2011 when the trust taxation rules change by upgrading our asset and opportunity base while continuing to focus on optimizing production and revenues at the lowest possible cost. This consistent effort has resulted in excellent operational and healthy financial results for the year and provides us with tremendous confidence heading into 2010.

Bonavista's determination to position our organization for long term growth and profitability resulted in the completion of a significant acquisition, at an opportune time, as signs of a recovering global economy began to emerge. On August 20, 2009, Bonavista completed the acquisition of certain long-life, liquids rich natural gas weighted properties located in its Western Region (the "Acquired Properties") for a cash purchase price of $698 million. In conjunction with this acquisition, Bonavista completed equity and bank financings and a property disposition of our entire southeast Saskatchewan assets. Details of all of these activities are as follows:

a) **Acquisition** - The acquisition is consistent with Bonavista's strategy of acquiring high quality, long-life oil and natural gas assets with significant low-risk development potential at opportunistic times in the cycle. The Acquired Properties are characterized by high working interests and operatorship with extensive underutilized gathering and processing infrastructure that result in low operating costs and accommodate efficient production additions. This area is characterized as one of the most prolific multi-zone regions in western Canada with a minimum of twelve different producing horizons available to pursue. Both production and reserves have grown by approximately 25% since acquiring the property. We have drilled 17 horizontal wells focusing primarily on the Glauconite Hoadley trend and have identified 230 horizontal drilling locations within numerous formations on the Acquired Properties.

b) **Financing** - The cash to close the acquisition was funded through a combination of bank debt and an issuance of units. Bonavista issued 25 million units at a price of $16.85 per unit for gross proceeds of approximately $421.3 million. In addition, Bonavista increased the bank facilities by $400 million with the current members of its banking syndicate having the same maturity and financial covenants of its existing bank credit facility. This provides Bonavista with $1.4 billion of total bank credit facilities to fund its ongoing capital programs.

c) **Disposition** - On August 31, 2009, Bonavista closed the disposition of its southeast Saskatchewan assets to Legacy Oil and Gas Inc. ("Legacy", formerly Glamis Resources Ltd.), for cash consideration of $98.7 million and approximately 650,000 common shares of Legacy. The rationale for this disposition was as follows:

- Bonavista received an attractive purchase price with equity upside in a high-growth company;
- The size of our southeastern Saskatchewan assets were less than 2% of our overall operations and the area had become extremely competitive making it difficult to expand operations significantly;
- Created an opportunity for Bonavista to focus both human and capital resources in areas of greater presence and higher impact, generating superior returns over the long term; and
- The assets were better suited to a junior oil and natural gas company with plans to aggressively accelerate capital investment to achieve significant growth objectives.

Further accomplishments for Bonavista in 2009 include:

- Operationally, production volumes averaged a record level of 55,299 boe per day during 2009, versus 53,190 boe per day in 2008, an increase of 4% year over year;

- Increased proved and probable reserves by 43% to 272.6 mmboe while spending 186% of funds from operations on all investment activities. The following attractive key reserve metrics were achieved:
  - Added 101.7 mmboe of proved and probable reserves, which replaced 500% of 2009 annual production;
  - Improved the Trust's proved and probable reserve life index to 11.5 years from 9.4 years in 2008 and increased the Trust's proven reserve life index to 8.6 years from 7.4 years in 2008;
  - Achieved attractive finding, development and acquisition costs, including changes in future development expenditures, of $15.83 per boe on a proved basis ($11.62 per boe excluding changes in future development expenditures) and $12.01 per boe on a proved and probable basis ($8.20 per boe excluding changes in future development expenditures);
  - Attained a 2009 proved and probable operating netback recycle ratio of 2.0:1 as a result of this level of finding, development and acquisition costs, including future development capital;
  - Increased proven and probable future development capital by 121% to $710.0 million representing the significant development and growth potential yet to be realized on our asset base;

- Maintained a conservative exploration and development program in 2009 investing $203.8 million compared to $305.5 million in the same period of 2008 by drilling 114 wells with an overall 98% success rate. We spent an additional $630.0 million, net of dispositions, on 20 synergistic property transactions within our core regions, one of which was our transformational Hoadley acquisition. Collectively, our drilling inventory has grown by approximately 40% with a significant enhancement in quality throughout 2009;

- Drilled 57 successful horizontal wells, on 13 different play types within our existing core regions. Sixteen of these wells were drilled on our highly prospective Hoadley Glauconite trend in our Western Region. These sixteen wells have collectively added over 9,000 boe per day in their first month of production at an average cost of approximately $2.7 million per well. Since inception, we have drilled 27 horizontal Glauconite wells, of which 21 have been brought on production and six wells are awaiting completion and tie-in. Eleven of these wells have been on production for greater than six months and their average rate over the first six months of production is in excess of 300 boe per day per well. Bonavista believes that our Glauconite horizontal development program continues to compete with the top tier resource developments in North America;

- Continued to participate at Crown land sales and freehold purchases, investing $20.4 million in land activity, further enhancing our future drilling prospect inventory for several years. Bonavista has 1.3 million net acres of undeveloped land holdings as at December 31, 2009;

- Generated funds from operations of $447.7 million ($3.46 per unit) for the year ended December 31, 2009 and $135.5 million ($0.93 per unit) for the fourth quarter of 2009. Of the total funds from operations generated in the respective periods, Bonavista distributed 49% of these funds for the year ended December 31, 2009 and 44% of these funds in the fourth quarter to Unitholders with the remaining funds reinvested in the business to continue growing our production base;

- Continued to record attractive levels of profitability for the fourth quarter and year ended December 31, 2009 with a return on equity of 13% and 11% respectively after adjusting net income to negate the impact of unrealized gains or losses on financial instruments and its related tax impact, and recorded an adjusted net income to funds from operations ratio of 42% for the fourth quarter of 2009 and 38% for the year ended December 31, 2009;

- Since inception as a Trust, Bonavista has delivered cumulative distributions of $1.7 billion or $21.11 per unit. These cumulative distributions are in excess of our closing price of $16.00 per unit on the first trading day after becoming an energy trust on July 2, 2003 and exceeds our initial market capitalization of $1.6 billion.

Strengths of Bonavista Energy Trust

Upon restructuring from an exploration and production corporation into an energy trust in July 2003, Bonavista employed the same strategy that resulted in our tremendous success between 1997 and 2003. We have maintained a high level of investment activity on our asset base, increasing current production by almost 80% since 2003. This activity stems from the operational and technical focus of our Trust, the attention to detail, and the ability to continuously generate economic prospects on our asset base within the Western Canadian Sedimentary Basin. Our experienced technical teams have a solid understanding of our assets and they continue to exercise the discipline and commitment required to deliver long-term profitable results to our Unitholders. We actively participate in undeveloped land acquisitions through Crown land sales, property purchases and farm-in opportunities, which have all enhanced the quality and quantity of our extensive low-risk drilling inventory. These activities have led to low cost reserve additions, lengthening of our reserve life index, a significant increase in our drilling inventory and a growing production base. Our production base, including the recently closed property transactions, is weighted 61% in favour of natural gas and 39% towards oil and liquids and is geographically focused within select, multi-zone regions primarily in Alberta and British Columbia. The low cost structure of our asset base maintains attractive operating netbacks in most operating environments. In addition, the high working interest asset base is predominantly operated by Bonavista, providing control over the pace of operations and ensuring that operating and capital cost efficiencies are realized.

Our team brings a successful track record of executing low to medium risk development programs, including both asset and corporate acquisitions, along with a solid track record of sound financial management. Despite its size, the recently announced acquisition has been integrated quickly and efficiently into our base of operations due to the concentrated nature of the assets and our existing presence in the area. Our management team and Board of Directors possess extensive experience in the oil and natural gas business, navigating successfully through many different economic cycles utilizing a proven strategy consisting of strict cost controls and prudent financial management. Directors, management and employees also own approximately 16% of the Trust after giving effect to the recent financing, resulting in a close alignment of interests with all Unitholders.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") of the financial condition and results of operations should be read in conjunction with Bonavista Energy Trust's ("Bonavista" or the "Trust") audited consolidated financial statements and MD&A for the year ended December 31, 2009. The following MD&A of the financial condition and results of operations was prepared at, and is dated March 4, 2010. Our audited consolidated financial statements, Annual Report, and other disclosure documents for 2009 will be available on or before March 31, 2010 through our filings on SEDAR at www.sedar.com or can be obtained from Bonavista's website at www.bonavistaenergy.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. A boe may be misleading, particularly if used in isolation. A boe conversion of 6 Mcf to one barrel is based on an energy equivalent 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, including management's assessment of Bonavista's future plans and operations, contains forward-looking statements including; (i) forecasted capital expenditures; (ii) exploration, drilling and development plans and prospects; (iii) anticipated production rates; (iv) expected royalty rate; (v) annualized debt to funds from operations; (vi) funds from operations, (vii) anticipated operating and service costs; (viii) expected service agreement fees; (ix) expected finding and development costs; (x) expected on-stream costs; (xi) our financial strength; (xii) incremental development opportunities, 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 Bonavista's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, changes in environmental tax and royalty legislation, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. 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. Bonavista'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 Bonavista will derive there from. Bonavista 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. Investors are also cautioned that cash-on-cash yield represents a blend of return of an investor's initial investment and a return on investors' initial investment and is not comparable to traditional yield on debt instruments where investors are entitled to full return of the principal amount of debt on maturity in addition to a return on investment through interest payments.*

Non-GAAP Measurements *- Within Management's discussion and analysis, references are made to terms commonly used in the oil and natural gas industry. Management uses "funds from operations" and the "ratio of debt to 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, net income 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 abandonment expenditures. Funds from operations per unit is calculated based on the weighted average number of trust units outstanding consistent with the calculation of net income per unit. Operating netbacks equal production revenue and realized gains or losses on financial instruments, less royalties, transportation and operating expenses calculated on a boe basis. Total boe is calculated by multiplying the daily production by the number of days in the period. Management uses these terms to analyze operating performance and leverage.*

Operations - Bonavista's exploration and development program for the year ended December 31, 2009 led to the drilling of 114 wells within our core regions with an overall success rate of 98%. This program resulted in 57 natural gas wells and 55 oil wells. Bonavista continues to shift toward higher impact drilling opportunities focusing on unconventional resource development through the use of horizontal drilling and multi-stage fracture stimulation technology. As a result, 50% of our wells drilled in 2009 were horizontal in nature. More specifically, operations in our Western region have resulted in superior capital efficiencies driven off of strong production performance, healthy reserve additions and a disciplined approach to spending with every well drilled. These activities, along with our significant third quarter acquisition, continue to enhance the predictability in our overall production base in addition to lengthening our reserve life index ("RLI") to approximately 11.5 years.

Reserves - Reserve estimates have been calculated in compliance with the National Instrument 51-101 Standards of Disclosure (“NI 51-101”). Under NI 51-101, proved reserves are defined as reserves that can be estimated with a high degree of certainty to be recoverable with a target of a 90% probability that the actual reserves recovered over time will equal or exceed proved reserve estimates, while probable reserves are defined as having an equal (50%) probability that the actual reserves recovered will equal or exceed the proved and probable reserve estimates. In accordance with NI 51-101, proved undeveloped reserves have been recognized in cases where plans are in place to bring the reserves on production within a short, well defined time frame. Proved undeveloped reserves often involve infill drilling into existing pools. Of the net present value of the Trust's reserves, 88% were evaluated by independent third party engineers, GLJ Petroleum Consultants Ltd. ("GLJ") and Ryder Scott Company Canada in their reports dated February 23, 2010 and February 11, 2010, respectively. The balance of approximately 12% of proved and probable net present value reserves were evaluated internally and reviewed by GLJ. The reserve estimates contained in the following tables represent Bonavista’s gross trust reserves as at December 31, 2009:

Trust Reserves(1):	Natural Gas (MMcf)	Light and Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Total Reserves(2) (Mboe)
Proved:					
Proved producing	454,249	25,185	5,436	18,774	125,103
Proved non-producing	38,361	1,009	1,865	1,346	10,613
Proved undeveloped	236,577	6,031	302	11,708	57,471
Total proved	729,187	32,225	7,604	31,828	193,187
Probable	306,299	10,386	3,098	14,192	78,725
Total proved and probable	**1,035,487**	**42,611**	**10,701**	**46,019**	**271,913**
Proved reserve life index, years(3)					**8.6**
Proved and probable reserve life index, years(3)					**11.5**

(1) Trust working interest reserves before royalties, boe (6:1), based on the February 23, 2010, GLJ reserve estimates based on forecast prices and costs as of January 1, 2010.
(2) Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6Mcf:1bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
(3) Calculated based on the amount for the relevant reserve category divided by the 2010 production forecast.

Reserve Reconciliation:	Proved (Mboe)	Probable (Mboe)	Proved and Probable Mboe)
Balance, December 31, 2008	141,441	48,799	190,240
Extensions and improved recovery	15,061	6,738	21,799
Technical revisions	295	(4,098)	(3,803)
Acquisitions	60,249	29,421	89,670
Dispositions	(3,517)	(2,066)	(5,583)
Economic factors	(190)	(68)	(258)
Production	(20,152)	-	(20,152)
Balance, December 31, 2009	**193,187**	**78,726**	**271,913**

Bonavista's 2009 year-end proved reserves totalled 193.2 mmboe, a 37% increase compared to the 141.4 mmboe at the year-end of 2008. Furthermore, Bonavista's proved and probable reserves increased by 43% to 271.9 mmboe when compared to the 190.2 mmboe at year-end 2008. The Trust had proved and probable negative reserve revisions of 3.8 mmboe which were primarily related to performance issues at four properties in British Columbia and three heavy oil properties in Alberta.

Proved and Probable Finding, Development and Acquisition Costs (1):	2009	2008	2007
Total capital expenditures ($ millions)	833.84	482.30	366.36
Total capital expenditures plus change			
in forecast future development costs ($ millions)	1,221.78	594.41	390.27
Proved and probable reserves (Mboe):			
Opening balance	190,240	178,575	173,959
Discoveries and extensions	21,799	23,861	15,798
Acquisitions and dispositions	84,087	10,373	8,211
Revisions and economic factors	(4,061)	(3,410)	(272)
Production	(20,152)	(19,159)	(19,121)
Closing balance	271,913	190,240	178,575
Proved and probable FD&A costs ($/boe) (2)	12.01	19.11	15.91
Proved and probable three-year FD&A costs ($/boe) (2)	15.68	16.77	14.78

(1) The aggregate of the exploration, development and acquisition costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.
(2) Amounts are calculated including the change in future development costs.

Finding, development and acquisition costs in 2009, including changes in future capital expenditures, amounted to $15.83 per boe ($11.62 per boe before changes in future capital expenditures) on a proved basis and $12.01 per boe ($8.20 per boe before changes in future capital expenditures) on a proved and probable basis.

Capital Efficiency:	2009	2008	2007	Three-Year Average
Operating netback ($/boe) (1)	23.77	35.49	28.77	29.34
Total capital expenditures				
(excluding future development costs)				
Proved and probable FD&A costs ($/boe) (2)	8.20	15.50	14.94	12.88
Recycle ratio (3)	2.9	2.3	1.9	2.3
Total capital expenditures				
(including future development costs)				
Proved and probable FD&A costs ($/boe)	12.01	19.11	15.91	15.68
Recycle ratio (3)	2.0	1.9	1.8	1.9

(1) Operating netback is calculated using production revenues including realized gains or losses on financial instruments less royalties, transportation and operating costs calculated on a per barrel of oil equivalent basis.
(2) FD&A costs take into account reserve revisions during the year on a per barrel of oil equivalent basis (6:1)
(3) Recycle ratio is defined as operating netback per barrel of oil equivalent divided by finding, development and acquisition costs on a per barrel of oil equivalent.

Bonavista generated attractive recycle ratios of 2.0:1 for proved and probable reserves and 1.5:1 for proved reserves which includes revisions and changes in future development expenditures; excluding changes in future development expenditures, the proved and probable recycle ratio improved to 2.9:1 and the proved recycle ratio improved to 2.0:1. Additional reserves disclosure tables, as required under NI 51-101, are contained in Bonavista's Annual Information Form that will be filed on SEDAR.

Financial and operating highlights - The following is a summary of key financial and operating results for the respective periods noted:

	Three months ended December 31,		Years ended December 31,	
	2009	**2008**	**2009**	**2008**
($ thousands, except per boe/Trust Unit Amounts and where noted)				
Product prices:				
Natural gas ($/mcf)	4.84	7.52	4.78	8.30
Oil and liquids ($/bbl)	62.79	53.05	58.18	70.68
Production:				
Natural gas (mmcf/d)	222	171	191	175
Oil and liquids (bbls/d)	24,849	24,733	23,484	24,079
Total production (boe/d)	61,832	53,288	55,299	53,190
Production revenues	232,870	221,782	759,423	1,234,391
per boe	40.94	45.24	37.62	63.41
Royalties	36,347	39,801	117,217	239,967
per boe	6.39	8.12	5.81	12.33
% of Production revenues	15.6%	17.9%	15.4%	19.4%
Operating expenses	51,407	48,603	197,795	184,053
per boe	9.04	9.91	9.80	9.45
Transportation expenses	9,435	9,589	36,833	38,744
per boe	1.66	1.96	1.82	1.99
General and administrative expenses	5,227	3,825	17,900	14,410
per boe	0.92	0.78	0.89	0.74
Financing expenses	4,456	5,761	14,035	32,535
per boe	0.78	1.18	0.70	1.67
Funds from operations	135,534	131,741	447,743	643,876
per boe	23.83	26.87	22.18	33.07
per unit – basic	0.93	1.12	3.46	5.64
Unit-based compensation	2,939	4,694	11,386	11,049
per boe	0.52	0.96	0.56	0.57
Depreciation, depletion and accretion	85,229	69,000	295,296	266,271
per boe	14.99	14.07	14.63	13.68
Income taxes (reduction)	(15,825)	23,324	(52,627)	49,451
per boe	(2.78)	4.76	(2.61)	2.54
Net income	39,647	129,192	106,606	438,366
per boe	6.97	26.35	5.28	22.52
per unit – basic	0.27	1.09	0.82	3.84
Distributions declared	59,783	85,824	217,965	332,540
per unit	0.48	0.90	2.00	3.60

Production - For the year ended December 31, 2009, production increased 4% to 55,299 boe per day when compared to 53,190 boe per day for the same period a year ago. Natural gas production increased 9% to 191 mmcf per day in 2009 from 175 mmcf per day for the same period a year ago, while total oil and liquids production decreased 2% to 23,484 bbls per day in 2009 from 24,079 bbls per day for the same period in 2008. For the fourth quarter of 2009, production increased 16% to a record 61,832 boe per day when compared to 53,288 boe per day for the same period a year ago. Natural gas production increased 30% to 222 mmcf per day in the fourth quarter of 2009 from 171 mmcf per day for the same period a year ago, while total oil and liquids production increased slightly to 24,849 bbls per day in the fourth quarter of 2009 from 24,733 bbls per day for the same period in 2008.

The following table highlights Bonavista's production by product for the three months and year ended December 31:

	Three months ended December 31,		**Year ended December 31,**	
	2009	**2008**	**2009**	**2008**
Natural gas (mmcf/day)	222	171	191	175
Oil and liquids (bbls/day):				
Light and medium oil	19,864	18,120	18,037	17,440
Heavy oil	4,985	6,613	5,447	6,639
Total oil and liquids (bbls/day)	24,849	24,733	23,484	24,079
Total oil equivalent (boe/day)	61,832	53,288	55,299	53,190

Bonavista's balanced commodity investment approach minimizes our dependence on any one product and has generated consistent results during the year and in the quarter. Our current production is approximately 62,500 boe per day consisting of 61% natural gas, 31% light and medium oil and 8% heavy oil.

Production revenues - Production revenues for the year ended December 31, 2009 decreased 38% to $759.4 million when compared to $1,234.4 million for the same period a year ago, primarily due to lower average commodity prices. For the year ended December 31, 2009, natural gas prices decreased 42% to $4.78 per mcf, when compared to $8.30 per mcf realized in the same period in 2008. The average oil and liquids price also decreased 18% to $58.18 per bbl for the year ended December 31, 2009 from $70.68 per bbl for the same period in 2008. Production revenues for the fourth quarter of 2009 increased 5% to $232.9 million when compared to $221.8 million for the same period a year ago, primarily due to higher production volumes. In the fourth quarter of 2009, natural gas prices decreased 36% to $4.84 per mcf, when compared to $7.52 per mcf realized in the same period in 2008. The average oil and liquids price increased 18% to $62.79 per bbl in the fourth quarter of 2009 from $53.05 per bbl for the same period in 2008.

The following table highlights Bonavista's realized commodity pricing for the three months and year ended December 31:

	Three months ended December 31,		**Years ended December 31,**	
	2009	**2008**	**2009**	**2008**
Natural gas ($/mcf):				
Production revenues	$ 4.72	$ 7.30	$ 4.48	$ 8.29
Realized gains on financial instruments	0.12	0.22	0.30	0.01
	4.84	7.52	4.78	8.30
Light and medium oil ($/bbl):				
Production revenues	58.35	48.06	51.67	81.40
Realized gains (losses) on financial instruments	3.70	4.84	7.22	(9.70)
	62.05	52.90	58.89	71.70
Heavy oil ($/bbl):				
Production revenues	65.16	43.76	53.74	76.08
Realized gains (losses) on financial instruments	0.54	9.71	2.08	(8.07)
	$ 65.70	$ 53.47	$ 55.82	$ 68.01

Commodity price risk management - As part of our financial management strategy, Bonavista has adopted a disciplined commodity price risk management program. The purpose of this program is to stabilize funds from operations against volatile commodity prices and protect acquisition economics. Bonavista's Board of Directors has approved a commodity price risk management limit of 60% of forecast production, net of royalties, primarily using costless collars. Our strategy of using costless collars limits Bonavista's exposure to downturns in commodity prices, while allowing for participation in commodity price increases.

For the year ended December 31, 2009, our risk management program on financial instruments resulted in a net loss of $13.6 million, consisting of a realized gain of $72.1 million and an unrealized loss of $85.7 million. The realized gain of $72.1 million consisted of a $20.4 million gain on natural gas commodity derivative contracts and a $51.7 million gain on crude oil commodity derivative contracts. For the same period in 2008, our risk management program on financial instruments resulted in a net gain of $40.5 million, consisting of a realized loss of $80.8 million and an unrealized gain of $121.3 million. The realized loss of $80.8 million consisted of a $744,000 gain on natural gas commodity derivative contracts and an $81.5 million loss on crude oil commodity derivative contracts. In the fourth quarter of 2009, our risk management program on financial instruments resulted in a loss of $13.5 million, consisting of a realized gain of $9.5 million and an unrealized loss of $23.0 million. The realized gain of $9.5 million consisted of a $2.5 million gain on natural gas commodity derivative contracts and a $7.0 million gain on crude oil commodity derivative contracts. For the same period in 2008, our risk management program on financial instruments resulted in a net gain of $112.0 million consisting of a realized gain of $17.5 million and an unrealized gain of $94.5 million. The realized gain of $17.5 million consisted of a $3.6 million gain on natural gas commodity derivative contracts and a $13.9 million gain on crude oil commodity derivative contracts.

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for crude oil and natural gas are impacted not only by global economic events that dictate the levels of supply and demand but also by the relationship between the Canadian and United States dollar. The Trust has attempted to mitigate a portion of the commodity price risk through the use of various financial instruments and physical delivery sales contracts.

i) Financial instruments:

As at December 31, 2009, the Trust has hedged by way of costless collars to sell natural gas and crude oil as follows:

Volume		Average Price	Term
5,000	gjs/d	CDN$5.00 - CDN$6.50 - AECO	January 1, 2010 – March 31, 2010
15,000	gjs/d	CDN$4.75 - CDN$6.45 - AECO	April 1, 2010 - October 31, 2010
5,000	gjs/d	CDN$4.50 - CDN$5.50 - AECO	January 1, 2010 - March 31, 2010
20,000	gjs/d	CDN$4.56 - CDN$6.12 - AECO	January 1, 2010 - December 31, 2010
10,000	gjs/d	CDN$5.25 - CDN$7.20 - AECO	January 1, 2011 - December 31, 2011
9,000	bbls/d	CDN$68.06 - CDN$92.83 - WTI	January 1, 2010 - December 31, 2010
1,000	bbls/d	CDN$80.00 - CDN$95.25 - WTI	January 1, 2011 - December 31, 2011

As at December 31, 2009, the Trust has limited its downside exposure to natural gas prices by purchasing a put option. The Trust has also hedged its exposure to electricity pricing by entering into a swap which determines a fixed price paid throughout the term of the contract. These financial instruments are outlined below:

Volume		Price	Contract	Term
5,000	gjs/d	CDN $4.50	Purchased Put - AECO	April 1, 2010 - October 31, 2010
1	mw/h	CDN$55.00	Swap - AESO	January 1, 2010 - December 31, 2010

Financial instruments are recorded on the consolidated balance sheet at fair value at each reporting period with the change in fair value being recognized as an unrealized gain or loss on the consolidated statements of operations, comprehensive income and accumulated earnings. As at December 31, 2009 the fair market value recorded on the consolidated balance sheet for these financial instruments was a net liability of $9.5 million, compared to an asset of $76.2 million in 2008. These financial instruments had the following gains and losses reflected in the consolidated statements of operations, comprehensive income and accumulated earnings:

	Years ended December 31, 2009	2008
Realized gains (losses) on financial instruments	$ 72,100	$ (80,806)
Unrealized gains (losses) on financial instruments	(85,746)	121,261
	$ (13,646)	$ 40,455

Bonavista mitigates its risk associated with fluctuations in commodity prices by utilizing financial instruments. A $0.10 change in the price per thousand cubic feet of natural gas @ AECO would have an impact of approximately $2.7 million on net income for those financial instruments that were in place as at December 31, 2009. A $1.00 change in the price per barrel of oil - WTI would have an impact of approximately of $1.4 million on net income for those financial instruments that were in place as at December 31, 2009.

Subsequent to December 31, 2009 the Trust has hedged by way of costless collars to sell natural gas and crude oil as follows:

Volume		Average Price	Term
5,000	gjs/d	CDN$4.50 - CDN$7.24 - AECO	March 1, 2010 - October 31, 2011
10,000	gjs/d	CDN$4.50 - CDN$6.50 - AECO	April 1, 2010 - October 31, 2010
10,000	gjs/d	CDN$5.00 - CDN$7.45 - AECO	November 1, 2010 - March 31, 2011
5,000	gjs/d	CDN$5.00 - CDN$6.50 - AECO	April 1, 2011 - October 31, 2011
1,000	bbls/d	CDN$75.00 - CDN$92.38 - WTI	January 1, 2010 - December 31, 2010
1,000	bbls/d	CDN$75.00 - CDN$91.03 - WTI	July 1, 2010 - September 30, 2010
1,500	bbls/d	CDN$80.00 - CDN$98.40 - WTI	January 1, 2011 - December 31, 2011

ii) Physical purchase contracts:

As at December 31, 2009, the Trust has entered into direct sale costless collars to sell natural gas as follows:

Volume		Average Price	Term
10,000	gjs/d	CDN$5.25 - CDN$6.53 - AECO	January 1, 2010 - March 31, 2010
5,000	gjs/d	CDN$5.25 - CDN$7.00 - AECO	April 1, 2010 - October 31, 2010
5,000	gjs/d	CDN$5.00 - CDN$6.60 - AECO	January 1, 2010 - December 31, 2010
10,000	gjs/d	CDN$5.13 - CDN$6.99 - AECO	January 1, 2011 - December 31, 2011
5,000	gjs/d	CDN$5.25 - CDN$8.18 - AECO	November 1, 2010 - March 31, 2011

As at December 31, 2009, the Trust has entered into physical swap contracts to sell natural gas and to purchase electricity as follows:

Volume		Average Price	Term
5,000	gjs/d	CDN $5.06 - AECO	January 1, 2010 - December 31, 2010
4	mw/h	CDN$50.54 - AESO	January 1, 2010 - December 31, 2010
2	mw/h	CDN$55.03 - AESO	January 1, 2011 - December 31, 2011

Subsequent to December 31, 2009 the Trust has entered into direct sale costless collars to sell natural gas as follows:

Volume		Average Price	Term
10,000	gjs/d	CDN$4.50 - CDN$6.11 - AECO	April 1, 2010 - October 31, 2010
5,000	gjs/d	CDN$5.00 - CDN$7.10 - AECO	November 1, 2010 - March 31, 2011

Physical purchase contracts are being accounted for as they are settled.

Royalties - For the year ended December 31, 2009, royalties decreased by 51% to $117.2 million from $240.0 million for the same period a year ago, largely attributed to a decrease in commodity prices. In addition, royalties as a percentage of revenues (including realized gains and losses on financial instruments) for the year ended 2009 decreased to 14.1% compared to 20.8% in 2008 for similar reasons discussed above and the impact of realized gains on financial instruments compared to realized losses on financial instruments in the comparable period of 2008. For the three months ended December 31, 2009, royalties decreased 8.7% to $36.3 million from $39.8 million for the same period a year ago, mainly due to a decrease in commodity prices. In addition, royalties as a percentage of revenue (including realized gains and losses on financial instruments) for the fourth quarter of 2009 also decreased from 16.6% in 2008 to 15.0% in 2009, for the same reasons as discussed above.

The following table highlights Bonavista's royalties by product for the three months and year ended December 31:

	Three months ended December 31,		Years ended December 31,	
	2009	2008	2009	2008
Natural gas ($/mcf):				
Royalties	0.51	1.50	0.59	1.82
% of revenues (1)	10.5%	19.9%	12.3%	21.9%
Light and medium oil ($/bbl):				
Royalties	11.59	6.76	9.05	13.82
% of revenues (1)	18.7%	12.8%	15.4%	19.3%
Heavy oil ($/bbl):				
Royalties	10.54	8.12	8.47	14.55
% of revenues (1)	16.0%	15.2%	15.2%	21.4%

(1) % of revenues include realized gains and losses on financial instruments

On October 25, 2007, the Alberta Government announced the New Royalty Framework ("NRF") which was subsequently revised on April 10, 2008 to provide further clarification on the NRF as well as to introduce two new royalty programs related to the development of deep oil and natural gas reserves. The NRF was legislated in November 2008 and took effect on January 1, 2009. Subsequent to legislation of the NRF, the Government of Alberta introduced the Transitional Royalty Plan ("TRP") in response to the decrease in development activity in Alberta resulting from declining commodity prices and the global economic downturn. The TRP offers reduced royalty rates for new wells drilled on or after November 19, 2008 that meet certain depth requirements. An election must be filed on an individual well basis in order to qualify for the TRP. The TRP is in place for a maximum of 5 years to December 31, 2013. All wells drilled between 2009 and 2013 that adopt the transitional rates will be required to shift to the NRF on January 1, 2014. On March 3, 2009, the Alberta Government announced a further royalty incentive program consisting of a three-point incentive program to stimulate new and continued economic activity in Alberta which includes a drilling royalty credit for new conventional oil and natural gas wells and a new royalty incentive program. The net effect of these programs added approximately $12.0 million of royalty and drilling credits in 2009. It is also expected that the Alberta Government will release the findings of their Royalty Competiveness Review in the first quarter of 2010.

Operating expenses - Operating expenses for the year ended December 31, 2009 increased 7% to $197.8 million compared to $184.1 million for the same period a year ago, mainly due to higher production volumes. Operating expenses for the fourth quarter of 2009 increased 6% to $51.4 million compared to $48.6 million for the same period a year ago, again largely due to increased production volumes offset somewhat by lower per boe operating expenses in the period. In the last half of 2009, Bonavista experienced operating cost reductions in many areas of its operations however operating expenses still rose slightly on a per boe basis increasing 4% for the year ended December 31, 2009 to $9.80 per boe, from $9.45 per boe in the comparable period of 2008. However, for the three months ended December 31, 2009 operating expenses per unit of production decreased 9% to $9.04 per boe, from $9.91 per boe in the comparable period of 2008. Bonavista anticipates that operating costs on a per boe basis will decrease in 2010 as compared to 2009. The following table highlights Bonavista's operating expenses by product for the three months and year ended December 31:

	Three months ended December 31,		Year ended December 31,	
	2009	**2008**	**2009**	**2008**
Natural gas ($/mcf)	$ 1.29	$ 1.44	$ 1.41	$ 1.35
Light and medium oil ($/bbl)	10.05	10.38	10.66	10.07
Heavy oil ($/bbl)	14.44	14.07	14.94	13.69
Total ($/boe)	$ 9.04	$ 9.91	$ 9.80	$ 9.45

Transportation expenses - For the year ended December 31, 2009, transportation expenses decreased 5% to $36.8 million ($1.82 per boe) when compared to $38.7 million ($1.99 per boe) for the same period in 2008. For the three months ended December 31, 2009, transportation expenses decreased 2% to $9.4 million ($1.66 per boe) when compared to $9.6 million ($1.96 per boe) for 2008. For the year ended December 31, 2009 transportation expenses by product were $0.33 per mcf for natural gas, $0.92 per bbl for light and medium oil and $3.83 per bbl for heavy oil compared to $0.38 per mcf for natural gas, $0.85 per bbl for light and medium oil and $3.64 per bbl for heavy oil for the same period in 2008. Transportation expenses by product for the fourth quarter of 2009 were $0.30 per mcf for natural gas, $0.94 per bbl for light and medium oil and $3.53 per bbl for heavy oil compared to $0.36 per mcf for natural gas, $0.86 per bbl for light and medium oil and $4.05 per bbl for heavy oil for the same period in 2008.

General and administrative expenses - General and administrative expenses, after overhead recoveries, increased 24% to $17.9 million for the year ended December 31, 2009 from $14.4 million in the same period in 2008 and increased 37% to $5.2 million for the three months ended December 31, 2009 from $3.8 million in the same period in 2008. On a per boe basis, general and administrative expenses increased 20% for the year ended December 31, 2009 to $0.89 per boe from $0.74 per boe in the same period in 2008 and increased 18% for the three months ended December 31, 2009 to $0.92 per boe from $0.78 per boe in the same period in 2008. These increases are largely due to higher costs of personnel required to manage our growing operations and the termination of general and administrative cost recoveries under the services agreement with NuVista Energy Ltd. Our current level of general and administrative expenses remains among the lowest in our sector.

In connection with its Trust Unit Incentive Rights and Restricted Trust Unit Plans, Bonavista recorded a unit-based compensation charge of $2.9 million and $11.4 million for the three months and year ended December 31, 2009 respectively, compared to $4.7 million and $11.0 million for the same periods in 2008.

Financing expenses - Financing expenses, which include interest expense on long-term debt and convertible debentures, decreased 57% to $14.0 million for the year ended December 31, 2009, from $32.5 million for the same period in 2008 and on a per boe basis, decreased 58% to $0.70 per boe for the year ended December 31, 2009 from $1.67 per boe for the same period in 2008. For the three months ended December 31, 2009 financing expenses decreased 23% to $4.5 million from $5.8 million for the same period in 2008 and on a per boe basis, decreased 34% to $0.78 per boe for the three months ended December 31, 2009 from $1.18 per boe for the same period in 2008. This decrease is due largely to a declining interest rate environment. For the year ended December 31, 2009, Bonavista paid cash interest of $14.4 million compared to $32.9 million for the same period in 2008. During the fourth quarter of 2009, Bonavista paid cash interest of $5.1 million compared to $6.4 million in 2008. Bonavista's effective interest rate as at December 31, 2009 was approximately 1.5% (2008 – 2%).

Depreciation, depletion and accretion expenses - Depreciation, depletion and accretion expenses increased 11% to $295.3 million for the year ended December 31, 2009 from $266.3 million for the same period of 2008. For the three months ended December 31, 2009, depreciation, depletion and accretion expenses increased by 24% to $85.2 million from $69.0 million for the same period in 2008. These increases are due to higher costs of finding, developing and acquiring reserves and a larger asset base in 2009. For the year ended December 31, 2009, the average cost increased to $14.63 per boe from $13.68 per boe for the same period in 2008 and for the three months ended December 31, 2009, the average cost increased to $14.99 per boe from $14.07 per boe for the same period a year ago.

Income taxes - For the year ended December 31, 2009, the reduction of income taxes was $52.6 million compared to a provision of $49.5 million for the same period in 2008. For the three months ended December 31, 2009, the reduction of income tax was $15.8 million compared to a provision of $23.3 million for the same period in 2008. The current year income tax reduction included approximately $22 million related to unrealized risk management losses (2008 - $34 million gains) and $3.8 million (2008 - nil) related to the rate reduction in the provincial component of the Specified Investment Flow-Through ("SIFT") tax rate enacted in the first quarter of 2009. Bonavista made no cash payments on tax installments for either the three months or year ended December 31, 2009, or for the comparative periods in 2008.

Funds from operations, net income and comprehensive income - For the year ended December 31, 2009, Bonavista experienced a 30% decrease in funds from operations to $447.7 million ($3.46 per unit, basic) from $643.9 million ($5.64 per unit, basic) for the same period in 2008. For the three months ended December 31, 2009, Bonavista experienced a 3% increase in funds from operations to $135.5 million ($0.93 per unit, basic) from $131.7 million ($1.12 per unit, basic) for the same period in 2008. Funds from operations decreased for the year ended December 31, 2009 primarily due to lower commodity prices partially offset by the impact of realized gains on financial instruments and slightly higher production volumes. For the three months ended December 31, 2009, funds from operations increased largely due to increased production volumes offset by lower overall commodity prices. Net income and comprehensive income for the year ended December 31, 2009, decreased 76% to $106.6 million ($0.82 per unit, basic) from $438.4 million ($3.84 per unit, basic) for the same period in 2008. For the three months ended December 31, 2009, net income and comprehensive income decreased 69% to $39.6 million ($0.27 per unit, basic) from $129.2 million ($1.09 per unit, basic) for the same period in 2008.

The following table is a reconciliation of a non-GAAP measure, funds from operations, to its nearest measure prescribed by GAAP:

Calculation of Funds From Operations:	Three months ended December 31, 2009	Three months ended December 31, 2008	Years ended December 31, 2009	Years ended December 31, 2008
(thousands)				
Cash flow from operating activities	$ 154,758	$ 141,448	$ 423,933	$ 678,228
Asset retirement expenditures	3,440	5,061	12,036	15,229
Changes in non-cash working capital	(22,664)	(14,768)	11,774	(49,581)
Funds from operations	$ 135,534	$ 131,741	$ 447,743	$ 643,876

Capital expenditures - Capital expenditures for the year ended December 31, 2009 were $833.8 million, consisting of $203.8 million spent on exploration and development activities and $630.0 million spent on property acquisitions, net of dispositions. For the same period in 2008, capital expenditures were $482.3 million, consisting of $305.5 million on exploration and development spending and $176.8 million on property acquisitions, net of dispositions. Capital expenditures for the three months ended December 31, 2009 were $75.2 million, consisting of $62.0 million on exploration and development spending and $13.2 million on property acquisitions, net of dispositions. For the same period in 2008 capital expenditures were $60.1 million, consisting of $60.2 million on exploration and development spending and $105,000 on net property dispositions. While we saw considerable downward movement in service costs throughout 2009, we anticipate service costs to stabilize at current levels for 2010. This attractive level will allow Bonavista to continue to generate attractive returns with its exploration and development program despite relatively weak commodity prices.

The following table outlines capital expenditures by category for the years ended December 31, 2009 and 2008:

	Years ended December 31, 2009	2008
(thousands)		
Land acquisitions	$ 20,385	$ 26,165
Geological and geophysical	6,829	10,687
Drilling and completion	133,811	176,361
Production equipment and facilities	41,704	91,138
Other	1,116	1,163
Exploration and development expenditures	203,845	305,514
Acquisitions	737,117	187,023
Dispositions	(107,118)	(10,240)
Net capital expenditures	$ 833,844	$ 482,297

Liquidity and capital resources - As at December 31, 2009, long-term debt including working capital (excluding unrealized losses on financial instruments, its related tax impact and convertible debentures) was $874.4 million with a debt to fourth quarter 2009 annualized funds from operations ratio of 1.6:1. Bonavista has significant flexibility to finance future expansions of its capital programs, through the use of its current funds generated from operations and our bank loan facilities of $1.4 billion, of which $525.6 million is unused borrowing capability.

Bonavista has two bank loan facilities totalling $1.4 billion provided by a syndicate of 12 domestic and international banks. Both facilities have a maturity date of August 10, 2011 and may, at the request of the Trust and with the consent of the lenders be extended on an annual basis.

Under the terms of both credit facilities, the Trust has provided the covenant that its: (i) consolidated senior debt borrowing will not exceed three times net income before unrealized gains and losses on financial instruments and marketable securities, interest, taxes and depreciation, depletion and accretion; (ii) consolidated total debt will not exceed three and one half times consolidated net income before unrealized gains and losses on financial instruments and marketable securities, interest, taxes and depreciation, depletion and accretion; and (iii) consolidated senior debt borrowing will not exceed one-half of consolidated total debt plus consolidated unitholders' equity of the Trust, in all cases calculated based on a rolling prior four quarters.

In 2010, Bonavista plans to invest between $300 and $330 million on its capital programs to expand its core regions. The Trust intends on financing its 2010 capital program with a combination of funds from operations, and to the extent required, its existing credit facility. Going forward, the Trust remains committed to the fundamental principle of maintaining financial flexibility and the prudent use of debt.

Unitholders' equity - As at December 31, 2009, Bonavista had 146.1 million equivalent trust units outstanding. This includes 9.7 million exchangeable shares, which are exchangeable into 21.5 million trust units. The exchange ratio in effect at December 31, 2009 for exchangeable shares was 2.21352:1. As at March 4, 2010, Bonavista had 146.5 million equivalent trust units outstanding. This includes 9.5 million exchangeable shares, which are exchangeable into 21.3 million trust units. The exchange ratio in effect at March 4, 2010 for exchangeable shares was 2.24429:1. In addition, Bonavista has 4.2 million trust unit incentive rights outstanding at March 4, 2010, with an average exercise price of $25.65 per trust unit.

Contractual obligations - The following is a summary of the Trust's contractual obligations and commitments as at December 31, 2009:

	Payments Due by Period					
	Total	2010	2011	2012	2013	2014 and thereafter
(thousands)						
Long-term debt repayments (1)	$ 832,138	$ -	$832,138	$ -	$ -	$ -
Convertible debentures (2)	38,567	38,567	-	-	-	-
Transportation expenses	51,417	16,114	11,570	8,314	6,665	8,754
Office premises	1,708	1,412	296	-	-	-
Total contractual obligations	**$ 923,830**	**$ 56,093**	**$844,004**	**$ 8,314**	**$ 6,665**	**$ 8,754**

(1) Based on the existing terms of the revolving credit facility, the amounts owing under this facility are required to be paid in 2011. However, it is expected that the revolving credit facility will be extended and no repayments will be required in the near term.

(2) The Trust may at its option redeem the principal amount of, and premiums (if any) on the Debentures that have matured by either the issuance of trust units or the cash equivalent to the holders of the Debentures.

Distributions - Bonavista's distribution policy is constantly monitored and is dependent upon its forecasted operations, funds from operations, debt levels and capital expenditures. One of the main objectives of the Trust is to maintain sustainability, which is defined as maintaining both production and reserves over an extended period of time with a minimum amount of capital. This is accomplished by retaining sufficient funds from operations to replace the reserves that have been produced. With these considerations, for the year ended December 31, 2009 the Trust declared distributions of $218.0 million ($2.00 per unit) compared to $332.5 million ($3.60 per unit) in the same period in 2008. For the three months ended December 31, 2009 the Trust declared distributions of $59.8 million ($0.48 per unit) compared to $85.8 million ($0.90 per unit) in the same period in 2008. We continuously monitor all the factors influencing our distribution rate and the necessity to adjust the monthly distribution in the future.

The following table illustrates the relationship between cash flow provided from operating activities and distributions declared, as well as net income and distributions declared. Net income includes significant non-cash charges, such as depreciation, depletion and accretion, unrealized gains and losses on financial instruments and marketable securities, fluctuations in future income taxes due to changes in tax rates and tax rules. These non-cash charges do not represent the actual cost of maintaining our production capacity given the natural declines associated with oil and natural gas assets. For the three months and year ended December 31, 2009, the non-cash charges amounted to $95.9 million and $341.1 million respectively compared to $2.5 million and $205.5 million for the same periods in 2008. In instances where distributions exceed net income, a portion of the cash distribution paid to Unitholders may be considered an economic return of Unitholders' capital.

	Three months ended December 31,		**Years ended December 31,**	
Distribution Analysis	**2009**	**2008**	**2009**	**2008**
(thousands)				
Cash flow provided from operating activities	$ 154,758	$ 141,448	$ 423,933	$ 678,228
Net income	39,647	129,192	106,606	438,366
Distributions declared	59,783	85,824	217,965	332,540
Excess of cash flow provided from operating activities over distributions declared	94,975	55,624	205,968	345,688
Excess (shortfall) of net income over distributions declared	(20,136)	43,368	(111,359)	105,826

Bonavista announces its distribution policy on a quarterly basis. Distributions are determined by the Board of Directors and are dependent upon the commodity price environment, production levels, and the amount of capital expenditures to be financed from funds from operations. Bonavista's current monthly distribution rate is $0.16 per unit, down from $0.20 per unit at the same time last year. For 2010, our objective is to distribute up to 50% of our funds from operations, which allows us to withhold sufficient funds to finance capital expenditures required to maintain or modestly grow our production base over a longer period of time. Our current distribution rate of $0.16 per unit per month will place us within this targeted level for the year assuming current strip prices are realized.

Annual financial information - The following table highlights selected annual financial information for each of the three years ended December 31, 2009, 2008 and 2007:

Years ended December 31,	**2009**	**2008**	**2007**
(thousands, except per unit amounts)			
Consolidated Statement of Operations Information:			
Production revenues, net of royalties	$ 642,206	$ 994,424	$ 755,760
Funds from operations	447,743	643,876	502,783
Per unit – basic	3.46	5.64	4.76
Per unit – diluted	3.43	5.56	4.69
Net income	106,606	438,366	218,187
Per unit – basic	0.82	3.84	2.07
Per unit – diluted	0.81	3.80	2.06
Consolidated Balance Sheet Information:			
Total capital expenditures	$ 833,844	$ 482,297	$ 366,356
Total assets	3,092,129	2,543,240	2,242,057
Working capital (deficiency)	(87,124)	(11,726)	(10,349)
Long-term debt	832,138	588,792	712,654
Unitholders' equity	1,723,583	1,411,972	1,060,967
Distributions declared	217,965	332,540	307,401

Quarterly financial information - The following table highlights Bonavista's performance for the eight quarterly periods ending on March 31, 2008 to December 31, 2009:

	2009				**2008**			
	December 31	**September 30**	**June 30**	**March 31**	**December 31**	**September 30**	**June 30**	**March 31**
($ thousands, except per unit amounts)								
Production revenues	232,870	180,977	166,430	179,146	221,782	354,667	361,555	296,387
Net income	39,647	33,339	661	32,959	129,192	207,594	29,282	72,298
Net income per unit:								
Basic	0.27	0.25	0.01	0.28	1.09	1.77	0.26	0.67
Diluted	0.27	0.25	0.01	0.28	1.09	1.75	0.26	0.67

Production revenues over the past eight quarters have fluctuated between a low of $166.4 million in the second quarter of 2009 to a high of $361.6 million in the second quarter of 2008, largely due to the volatility of commodity prices. Net income in the past eight quarters has fluctuated from a low of $661,000 in the second quarter of 2009 to a high of $207.6 million in the third quarter of 2008. These fluctuations are primarily influenced by commodity prices, realized and unrealized gains and losses on financial instruments and future income tax recoveries associated with the reduction in corporate income tax rates. Net income decreased 69% in the fourth quarter of 2009 as compared to the fourth quarter of 2008. The decrease in net income in the fourth quarter of 2009 is largely attributed to lower overall commodity prices and the impact of the unrealized losses on financial instruments offset however by an increase in production volumes as compared to the same period in 2008.

Disclosure controls and procedures - Disclosure controls and procedures have been designed to ensure that information to be disclosed by Bonavista is accumulated and communicated to management, as appropriate, to allow timely decisions regarding required disclosures. The Chief Executive Officer and Chief Financial Officer have concluded, as of the end of the period covered by the interim and year end filings that Bonavista's disclosure controls and procedures are appropriately designed and operating effectively to provide reasonable assurance that material information relating to the issuer is made know to them by others within the Trust.

Internal control over financial reporting - Internal control over financial reporting is a process designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely information. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system is met. Management has assessed the effectiveness of Bonavista's internal control over financial reporting as defined by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Management has concluded that their internal control over financial reporting was effective as of December 31, 2009. There were no material changes to the internal controls over financial reporting during the year ended December 31, 2009.

Update on SIFT tax and corporate conversion - Bonavista is currently reviewing alternative legal structures for post December 31, 2010. Although we believe a conversion back to a corporate structure is the most likely scenario when the SIFT tax rules come into effect, we have not finalized this decision at this time. The form of legal structure and the timing of such conversion are dependent on many factors such as the strength of commodity prices and equity markets, operating performance, tax regulations and Bonavista's continued success in developing its inventory of prospects. If there is a conversion to a corporation, total shareholder return is still expected to have a component of both growth and yield.

Update on financial reporting matters - On February 13, 2008, Canada's Accounting standards Board confirmed January 1, 2011 as the effective date for complete convergence of Canadian GAAP to International Financial Reporting Standards ("IFRS"). There are significant differences that exist under the IFRS framework compared to Canadian GAAP in the areas of accounting policy choices and increased disclosure requirements. In July 2009, the International Accounting Standards Board ("IASB") issued amendments to IFRS 1, "First Time Adoption of IFRS" allowing an entity that used full cost accounting under its previous GAAP to elect, at its time of adoption, to measure exploration and evaluation assets at the amount determined under the entity's previous GAAP and to measure oil and natural gas assets in the development or production phases by allocating the amount determined under the entity's previous GAAP for those assets to the underlying assets pro rata using reserve volumes or reserve values as of that date. Bonavista is currently planning to adopt this exemption.

In 2009, Bonavista completed a preliminary analysis of the accounting differences between Canadian GAAP and IFRS. The Trust then moved into the impact analysis and evaluation phase which focused on the determination of cash generating units and accounting policy choices. There are currently numerous significant accounting differences between our current accounting policies under Canadian GAAP and IFRS. We are currently in the process of evaluating the impact these different accounting policy choices have on the results of operations, financial position and disclosures. Once concluded the audit committee will review and approve all accounting policy choices as proposed by management.

Effective January 1, 2009, Bonavista adopted Canadian Institute of Chartered Accountants ("CICA") Section 3064, "Goodwill and Intangible Assets", which defines the criteria for the recognition of intangible assets. The adoption of this standard did not impact the Trust's consolidated financial statements.

Effective December 31, 2009, Bonavista adopted CICA issued amendments to Section 3862, "Financial Instruments - Disclosures". The amendments include enhanced disclosures relating to the fair value of financial instruments and liquidity risk associated with financial instruments. The adoption of these amendments did not have a material impact on our results of operations, financial position and disclosures. The impact of this amendment has been disclosed within note 11 of the Notes to the Consolidated Financial Statements.

Critical Accounting Estimates **-** The consolidated financial statements have been prepared in accordance with Canadian GAAP. A summary of significant accounting policies are presented in note 1 of the Notes to the Consolidated Financial Statements. Certain accounting policies are critical to understanding the financial condition and results of operations of Bonavista.

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 Bonavista'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 Trust's development plans. The effect of changes in proved oil and natural gas reserves on the financial results and position of the Trust is described in b) below.

b) ***Depreciation, depletion and accretion expense*** - Bonavista 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 assets 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 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 abandonment and reclamation discounted at a credit adjusted risk free rate. The costs are included in property, plant and equipment and amortized over their 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 the Trust's 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.

Assessment of Business Risks

The following are the primary risks associated with the business of the Trust. These risks are similar to those affecting others in the conventional energy trust sector. The Trust's financial position, results of operations and distributions to Unitholders are directly impacted by these factors and include:

1) operational risk associated with the production of oil and natural gas;
2) reserve risk in respect to the quantity and quality of recoverable reserves;
3) market risk relating to the availability of transportation systems to move the product to market;
4) commodity risk as crude oil and natural gas prices fluctuate due to market forces;
5) financial risk such as volatility of the Canadian/US dollar exchange rate, interest rates and debt service obligations;
6) potential risk of change in distributions;
7) environmental and safety risk associated with well operations and production facilities;
8) 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 the income trust sector;
9) potential risk of liability to Unitholders resident in jurisdictions where there is no statutory protection for Unitholders from liabilities of the Trust;
10) continued participation of the Trust's lenders;
11) counterparty risk with respect to non-performance by counterparties to financial derivative contracts; and
12) financial risk associated with domestic and international debt and equity markets.

The Trust seeks to mitigate these risks by:

1) acquiring properties with well established production trends to reduce technical uncertainty;
2) acquiring long life reserves to ensure more stable production and to reduce the economic risks associated with commodity price cycles;
3) maintaining a low cost structure to maximize product netbacks and reduce impact of commodity price cycles;
4) diversifying properties to mitigate individual property and well risk;
5) maintaining product mix to balance exposure to commodity prices;
6) conducting rigorous reviews of all property acquisitions;
7) monitoring pricing trends and developing a mix of contractual arrangements for the marketing of products with creditworthy counterparties;
8) maintaining a hedging program to hedge commodity prices and foreign exchange currency rates with creditworthy counterparties;
9) ensuring strong third party-operators for non-operated properties;
10) adhering to the Trust's safety program and keeping abreast of current operating best practices;
11) 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;
12) carrying insurance to cover losses and business interruption; and
13) establishing and maintaining adequate cash resources to fund future abandonment and site restoration costs.

OUTLOOK

As we navigate through our thirteenth year since restructuring Bonavista in 1997, and our seventh year since converting to an energy trust, we continue to benefit from the same qualities that drove the success of Bonavista both as a corporation and an energy trust. We continue to apply the same proven strategy and execute this strategy in a disciplined and cost-effective manner, much the same way we did in 1997 when we started on our journey of creating value for our investors. The foundation of this strategy is to actively pursue low to medium-risk drilling opportunities on our extensive land base within geographically concentrated areas of operations. Even with a very active exploration and development program over the past several years, the quality and quantity of our inventory of opportunities continues to improve each and every year. Our consistent strategy also involves a component of strategic and timely acquisitions where we can add value utilizing our own technical expertise. In the third quarter of 2009 we closed the most significant acquisition in our history. This acquisition grew our prospect inventory by 25% to approximately 860 locations, adding high quality and low cost drilling prospects to our previous healthy inventory of opportunities. This is truly a transformational transaction for Bonavista and will lead to several years of drilling and tuck-in acquisition opportunities in an area where we have established a dominant presence of operations. Our timely and prudent approach to capital investments has been very effective in the past, and our attention to detail together with our steadfast commitment to adding Unitholder value, will continue to provide the foundation for the future success of our organization. Today our efficiency, productivity, and confidence remains among the strongest levels in our twelve year history.

As we approach the spring of 2010 we are continuing to monitor natural gas fundamentals very closely and remain optimistic that the current North American oversupply situation will ultimately balance itself. A reduced amount of capital expenditures being directed towards natural gas projects within North America is resulting in a slow and steady decline in supply which, when coupled with stabilizing or modestly increasing industrial demand, should result in stabilizing or improving natural gas prices throughout the year. With this in mind, Bonavista will continue to maintain maximum flexibility with its capital spending program by directing capital to the most profitable opportunities. We have established a capital spending program of between $300 and $330 million, which at this time, will be entirely directed toward our exploration and development program. Approximately two-thirds of the expenditures will be devoted to our Western Region development initiatives with the remaining one-third directed towards our Eastern and Northern Regions. In total for 2010, we expect to drill between 120 and 130 wells, of which 60% to 70% will be high-impact horizontal wells focusing on multi-stage stimulation within large tight reservoirs. This activity should lead to production levels averaging between 62,000 and 63,000 boe per day in 2010. As always, we will continue to closely monitor the economic climate together with our drilling results and remain flexible to adjust the level of spending depending on the circumstances. In particular, an unprecedented amount of Crown land and property acquisition opportunities are being brought to the market in 2010. As a result, we are exercising extra diligence when considering these incremental investment opportunities. As in the past, our objective will be to invest in those projects that will maximize value both in the short and long term.

We are extremely proud of what our team has accomplished over the past year and despite some short term commodity weakness, our enthusiasm and confidence about our future is greater than it has ever been. We would like to thank our employees for their significant effort and their continued perseverance as we position our company for the future. Although we have endured some setbacks over the past couple of years, including the passage of federal legislation on the taxation of distributions from certain publicly traded Canadian trusts, the introduction of the New Royalty Framework by the Government of Alberta, and the volatile capital and commodity markets, Bonavista's commitment and value creation process has not waivered. We remain confident that our operating philosophy works well in any environment. Throughout many business cycles and changes in the business environment, Bonavista has converted adversity into opportunity, pursued counter-cyclical strategies and has emerged an even stronger entity as a result of this approach. Ultimately our legal structure may change back to a corporation in 2011, but our primary focus of executing a proven strategy that has worked so well over twelve years will remain unchanged. Our team is very committed to this vision.

On behalf of the Board of Directors

Keith A. MacPhail
Chairman and Chief Executive Officer

Jason E. Skehar
President and Chief Operating Officer

March 4, 2010
Calgary, Alberta

MANAGEMENT'S REPORT

The preparation of the accompanying consolidated financial statements in accordance with accounting principles generally accepted in Canada is the responsibility of management. Financial information contained elsewhere in this Annual Report is consistent with that in the consolidated financial statements.

Management is responsible for the integrity and objectivity of the financial statements. Where necessary, the financial statements include estimates, which are based on management's informed judgments. Management has established systems of internal controls, which are designed to provide reasonable assurance those assets, are safeguarded from loss or unauthorized use and to produce reliable accounting records for the preparation of financial information.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. It exercises its responsibilities primarily through the Audit Committee, all of whose members are non-management directors. The Audit Committee has reviewed the consolidated financial statements with management and the auditors and has reported to the Board of Directors, which have approved the consolidated financial statements.

KPMG LLP are independent auditors appointed by Bonavista's unitholders. The auditors have considered, for the purposes of determining the nature, timing and extent of their audit procedures, the Trust's internal controls and have audited the consolidated financial statements in accordance with generally accepted auditing standards to enable them to express an opinion on the fairness of the financial statements in accordance with Canadian generally accepted accounting principles.

Keith A. MacPhail
Chairman and Chief Executive Officer

Glenn A. Hamilton
Senior Vice President and Chief Financial Officer

March 4, 2010
Calgary, Alberta

AUDITORS' REPORT TO THE UNITHOLDERS

We have audited the consolidated balance sheets of Bonavista Energy Trust as at December 31, 2009 and 2008 and the consolidated statements of operations, comprehensive income and accumulated earnings and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2009 and 2008 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada
March 4, 2010, except as to note 14 which is as of March 26, 2010

BONAVISTA ENERGY TRUST
Consolidated Balance Sheets

December 31,	2009	2008
(thousands)		
Assets:		
Current assets:		
Accounts receivable and prepaids	$ 128,363	$ 106,116
Marketable securities	6,322	-
Financial instrument contracts (note 11)	5,626	76,203
Future income tax asset (note 10)	4,424	-
	144,735	182,319
Oil and natural gas properties and equipment (note 6)	2,906,073	2,319,600
Goodwill	41,321	41,321
	$ 3,092,129	$ 2,543,240
Liabilities and Unitholders' Equity:		
Current liabilities:		
Accounts payable and accrued liabilities	$ 157,019	$ 143,093
Distributions payable	19,937	28,731
Financial instrument contracts (note 11)	15,169	-
Convertible debentures (note 8)	38,093	-
Future income tax (note 10)	1,641	22,221
	231,859	194,045
Long-term debt (note 7)	832,138	588,792
Convertible debentures (note 8)	-	43,711
Asset retirement obligations (note 4)	160,314	127,467
Future income taxes (note 10)	144,235	177,253
Unitholders' equity:		
Unitholders' capital and debenture conversion component (notes 8 and 9)	1,531,299	1,100,768
Exchangeable shares (note 9)	59,295	69,488
Contributed surplus (note 9)	13,319	10,687
Accumulated earnings	119,670	231,029
	1,723,583	1,411,972
Commitments (note 13)		
	$ 3,092,129	$ 2,543,240

See accompanying notes to the consolidated financial statements.

Approved on behalf of Bonavista Energy Trust, by Bonavista Petroleum Ltd. as administrator:

Ian S. Brown, Director

Michael M. Kanovsky, Director

BONAVISTA ENERGY TRUST

Consolidated Statements of Operations, Comprehensive Income and Accumulated Earnings

Years ended December 31, (thousands, except per unit amounts)	**2009**	**2008**
Revenues:		
Production	$ 759,423	$ 1,234,391
Royalties	(117,217)	(239,967)
	642,206	994,424
Realized gains (losses) on financial instruments (note 11)	72,100	(80,806)
Unrealized gains (losses) on financial instruments (note 11)	(85,746)	121,261
	(13,646)	40,455
	628,560	1,034,879
Expenses:		
Operating	197,795	184,053
Transportation	36,833	38,744
General and administrative	17,900	14,410
Financing	14,035	32,535
Unrealized loss on marketable securities	1,336	-
Unit-based compensation	11,386	11,049
Depreciation, depletion and accretion	295,296	266,271
	574,581	547,062
Income before taxes	53,979	487,817
Income taxes (reductions) (note 10)	(52,627)	49,451
Net income and comprehensive income	106,606	438,366
Accumulated earnings, beginning of year	231,029	125,203
Distributions declared	(217,965)	(332,540)
Accumulated earnings, end of year	$ 119,670	$ 231,029
Net income per unit – basic	$ 0.82	$ 3.84
Net income per unit – diluted	$ 0.81	$ 3.80

See accompanying notes to the consolidated financial statements.

BONAVISTA ENERGY TRUST
Consolidated Statements of Cash Flows

Years ended December 31,	**2009**	**2008**
(thousands, except per unit amounts)		
Cash provided by (used in):		
Operating Activities:		
Net income	$ 106,606	$ 438,366
Items not requiring cash from operations:		
Depreciation, depletion and accretion	295,296	266,271
Unit-based compensation	11,386	11,049
Unrealized (gains) losses on financial instruments	85,746	(121,261)
Unrealized loss on marketable securities	1,336	-
Future income tax (reductions)	(52,627)	49,451
Asset retirement expenditures	(12,036)	(15,229)
Changes in non-cash working capital items	(11,774)	49,581
	423,933	678,228
Financing Activities:		
Issuance of equity, net of issue costs	404,115	223,152
Distributions	(226,759)	(329,538)
Changes in long-term debt	243,346	(123,862)
Repayment of convertible debentures	(6,586)	-
Changes in non-cash working capital items	(349)	(344)
	413,767	(230,592)
Investing Activities:		
Exploration and development	(203,845)	(305,514)
Property acquisitions	(737,117)	(187,023)
Property dispositions	107,118	10,240
Changes in non-cash working capital items	(3,856)	34,661
	(837,700)	(447,636)
Change in cash	-	-
Cash, beginning of year	-	-
Cash, end of year	$ -	$ -

See accompanying notes to the consolidated financial statements.

Structure of the Trust and Basis of Presentation:

Bonavista Energy Trust ("Bonavista" or the "Trust") is an open-ended unincorporated investment trust governed by the laws of the Province of Alberta. The Trust was established on July 2, 2003 under a Plan of Arrangement entered into by the Trust, Bonavista Petroleum Ltd. ("BPL") and its subsidiaries and partnerships and NuVista Energy Ltd. ("NuVista"). Under the Plan of Arrangement, a wholly-owned subsidiary of the Trust amalgamated with BPL and became the successor company. The Trust has two significant subsidiaries in which it owns 100% of the common shares of BPL (excluding the exchangeable shares – see note 9) and 100% of the units of Bonavista Trust (2003) ("BT"). The activities of these entities are financed through interest bearing notes from the Trust and third party debt as described in the notes to the consolidated financial statements. The business of the Trust is carried on through the entities owned by the subsidiaries of the Trust, Bonavista Petroleum, a general partnership ("BP") and Bonavista Energy Limited Partnership ("BELP"). The net income of the Trust is generated from interest on notes advanced to its subsidiaries, royalty payments on oil and natural gas assets owned by BP, as well as any dividends or distributions paid by its subsidiaries. The Trustee must declare payable to the Trust Unitholders all of the taxable income of the Trust.

1. Significant accounting policies:

As determination of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of these consolidated financial statements requires the use of estimates and assumptions, which have been made using careful judgment. In particular, the amounts recorded for depreciation, depletion and accretion of the oil and natural gas properties and for asset retirement obligations are based on estimates of reserves and future costs. By their nature, these estimates, and those related to future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material. In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized below:

a) Principles of consolidation:

The consolidated financial statements include the accounts of the Trust and its wholly-owned subsidiaries, trusts and proportionate share of its partnerships. All inter-entity transactions have been eliminated.

b) Oil and natural gas properties and equipment:

The Trust follows the full cost method of accounting, whereby all costs associated with the exploration for and development of oil and natural gas reserves are capitalized in cost centres on a country-by-country basis. Such costs include land and property acquisitions, geological and geophysical activities, drilling, well equipment and facilities. Gains or losses are not recognized upon disposition of oil and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion by 20% or more.

Costs capitalized in the cost centres, including well equipment, together with estimated future capital costs associated with proven reserves, are depreciated and depleted using the unit-of-production method which is based on gross production and estimated proven oil and natural gas reserves as determined by independent engineers. The cost of unproven properties is excluded from the depreciation and depletion base. For purposes of the depreciation and depletion calculations, oil and natural gas reserves are converted to a common unit of measure on the basis of their relative energy content, being six thousand cubic feet of natural gas for one barrel of oil. Facilities are depreciated using the declining balance method over their useful lives, which range from 12 to 15 years.

Oil and natural gas properties and equipment are evaluated in each reporting period to determine whether the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre. The carrying amounts are assessed to be recoverable when the sum of the undiscounted future cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying amount of the cost centre. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount of the cost centre exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects of the cost centre. The cash flows are estimated using expected future product prices and costs, and are discounted using a risk-free interest rate.

c) Joint operations:

A portion of Bonavista's oil and natural gas operations are conducted jointly with others. Accordingly, the consolidated financial statements reflect only Bonavista's proportionate interest in such activities.

d) Goodwill:

Goodwill is tested for impairment on an annual basis in the fourth quarter of each year. If indications of impairment are present, a loss would be charged to net income for the amount that the carrying value of goodwill exceeds its fair value.

e) Asset retirement obligations:

Bonavista records a liability for the fair value of legal obligations associated with the retirement of long-lived tangible assets in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability there is a corresponding increase in the carrying amount of the related asset known as the asset retirement cost, which is depleted on a unit-of-production basis over the life of the reserves. 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. Actual costs incurred upon settlement of the obligations are charged against the liability.

f) Revenue recognition:

Revenues from the sale of oil and natural gas are recorded when title passes to an external party.

g) Financial instruments:

i) A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument to another entity. Upon initial recognition, all financial instruments, including all derivatives, are recognized on the balance sheet at fair value. Subsequent measurement is then based on the financial instruments being classified into one of five categories: held for trading, held to maturity, loans and receivables, available for sale and other liabilities. The Trust has designated its cash and cash equivalents and investments, other than equity investments, as held for trading which are measured at fair value. Accounts receivable are classified as loans and receivables which are measured at amortized cost. Accounts payable and accrued liabilities, distributions payable and bank debt are classified as other liabilities which are measured at amortized cost, which is determined using the effective interest method. The convertible debentures are classified as debt on the balance sheet with a portion of the proceeds allocated to equity. The debt component has been measured at amortized cost.

ii) The Trust is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments may be used by the Trust to reduce its exposure to fluctuations in commodity prices, foreign exchange rates, and interest rates. The Trust does not use these derivative instruments for trading or speculative purposes. The Trust considers all of these transactions to be economic hedges; however, the majority of the Trust's contracts do not qualify or have not been designated as hedges for accounting purposes. As a result, all derivative contracts are classified as held for trading and are recorded on the balance sheet at fair value, with changes in the fair value recognized in net income, unless specific hedge criteria are met. The fair values of these derivative instruments are based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity given future market prices and other relevant factors. Proceeds and costs realized from holding the derivative contracts are recognized in net income at the time each transaction under a contract is settled. The Trust has elected to account for its physical delivery sales contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts on an accrual basis rather than as non-financial derivatives. The Trust nets all transaction costs incurred, in relation to the acquisition of a financial asset or liability, against the related financial asset or liability. In accordance with this policy convertible debentures are recorded net of issue costs and bank debt is presented net of deferred interest payments, with interest recognized in net income on an effective interest basis.

h) Unit-based compensation:

Bonavista has an equity incentive plan, which is described in note 9. The trust unit incentive right compensation plan for employees do not involve the direct award of trust units, or call for the settlement in cash or other assets. Bonavista uses the fair value method for valuing the granting of trust unit incentive rights. Under this method, the compensation cost attributable to all the trust unit rights granted is measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. Upon the exercise of the trust unit rights, consideration received together with the amount previously recognized in contributed surplus is recorded as an increase to Unitholders' equity.

i) Restricted trust unit incentive plan:

Bonavista has established a Restricted Trust Unit Incentive Plan (the "RTU Plan") for our employees as described in note 9. Vesting arrangements are within the discretion of our board of directors, but all awards will vest within three years from the date of grant. On the vesting date, at the discretion of Trust, the holder will receive for each unit award, including distributions made on the trust units from the date of the grant to and including the vesting date, net of statutory withholding tax, either: (i) equivalent trust units; or (ii) the cash equivalent. Trust units may be issued from treasury or purchased on the open market. The Trust has not incorporated an estimated forfeiture rate for Restricted Trust Units that will not vest, rather the Trust accounts for actual forfeitures as they occur.

j) Income taxes:

Bonavista is a taxable entity under the Canadian Income Tax Act and until 2011 is taxable only on income that is not distributed or distributable to its unitholders. Commencing in 2011, distributions paid to unitholders will not be deductible for tax and Bonavista will be taxed on its income similar to corporations. The Trust follows the asset and liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements of BPL and its subsidiaries and their respective tax basis, using substantively enacted income tax rates expected to be in effect when the temporary differences are anticipated to reverse. In addition, income tax liabilities and assets are recognized for the estimated tax consequences of temporary differences arising in the Trust that reverse after 2011. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in net income in the period that the change occurs.

k) Per unit amounts:

Diluted per unit amounts reflect the potential dilution that could occur if securities or other contracts to issue trust units were exercised or converted to trust units. The treasury stock method is used to determine the dilutive effect of unit incentive rights and other dilutive instruments.

l) Comparative figures:

The comparative figures have been reclassified to reflect the current year presentation.

2. Changes in accounting policies:

a) Goodwill:

On January 1, 2009, the Trust adopted CICA Handbook Section 3064 "Goodwill and Intangible Assets", which defines the criteria for the recognition of intangible assets. The adoption of this standard did not impact the Trust's consolidated financial statements.

b) Financial Instruments - Disclosures:

Effective December 31, 2009, Bonavista adopted CICA issued amendments to Section 3862, "Financial Instruments - Disclosures", the amendment outlines a hierarchy of methods to be used to determine the fair value of financial instruments on the balance sheet date. The adoption of these amendments did not have a material impact on our results of operations, financial position and disclosures.

c) International Financial Reporting Standards:

On February 13, 2008, Canada's Accounting Standards Board confirmed January 1, 2011 as the effective date for the convergence of Canadian GAAP to International Financial Reporting Standards ("IFRS"). The Canadian Securities Administrators are in the process of examining the changes to securities rules as a result of this initiative. Bonavista has completed a preliminary analysis of the accounting differences and is in the process of performing a detailed assessment of the impact of IFRS on our results of operations, financial position and disclosures.

3. Business relationships:

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

For the year ended December 31, 2009, Bonavista charged NuVista no fees (2008 - $1.1 million) relating to general and administrative services provided to NuVista. NuVista charged Bonavista management fees for a jointly owned partnership totaling $1.2 million (2008 - $1.4 million). As at December 31, 2009, the amount payable to NuVista was $343,000.

4. Asset retirement obligations:

The Trust's asset retirement obligations result from net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. The Trust estimates the total undiscounted amount of expenditures required to settle its asset retirement obligations is approximately $753.5 million (2008 - $587.0 million) which will be incurred over the next 51 years. The majority of the costs will be incurred between 2011 and 2038. A credit-adjusted risk-free rate of 7.5% (2008 - 7.5%) 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:

	Years ended December 31, 2009	**2008**
(thousands)		
Balance, beginning of year	$ 127,467	$ 116,893
Accretion expense	10,033	8,577
Liabilities incurred	3,195	9,177
Liabilities acquired	31,234	2,746
Liabilities settled	(12,036)	(15,229)
Change in estimate	421	5,303
Balance, end of year	**$ 160,314**	**$ 127,467**

5. Property acquisition:

On August 20, 2009, Bonavista acquired certain long-life natural gas weighted properties located in its Western Region for a cash purchase price of approximately $698 million.

6. Oil and natural gas properties and equipment:

December 31, 2009		Cost		Accumulated depreciation and depletion		Net book value
(thousands)						
Oil and natural gas properties	$	3,667,533	$	1,423,169	$	2,244,364
Facilities		842,307		183,886		658,421
Office equipment		8,378		5,090		3,288
	$	**4,518,218**	**$**	**1,612,145**	**$**	**2,906,073**

December 31, 2008		Cost		Accumulated depreciation and depletion		Net book value
(thousands)						
Oil and natural gas properties	$	2,966,957	$	1,174,448	$	1,792,509
Facilities		673,240		149,143		524,097
Office equipment		7,262		4,268		2,994
	$	**3,647,459**	**$**	**1,327,859**	**$**	**2,319,600**

Unproved property costs of $179.7 million as at December 31, 2009 (2008 - $161.8 million) were excluded from the depreciation and depletion calculation. Future development costs of $587.0 million (2008 - $241.8 million) were included in the depreciation and depletion calculation.

Bonavista has calculated the ceiling test as of December 31, 2009. Based on the calculation, the present value of future net revenues from the Trust's proved reserves exceeds the carrying value of the Trust's oil and natural gas properties and equipment at December 31, 2009. The benchmark reference prices, as provided by our independent engineering consultants, used in the calculation and adjusted for commodity differentials specific to Bonavista are as follows.

Benchmark Reference Price Forecasts:

Year	WTI Oil (US$/bbl)	AECO Gas (Cdn$/mmbtu)	USD/CAD Exchange Rates
2010	80.00	5.96	0.95
2011	83.00	6.79	0.95
2012	86.00	6.89	0.95
2013	89.00	6.95	0.95
2014	92.00	7.05	0.95
2015	93.84	7.16	0.95
2016	95.72	7.42	0.95
2017	97.64	7.95	0.95
2018	99.59	8.52	0.95
2019	101.58	8.69	0.95
Remainder (1)	2.0%	2.0%	0.95

(1) Escalated at 2% per year thereafter

7. Long-term debt:

The Trust has two bank loan facilities totaling $1.4 billion with a syndicate of chartered banks. These combined facilities are unsecured, covenant-based, extendible revolving facilities and include a $50 million working capital facility. The facilities provide that advances may be made by way of prime rate loans, bankers' acceptances and/or US dollar LIBOR advances. These advances bear interest at the banks' prime rate and/or at money market rates plus a stamping fee. The facilities are revolving credit and may, at the request of the Trust with the consent of the lenders, be extended on an annual basis. The facilities have a maturity of August 10, 2011 with no principal payments required until then. There is an accordion feature providing that at anytime during the term, on participation of any existing or additional lenders, we can increase the facility by $250 million.

Under the terms of the credit facilities, the Trust has provided the covenant that its: (i) consolidated senior debt borrowing will not exceed three times net income before unrealized gains and losses on financial instruments and marketable securities, interest, taxes and depreciation, depletion and accretion; (ii) consolidated total debt will not exceed three and one half times consolidated net income before unrealized gains and losses on financial instruments and marketable securities, interest, taxes and depreciation, depletion and accretion; and (iii) consolidated senior debt borrowing will not exceed one-half of consolidated total debt plus consolidated unitholders' equity of the Trust, in all cases calculated based on a rolling prior four quarters.

Financing expenses for the year ended December 31, 2009 include interest on bank loans of $11.2 million (2008 – $29.3 million) and convertible debentures of $2.8 million (2008 – $3.2 million). For the year ended December 31, 2009, Bonavista paid cash interest of $14.4 million (2008 – $32.9 million). For the year ending December 31, 2009 our effective interest rate was approximately 1.5% (2008 – 3.9%).

8. Convertible debentures:

The debt component of the debentures has been recorded net of the fair value of the conversion feature and issue costs. The fair value of the conversion feature of the debentures included in Unitholders' equity at the date of issue was $4.7 million. The issue costs are amortized to net income over the term of the obligation. The debt portion is accreted over the term of the obligation to the principal value on maturity with a corresponding charge to net income. On June 30, 2009, the 7.5% convertible debentures matured and were cash settled. The following table sets out the convertible debenture activities to December 31, 2009:

	Debt Component	Equity Component
(thousands)		
Balance, December 31, 2007	$ 48,830	$ 1,054
Accretion	57	-
Issue expenses related to conversions to trust units	42	-
Amortization of issue expenses	684	-
Conversion to trust units	(5,902)	(121)
Balance, December 31, 2008	$ 43,711	$ 933
Accretion	452	-
Issue expenses related to conversions to trust units	2	-
Amortization of issue expenses	525	-
Repayment of convertible debentures on maturity	(6,586)	(123)
Conversion to trust units	(11)	(2)
Balance, December 31, 2009	**$ 38,093**	**$ 808**

9. Unitholders' equity:

a) Authorized:

Unlimited number of voting trust units.

b) Issued and outstanding:

(i) Trust units:

	Number of Units	Amount
(thousands)		
Balance, December 31, 2007	85,757	850,631
Issued for cash	7,000	214,200
Issued on conversion of convertible debentures	215	5,902
Issued on conversion of exchangeable shares	1,632	5,222
Issued upon exercise of trust unit incentive rights	1,099	19,957
Conversion of restricted trust units	67	-
Issue costs, related to debenture conversions	-	(42)
Issue costs, net of future tax benefit	-	(7,924)
Adjustment to equity component of debenture on conversion	-	121
Unit-based compensation	-	11,768
Balance, December 31, 2008	95,770	1,099,835
Issued for cash	25,000	421,250
Issued on conversion of convertible debentures	1	11
Issued on conversion of exchangeable shares	3,380	10,193
Issued upon exercise of trust unit incentive rights	335	4,478
Conversion of restricted trust units	118	-
Issue costs, related to debenture conversions	-	(2)
Issue costs, net of future tax benefit	-	(16,218)
Adjustment to equity component of debenture on conversion	-	2
Unit-based compensation	-	10,942
Balance, December 31, 2009	**124,604**	**$ 1,530,491**

Redemption right:

Unitholders may redeem their Trust Units at any time by delivering their Unit Certificates to the Trustee, together with a properly completed notice requesting redemption. The redemption amount per Trust Unit will be the lesser of 90% of the weighted average trading price of the Trust Units on the principal market on which they are traded for the 10 day period after the Trust Units have been validly tendered for redemption and the "closing market price" of the Trust Units. The redemption amount will be payable on the last day of the following calendar month. The "closing market price" will be the closing price of the Trust Units on the principal market in which they are traded on the date on which they were validly tendered for redemption, or, if there was no trade of the Trust Units on that date, the average of the last bid and ask prices of the Trust Units on that date. Cash payments for Units tendered for redemption are limited to $250,000 per month with redemption requests in excess of this amount, eligible to receive a note from BPL.

(ii) Contributed surplus:

		Amount
(thousands)		
Balance, December 31, 2007	$	9,369
Unit-based compensation expense		11,049
Unit-based compensation capitalized		2,037
Exercise of trust unit incentive rights and conversion of restricted trust units		(11,768)
Balance, December 31, 2008		10,687
Unit-based compensation expense		11,386
Unit-based compensation capitalized		2,065
Adjustment to equity component of debenture on repayment		123
Exercise of trust unit incentive rights and conversion of restricted trust units		(10,942)
Balance, December 31, 2009	**$**	**13,319**

(iii) Exchangeable shares:

Pursuant to the Plan of Arrangement, 15,999,999 exchangeable shares were authorized and issued. The exchangeable shares of BPL are exchangeable only into trust units based on the exchange ratio, which is adjusted monthly, to reflect the distribution paid on the trust units. As a result distributions are not paid on the exchangeable shares.

	Years ended December 31,			
	2009		**2008**	
	Number	**Amount**	**Number**	**Amount**
(thousands)				
Balance, beginning of year	11,375	$ 69,488	12,230	$ 74,710
Exchanged for trust units	(1,668)	(10,193)	(855)	(5,222)
Balance, end of year	**9,707**	**$ 59,295**	**11,375**	**$ 69,488**
Exchange ratio, end of year	2.21352	-	1.96225	-
Trust units issuable on exchange	**21,486**	**$ 59,295**	**22,321**	**$ 69,488**

As a result of minimal conversions of exchangeable shares into trust units over the last few years, Bonavista elected to redeem 10% of its exchangeable shares outstanding on January 16, 2009. This redemption allows Bonavista to manage the dilution created by the compounding effect of the exchangeable shares, maintain an optimal capital and tax efficient trust structure for the Trust and its unitholders. On January 16, 2009, 1.1 million exchangeable shares were redeemed for 2.3 million trust units.

On July 2, 2013, subject to extension of such date by the Board of Directors of BPL, the Exchangeable Shares will be redeemed for Trust Units at a price equal to the value of that number of Trust Units based on the exchange ratio as at the last business day prior to the redemption date. BPL may redeem all but not less than all of the outstanding Exchangeable Shares at any time when the aggregate number of issued and outstanding Exchangeable Shares is less than 1,000,000. BPL will, at least 90 days prior to any redemption date, provide the registered holders with written notice of the prospective redemption. The redemption price is equal to that described previously.

c) Trust unit incentive rights plan:

The Trust has a unit incentive rights plan that allows the Trust to issue rights to acquire trust units to directors, officers, employees and service providers. The number of trust unit rights available under both long-term incentive plans shall be limited to 5% of the aggregate number of issued and outstanding trust units of the Trust. Trust unit incentive right exercise prices are equal to the market price for the trust units on the date that the unit rights are granted. If certain conditions are met, the exercise price per unit may be calculated by deducting from the grant price the aggregate of all distributions, on a per unit basis, made by the Trust after the grant date. The trust unit incentive rights granted under the plan vest over a four-year period and expire two years after each vesting date.

	Number of Trust Unit Incentive Rights	Weighted Average Exercise Price
Balance, December 31, 2007	3,726,125	$ 24.76
Granted	960,840	33.68
Exercised	(1,099,250)	(18.16)
Expired and forfeited	(378,920)	(26.54)
Reduction in exercise price	-	(3.60)
Balance, December 31, 2008	3,208,795	25.88
Granted	1,616,820	16.57
Exercised	(335,410)	(13.35)
Expired and forfeited	(673,963)	(22.62)
Reduction in exercise price	-	(1.80)
Balance, December 31, 2009	**3,816,242**	**$ 21.28**
Exercisable, December 31, 2009	**993,960**	**$ 22.63**

The following table summarizes trust unit incentive rights outstanding and exercisable under the plan at December 31, 2009:

	Trust Unit Incentive Rights Outstanding			Trust Unit Incentive Rights Exercisable	
Range of exercise prices	Number outstanding at year-end	Weighted average remaining contractual life	Weighted average exercise price	Number exercisable at year-end	Weighted average exercise price
$ 11.01 - 15.71	1,303,914	3.5	$ 14.29	145,955	$ 14.19
15.72 - 22.82	1,118,873	1.6	21.16	465,565	21.33
22.83 - 38.23	1,393,455	2.4	27.92	382,440	27.42
$ 11.01 - 38.23	3,816,242	2.5	$ 21.28	993,960	$ 22.63

d) Unit-based compensation:

The Trust uses the fair value based method for the determination of the unit-based compensation costs. The fair value of each incentive right granted was estimated on the date of grant using the modified Black-Scholes option-pricing model. In the pricing model, the risk free interest was 3.5% (2008 - 3.5%); average volatility of 66% (2008 - 32%); a forfeiture rate of 10% (2008 - 10%) and an expected life of 4.5 years. The fair value of the options granted in 2009 average $9.76 (2008 - $9.05) per incentive right.

e) Restricted trust unit incentive plan:

The Trust has a Restricted Trust Unit Incentive Plan that allows the Trust to award trust units to directors, officers, employees and service providers. The number of restricted trust units available under both long-term incentive plans shall be limited to 5% of the aggregate number of issued and outstanding units of the Trust. Vesting arrangements are within the discretion of our board of directors, but all awards will vest within three years from the date of grant. On the vesting date, at the discretion of Trust, the holder will receive for each unit award, including distributions made on the trust units from the date of the grant to and including the vesting date, net of statutory withholding tax, either: (i) equivalent trust units; or (ii) the cash equivalent.

The following table summarizes the restricted trust unit's outstanding under the plan at December 31, 2009:

Balance, December 31, 2008	150,573
Granted	171,450
Forfeited	(16,971)
Conversion of restricted trust units	(107,156)
Balance, December 31, 2009	**197,896**

For the year ended December 31, 2009, the Trust expensed $2.2 million (2008 – $3.7 million) relating to the Restricted Trust Unit Incentive Plan.

f) Per unit amounts:

The following table summarizes the weighted average trust units, exchangeable shares and convertible debentures used in calculating net income per trust unit:

	Years ended December 31, 2009	2008
(thousands)		
Trust units	108,029	91,703
Exchangeable shares converted at the exchange ratio	21,234	22,487
Basic equivalent trust units	129,263	114,190
Convertible debentures	1,471	1,713
Trust unit incentive rights	281	435
Restricted trust units	218	130
Diluted equivalent trust units	**131,233**	**116,468**

For the purposes of calculating net income per trust unit on a diluted basis, the net income has been increased by $3.8 million (2008 - $4.0 million) with respect to the accretion, amortization and interest expense on the convertible debentures. For the year ended December 31, 2009 the Trust excluded 3.5 million (2008 - 2.8 million) weighted average trust unit incentive rights from the diluted unit calculation as they are anti-dilutive.

10. Income taxes:

The provision for income tax differs from the result which would have been obtained by applying the combined Federal and Provincial income tax rates to net income before taxes. This difference results from the following items:

		Years ended December 31, 2009		2008
Expected tax rate		29.2%		29.8%
(thousands)				
Expected tax expense	$	15,762	$	145,436
Effect of change in tax rate		(8,949)		(761)
Distributions to unitholders		(63,701)		(99,142)
Other		4,261		3,918
Provision for income taxes (reduction)	**$**	**(52,627)**	**$**	**49,451**
The provision for income taxes consists of:				
Current	$	-	$	-
Future (reduction)		(52,627)		49,451
Provision for income taxes (reduction)	**$**	**(52,627)**	**$**	**49,451**

The significant components of future income tax assets and liabilities as at December 31 are:

		2009		2008
(thousands)				
Oil and natural gas properties	$	146,547	$	167,146
Facilities		36,135		41,214
Asset retirement obligations		(38,354)		(31,107)
Unrealized financial instruments & Other		(2,876)		22,221
Future income taxes	**$**	**141,452**	**$**	**199,474**

For the years ended December 31, 2009 and 2008 Bonavista paid no tax installments.

11. Financial instruments:

The Trust has exposure to credit, liquidity and market risks from its use of financial instruments. This note provides information about the Trust's exposure to each of these risks, the Trust's objectives, policies and processes for measuring and managing risk. Further quantitative disclosures are included throughout these financial statements.

a) Credit risk:

The carrying amount of accounts receivable represents the maximum credit exposure. As at December 31, 2009 the Trust's receivables consisted of $83.8 million of receivables from crude oil and natural gas marketers which has substantially been collected, subsequent to December 31, 2009, $19.6 million from joint venture partners of which $5.2 million has been subsequently collected, and $25.0 million of Crown deposits and prepaid expenses. As at December 31, 2009 the Trust has $10.7 million in accounts receivable that is considered to be past due. Although these amounts have been outstanding for greater than 90 days, they are still deemed to be collectible. The Trust does not have an allowance for doubtful accounts as at December 31, 2009 and did not provide for any doubtful accounts nor was it required to write-off any receivables during the year ended December 31, 2009.

b) Liquidity risk:

Liquidity risk is the risk that the Trust will encounter difficulty in meeting obligations associated with the financial liabilities. The Trust's financial liabilities consist of accounts payable and accrued liabilities, financial instruments, bank debt and convertible debentures. Accounts payable consists of invoices payable to trade suppliers for office, field operating activities, capital expenditures, and distributions payable. The Trust processes invoices within a normal payment period.

Accounts payable and financial instruments have contractual maturities of less than one year. The Trust maintains a three year revolving credit facility, as outlined in note 7, which may, at the request of the Trust with the consent of the lenders, be extended on an annual basis. The Trust also has a series of convertible debentures outstanding. The 6.75% debentures have a conversion price of $29.00 per trust unit, maturing on June 30, 2010. The Trust may elect to satisfy the principal obligation of this debenture by issuing trust units to the holders of the debentures. The Trust also maintains and monitors a certain level of cash flow which is used to partially finance all operating, investing and capital expenditures.

c) Commodity price risk:

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for crude oil and natural gas are impacted not only by global economic events that dictate the levels of supply and demand but also by the relationship between the Canadian and United States dollar. The Trust has attempted to mitigate a portion of the commodity price risk through the use of various financial instruments and physical delivery sales contracts. The Trust's policy is to enter into commodity price contracts when considered appropriate to a maximum of 60% of net after royalty, forecasted production volumes.

i) Financial instruments:

As at December 31, 2009, the Trust has hedged by way of costless collars to sell natural gas and crude oil as follows:

Volume		**Average Price**	**Term**
5,000	gjs/d	CDN$5.00 - CDN$6.50 - AECO	January 1, 2010 – March 31, 2010
15,000	gjs/d	CDN$4.75 - CDN$6.45 - AECO	April 1, 2010 - October 31, 2010
5,000	gjs/d	CDN$4.50 - CDN$5.50 - AECO	January 1, 2010 - March 31, 2010
20,000	gjs/d	CDN$4.56 - CDN$6.12 - AECO	January 1, 2010 - December 31, 2010
10,000	gjs/d	CDN$5.25 - CDN$7.20 - AECO	January 1, 2011 - December 31, 2011
9,000	bbls/d	CDN$68.06 - CDN$92.83 - WTI	January 1, 2010 - December 31, 2010
1,000	bbls/d	CDN$80.00 - CDN$95.25 - WTI	January 1, 2011 - December 31, 2011

As at December 31, 2009, the Trust has limited its downside exposure to natural gas prices by purchasing a put option. The Trust has also hedged its exposure to electricity pricing by entering into a swap which determines a fixed price paid throughout the term of the contract. These financial instruments are outlined below:

Volume		**Price**	**Contract**	**Term**
5,000	gjs/d	CDN $4.50	Purchased Put - AECO	April 1, 2010 - October 31, 2010
1	mw/h	CDN$55.00	Swap - AESO	January 1, 2010 - December 31, 2010

Financial instruments are recorded on the consolidated balance sheet at fair value at each reporting period with the change in fair value being recognized as an unrealized gain or loss on the consolidated statements of operations, comprehensive income and accumulated earnings. As at December 31, 2009 the fair market value recorded on the consolidated balance sheet for these financial instruments was a net liability of $9.5 million, compared to an asset of $76.2 million in 2008. These financial instruments had the following gains and losses reflected in the consolidated statements of operations, comprehensive income and accumulated earnings:

	Years ended December 31, 2009	**2008**
Realized gains (losses) on financial instruments	$ 72,100	$ (80,806)
Unrealized gains (losses) on financial instruments	(85,746)	121,261
	$ (13,646)	$ 40,455

Bonavista mitigates its risk associated with fluctuations in commodity prices by utilizing financial instruments. A $0.10 change in the price per thousand cubic feet of natural gas @ AECO would have an impact of approximately $2.7 million on net income for those financial instruments that were in place as at December 31, 2009. A $1.00 change in the price per barrel of oil – WTI would have an impact of approximately $1.4 million on net income for those financial instruments that were in place as at December 31, 2009.

Subsequent to December 31, 2009 the Trust has hedged by way of costless collars to sell natural gas and crude oil as follows:

Volume		Average Price	Term
5,000	gjs/d	CDN$4.50 - CDN$7.24 - AECO	March 1, 2010 - October 31, 2011
10,000	gjs/d	CDN$4.50 - CDN$6.50 - AECO	April 1, 2010 - October 31, 2010
10,000	gjs/d	CDN$5.00 - CDN$7.45 - AECO	November 1, 2010 - March 31, 2011
5,000	gjs/d	CDN$5.00 - CDN$6.50 - AECO	April 1, 2011 - October 31, 2011
1,000	bbls/d	CDN$75.00 - CDN$92.38 - WTI	January 1, 2010 - December 31, 2010
1,000	bbls/d	CDN$75.00 - CDN$91.03 - WTI	July 1, 2010 - September 30, 2010
1,500	bbls/d	CDN$80.00 - CDN$98.40 - WTI	January 1, 2011 - December 31, 2011

ii) Physical purchase contracts:

As at December 31, 2009, the Trust has entered into direct sale costless collars to sell natural gas as follows:

Volume		Average Price	Term
10,000	gjs/d	CDN$5.25 - CDN$6.53 - AECO	January 1, 2010 - March 31, 2010
5,000	gjs/d	CDN$5.25 - CDN$7.00 - AECO	April 1, 2010 - October 31, 2010
5,000	gjs/d	CDN$5.00 - CDN$6.60 - AECO	January 1, 2010 - December 31, 2010
10,000	gjs/d	CDN$5.13 - CDN$6.99 - AECO	January 1, 2011 - December 31, 2011
5,000	gjs/d	CDN$5.25 - CDN$8.18 - AECO	November 1, 2010 - March 31, 2011

As at December 31, 2009, the Trust has entered into physical swap contracts to sell natural gas and to purchase electricity as follows:

Volume		Average Price	Term
5,000	gjs/d	CDN $5.06 - AECO	January 1, 2010 - December 31, 2010
4	mw/h	CDN$50.54 - AESO	January 1, 2010 - December 31, 2010
2	mw/h	CDN$55.03 - AESO	January 1, 2011 - December 31, 2011

Subsequent to December 31, 2009 the Trust has entered into direct sale costless collars to sell natural gas as follows:

Volume		Average Price	Term
10,000	gjs/d	CDN$4.50 - CDN$6.11 - AECO	April 1, 2010 - October 31, 2010
5,000	gjs/d	CDN$5.00 - CDN$7.10 - AECO	November 1, 2010 - March 31, 2011

Physical purchase contracts are being accounted for as they are settled.

iii) Foreign currency exchange rate risk:

Foreign currency exchange rate risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. The Trust sells crude oil and natural gas that is denominated in both US and Canadian dollars. Canadian commodity prices are influenced by fluctuations in the Canadian to U.S. dollar exchange rate. The Trust had no forward exchange rate contracts in place as at or during the period ended December 31, 2009.

iv) Interest rate risk:

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Trust is exposed to interest rate fluctuations on its bank debt which bears a floating rate of interest. If the interest rates applicable to Bonavista's bank debt were to change by 100 basis points and assuming that the changes in bank debt are consistent with what actually occurred in the period, we would estimate that net income for the year ended December 31, 2009 would have a $5.5 million (2008 - $5.0 million) impact. The sensitivity impact is higher for the year ended in 2009 because of higher weighted average bank debt compared to the year ended December 31, 2008, notwithstanding that the weighted average interest rate is lower in 2009 compared to the same period in 2008. The Trust had no interest rate swap or financial contracts in place as at or during the period ended December 31, 2009.

Fair value of financial instruments:

The financial instruments carried on the Trust's consolidated balance sheet have been assessed on the fair value hierarchy set out under amended Section 3862, "Financial Instruments – Disclosures". The Trust has classified the fair value of these transactions according to the following hierarchy based on the amount of observable inputs used to value the instruments.

Level 1 – quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3 – valuation in this level are those with inputs for the asset or liabilities that are not based on observable market data.

All of the Trust's financial contracts, marketable securities, convertible debentures and bank debt have been fair valued based on the policy outlined above. The Trust's marketable securities and convertible debentures have been classified as Level 1, the financial contracts are classified as Level 2 and bank debt is classified as Level 3.

The fair value of financial instruments is determined by the financial intermediary to extinguish all rights or obligations of the financial instruments. As at December 31, 2009, the fair market value of these financial instruments was a net liability of approximately $9.5 million (2008 - $76.2 million asset).

Fair market value of the convertible debentures as at December 31, 2009 is $38.9 million (2008 - $44.4 million), as determined by its most recent closing trading price.

Fair market value of marketable securities as at December 31, 2009 is $6.3 million (2008 - nil), as determined by the closing price of common shares of Legacy Oil and Gas Inc.

Bank debt bears interest at a floating market rate and accordingly the fair market value approximates the carrying value.

12. Capital management:

The Trust's objective when managing capital is to maintain a flexible capital structure which allows it to execute its growth strategy through strategic acquisitions and expenditures on exploration and development activities while maintaining a strong financial position that provides our unitholders with stable distributions and rates of return.

The Trust considers its capital structure to include working capital (excluding unrealized gains and losses on financial instruments), convertible debentures, bank debt, and unitholders' equity. The Trust monitors capital based on the ratio of net debt to annualized funds from operations. The ratio represents the time period it would take to pay off the debt if no further capital expenditures were incurred and if funds from operations remained constant. This ratio is calculated as net debt, defined as outstanding bank debt plus or minus net working capital, divided by funds from operations for the most recent calendar quarter, annualized (multiplied by four). The Trust's strategy is to maintain a ratio of less than 2.0 to 1. This strategy is more restrictive than the existing financial covenants on the Trust's credit facility. This ratio may increase at certain times as a result of acquisitions or low commodity prices. As at December 31, 2009, the Trust's ratio of net debt to fourth quarter annualized funds from operations was 1.6 to 1 (2008 – 1.2 to 1), which is within the acceptable range established by the Trust.

In order to facilitate the management of this ratio, the Trust prepares annual funds from operations and capital expenditure budgets, which are updated as necessary, and are reviewed and periodically approved by the Trust's Board of Directors. The Trust manages its capital structure and makes adjustments by continually monitoring its business conditions, including; the current economic conditions; the risk characteristics of the Trust's crude oil and natural gas assets; the depth of its investment opportunities; current and forecasted net debt levels; current and forecasted commodity prices; and other factors that influence commodity prices and funds from operations, such as quality and basis differential, royalties, operating costs and transportation costs.

In order to maintain or adjust the capital structure, the Trust will consider; its forecasted ratio of net debt to forecasted funds from operations while attempting to finance an acceptable capital expenditure program including acquisition opportunities; the current level of bank credit available from the Trust's lenders; the level of bank credit that may be attainable from its lenders as a result of crude oil and natural gas reserves; the availability of other sources of debt with different characteristics than the existing bank debt; the sale of assets; limiting the size of the capital expenditure program; issuance of new equity if available on favourable terms; and its level of distributions payable to its unitholders. The Trust's unitholder's capital is not subject to external restrictions, however the Trust's credit facility does contain financial covenants that are outlined in note 7 of the consolidated financial statements.

There has been no change in the Trust's approach to capital management during the year ended December 31, 2009.

13. Commitments:

The following is a summary of the Trust's commitments as at December 31, 2009:

	Payments Due by Period					
	Total	2010	2011	2012	2013	2014 and thereafter
(thousands)						
Transportation expenses	$ 51,417	$ 16,114	$ 11,570	$ 8,314	$ 6,665	$ 8,754
Office premises	1,708	1,412	296	-	-	-
Total commitments	**$ 53,125**	**$ 17,526**	**$ 11,866**	**$ 8,314**	**$ 6,665**	**$ 8,754**

14. Subsequent events:

a) Property acquisitions:

On March 24, 2010, the Trust announced that it had entered into an agreement to acquire certain long-life natural gas weighted properties located adjacent to our Whitecourt property in west central Alberta. The acquisition has an effective date of January 1, 2010 and is expected to close on or about May 31, 2010 for a cash purchase price, at closing, of approximately $228 million.

b) Financing:

In conjunction with the acquisition, Bonavista has entered into an agreement to sell, on a bought deal basis, 7.5 million Trust Units at a price of $23.60 per Trust Unit for gross proceeds of approximately $177 million to a syndicate of underwriters.

CORPORATE INFORMATION

DIRECTORS

Keith A. MacPhail,
Chairman and CEO
Ian S. Brown,
Independent Businessman
Michael M. Kanovsky,
Sky Energy Corporation
Harry L. Knutson,
Nova Bancorp Inc.
Margaret A. McKenzie,
Range Royalty Management Ltd.
Ronald J. Poelzer,
Executive Vice President and Vice Chairman
Christopher P. Slubicki,
OPTI Canada Inc.
Walter C. Yeates,
Independent Businessman

OFFICERS

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Jason E. Skehar,
President and COO
Ronald J. Poelzer,
Executive Vice President and Vice Chairman
Glenn A. Hamilton,
Senior Vice President and CFO
Thomas J. Mullane,
Senior Vice President, Engineering
Johannes H. Thiessen,
Senior Vice President, Exploration
Scott H. Hanson,
Vice President, Production
Orest G. Humeniuk,
Vice President, Land
Dean M. Kobelka,
Vice President, Finance
Lynda J. Robinson,
Vice President, Human Resources and Administration
Hank R. Spence,
Vice President, Operations
Grant A. Zawalsky,
Corporate Secretary

AUDITORS

KPMG LLP
Chartered Accountants
Calgary, Alberta

BANKERS

Canadian Imperial Bank of Commerce
The Toronto-Dominion Bank
Bank of Montreal
Royal Bank of Canada
The Bank of Nova Scotia
National Bank of Canada
Alberta Treasury Branches
Union Bank of California, N.A. (Canada Branch)
Fortis Capital (Canada) Ltd.
HSBC Bank Canada
Société Générale (Canada Branch)
Sumitomo Mitsui Banking Corporation of Canada
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ENGINEERING CONSULTANTS

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Ryder Scott Company Canada
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
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BONAVISTA
ENERGY TRUST