BAYTEX

ENERGY TRUST

FOR IMMEDIATE RELEASE – CALGARY, ALBERTA –MARCH 10, 2009

BAYTEX ENERGY TRUST ANNOUNCES RECORD PRODUCTION, CASH FLOW AND NET INCOME FOR 2008

Baytex Energy Trust (TSX: BTE.UN; NYSE: BTE) is pleased to announce its operating and financial results for the three months and year ended December 31, 2008.

Highlights

- Produced an average of 42,035 boe/d for Q4/08 and record annual production of 40,239 boe/d for 2008;
- Generated cash flow of $60.5 million ($0.61 per diluted unit) for the fourth quarter of 2008, and record annual cash flow of $433.8 million ($4.51 per diluted unit) for 2008;
- Earned net income of $52.4 million ($0.53 per diluted unit) for the fourth quarter of 2008, and record annual net income of $259.9 million ($2.74 per diluted unit) for 2008;
- Increased proved reserves by 8% to 125.7 million boe, and proved plus probable reserves by 11% to 187.1 million boe at year end 2008;
- Attained reserve replacement ratio of 119% for the exploration and development capital program alone and 233% for the total capital program, including acquisitions;
- Achieved three-year finding, development and acquisition ("FD&A") costs of $11.02/boe of proved plus probable reserves excluding future development costs ("FDC") and $12.98/boe including FDC;
- Realized recycle ratios of 2.9 (one-year) and 2.8 (three-year); and
- Grew net asset value per trust unit by 30% to $31.57.

FINANCIAL	Three Months Ended			Year Ended	
($ thousands, except per unit amounts)	**December 31, 2008**	September 30, 2008	December 31, 2007	**December 31, 2008**	December 31, 2007
Petroleum and natural gas sales	**199,890**	363,044	233,856	**1,159,718**	745,885
Cash flow from operations (1)	**60,472**	146,586	98,667	**433,823**	286,030
Per unit - basic	**0.62**	1.53	1.17	**4.73**	3.57
- diluted	**0.61**	1.47	1.10	**4.51**	3.34
Cash distributions	**55,314**	57,233	37,314	**197,026**	145,927
Per unit	**0.68**	0.75	0.54	**2.64**	2.16
Net Income	**52,401**	137,228	41,353	**259,894**	132,860
Per unit - basic	**0.54**	1.44	0.49	**2.83**	1.66
- diluted	**0.53**	1.39	0.48	**2.74**	1.60
Exploration and development	**42,969**	48,584	34,349	**185,083**	148,719
Acquisitions – net of dispositions	**8,174**	78,635	5,064	**265,099**	245,427
Total capital expenditures	**51,143**	127,219	39,413	**450,182**	394,146
Long-term notes	**220,362**	190,725	177,805	**220,362**	177,805
Bank loan	**208,482**	200,445	241,748	**208,482**	241,748
Convertible debentures	**10,195**	10,377	16,150	**10,195**	16,150
Working capital deficiency	**93,979**	56,446	8,362	**93,979**	8,362
Total monetary debt(2)	**533,018**	457,993	444,065	**533,018**	444,065

	Three Months Ended			Year Ended	
	December 31, 2008	September 30, 2008	December 31, 2007	**December 31, 2008**	December 31, 2007
OPERATING					
Daily production					
Light oil & NGL (bbl/d)	**7,803**	8,377	8,123	**7,575**	5,483
Heavy oil (bbl/d)	**24,635**	24,078	22,196	**23,530**	22,092
Total oil (bbl/d)	**32,438**	32,455	30,319	**31,105**	27,575
Natural gas (MMcf/d)	**57.6**	60.5	53.9	**54.8**	51.9
Oil equivalent (boe/d @ 6:1)	**42,035**	42,538	39,304	**40,239**	36,222
Average prices (before hedging)					
WTI oil (US$/bbl)	**58.35**	118.36	90.68	**99.59**	72.31
Edmonton par oil ($/bbl)	**63.94**	122.77	86.41	**102.86**	76.35
BTE light oil & NGL ($/bbl)	**55.31**	107.41	74.77	**88.92**	65.53
BTE heavy oil ($/bbl) (3)	**38.93**	84.65	50.36	**65.22**	44.53
BTE total oil ($/bbl)	**42.83**	90.56	56.55	**70.94**	48.65
BTE natural gas ($/Mcf)	**7.05**	8.01	6.31	**7.92**	6.61
BTE oil equivalent ($/boe)	**42.71**	80.44	52.45	**65.66**	46.53
TRUST UNIT INFORMATION					
TSX (C$)					
Unit price					
High	**$27.05**	$35.01	$20.65	**$35.37**	$22.92
Low	**$12.81**	$23.15	$18.08	**$12.81**	$16.68
Close	**$14.65**	$25.73	$19.00	**$14.65**	$19.00
Volume traded (thousands)	**31,267**	31,620	17,426	**123,417**	86,185
NYSE (US$)					
Unit price					
High	**$25.49**	$35.20	$21.74	**$35.20**	$21.74
Low	**$10.16**	$22.35	$18.19	**$10.16**	$15.51
Close	**$11.95**	$24.71	$19.11	**$11.95**	$19.11
Volume traded (thousands)	**14,498**	10,240	5,433	**34,514**	18,063
Units outstanding (thousands) (4)	**97,685**	96,934	87,169	**97,685**	87,169

(1) Cash flow from operations is a non-GAAP term that represents cash generated from operating activities before changes in non-cash working capital and other operating items (see reconciliation under MD&A). The Trust's cash flow from operations may not be comparable to other issuers. The Trust considers cash flow a key measure of performance as it demonstrates the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.

(2) Total monetary debt is a non-GAAP term, and is defined in note 16 to the consolidated financial statements.

(3) Heavy oil wellhead prices are net of blending costs.

(4) Number of trust units outstanding includes the conversion of exchangeable shares at the exchange ratios in effect at the end of the applicable reporting periods.

This press release contains certain forward-looking information and statements. We refer you to the end of the Management's Discussion and Analysis section of this press release for our advisory on forward-looking information and statements.

Operations Review

Capital expenditures for exploration and development activities totaled $43.0 million for the fourth quarter of 2008. During this quarter, Baytex participated in drilling 28 (18.1 net) wells, resulting in 22 (15.5 net) oil wells and six (2.6 net) gas wells, with a 100% success rate. Fourth quarter drilling included 18 (12.5 net) Lloydminster area heavy oil wells, six (2.6 net) east-central Alberta gas wells, two (2.0 net) Seal horizontal heavy oil wells, and two (0.98 net) oil wells in the United States.

Production averaged 42,035 boe/d during the fourth quarter of 2008, as compared to 42,538 for the third quarter of 2008. Fourth quarter production at our key Seal property averaged 4,658 bbl/d. In the quarter, nine new dual-leg horizontal wells, seven of which were drilled late in the third quarter, were brought on production at average initial production rates of 220 bbl/d per well.

Our thermal pilot test well at Seal continued to exceed our original expectations. As of year end 2008, the project has yielded an incremental steam oil ratio (“SOR”) of 1.5 (after deducting projected primary production). SOR is the best single proxy for thermal operating economics. The incremental SOR from our pilot reflects very high thermal efficiency and bodes well for the economics of commercial steam development on our land base at Seal. Moreover, the thermal pilot performance has validated our numerical reservoir simulation models and will assist design and performance prediction for a permanent project. We have targeted production from a permanent steam project at Seal before the end of 2011. We reached another important milestone with the first booking of probable reserves using thermal recovery in our 2008 year-end reserve report. Although covering only approximately the top one-third of the Bluesky Oil Sand on one of our 105 sections of leasehold at Seal, this reserve booking further supports the economics of thermal development.

During the fourth quarter, the Burmis acquisition assets continued to meet our pre-acquisition expectations, delivering 3,426 boe/d. Three wells drilled late in the third quarter on Burmis lands in the Ferrier region were tied-in for production during the fourth quarter. Strong well performance was partially constrained by pipeline capacity restrictions. To alleviate the capacity constraints, Baytex is currently constructing an 8 km pipeline which is expected to be completed in the first quarter of 2009.

Baytex continued to develop our extensive leasehold position in the Williston Basin in North Dakota in the Bakken/Three Forks light oil resource play. During the fourth quarter, we participated in drilling one (0.375 net) horizontal production well. Baytex also participated in the acquisition of a new 3D seismic survey covering 188,000 acres. The seismic survey was 73% complete at the end of 2008. Net production from North Dakota was 341 bbl/d in the fourth quarter, with 2 (0.75 net) wells awaiting completion.

We are maintaining our 2009 average production guidance at 40,000 boe/d. The exploration and development capital budget to deliver this production level is set at $150 million. In addition, we expect to incur $10 million in deferred acquisition payments in respect of our North Dakota land purchase in 2008.

Financial Review

Cash flow from operations for the fourth quarter was $60.5 million, a decrease of 59% compared to $146.6 million for the third quarter of 2008. The largest contributor to the decline was a decrease in commodity prices in the fourth quarter. Baytex received an average oil price of $42.83/bbl before hedging in the fourth quarter, a decrease of 53% compared to $90.56/bbl before hedging in the third quarter. Natural gas prices also decreased in the fourth quarter, with Baytex receiving an average wellhead price of $7.05/Mcf, 12% lower than the third quarter.

Net income for the fourth quarter of 2008 was $52.4 million. The decline in commodity pricing noted above was partially offset by unrealized fourth quarter gains of $86.5 million for mark-to-market changes in the value of our financial derivatives contracts. The cash flow contribution of these contracts, which have locked in an average floor price of US$100 per barrel on 4,000 bbl/d for WTI for the 2009 calendar year, will be realized in 2009.

The heavy oil pricing differential averaged 34% of WTI for the fourth quarter of 2008, as compared to 15% in the third quarter. The increase in heavy oil differential, when expressed as a percentage of WTI, was exacerbated by the method by which heavy oil differentials are set. Because heavy oil differentials are priced in dollars in the month preceding delivery of the heavy crude, the percentage differential will typically increase in a rapidly declining WTI market, as occurred in the fourth quarter of 2008. Although WTI prices remain volatile on a daily basis, the downtrend in WTI has largely ceased since December 2008. Consequently, the volatility in percentage differentials for heavy oil experienced in the fourth quarter of 2008 has subsided. Heavy oil differentials for the first quarter of 2009 have averaged approximately US$9.00 per barrel, or 22% of the WTI price. Differentials for the second quarter of 2009 are currently being forward-traded at approximately 15% of WTI, resulting in estimated wellhead pricing of $40 per barrel for Lloydminster-area raw heavy crude, based on current WTI prices, foreign exchange rates and condensate costs.

Total cash distributions in the year of $197 million, or $2.64 per unit, represented a payout ratio of 45% net of DRIP participation (56% before DRIP), as compared to our 2007 payout ratio of 51% net of DRIP (61% before DRIP). Our payout ratio has remained consistently conservative since our conversion to a Trust in late 2003. In order to conserve our corporate liquidity, and to better match our distribution levels with the prevailing commodity price, we reduced our monthly distribution from $0.25 to $0.18 per unit in respect of December 2008 operations, and again from $0.18 to $0.12 per unit in respect of February 2009 operations.

Total net monetary debt, excluding notional mark-to-market assets at the end of the year, was $533.0 million which was an increase of $75.0 million from the end of the third quarter. Included in this increase is a $29.6 million unrealized foreign exchange loss related to the translation of our U.S. dollar denominated notes. Our total net monetary debt represents 1.2 times 2008 cash flow. At the end of 2008, Baytex had over $180 million in available undrawn credit lines, providing us with sufficient liquidity to manage through the current economic crisis.

The commodity price environment outlook continues to be challenging. Sustained improvement will depend on a combination of demand stabilization through economic recovery and supply erosion from OPEC production cuts and natural declines around the world due to reduced capital investment. In this economic environment, Baytex is taking the prudent steps required to ensure that we maintain our strong financial position.

Capital Program Efficiency

Since the conversion to an income trust in late 2003, Baytex has consistently demonstrated superior capital and operational efficiencies as we execute our strategy for long-term sustainability. Based on the reports prepared in accordance with National Instrument 51-101 ("NI 51-101") by our independent reserve evaluator, Sproule Associates Limited ("Sproule"), the efficiency of Baytex's capital programs is summarized as follows:

	2008	**2007**	**2006**	**Three Year Average 2006 - 2008**
Excluding Future Development Costs				
FD&A costs – Proved ($/boe)				
Exploration and development	$ 14.26	$ 10.03	$ 9.61	$ 11.21
Acquisitions (net of dispositions)	22.99	20.63	5.38	21.70
Total	$ 18.37	$ 14.75	$ 9.57	$ 15.01
FD&A costs – Proved plus Probable ($/boe)				
Exploration and development	$10.53	$9.17	$7.35	$ 9.00
Acquisitions (net of dispositions)	15.83	12.30	3.89	13.86
Total	$ 13.11	$ 10.90	$ 7.31	$ 11.02
Recycle ratio based on operating netback				
Proved plus Probable	2.9	2.4	3.7	2.8
Reserves Replacement Ratio				
Proved plus Probable	233%	274%	145%	219%
Including Future Development Costs				
FD&A costs – Proved ($/boe)				
Exploration and development	$ 11.01	$ 8.82	$ 20.49	$ 13.37
Acquisitions (net of dispositions)	27.87	22.93	6.46	25.26
Total	$ 18.95	$ 15.10	$ 20.36	$ 17.67
FD&A costs – Proved plus Probable ($/boe)				
Exploration and development	$ 12.09	$ 9.27	$ 15.77	$ 10.73
Acquisitions (net of dispositions)	20.23	14.05	4.44	16.13
Total	$ 16.06	$ 11.91	$ 15.66	$ 12.98

Notes:

(1) The aggregate of the exploration and development 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 reserve additions for that year.

In 2008, Baytex invested $67 million in undeveloped land in Divide Country in North Dakota and at Dodsland in Saskatchewan. Excluding the cost of these lands, our FD&A cost on a proved plus probable basis is $11.16 per boe excluding FDC ($14.11 per boe including FDC), with a resulting 2008 recycle ratio of 3.4 excluding FDC (2.7 including FDC).

Net Asset Value

The following net asset value calculation utilizes what is generally referred to as the "produce-out" net present value of Baytex's oil and gas reserves as evaluated by Sproule. It does not take into account the possibility of Baytex being able to recognize additional reserves through future capital investment in our existing properties beyond those included in the 2008 year-end report.

Forecast Prices Before Tax

	($ thousands)
Proved plus probable reserves (1)	3,478,854
Undeveloped land (2)	199,222
Net monetary debt (3)	(522,823)
Asset retirement obligations (4)	(49,351)
Net asset value	3,105,902
Diluted trust units (5)	98,390,282
Net asset value per trust unit	$31.57

Forecast Prices After Tax

	($ thousands)
Proved plus probable reserves (1)	2,887,480
Undeveloped land (2)	199,222
Net monetary debt (3)	(522,823)
Asset retirement obligations (4)	(36,699)
Net asset value	2,527,180
Diluted trust units (5)	98,390,282
Net asset value per trust unit	$25.69

Notes:

(1) Net present value of future net revenue discounted at 10% as evaluated by Sproule as at December 31, 2008. Net present value of future net revenue does not represent fair market value of the reserves.

(2) The value ascribed to the 797,130 net acres of undeveloped land Baytex held at December 31, 2008 was estimated by Management. This internal evaluation generally represents what we believe to be the replacement cost of our land at the present time based upon current industry activity. In order to determine replacement cost, we have analyzed land sale prices paid during 2008 at provincial crown and state lands sales for the properties in the vicinity of our land holdings, less an allowance for near-term expiries. The 2008 acquisitions of land in North Dakota and Dodsland in Saskatchewan, which were made primarily in the second half of 2008, were valued at the amounts paid, totaling $61.4 million, less an allowance for near-term expiries.

(3) Net monetary debt is long-term debt net of working capital as at December 31, 2008, excluding convertible debentures (which are assumed to be converted into trust units in the Net Asset Value calculation) and notional assets and liabilities associated with the mark-to-market value of derivative contracts (as the pricing effect of the derivatives contracts have already been reflected by Sproule in the values noted above).

(4) Management estimate of asset retirement obligations as at December 31, 2008 discounted at 8% (net of applicable future tax for "Forecast Prices After Tax" calculations).

(5) Includes 97,685,333 trust units and 704,949 trust units issuable on the conversion of the $10.4 million outstanding convertible debentures as at December 31, 2008.

Oil and Gas Reserves

Baytex announced certain of its year-end 2008 reserves information on February 17, 2009. The following is additional summary information with regard to oil and gas reserves as at December 31, 2008. Other detailed information as required under NI 51-101 will be included in Baytex's Annual Information Form for the year ended December 31, 2008, which will be filed in late March 2009.

Reconciliation of Gross Company Interest Reserves (1)
By Principal Product Type
Forecast Prices and Costs

	Light and Medium Crude Oil			Heavy Oil		
	Proved (2) (Mbbl)	Probable (2) (Mbbl)	Proved + Probable (2) (Mbbl)	Proved (2) (Mbbl)	Probable (2) (Mbbl)	Proved + Probable (2) (Mbbl)
December 31, 2007	10,037	5,295	15,332	85,069	37,392	122,461
Extensions	-	-	-	409	334	743
Discoveries	-	-	-	37	15	52
Improved Recoveries	467	3,615	4,082	3,306	7,381	10,687
Technical Revisions	2,017	(330)	1,687	6,269	(8,819)	(2,550)
Acquisitions	4,604	2,191	6,795	81	86	167
Dispositions	-	-	-	-	-	-
Economic Factors	37	13	50	487	263	750
Production	(2,133)	-	(2,133)	(8,722)	-	(8,722)
December 31, 2008	15,029	10,784	25,813	86,936	36,652	123,588

	Bitumen (4)			Natural Gas Liquids		
	Proved (2) (Mbbl)	Probable (2) (Mbbl)	Proved + Probable (2) (Mbbl)	Proved (2) (Mbbl)	Probable(2) (Mbbl)	Proved + Probable (2) (Mbbl)
December 31, 2007	-	-	-	3,603	1,870	5,473
Extensions	-	-	-	32	6	38
Discoveries	-	-	-	-	-	-
Improved Recoveries	-	2,464	2,464	166	67	233
Technical Revisions	-	-	-	(503)	(563)	(1,066)
Acquisitions	-	-	-	1,032	445	1,477
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	35	22	57
Production	-	-	-	(639)	-	(639)
December 31, 2008	-	2,464	2,464	3,726	1,847	5,573

	Natural Gas including solution gas			Oil Equivalent (3)		
	Proved (2) (MMcf)	Probable (2) (MMcf)	Proved + Probable (2) (MMcf)	Proved (2) (Mboe)	Probable (2) (Mboe)	Proved + Probable (2) (Mboe)
December 31, 2007	103,969	44,888	148,857	116,038	52,038	168,076
Extensions	248	393	641	482	406	888
Discoveries	-	-	-	37	15	52
Improved Recoveries	6,756	5,121	11,877	5,065	14,381	19,446
Technical Revisions	(6,053)	(7,620)	(13,673)	6,774	(10,982)	(4,208)
Acquisitions	33,880	14,893	48,773	11,364	5,204	16,568
Dispositions	-	-	-	-	-	-
Economic Factors	1,233	551	1,784	765	390	1,154
Production	(20,057)	-	(20,057)	(14,837)	-	(14,837)
December 31, 2008	119,976	58,226	178,202	125,688	61,451	187,139

Notes:
(1) Gross Company interest reserves include solution gas but do not include royalty interest.
(2) Reserves information as at December 31, 2008 and 2007 is prepared in accordance with NI 51-101.
(3) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
(4) Bitumen relates to probable reserves attributed to thermal production.

Management's Discussion and Analysis

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Trust ("Baytex" or the "Trust") for the three months and year ended December 31, 2008. This information is provided as of March 9, 2009. The fourth quarter results have been compared with the corresponding period in 2007. This MD&A should be read in conjunction with the Trust's unaudited interim comparative consolidated financial statements for the three months and year ended December 31, 2008 and 2007, audited consolidated comparative financial statements for the years ended December 31, 2007 and 2006, together with accompanying notes, and Annual Information Form for the year ended December 31, 2007. The Trust's audited consolidated comparative financial statements, MD&A and Annual Information Form for the year ended December 31, 2008 will be filed in late March 2009. These documents and additional information about the Trust are available on SEDAR at www.sedar.com.

In this MD&A, barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil, which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

This MD&A contains forward-looking information and statements. We refer you to the end of the MD&A for our advisory on forward-looking information and statements.

Non-GAAP Financial Measures

The Trust evaluates performance based on net income and cash flow from operations. Cash flow from operations and cash flow from operations per unit are not measurements based on Generally Accepted Accounting Principles in Canada ("GAAP"), but are financial terms commonly used in the oil and gas industry. Cash flow from operations represents cash generated from operating activities before changes in non-cash working capital, site restoration and reclamation expenditures, deferred charges and other assets. The Trust's determination of cash flow from operations may not be comparable with the calculation of similar measures for other entities. The Trust considers cash flow from operations a key measure of performance as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions to unitholders and capital investments. The most directly comparable measures calculated in accordance with GAAP are cash flow from operating activities and net income. For a reconciliation of cash flow from operations to cash flow from operating activities, see "Cash Flow from Operations, Payout Ratio and Distributions".

Production

Light oil and natural gas liquids ("NGL") production for the fourth quarter of 2008 decreased by 4% to 7,803 bbl/d from 8,123 bbl/d a year earlier. Heavy oil production for the fourth quarter of 2008 increased by 11% to 24,635 bbl/d from 22,196 bbl/day a year ago due to development drilling in the Seal and Lloydminster areas. Natural gas production increased by 7% to 57.6 MMcf/d for the fourth quarter of 2008, as compared to 53.9 MMcf/d for the same period last year primarily due to the acquisition of Burmis Energy Inc. in June 2008.

For the year ended December 31, 2008, light oil and NGL production increased by 38% to 7,575 bbl/d from 5,483 bbl/d for last year. The increase primarily resulted from the inclusion of full-year results from the Pembina assets acquired in June 2007 and from the acquisition of Burmis Energy Inc. in June 2008. Heavy oil production for 2008 increased by 7% to 23,530 bbl/d, as compared to 22,092 bbl/d for 2007. The increase in heavy oil production stemmed from development activities and the inclusion of full-year production from the Lindbergh assets acquired in June 2007. Natural gas production increased by 6% to average 54.8 MMcf/d for 2008 compared to 51.9 MMcf/d for 2007 due largely to the Pembina and Burmis acquisitions in June 2007 and 2008, respectively.

Revenue

Petroleum and natural gas sales decreased 15% to $199.9 million for the fourth quarter of 2008 from $233.9 million for the same period in 2007**.** Commencing with the first quarter of 2008, Baytex began reporting revenue from our heavy oil sales based on the price of the blend crude sold to the refineries. The cost of the blending diluent is reported as an expense. There is no impact to cash flow compared to the previous practice of reporting revenue based on heavy oil wellhead price net of blending charges.

For the per sales unit calculations, heavy oil sales for the three months ended December 31, 2008 were 345 bbl/d higher (three months ended December 31, 2007 – 1,717 bbl/d higher) than the production for the period due to changes in inventory. The corresponding number for the year ended December 31, 2008 was an increase of 300 bbl/d (year ended December 31, 2007 – an increase of 340 bbl/d).

Revenue from light oil and NGL for the fourth quarter of 2008 decreased 29% from the same period a year ago due to a 4% decrease in sales volume and a 26% decrease in wellhead prices. Revenue from heavy oil decreased 19% as the result of a 23% decrease in wellhead prices partially offset by a 4% increase in sales volume. Revenue from natural gas increased 19% as the result of a 7% increase in volume and a 12% increase in wellhead prices.

	Three Months ended December 31			
	2008		2007	
	$000s	**$/Unit(1)**	$000s	$/Unit(1)
Oil revenue				
Light oil & NGL	**39,703**	**55.31**	55,872	74.77
Heavy oil (2)	**89,464**	**38.93**	110,789	50.36
Total oil revenue	**129,167**	**42.83**	166,661	56.55
Natural gas revenue	**37,342**	**7.05**	31,285	6.31
Total oil and gas revenue	**166,509**	**42.71**	197,946	52.45
Sulphur revenue	**860**		-	
Other income	**-**		-	
Sales of heavy oil blending diluent	**32,521**	**73.34**	35,910	96.10
Total petroleum and natural gas sales	**199,890**		233,856	

(1) Per-unit oil revenue is in $/bbl; per-unit natural gas revenue is in $/Mcf; and per-unit total revenue is in $/boe.
(2) Heavy oil wellhead prices are net of blending costs.

For the year ended December 31, 2008, light oil and NGL revenue increased 88% from the same period last year due to a 36% increase in wellhead prices and a 39% increase in sales volume. Revenue from heavy oil increased 56% percent due to a 46% increase in wellhead prices and a 7% increase in sales volume. Revenue from natural gas production increased 27% compared to 2007, as production increased 6% combined with a price increase of 20%.

	Year ended December 31			
	2008		2007	
	$000s	**$/Unit(1)**	$000s	$/Unit(1)
Oil revenue				
Light oil & NGL	**246,516**	**88.92**	131,143	65.53
Heavy oil (2)	**568,841**	**65.22**	364,581	44.53
Total oil revenue	**815,357**	**70.94**	495,724	48.65
Natural gas revenue	**158,845**	**7.92**	125,235	6.61
Total oil and gas revenue	**974,202**	**65.66**	620,959	46.53
Sulphur revenue	**6,820**		-	
Other income	**2,000**		-	
Sales of heavy oil blending diluent	**176,696**	**110.30**	124,926	82.94
Total petroleum and natural gas sales	**1,159,718**		745,885	

(1) Per-unit oil revenue is in $/bbl; per-unit natural gas revenue is in $/Mcf; and per-unit total revenue is in $/boe.
(2) Heavy oil wellhead prices are net of blending costs.

During the current quarter, sulphur production averaged 69.4 tonnes per day with an average price of $131 per tonne. For the year ended December 31, 2008, sulphur production averaged 48.9 tonnes per day with an average price of $381 per tonne. In prior years, sulphur revenue was not material for reporting purposes.

During the first quarter of 2008, Baytex received a $2.0 million payment from a company as compensation for non-performance of a drilling obligation which was reported as other income under petroleum and natural gas sales.

Financial Instruments

The gain on financial instruments for the fourth quarter was $84.3 million, as compared to a loss of $31.6 million the fourth quarter of 2007. This is comprised of $2.2 million in realized loss and $86.5 million in unrealized gain for the fourth quarter of 2008 compared to $4.4 million in realized loss and $27.2 million in unrealized loss in the same period one year ago.

The gain on financial instruments for the year ended December 31, 2008 was $59.8 million, as compared to a loss of $34.5 million in 2007. This is comprised of $60.1 million in realized loss and $119.9 million in unrealized gain for 2008 compared to $3.2 million in realized loss and $31.3 million in unrealized loss in 2007.

Royalties

Total royalties decreased to $31.7 million for the fourth quarter of 2008 from $32.5 million in 2007. Royalties for the current quarter include $0.2 million related to the production of sulphur. Total royalties for the fourth quarter of 2008 were 19% of oil and gas revenue (excluding sales of heavy oil diluent), as compared to 17% for the same period in 2007. For the fourth quarter of 2008, royalties were 23% of sales for light oil, NGL and natural gas, and 16% of sales for heavy oil (excluding sales of heavy oil diluent), as compared to 20% and 14%, respectively, for the same period last year. Royalties are generally based on well productivity and market index prices in the period, with rates increasing as price and volume increase. Heavy oil royalties also increased in 2008 as certain oil sands projects at Seal and Cold Lake reached payout in the third quarter, with the pre-payout royalty of 1% of gross revenue converting to a post-payout 25% net profit interest.

For the year ended December 31, 2008, royalties increased to $207.5 million from $102.8 million for last year. Royalties for 2008 include $0.9 million related to the production of sulphur. Total royalties in 2008 were 21% of oil and gas revenue (excluding sales of heavy oil diluent),as compared to 17% of sales for 2007. For 2008, royalties were 23% of sales for light oil, NGL and natural gas and 20% for heavy oil (excluding sales of heavy oil diluent), as compared to 19% and 15%, respectively, for the same period in 2007. Royalties are generally based on well productivity and market index prices in the period, with rates increasing as price and volume increase. Heavy oil royalties as a percentage of revenue were higher in the year as market prices, on average, were higher than the prices realized by Baytex under fixed differential supply agreements. Heavy oil royalties also increased in 2008 as certain oilsands projects at Seal and Cold Lake reached payout, with the pre-payout royalty of 1% of gross revenue converting to a post-payout 25% net profit interest.

Operating Expenses

Operating expenses for the fourth quarter of 2008 increased to $47.4 million from $38.7 million in the corresponding quarter last year. Operating expenses for the current quarter include $0.1 million related to the production of sulphur. Operating expenses were $12.15 per boe for the fourth quarter of 2008 compared to $10.25 per boe for the fourth quarter of 2007. For the fourth quarter of 2008, operating expenses were $12.88 per boe of light oil, NGL and natural gas, and $11.59 per barrel of heavy oil, as compared to $9.67 and $10.66, respectively for the same period in 2007. In the case of light oil, NGL and natural gas, the largest single driver of the increase in unit operating expense was prior-period adjustments to third-party processing costs, which were responsible for large majority of the quarter-over-quarter increase. Other drivers of the increase for light oil, NGL and natural gas were increases in labor costs, fuel, power and property taxes. In the case of heavy oil, the increase in quarter-over-quarter operating expense was due primarily to increased fluid hauling charges.

Operating expenses for the year ended December 31, 2008 increased to $172.5 million from $134.7 million in 2007. Operating expenses for 2008 include $0.3 million related to the production of sulphur. Operating expenses were $11.62 per boe for 2008, as compared to $10.09 per boe for the prior year. In 2008, operating expenses were $11.68

per boe of light oil, NGL and natural gas and $11.55 per barrel of heavy oil, as compared to $9.61 and $10.40, respectively, in 2007. In the case of light oil, and natural gas, increased operating expense was driven primarily by increases in costs for third-party processing (including prior-period adjustments), fuel, power and labor. In the case of heavy oil, increased operating expense was due primarily to increased fluid hauling charges and higher property taxes. Heavy oil operating expense was also negatively impacted by inclusion of higher-cost production at Lindbergh for the full year.

Transportation and Blending Expenses

Transportation and blending expenses for the fourth quarter of 2008 were $45.7 million compared to $43.9 million for the fourth quarter of 2007. Transportation expenses for the current quarter include $0.4 million related to the transportation of sulphur. Transportation expenses were $3.38 per boe for the fourth quarter of 2008 compared to $2.11 for the same period in 2007. Transportation expenses were $0.48 per boe of light oil, NGL and natural gas and $5.24 per barrel of heavy oil in the fourth quarter of 2008 as compared to $0.67 and $3.15 for the same period of 2007. The increase in transportation cost per unit was driven by increased long-haul trucking from Seal and higher fuel costs which, as of the fourth quarter of 2008, had yet to fully respond to benchmark price.

The heavy oil produced by Baytex requires blending to reduce its viscosity in order to meet pipeline specifications. Baytex purchases primarily condensate as the blending diluent from industry producers to facilitate the marketing of our heavy oil. In the fourth quarter of 2008, the blending cost was $32.5 million for the purchase of 4,820 bbl/d of condensate at $73.34 per barrel, as compared to 4,062 bbl/d at $96.10 per barrel for the same period last year. The cost of diluent is effectively recovered in the sale price of a blended product.

Transportation and blending expenses for the year ended December 31, 2008 were $218.7 million compared to $155.8 million for 2007. Transportation expense for 2008 included $1.3 million related to the transportation of sulphur. Transportation expenses were $2.83 per boe in 2008 compared to $2.31 per boe in 2007. Transportation expenses were $0.64 per boe of light oil, NGL and natural gas and $4.22 per barrel of heavy oil in 2008, compared to $0.80 and $3.26, respectively, in 2007. The increase in transportation cost per unit was driven by increased long-haul trucking from Seal and fuel costs which increased by over 25% from 2007 to 2008. In 2008, the blending cost was $176.7 million for the purchase of 4,377 bbl/d of condensate at $110.30 per barrel, as compared to 4,127 bbl/d at $82.94 per barrel in 2007.

General and Administrative Expenses

General and administrative expenses for the fourth quarter of 2008 increased to $7.6 million from $6.8 million a year earlier. On a per sales unit basis, these expenses were $1.96 per boe for the fourth quarter of 2008 compared to $1.81 per boe for the same period in 2007.

General and administrative expenses for the year ended December 31, 2008 were $29.6 million, compared to $23.6 million for the prior year. On a per sales unit basis, these expenses were $2.00 per boe in 2008 and $1.77 per boe in 2007. The increase is attributable to escalating costs in the labour market and additional expenses associated with a new office in Denver to manage the U.S. operations. In accordance with our full cost accounting policy, no expenses were capitalized in either 2008 or 2007.

Unit-based Compensation Expense

Compensation expense related to the Trust's unit rights incentive plan was $1.6 million for the fourth quarter of 2008 compared to $1.8 million for the fourth quarter of 2007. For the year ended December 31, 2008, compensation expense was $7.8 million compared to $8.0 million for 2007.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

Interest Expense

Interest expense for the fourth quarter of 2008 decreased to $7.9 million compared to $8.6 million in the same quarter last year. The decrease is primarily due to the decrease in prime lending rates and a reduction in bank loan, partially offset by higher foreign exchange rates on payment of interest on the U.S. dollar denominated debt.

For the year ended December 31, 2008, interest expense was $33.0 million compared to $35.2 million for last year. Interest expense was affected by a more favorable exchange rate on the U.S. dollar denominated interest expenses and through decreased interest on reduced bank borrowings. These factors were partially offset by accretion of the discontinued fair value hedge.

Foreign Exchange

Foreign exchange loss in the fourth quarter of 2008 was $24.8 million compared to a gain of $1.2 million in the fourth quarter of 2007. The loss is comprised of an unrealized foreign exchange loss of $29.0 million and a realized foreign exchange gain of $4.2 million. The gain for the same period in 2007 was comprised of an unrealized foreign exchange gain of $1.5 million and a realized foreign exchange loss of $0.3 million. The current quarter's unrealized loss is based on the translation of the U.S. dollar denominated debt at 0.8166 at December 31, 2008 compared to 0.9435 at September 30, 2008. The prior period gain is based on translation at 1.0120 at December 31, 2007 compared to 1.0037 at September 30, 2007.

The foreign exchange loss for the year ended December 31, 2008 was $37.7 million compared to a $32.4 million gain in the prior year. The 2008 loss is comprised of an unrealized foreign exchange loss of $41.7 million and a realized foreign exchange gain of $4.0 million. The 2007 gain was substantially unrealized. The 2008 unrealized loss stemmed from the translation of the U.S. dollar denominated debt at 0.8166 at December 31, 2008 compared to 1.0120 at December 31, 2007. The 2007 unrealized gain was based on translation at 1.0120 at December 31, 2007 compared to 0.8581 at December 31, 2006.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion for the fourth quarter of 2008 increased to $61.3 million from $54.1 million for the same quarter in 2007. On a sales-unit basis, the provision for the current quarter was $15.71 per boe compared to $14.33 per boe for the same quarter in 2007. The higher rate is primarily due to the costs of the acquisitions completed in June 2008.

Depletion, depreciation and accretion increased to $223.9 million for the year ended December 31, 2008 compared to $189.5 million for 2007. On a sales-unit basis, the provision for the current year was $15.09 per boe compared to $14.20 per boe for 2007. The higher rate is primarily due to the costs of the acquisitions completed in June 2008.

Taxes

On June 22, 2007, the federal government's bill (the "government's bill") regarding the taxation of distributions from publicly traded income trusts beginning January 1, 2011 received Royal Assent. As a result, a future tax recovery of $0.5 million was recognized in the second quarter of 2007 relating to unutilized tax pools in the Trust which will be deductible to the Trust after 2010. The majority of the Trust's temporary differences reside in a consolidated subsidiary which is not subject to the distribution tax, and is therefore not impacted by this legislative change.

The government's bill provides that the new regime for income trusts will not apply until January 1, 2011 so long as the Trust experiences only "normal growth" and no "undue expansion". As part of the government's bill, a "safe harbour" limit was established for existing income trusts by limiting future equity issues to 40% of that trust's October 31, 2006 market capitalization for the period November 1, 2006 to December 31, 2007, and an additional 20% of this market capitalization for each of 2008, 2009 and 2010. For Baytex, the limits are approximately $730 million for 2006 / 2007 and $365 million for each of the subsequent three years. Issuance of equity or convertible debt beyond these limits will result in the new regime applying to the Trust before 2011.

In 2008, the Canadian federal government introduced draft tax legislation that allowed for the conversion of a specified investment flow through ("SIFT") entity into corporate form on a tax deferred basis, defined the provincial tax component of the SIFT tax, and accelerated the recognition of the "safe harbor" limit. None of the above was enacted prior to prorogation of parliament in December 31, 2008. Therefore, all bills containing the draft legislation have lapsed.

Subsequent to the year end, the federal government has introduced draft tax legislation which includes the above mentioned measures as part of Canada's Economic Action Plan. This legislation has not yet been enacted into law.

Current tax of $1.7 million for the fourth quarter of 2008 is comprised primarily of Saskatchewan capital tax and resource surcharge. Current tax of the same period a year ago was $2.1 million and was also comprised primarily of Saskatchewan capital tax and resource surcharge. Current tax expense for the year ended December 31, 2008 is comprised of $10.2 million of Saskatchewan capital tax and resource surcharge. The 2007 current tax expense included $7.2 million of Saskatchewan capital tax and resource surcharge, and a recovery of $0.5 million relating to a prior period.

For the fourth quarter of 2008, future tax expense totaled $2.2 million compared to a recovery of $27.7 million in the same period in 2007. The fiscal 2008 provision for future taxes was an expense of $15.4 million compared to a recovery of $49.4 million for the prior year. As at December 31, 2008, total future tax liability of $217.8 million (December 31, 2007 - $142.4 million) consisted of a $25.4 million current future tax liability (December 31, 2007 - $11.5 million current future tax asset) and a $192.4 million long-term future tax liability (December 31, 2007 - $153.9 million). The increase from the prior year is due to future tax liability recognized on the Burmis acquisition of $37.9 million and current year provision of $25.4 million attributable to the unrecognized gain on financial instruments of $119.9 million.

Net Income

Net income for the fourth quarter of 2008 was $52.4 million compared to $41.4 million for the fourth quarter in 2007. The increase was the result of the unrealized gain on financial instruments offset by reduced petroleum and natural gas revenue, higher depletion, foreign exchange losses and future tax expense.

Net income for the year ended December 31, 2008 was $259.9 million compared to $132.9 million for 2007. The increase is the result of increased production, increased sales prices and unrealized gain on financial instruments, partially offset by increased royalties, increased loss on foreign exchange and depletion.

Cash Flow from Operations, Payout Ratio and Distributions

Cash flow from operations and payout ratio are non-GAAP terms. Cash flow from operations represents cash flow from operating activities before changes in non-cash working capital, and other operating items. The Trust's payout ratio is calculated as cash distributions (net of participation in our Distribution Reinvestment Plan ("DRIP")) divided by cash flow from operations. The Trust considers these to be key measures of performance as they demonstrate the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.

The following table reconciles cash flow from operating activities (a GAAP measure) to cash flow from operations (a non-GAAP measure):

	Three Months Ended			Year Ended	
	December 31, 2008	September 30, 2008	December 31, 2007	December 31, 2008	December 31, 2007
Cash flow from operating activities	**$ 98,407**	$ 150,815	$ 100,131	**$ 471,237**	$ 286,450
Change in non-cash working capital	**(38,667)**	(4,591)	(3,145)	**(38,896)**	(5,140)
Asset retirement expenditures	**725**	351	1,131	**1,443**	2,442
Decrease in deferred obligations	**7**	11	550	**39**	2,278
Cash flow from operations	**$ 60,472**	$ 146,586	$ 98,667	**$ 433,823**	$ 286,030
Cash distributions declared	**$ 55,314**	$ 57,233	$ 37,314	**$ 197,026**	$ 145,927
Payout ratio	**91%**	39%	38%	**45%**	51%

The Trust does not deduct capital expenditures when calculating the payout ratio. Due to the depleting nature of oil and gas assets, certain levels of capital expenditures are required to minimize production declines. In the oil and gas industry, due to the nature of reserve reporting, natural production declines and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Should the costs to explore for, develop or acquire oil and natural gas assets increase significantly, it is possible that the Trust would be required to reduce or eliminate its distributions in order to fund capital expenditures. There can be no certainty that the Trust will be able to maintain current production levels in future periods.

Cash distributions, net of DRIP participation, of $55.3 million for the fourth quarter of 2008 were funded through cash flow from operations of $60.5 million. For the year ended December 31, 2008, cash distributions of $197.0 million were funded through cash flow from operations of $433.8 million.

The following tables compare cash distributions to cash flow from operating activities and net income:

	Three Months Ended			Year Ended	
($000's)	**December 31, 2008**	September 30, 2008	December 31, 2007	**December 31, 2008**	December 31, 2007
Cash flow from operating activities	**98,407**	150,815	100,131	**471,237**	286,450
Cash distributions declared	**55,314**	57,233	37,314	**197,026**	145,927
Excess of cash flow from operating activities over cash distributions declared	**43,093**	93,582	62,817	**274,211**	140,523
Net income	**52,401**	137,228	41,353	**259,894**	132,860
Cash distributions declared	**55,314**	57,233	37,314	**197,026**	145,927
Excess (shortfall) of net income over cash distributions declared	**(2,913)**	79,995	4,039	**62,868**	(13,067)

It is Baytex's long-term operating objective to substantially fund cash distributions and capital expenditures for exploration and development activities through cash flow from operating activities. Future production levels are highly dependent upon our success in exploiting our asset base and acquiring additional assets. The success of these activities, along with commodity prices realized are the main factors influencing the sustainability of our cash distributions. During periods of lower commodity prices, or periods of higher capital spending for acquisitions, it is possible that internally generated cash flow will not be sufficient to fund both cash distributions and capital spending. In these instances, the cash shortfall may be funded through a combination of equity and debt financing.

As at December 31, 2008, Baytex had approximately $183 million in available undrawn credit facilities to fund any such shortfall. As Baytex strives to maintain a consistent distribution level under the guidance of prudent financial parameters, there may be times when a portion of our cash distributions would represent a return of capital.

For the three months ended December 31, 2008, the Trust's cash distributions exceeded net income by $2.9 million, with net income reduced by $46.0 million of non-cash items. For the year ended December 31, 2008, the Trust's net income exceeded cash distributions by $62.9 million with net income reduced by $211.3 million of non-cash items. Non-cash items such as depletion, depreciation and accretion are not fair indicators for the cost of maintaining our productive capacity as they are based on historical costs of assets and not the fair value of replacing those assets under current market conditions.

Liquidity and Capital Resources

The current worldwide economic crisis has resulted in disruptions in the availability of credit. In light of this situation, we have undertaken a thorough review of our liquidity sources as well as our exposure to counterparties and have concluded that our capital resources are sufficient to meet our ongoing short, medium and long-term commitments. Specifically, we believe that our internally generated cash flow from operations, augmented by our hedging program and existing credit facilities, will provide sufficient liquidity to sustain our operations in the short, medium, and long-term. Further, we believe that our counterparties currently have the financial capacities to honor outstanding obligations to us in the normal course of business and, where necessary, we have implemented enhanced credit protection with certain of these counterparties.

At December 31, 2008, total net monetary debt was $533.0 million compared to $444.1 million at the end of 2007. Bank borrowings and working capital deficiency at the end of 2008 were $302.5 million compared to total credit facilities of $485.0 million.

Baytex has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances under the credit facilities or letters of credit can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. The syndicated credit facilities were increased from $370.0 million to $485.0 million in June 2008. The facilities are subject to semi-annual review and are secured by a floating charge over all of Baytex's assets. The credit facilities mature on July 1, 2009, and are eligible for extension.

Baytex's credit facilities are available pursuant to an agreement with a syndicate of nine financial institutions, a summary of which was filed on September 15, 2008 as a "Material Document" on our SEDAR profile at www.sedar.com. Of the nine syndicate members in our facilities, five are major Canadian banks which represent $275 million or 57% of the commitments under the $485 million facilities. We have had discussions with members of our lending syndicate, and have no reason to believe that the facilities will not be extended upon maturity; however the amount of the facilities available upon extension has not yet been determined. Under the terms of our credit agreement, we may request for extension as early as April 1, 2009.

Baytex has US$179.7 million of 9.625% senior subordinated notes due July 15, 2010. These notes are unsecured and are subordinate to Baytex's bank credit facilities.

Pursuant to various agreements with Baytex's creditors, we are restricted from making distributions to Unitholders if the distribution would or could have a material adverse effect on the Trust or its subsidiaries' ability to fulfill its obligations under Baytex's credit facilities or the U.S. dollar denominated debt.

The Trust believes that cash flow generated from operations, together with the existing bank facilities, will be sufficient to substantially finance current operations, distributions to the unitholders and planned capital expenditures for the ensuing year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments. The level of distribution is also discretionary, and the Trust has the ability to modify distribution levels should cash flow from operations be negatively impacted by a reduction in commodity prices.

The Trust has a number of financial obligations in the ordinary course of business. These obligations are of a recurring and consistent nature and impact the Trust's cash flows in an ongoing manner. A significant portion of these obligations will be funded through operating cash flow. These obligations as of December 31, 2008, and the expected timing of funding of these obligations are noted in the table below.

($000s)	Total	1 year	2-3 years	4-5 years	Beyond 5 years
Accounts payable and accrued liabilities	164,279	164,279	-	-	-
Distributions payable to unitholders	17,583	17,583	-	-	-
Bank loan (1)	208,482	208,482	-	-	-
Long-term debt (2)	220,362	-	220,362	-	-
Convertible debentures (2)	10,398	-	10,398	-	-
Deferred obligations	74	46	23	5	-
Operating leases	42,732	2,776	7,112	7,887	24,957
Processing and transportation agreements	22,350	8,478	13,631	241	-
Total	686,260	401,644	251,526	8,133	24,957

(1) The bank loan is a 364-day revolving loan with the ability to extend the term. The Trust has no reason to believe that it will be unable to extend the credit facility when it matures on July 1, 2009.
(2) Principal amount of instruments.

The Trust is authorized to issue an unlimited number of trust units. As at February 28, 2009, the Trust had 98,212,328 trust units issued and outstanding.

At February 28, 2009, the Trust had $10.4 million convertible unsecured subordinated debentures outstanding which are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per unit.

Effective August 29, 2008, all of the outstanding exchangeable shares were purchased by Baytex ExchangeCo Ltd. for consideration of 1.79560 trust units for each exchangeable share.

Capital Expenditures

Capital expenditures for the three months and years ended December 31, 2008 and 2007 are summarized as follows:

	Three Months Ended December 31,		Year Ended December 31	
($thousands)	**2008**	2007	**2008**	2007
Land	**4,898**	1,197	**9,534**	7,253
Seismic	**3,508**	471	**4,947**	1,994
Drilling and completion	**27,793**	23,041	**132,296**	108,106
Equipment	**5,752**	8,148	**34,720**	26,624
Other	**1,018**	1,492	**3,586**	4,742
Total exploration and development	**42,969**	34,349	**185,083**	148,719
Corporate acquisition (net of working capital)	**2,116**	3,389	**180,467**	243,273
Property acquisitions	**6,124**	2,038	**84,826**	2,877
Property dispositions	**(66)**	(363)	**(194)**	(723)
Total capital expenditures	**51,143**	39,413	**450,182**	394,146

Financial Instruments and Risk Management

The Trust is exposed to a number of financial risks, including market risk, credit risk and liquidity risk. Market risk is the risk that the fair value of future cash flows will fluctuate due to movements in market prices, and is comprised of currency risk, interest rate risk and commodity price risk. Market risk is managed by the Trust through a series of derivative contracts intended to manage the volatility of our operating cash flow. Liquidity risk is the risk that the Trust will encounter difficulty in meeting obligations associated with financial liabilities. The Trust manages its liquidity risk through cash and debt management. Credit risk is the risk that a counterparty to a financial asset will default resulting in the Trust incurring a loss. The Trust manages this credit risk by entering into sales contracts with credit worthy entities and reviewing its exposure to individual entities on a regular basis.

Details of the risk management contracts in place as at December 31, 2008, and the accounting for the Trust's financial instruments are disclosed in note 14 to the consolidated financial statements.

Selected Quarterly Financial Information

($000s, except per unit data)	**2008**				2007			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Petroleum and natural gas sales	**199,890**	363,044	332,336	264,448	233,856	193,784	156,670	161,575
Net income	**52,401**	137,228	34,417	35,848	41,353	36,674	31,050	23,783
Net income per trust unit								
Basic	**0.54**	1.44	0.39	0.42	0.49	0.44	0.41	0.32
Diluted	**0.53**	1.39	0.38	0.41	0.46	0.43	0.39	0.30

Changes in Accounting Policies

Effective January 1, 2008, the Trust adopted the following accounting standards of the Canadian Institute of Chartered Accountants ("CICA"): Section 3862 "Financial Instruments – Disclosures"; Section 3863 "Financial Instruments – Presentation"; and Section 1535 "Capital Disclosures". The adoption of the new standards resulted in additional disclosures with regard to financial instruments (note 14) and the Trust's objectives, policies and process for managing capital (note 16).

The Trust also adopted Section 3031 "Inventories". This new standard replaces the previous inventories standard and requires inventory to be valued on a first-in, first-out or weighted average basis. The adoption of Section 3031 did not have an impact on the consolidated financial statements of the Trust.

Future Accounting Changes

In February 2008, the CICA issued Section 3064 "Goodwill and Intangible Assets", which replaces Section 3062 "Goodwill and Other Intangible Assets" and Section 3450 "Research and Development Costs". This section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets by profit-oriented enterprises subsequent to their initial measurement. The new standard will be effective on January 1, 2009. The Trust does not expect the adoption of this new standard to have a material impact on its consolidated financial statements.

In April 2008, the CICA published the exposure draft "Adopting IFRS in Canada". The exposure draft proposes to incorporate International Financial Reporting Standards ("IFRS") into the CICA Accounting Handbook effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. At this date, publicly accountable enterprises will be required to prepare financial statements in accordance with IFRS. The Trust is currently reviewing the standards to determine the potential impact on its consolidated financial statements. The Trust has appointed internal staff to lead the conversion project along with sponsorship from the senior leadership team. In addition, an external advisor has been retained to assist the Trust in scoping its conversion project. The Trust has performed a diagnostic analysis that identifies differences between the Trust's current accounting policies and IFRS. At this time, the Trust is evaluating the impact of these differences and assessing the need for amendments to existing accounting policies in order to comply with IFRS.

In January 2009, the CICA issued Section 1582 "Business Combinations", which replaces former guidance on business combinations. Section 1582 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 2011 with earlier application permitted. The Trust plans to adopt this standard prospectively effective January 1, 2009 and does not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In January 2009, the CICA issued Section 1601 "Consolidated Financial Statements" and Section 1602 "Non-controlling Interests", which replaces existing guidance. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. These standards are effective on or after the beginning of the first annual reporting period beginning on or after January 2011 with earlier application permitted. The Trust plans to adopt these standards effective January 1, 2009 and does not expect the adoption will have a material impact on the results of operations or financial position.

Conference Call

Baytex will host a conference call and question and answer session at 2:00 p.m. MT (4:00 p.m. ET) on Tuesday, March 10, 2009 to discuss our 2008 results. The conference call will be hosted by Anthony Marino, President and Chief Executive Officer, and Derek Aylesworth, Chief Financial Officer. Interested parties are invited to participate by calling toll-free across North America at 1-888-818-4097. An archived recording of the call will be available from March 10, 2009 until March 24, 2009 by dialing 1-800-408-3053 or 416-695-5800 within the Toronto area and entering the reservation code 3282054. The conference call will also be archived on Baytex's website at www.baytex.ab.ca.

Oil and Gas Advisory

The reserves information contained in this press release has been prepared in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" of the Canadian Securities Administrators ("NI 51-101"). Complete NI 51-101 reserve disclosure will be included in our Annual Information Form for the year ended December 31, 2008, which will be filed in late March 2009. Listed below are cautionary statements that are specifically required by NI 51-101:

Where applicable, oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

With respect to finding and development costs, the aggregate of the exploration and development 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.

This press release contains estimates of the net present value of our future net revenue from our reserves. Such amounts do not represent the fair market value of our reserves.

All amounts in this press release are stated in Canadian dollars unless otherwise specified.

Advisory Regarding Forward-Looking Statements

In the interest of providing Baytex's unitholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements in this document are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this document speak only as of the date of this document and are expressly qualified by this cautionary statement.

Specifically, this press release contains forward-looking statements relating to our heavy oil resource play at Seal, including our assessment of the viability and economics of a commercial-scale cyclic steam injection project, the timing for completion of a commercial-scale cyclic steam injection project and the resource potential of our undeveloped land; the pricing differential between light and heavy oil prices; our liquidity and financial capacity; funding sources for our cash distributions and capital program; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; the extension of our credit facilities upon maturity; and the impact of the adoption of new accounting standards on our financial results. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: oil and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; the availability and cost of labour and other industry services; the amount of future cash distributions that we intend to pay; interest and foreign exchange rates; and the continuance of existing and, in certain circumstances, proposed tax and royalty regimes. The reader is cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; fluctuations in market prices for oil and natural gas; liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; incorrect assessments of the value of acquisitions; fluctuations in foreign exchange or interest rates; stock market volatility and market valuations; geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves; changes in income tax laws, royalty rates and incentive programs relating to the oil and gas industry and income trusts; changes in environmental and other regulations; risks associated with oil and gas operations; and other factors, many of which are beyond the control of Baytex. These risk factors are discussed in Baytex's Annual Information Form, Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2007, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

Unaudited financial statements for the periods ended December 31, 2008 and 2007 are attached.

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Baytex Energy Trust
Consolidated Balance Sheets

(thousands of Canadian dollars)	**December 31, 2008**	December 31, 2007
ASSETS		
Current assets		
Accounts receivable	**$ 87,551**	$ 105,176
Crude oil inventory	**332**	5,997
Financial instruments (note 14)	**85,678**	-
Future tax asset (note 11)	**-**	11,525
	173,561	122,698
Petroleum and natural gas properties	**1,601,017**	1,246,697
Goodwill	**37,755**	37,755
	$ 1,812,333	$ 1,407,150
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**$ 164,279**	$ 104,318
Distributions payable to unitholders	**17,583**	15,217
Bank loan	**208,482**	241,748
Financial instruments (note 14)	**-**	34,239
Future tax liability (note 11)	**25,358**	-
	415,702	395,522
Long-term debt (note 4)	**217,273**	173,854
Convertible debentures (note 5)	**10,195**	16,150
Asset retirement obligations (note 6)	**49,351**	45,113
Deferred obligations	**74**	113
Future tax liability (note 11)	**192,411**	153,943
	885,006	784,695
Non-controlling interest (note 8)	**-**	21,235
UNITHOLDERS' EQUITY		
Unitholders' capital (note 7)	**1,129,909**	821,624
Conversion feature of debentures (note 5)	**498**	796
Contributed surplus (note 9)	**21,234**	18,527
Deficit	**(224,314)**	(239,727)
	927,327	601,220
	$ 1,812,333	$ 1,407,150

Commitments an contingencies (note 15)
See accompanying notes to the consolidated financial statements.

Baytex Energy Trust
Consolidated Statements of Income and Comprehensive Income
(thousands of Canadian dollars)

	Three Months Ended December 31		Year Ended December 31	
	2008	2007	**2008**	2007
Revenue				
Petroleum and natural gas	**$ 199,890**	$ 233,856	**$ 1,159,718**	$ 745,885
Royalties	**(31,690)**	(32,524)	**(207,522)**	(102,805)
Gain (loss) on financial instruments (note 14)	**84,341**	(31,631)	**59,816**	(34,484)
	252,541	169,701	**1,012,012**	608,596
Expenses				
Operating	**47,355**	38,686	**172,471**	134,696
Transportation and blending	**45,718**	43,888	**218,706**	155,754
General and administrative	**7,635**	6,815	**29,603**	23,565
Unit-based compensation (note 9)	**1,563**	1,810	**7,812**	7,986
Interest (note 12)	**7,860**	8,570	**32,962**	35,162
Foreign exchange loss (gain) (note 13)	**24,809**	(1,237)	**37,746**	(32,414)
Depletion, depreciation and accretion	**61,251**	54,086	**223,900**	189,512
	196,191	152,618	**723,200**	514,261
Income before taxes and non-controlling interest	**56,350**	17,083	**288,812**	94,335
Tax expense (recovery) (note 11)				
Current expense	**1,732**	2,109	**10,177**	6,713
Future expense (recovery)	**2,217**	(27,659)	**15,383**	(49,369)
	3,949	(25,550)	**25,560**	(42,656)
Income before non-controlling interest	**52,401**	42,633	**263,252**	136,991
Non-controlling interest (note 8)	**-**	(1,280)	**(3,358)**	(4,131)
Net income/Comprehensive income	**$ 52,401**	$ 41,353	**$ 259,894**	$ 132,860

Consolidated Statements of Deficit
(*(thousands of Canadian dollars except per unit data)*

	Three Months Ended December 31		Year Ended December 31	
	2008	2007	**2008**	2007
Deficit, beginning of period	**$ (210,494)**	$ (235,522)	**$ (239,727)**	$ (198,520)
Net Income	**52,401**	41,353	**259,894**	132,860
Distributions to unitholders	**(66,221)**	(45,558)	**(244,481)**	(174,067)
Deficit, end of period	**$ (224,314)**	$ (239,727)	**$ (224,314)**	$ (239,727)
Net income per trust unit (note 10)				
Basic	**$ 0.54**	$ 0.49	**$ 2.83**	$ 1.66
Diluted	**$ 0.53**	$ 0.48	**$ 2.74**	$ 1.60
Weighted average trust units (note 10)				
Basic	**97,304**	84,267	**91,683**	80,029
Diluted	**99,241**	89,898	**96,391**	85,975

See accompanying notes to the consolidated financial statements.

Baytex Energy Trust
Consolidated Statements of Cash Flows
(thousands of Canadian dollars)

	Three Months Ended December 31		Year Ended December 31	
	2008	2007	**2008**	2007
Cash provided by (used in):				
OPERATING ACTIVITIES				
Net income	**$ 52,401**	$ 41,353	**$ 259,894**	$ 132,860
Items not affecting cash:				
Unit based compensation (note 9)	**1,563**	1,810	**7,812**	7,986
Unrealized foreign exchange loss (gain) (note 13)	**29,032**	(1,526)	**41,712**	(32,574)
Depletion, depreciation and accretion	**61,251**	54,086	**223,900**	189,512
Accretion on debentures and notes (notes 4 & 5)	**519**	2,059	**1,681**	2,164
Unrealized (gain) loss on financial instruments (note 14)	**(86,511)**	27,264	**(119,917)**	31,320
Future tax expense (recovery)	**2,217**	(27,659)	**15,383**	(49,369)
Non-controlling interest (note 8)	**-**	1,280	**3,358**	4,131
	60,472	98,667	**433,823**	286,030
Change in non-cash working capital	**38,667**	3,145	**38,896**	5,140
Asset retirement expenditures	**(725)**	(1,131)	**(1,443)**	(2,442)
Decrease in deferred obligations	**(7)**	(550)	**(39)**	(2,278)
	98,407	100,131	**471,237**	286,450
FINANCING ACTIVITIES				
Increase (decrease) in bank loan	**8,067**	(17,580)	**(33,236)**	114,253
Payments of distributions	**(61,227)**	(37,415)	**(194,728)**	(144,609)
Issue of trust units, net of issuance costs (note 7)	**377**	1,363	**10,502**	147,221
	(52,783)	(53,632)	**(217,462)**	116,865
INVESTING ACTIVITIES				
Petroleum and natural gas property expenditures	**(42,969)**	(34,349)	**(185,083)**	(148,719)
Acquisition (net of disposal) of petroleum and natural gas properties	**(8,174)**	(5,064)	**(88,566)**	(258,656)
Change in non-cash working capital	**5,519**	(7,086)	**19,874**	4,060
	(45,624)	(46,499)	**(253,775)**	(403,315)
Change in cash and cash equivalents	-	-	**-**	-
Cash and cash equivalents, beginning of period	-	-	**-**	-
Cash and cash equivalents, end of period	**$ -**	$ -	**$ -**	$ -

See accompanying notes to the consolidated financial statements.

Baytex Energy Trust
Notes to the Consolidated Financial Statements
Three Months and Years ended December 31, 2008 and 2007
(all tabular amounts in thousands of Canadian dollars, except per unit amounts)

1. BASIS OF PRESENTATION

Baytex Energy Trust (the "Trust") was established on September 2, 2003 under a Plan of Arrangement involving the Trust and Baytex Energy Ltd. (the "Company"). The Trust is an open-ended investment trust created pursuant to a trust indenture. Subsequent to the Plan of Arrangement, the Company is a subsidiary of the Trust.

The consolidated financial statements include the accounts of the Trust and its subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles.

The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements of the Trust as at December 31, 2007, except as noted below. The interim consolidated financial statements contain disclosures, which are supplemental to the Trust's annual consolidated financial statements. Certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. The interim consolidated financial statements should be read in conjunction with the Trust's consolidated financial statements and notes thereto for the year ended December 31, 2007.

2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2008, the Trust adopted three new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA"): Section 1535, Capital Disclosures, Section 3862, Financial Instruments - Disclosures and Section 3863, Financial Instruments - Presentation.

A. Capital Disclosures

Section 1535 establishes standards for disclosing information regarding an entity's capital and how it is managed.

B. Financial Instruments - Disclosures, Financial Instruments - Presentation

Sections 3862 and 3863 establish standards for enhancing financial statements users' understanding of the significance of financial instruments to an entity's financial position, performance and cash flows. They require that entities provide disclosures regarding the nature and extent of risks arising from financial instruments to which they are exposed both during the reporting period and at the balance sheet date, as well as how the entities manage those risks.

C. Inventories

Section 3031 replaces the previous inventories standard and requires inventory be valued on a first-in, first-out basis. The adoption of Section 3031 did not have an impact on the consolidated financial statements of the Trust.

These standards were adopted prospectively.

Future Accounting Changes

A. Goodwill and Intangible Assets

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, replacing Section 3062, Goodwill and Other Intangible Assets and Section 3450, Research and Development Costs. The new Section will be effective on January 1, 2009. Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The Trust is currently evaluating the impact of the adoption of this new Section, however does not expect a material impact on its consolidated financial statements.

B. International Financial Reporting Standards ("IFRS").

In April 2008, the CICA published the exposure draft "Adopting IFRSs in Canada". The exposure draft proposes to incorporate IFRS into the CICA Accounting Handbook effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. At this date, publicly accountable enterprises will be required to prepare financial statements in accordance with IFRS. The Trust has performed a diagnostic analysis that identifies differences between the Trust's current accounting policies and IFRS. At this time, the Trust is evaluating the impact of these differences to determine the potential impact on its Consolidated Financial Statements and assessing the need for amendments to existing accounting policies in order to comply with IFRS.

C. Business Combinations

In January 2009, the CICA issued Section 1582, “Business Combinations”, which replaces former guidance on business combinations. Section 1582 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 2011 with earlier application permitted. The Trust plans to adopt this standard prospectively effective January 1, 2009 and does not expect the adoption of this statement to have a material impact on our results of operations or financial position.

D. Consolidated Financial Statements

In January 2009, the CICA issued Sections 1601, “Consolidated Financial Statements”, and 1602, “Non-controlling Interests”, which replaces existing guidance. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. These standards are effective on the first annual reporting period beginning on or after January 2011 with earlier application permitted. The Trust plans to adopt these standards effective January 1, 2009 and does not expect the adoption will have a material impact on the results of operations or financial position.

3. CORPORATE ACQUISITIONS

On June 4, 2008, Baytex acquired all the issued and outstanding shares of Burmis Energy Inc., a public company which had interests in certain natural gas and light oil properties located primarily in west central Alberta. The results of operations from these properties have been included in the consolidated financial statements since the closing of the acquisition on June 4, 2008. In conjunction with the acquisition, Burmis Energy Inc. was amalgamated with the Company.

This transaction has been accounted for using the purchase method of accounting. The estimated fair value of the assets acquired and liabilities assumed at the date of acquisition is summarized below:

Consideration for the acquisition:	
Trust units issued	$ 152,053
Net debt assumed	24,480
Costs associated with acquisition	3,934
Total purchase price	$ 180,467
Allocation of purchase price:	
Property, plant and equipment	$ 219,913
Future income taxes	(37,910)
Asset retirement obligations	(1,536)
Total net assets acquired	$ 180,467

All of the issued and outstanding shares of Burmis were acquired on the basis of 0.1525 of a Baytex trust unit for each Burmis share, resulting in the issuance of 6,383,416 Baytex trust units valued at $23.82 per unit, which was the average closing price of Baytex trust units for the ten trading days bordering the initial public announcement of the transaction.

On June 26, 2007, Baytex acquired all the issued and outstanding shares of a private company which had interests in certain petroleum and natural gas properties and related assets located primarily in the Pembina and Lindbergh areas of Alberta. The results of operations from these properties have been included in the consolidated financial statements since the closing of the acquisition on June 26, 2007. Subsequent to the acquisition, the private company was amalgamated with the Company.

This transaction has been accounted for using the purchase method of accounting. The fair value of the assets acquired and liabilities assumed at the date of acquisition is summarized below:

Consideration for the acquisition:	
Cash paid for property, plant and equipment	$ 241,092
Costs associated with acquisition	2,181
Cash paid for working capital	13,229
Total purchase price	$ 256,502

Allocation of purchase price:	
Working capital	$ 13,229
Property, plant and equipment	320,036
Future income taxes	(74,524)
Asset retirement obligations	(2,239)
Total net assets acquired	$ 256,502

4. LONG-TERM DEBT

	As at December 31	
	2008	2007
10.5% senior subordinated notes (US$247)	**$ 303**	$ 244
9.625% senior subordinated notes (US$179,699)	**220,059**	177,561
	220,362	177,805
Discontinued fair value hedge	**(3,089)**	(3,951)
	$ 217,273	$ 173,854

The Company has US$0.2 million senior subordinated notes bearing interest at 10.5% payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and are subordinate to the Company's bank credit facilities.

The Company also has US$179.7 million senior subordinated notes bearing interest at 9.625% payable semi-annually with principal repayable on July 15, 2010. These notes are unsecured and are subordinate to the Company's bank credit facilities. After July 15 in each of the following years, these notes are redeemable at the Company's option, in whole or in part with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as percentage of the principal amount of the notes): 2008 at 102.406%, 2009 and thereafter at 100%. These notes are carried at amortized cost net of a discontinued fair value hedge of $6.0 million recorded on adoption of CICA Handbook Section 3865 "Hedges". The notes will accrete up to the principal balance at maturity using the effective interest method. Accretion expense of $1.6 million had been recorded for the year ended December 31, 2008 (December 31, 2007 - $2.0 million). The effective interest rate is 10.6%. The Company had an interest rate swap contract converting the fixed rate to a floating rate reset quarterly at the three-month LIBOR rate plus 5.2% until the maturity of these notes. In November 2007, the Company terminated the interest rate swap contract. A gain on termination of $2.0 million was recorded as a reduction to interest expense in 2007.

5. CONVERTIBLE UNSECURED SUBORDINATED DEBENTURES

In June 2005, the Trust issued $100.0 million principal amount of 6.5% convertible unsecured subordinated debentures for net proceeds of $95.8 million. The debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per trust unit. The debentures mature on December 31, 2010, at which time they are due and payable.

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' equity. This resulted in $95.2 million being classified as debt and $4.8 million being classified as equity. The debt portion will accrete up to the principal balance at maturity, using the effective interest rate of 7.6%. The accretion and the interest paid are expensed as interest expense in the consolidated statement of income and comprehensive income. If the debentures are converted to trust units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to unitholders' capital along with the principal amounts converted.

	Number of Debentures	Convertible Debentures	Conversion Feature of Debentures
Balance, December 31, 2006	19,619	$ 18,906	$ 940
Conversion	(2,999)	(2,895)	(144)
Accretion	-	139	-
Balance, December 31, 2007	16,620	$ 16,150	$ 796
Conversion	(6,222)	(6,052)	(298)
Accretion	-	97	-
Balance, December 31, 2008	**10,398**	**$ 10,195**	**$ 498**

6. ASSET RETIREMENT OBLIGATIONS

	2008	2007
Balance, beginning of year	**$ 45,113**	$ 39,855
Liabilities incurred	**871**	2,180
Liabilities settled	**(1,443)**	(2,442)
Acquisition of liabilities	**1,536**	2,239
Disposition of liabilities	**(904)**	(585)
Accretion	**3,802**	3,404
Change in estimate[(1)]	**376**	462
Balance, end of year	**$ 49,351**	$ 45,113

[(1)] Change in status of wells and change in the estimated costs of abandonment and reclamations are factors resulting in a change in estimate.

The Trust's asset retirement obligations are based on the Trust's net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. These costs are expected to be incurred over the next 50 years. The undiscounted amount of estimated cash flow required to settle the retirement obligations at December 31, 2008 is $274.0 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0 percent and an estimated annual inflation rate of 2.0 percent.

7. UNITHOLDERS' CAPITAL

The Trust is authorized to issue an unlimited number of trust units.

	Number of Units	Amount
Balance, December 31, 2006	75,122	$ 637,156
Issued from treasury for cash	7,000	142,135
Issued on conversion of debentures	203	3,037
Issued on conversion of exchangeable shares	12	230
Issued on exercise of trust unit rights	739	5,482
Transfer from contributed surplus on exercise of trust unit rights	-	2,816
Issued pursuant to distribution reinvestment plan	1,464	27,763
Cumulative effect of change in accounting policy	-	3,005
Balance, December 31, 2007	84,540	821,624
Issued on conversion of debentures	422	6,350
Issued on conversion of exchangeable shares	2,787	86,888
Issued on exercise of trust unit rights	1,386	10,653
Transfer from contributed surplus on exercise of trust unit rights	-	5,105
Issued on acquisition of Burmis Energy Inc. net of issuance costs	6,383	151,903
Issued pursuant to distribution reinvestment plan	2,167	47,386
Balance, December 31, 2008	**97,685**	**$ 1,129,909**

8. NON-CONTROLLING INTEREST

The Company is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares can be converted (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by the Company for either a cash payment or the issue of trust units. The number of trust units issued upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is adjusted monthly to account for distributions paid on the trust units by dividing the cash distribution paid by the weighted average trust unit price for the five-day trading period ending on the record date. Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being converted to trust units.

The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the balance sheet.

	Number of Exchangeable Shares	Amount
Balance, December 31, 2006	1,573	$ 17,187
Exchanged for trust units	(7)	(83)
Non-controlling interest in net income	-	4,131
Balance, December 31, 2007	1,566	$ 21,235
Exchanged for trust units	(1,566)	(24,593)
Non-controlling interest in net income	-	3,358
Balance, December 31, 2008	**-**	**$ -**

On May 30, 2008, the Trust announced that Baytex Energy Ltd. had elected to redeem all of its exchangeable shares outstanding on August 29, 2008. In connection with this redemption, Baytex ExchangeCo Ltd. exercised its overriding "redemption call right" to purchase such exchangeable shares from holders of record. Each exchangeable share was exchanged for units of the Trust in accordance with the exchange ratio in effect at August 28, 2008. As at December 31, 2008, there were no exchangeable shares outstanding.

9. TRUST UNIT RIGHTS INCENTIVE PLAN

The Trust has a Trust Unit Rights Incentive Plan (the "Plan") whereby the maximum number of trust units issuable pursuant to the Plan is a "rolling" maximum equal to 10.0% of the outstanding trust units plus the number of trust units which may be issued on the exchange of outstanding exchangeable shares. Any increase in the issued and outstanding trust units will result in an increase in the number of trust units available for issuance under the Plan, and any exercises of rights will make new grants available under the Plan, effectively resulting in a re-loading of the number of rights available to grant under the Plan. Trust unit rights are granted at the volume weighted average trading price of the trust units for the five trading days prior to the date of grant, vest over three years and have a term of five years. The Plan provides for the exercise price of the rights to be reduced in future periods by a portion of the future distributions, subject to certain performance criteria.

The Trust recorded compensation expense of $1.6 million for the three months ended December 31, 2008 ($1.8 million in 2007) and $7.8 million for the year ended December 31, 2008 ($8.0 million in 2007) related to the rights granted under the plan.

The Trust uses the binomial-lattice model to calculate the estimated weighted average fair value of $2.42 per unit for rights issued during 2008 ($3.87 per unit in 2007). The following assumptions were used to arrive at the estimate of fair values:

	2008	2007
Expected annual right's exercise price reduction	**$2.64**	$2.16
Expected volatility	**28% - 39%**	28%
Risk-free interest rate	**2.98% - 4.17%**	3.77% - 4.50%
Expected life of right (years)	**Various [1]**	Various [1]

[1] The binomial-lattice model calculates the fair values based on an optimal strategy, resulting in various expected life of unit rights. The maximum term is limited to five years by the Plan.

The number of unit rights outstanding and exercise prices are detailed below:

	Number of rights	Weighted average exercise price [1]
Balance, December 31, 2006	6,313	$ 14.00
Granted	2,642	$ 19.85
Exercised	(739)	$ 7.42
Cancelled	(554)	$ 16.91
Balance, December 31, 2007	7,662	$ 14.67
Granted	2,838	$ 19.27
Exercised	(1,386)	$ 7.69
Cancelled	(665)	$ 21.79
Balance, December 31, 2008	**8,449**	**$ 14.58**

[1] Exercise price reflects grant prices less reduction in exercise price as discussed above.

The following table summarizes information about the unit rights outstanding at December 31, 2008:

Range of Exercise Prices	Number Outstanding at December 31, 2008	Weighted Average Remaining Term *(years)*	Weighted Average Exercise Price	Number Exercisable at December 31, 2008	Weighted Average Exercise Price
$ 1.00 to $ 6.00	706	0.9	$ 3.71	706	$ 3.71
$ 6.01 to $11.00	1,352	1.8	$ 8.35	1,254	$ 8.17
$11.01 to $16.00	399	3.2	$15.08	183	$15.14
$16.01 to $21.00	5,947	3.9	$17.18	1,637	$17.05
$21.01 to $32.28	45	4.4	$25.93	-	-
$ 1.00 to $32.28	8,449	3.3	$14.58	3,780	$11.52

The following table summarizes the changes in contributed surplus:

Balance, December 31, 2006	$	13,357
Compensation expense		7,986
Transfer from contributed surplus on exercise of trust unit rights [1]		(2,816)
Balance, December 31, 2007	$	18,527
Compensation expense		7,812
Transfer from contributed surplus on exercise of trust unit rights [1]		(5,105)
Balance, December 31, 2008	**$**	**21,234**

[1] Upon exercise of rights, contributed surplus is reduced with a corresponding increase in unitholders' capital.

10. NET INCOME PER UNIT

The Trust applies the treasury stock method to assess the dilutive effect of outstanding trust unit rights on net income per unit. The weighted average exchangeable shares outstanding during the period, converted at the year-end exchange ratio, and the trust units issuable on conversion of convertible debentures, have also been included in the calculation of the diluted weighted average number of trust units outstanding:

Three Months Ended	**December 31, 2008**			December 31, 2007		
	Net Income	**Trust Units**	**Net Income per Unit**	Net Income	Trust Units	Net Income per Unit
Net income per basic unit	**$ 52,401**	**97,304**	**$ 0.54**	$ 41,353	84,267	$ 0.49
Dilutive effect of trust unit rights	**-**	**1,318**		-	1,858	
Conversion of convertible debentures	**133**	**619**		203	1,144	
Exchange of exchangeable shares	**-**	**-**		1,279	2,629	
Net income per diluted unit	**$ 52,534**	**99,241**	**$ 0.53**	$ 42,835	89,898	$ 0.48

Year Ended	**December 31, 2008**			December 31, 2007		
	Net Income	**Trust Units**	**Net Income per Unit**	Net Income	Trust Units	Net Income per Unit
Net income per basic unit	**$ 259,894**	**91,683**	**$ 2.83**	$ 132,860	80,029	$ 1.66
Dilutive effect of trust unit rights	**-**	**2,955**		-	2,110	
Conversion of convertible debentures	**654**	**882**		855	1,206	
Exchange of exchangeable shares	**3,358**	**871**		4,131	2,630	
Net income per diluted unit	**$ 263,906**	**96,391**	**$ 2.74**	$ 137,846	85,975	$ 1.60

The dilutive effect of trust unit rights for the year ended December 31, 2008 did not include 45,000 trust unit rights (2007 – 4.1 million) because the respective proceeds of exercise plus the amount of compensation expense attributed to future services not yet recognized exceeded the average market price of the trust units during the period.

11. TAX EXPENSE (RECOVERY)

The provision for (recovery of) taxes has been computed as follows:

	2008	2007
Income before taxes and non-controlling interest	**$ 288,812**	$ 94,335
Expected taxes at the statutory rate of 30.22% (2007 – 34.02%)	**87,279**	32,094
Increase (decrease) in taxes resulting from:		
Net income of the Trust	**(79,930)**	(62,615)
Non-taxable portion of foreign exchange loss (gain)	**6,204**	(5,424)
Effect of change in tax rate	**(1,402)**	(15,806)
Effect of change in opening tax pool balances	**878**	(834)
Effect of change in valuation allowance	**-**	2,075
Unit-based compensation	**2,361**	2,717
Other	**(7)**	(1,576)
Future tax expense (recovery)	**15,383**	(49,369)
Current tax expense	**10,177**	6,713
Total tax expense (recovery)	**$ 25,560**	$ (42,656)

On June 22, 2007, Bill C-52 Budget Implementation Act, which contains legislative provisions to tax publicly traded income trusts in Canada, received Royal Assent in the Canadian House of Commons. The new tax is not expected to apply to the Trust until 2011. As a result of the tax legislation becoming enacted, an additional future tax recovery of $0.5 million was recorded in 2007.

The components of the net future tax liability at December 31 are as follows:

	As at December 31	
	2008	2007
Future tax liabilities:		
Petroleum and natural gas properties	**$ 197,694**	$ 155,921
Financial instruments	**25,358**	-
Other	**14,215**	18,271
Future tax assets:		
Asset retirement obligations	**(12,652)**	(11,796)
Non-capital loss carry-forward	**(11,813)**	(8,058)
Valuation allowance on non-capital losses	**4,967**	-
Financial instruments	**-**	(11,525)
Other	**-**	(395)
Net future tax liability[(1)]	**217,769**	142,418
Current portion of net future tax liability (asset)	**25,358**	(11,525)
Long-term portion of net future tax liability	**$ 192,411**	$ 153,943

[(1)] Non-capital loss carry-forwards, excluding those for which a valuation allowance has been taken, amongst Canadian and U.S. subsidiaries, totaled $42.9 million ($62.0 million in 2007) and expire from 2014 to 2017.

12. INTEREST EXPENSE

The Trust incurred interest expense on its outstanding debt as follows:

	Three Months Ended December 31		Year Ended December 31	
	2008	2007	**2008**	2007
Bank loan and miscellaneous financing	**$ 2,656**	$ 3,658	**$ 12,685**	$ 13.296
Convertible debentures	**193**	308	**945**	1,295
Long-term debt	**5,011**	4,604	**19,332**	20.571
Total interest	**$ 7,860**	$ 8,570	**$ 32,962**	$ 35,162

13. SUPPLEMENTAL INFORMATION

	Three Months Ended December 31		Year Ended December 31	
	2008	2007	**2008**	2007
Interest paid	**$ 2,533**	$ 2,340	**$ 30,655**	$ 32,321
Current income taxes	**$ 5,822**	$ 2,242	**$ 9,972**	$ 9,436

	Three Months Ended December 31		Year Ended December 31	
	2008	2007	**2008**	2007
Unrealized foreign exchange loss (gain)	**$ 29,032**	**$ (1,526)**	**$ 41,712**	$ (32,574)
Realized foreign exchange loss (gain)	**(4,223)**	**289**	**(3,966)**	160
Total foreign exchange loss (gain)	**$ 24,809**	**$ (1,237)**	**$ 37,746**	$ (32,414)

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Trust's financial assets and liabilities are comprised of accounts receivable, accounts payable and accrued liabilities, distributions payable to unitholders, bank loan, financial derivative contracts, long-term debt, convertible debentures and deferred obligations.

Categories of Financial Instruments

Under Canadian generally accepted accounting principles, financial instruments are classified into one of the following 5 categories: held-for-trading, held to maturity, loans and receivables, available-for-sale and other financial liabilities. The carrying value and fair value of the Trust's financial instruments on the consolidated balance sheet are classified into the following categories:

	December 31, 2008		December 31, 2007	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Financial Assets				
Loans and receivables				
Accounts receivable	**$ 87,551**	**$ 87,551**	$ 105,176	$ 105,176
Total loans and receivables	**$ 87,551**	**$ 87,551**	$ 105,176	$ 105,176
Held for trading				
Derivatives designated as held for trading	**$ 85,678**	**$ 85,678**	-	-
Total held for trading	**$ 85,678**	**$ 85,678**	-	-
Financial Liabilities				
Held for trading				
Derivatives designated as held for trading	-	-	$ (34,239)	$ (34,239)
Total held for trading	-	-	$ (34,239)	$ (34,239)

Other financial liabilities				
Accounts payable and accrued liabilities	**$ (164,279)**	**$ (164,279)**	$ (104,318)	$ (104,318)
Distributions payable to unitholders	**(17,583)**	**(17,583)**	(15,217)	(15,217)
Bank loan	**(208,482)**	**(208,482)**	(241,748)	(241,748)
Long-term debt	**(217,273)**	**(200,557)**	(173,854)	(182,132)
Convertible debentures	**(10,195)**	**(9,837)**	(16,150)	(19,481)
Deferred obligations	**(74)**	**(74)**	(113)	(113)
Total other financial liabilities	**$ (617,886)**	**$ (600,812)**	$ (551,400)	$ (563,009)

The estimated fair values of the financial instruments have been determined based on the Trust's assessment of available market information. These estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction. The fair values of financial instruments, other than bank loan, and long-term borrowings approximate their book amounts due to the short-term maturity of these instruments. The fair value of the bank loan approximates its book value as it is at a market rate of interest. The fair value of the long-term debt is based on the trading value of the instrument. The fair value of the convertible debentures has been calculated based on the lower of trading value and the present value of future cash flows associated with the debentures.

Financial Risk

The Trust is exposed to a variety of financial risk, including market risk, credit risk and liquidity risk. The Trust monitors and, when appropriate, utilizes derivative contracts to manage its exposure to these risks. The Trust does not enter into derivative contracts for speculative purposes.

Market Risk

Market risk is the risk that the fair value or future cash flows of financial assets or liabilities will fluctuate due to movements in market prices. Market risk is comprised of foreign currency risk, interest rate risk and commodity price risk.

Foreign currency risk
The Trust is exposed to fluctuations in foreign currency as a result of its U.S. dollar denominated notes, crude oil sales based on U.S. dollar indices and commodity contracts that are settled in U.S. dollars. The Trust's net income and cash flow will therefore be impacted by fluctuations in foreign exchange rates.

In order to manage these risks, the Trust may enter into agreements to fix the exchange rate of Canadian to U.S. dollar in order to lessen the impact of currency rate fluctuations.

At December 31, 2008, the Trust had in place the following currency swap:

	Period	Amount	Swap Price
Swap	January 1, 2009 to December 31, 2009	USD 8.3 million per month	CAD/USD 1.2394 (weighted average)

The following table demonstrates the effect of exchange rate movement on net income before taxes and non-controlling interest due to changes in the fair value of its currency swap as well as gains and losses on the revaluation of U.S. dollar denominated monetary assets and liabilities at December 31, 2008.

	$0.10 Increase/Decrease in CAD/USD Exchange Rate
Gain/loss on currency swap	$ (189)
Gain/loss on other monetary assets/liabilities	10,939
Impact on income before taxes and non-controlling interest	$ 10,750

The carrying amounts of the Trust's foreign currency denominated monetary assets and liabilities at the reporting date are as follows:

	Assets		Liabilities	
	December 31, 2008	December 31, 2007	December 31, 2008	December 31, 2007
U.S. dollar denominated	USD 84,070	USD 54,674	USD 191,571	USD 226,528

Subsequent to December 31, 2008, the Trust added the following currency swap:

	Period	Amount	Swap Price
Swap	January 1, 2009 to December 31, 2009	USD 1.7 million per month	CAD/USD 1.2345

Interest rate risk
The Trust's interest rate risk arises from its floating rate bank loan. As at December 31, 2008, $208.5 million of the Trust's total debt is subject to movements in floating interest rates. An increase or decrease of 1.0% in interest rates would impact cash flow for 2008 by approximately $2.2 million.

Commodity Price Risk
The Trust monitors and, when appropriate, utilizes financial derivative agreements or fixed price physical delivery contracts to manage the risk associated with changes in commodity prices. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors of the Company. Under the Trust's risk management policy, financial instruments are not used for speculative purposes.

When assessing the potential impact of commodity price changes, a 10% increase in commodity prices could have resulted in a reduction to the unrealized gain in 2008 of $8.5 million relating to the financial derivative instruments outstanding as at December 31, 2008, while a 10% decrease could have resulted in $8.8 million of additional gain.

At December 31, 2008, the Trust had the following commodity derivative contracts:

OIL	Period	Volume	Price	Index
Price collar	Calendar 2009	2,000 bbl/d	USD 90.00 – 136.40	WTI
Price collar	Calendar 2009	2,000 bbl/d	USD 110.00 – 172.70	WTI

Derivative contracts are marked to market at the end of each reporting period, with the following reflected in the income statement:

	Three Months Ended December 31		Year Ended December 31	
	2008	2007	**2008**	2007
Realized (loss) on financial instruments	**$ (2,170)**	$ (4,367)	**$ (60,101)**	$ (3,164)
Unrealized gain (loss) on financial instruments	**86,511**	(27,264)	**119,917**	(31,320)
Gain (loss) on financial instruments	**$ 84,341**	$ (31,631)	**$ 59,816**	$ (34,484)

Subsequent to December 31, 2008, the Trust added the following commodity derivative contracts:

GAS	Period	Volume	Price	Index
Price collar	April 1, 2009 to December 31, 2010	5,000 GJ/d	CAD 5.00 – 6.30	AECO

Liquidity risk

Liquidity risk is the risk that the Trust will encounter difficulty in meeting obligations associated with financial liabilities. The Trust manages its liquidity risk through cash and debt management. As at December 31, 2008, the Trust had available unused bank credit facilities in the amount of $183 million. The Trust believes it has sufficient funding capacity through its credit facilities to meet foreseeable borrowing requirements.

The timing of cash outflows (excluding interest) relating to financial liabilities are outlined in the table below:

	Total	1 year	2-3 years	4-5 years	Beyond 5 years
Accounts payable and accrued liabilities	164,279	164,279	-	-	-
Distributions payable to unitholders	17,583	17,583	-	-	-
Bank loan [(1)]	208,482	208,482	-	-	-
Long-term debt [(2)]	220,362	-	220,362	-	-
Convertible debentures [(2)]	10,398	-	10,398	-	-
Deferred obligations	74	46	23	5	-
	621,178	390,390	230,783	5	-

[(1)] The bank loan is a 364-day revolving loan with the ability to extend the term. The Trust has no reason to believe that it will be unable to extend the credit facility when it matures on July 1, 2009.
[(2)] Principal amount of instruments.

Credit risk

Credit risk is the risk that a counterparty to a financial asset will default resulting in the Trust incurring a loss. Most of the Trust's accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. The Trust manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis. Credit risk may also arise from financial derivative instruments. The maximum exposure to credit risk is equal to the carrying value of the financial assets.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the loss is recognized in net income.

As at December 31, 2008, accounts receivable include a $9.9 million balance over 90 days (December 31, 2007 - $3.5 million). A balance of $2.4 million (December 31, 2007 - $0.2 million) has been set up as allowance for doubtful accounts.

15. COMMITMENTS AND CONTINGENCIES

At December 31, 2008, the Trust had the following crude oil supply contracts:

Heavy Oil	Period	Volume	Price
Price Swap – WCS Blend	Calendar 2009	10,340 bbl/d	WTI x 67.0% (weighted average)

Subsequent to December 31, 2008, the Trust added the following physical crude oil supply contracts:

Heavy Oil	Period	Volume	Price
Price Swap – WCS Blend	April 1, 2009 to August 30, 2009	775 bbl/d	WTI x 80.0%
Price Swap – WCS Blend	April 1, 2009 to August 30, 2009	775 bbl/d	WTI less US$10

At December 31, 2008, the Trust had the following natural gas physical sales contract:

GAS	Period	Volume	Price/GJ
Price Collar	Calendar 2009	5,000 GJ/d	$7.00 - $7.95

At December 31, 2008, the Trust had the following power contracts:

POWER	Period	Volume	Price/MWh
Fixed	October 1, 2008 to December 31, 2009	0.6 MW/hr	$78.61
Fixed	October 1, 2008 to December 31, 2009	0.6 MW/hr	$79.92

Subsequent to December 31, 2008, the Trust added the following physical power contract:

POWER	**Period**	**Volume**	**Price/MWh**
Fixed	March 1, 2009 to June 30, 2010	0.6 MW/hr	$76.89

At December 31, 2008, the Trust had operating lease and transportation obligations as summarized below:

	Total	**Payments Due Within**					**Beyond**
		1 year	**2 years**	**3 years**	**4 years**	**5 years**	**5 years**
Operating leases	$ 42,732	$ 2,776	$ 3,327	$ 3,785	$ 4,073	$ 3,814	$ 24,957
Processing and transportation agreements	22,350	8,478	7,435	6,196	178	63	-
Total	$ 65,082	$ 11,254	$ 10,762	$ 9,981	$ 4,251	$3,877	$24,957

Other

At December 31, 2008, there were outstanding letters of credit aggregating $2.3 million (December 31, 2007 - $4.9 million) issued as security for performance under certain contracts.

In connection with a purchase of properties in 2005, Baytex became liable for contingent consideration whereby an additional amount would be payable by Baytex if the price for crude oil exceeds a base price in each of the succeeding six years. An amount payable was not reasonably determinable at the time of the purchase, therefore such consideration should be recognized only when the contingency is resolved. As at December 31, 2008, additional payments totaling $5.3 million have been paid under the agreement and have been recorded as an adjustment to the original purchase price of the properties. It is currently not determinable if further payments will be required under this agreement, therefore no accrual has been made.

The Trust is engaged in litigation and claims arising in the normal course of operations, none of which could reasonably be expected to materially affect the Trust's financial position or reported results of operations.

16. CAPITAL STRUCTURE

The Trust's objectives when managing capital are to: (i) maintain financial flexibility in its capital structure; (ii) optimize its cost of capital at an acceptable level of risk; and (iii) preserve its ability to access capital to sustain the future development of the business through maintenance of investor, creditor and market confidence.

The Trust considers its capital structure to include total monetary debt and unitholders' equity. Total monetary debt is a non-GAAP term which we define to be the sum of monetary working capital, which is current assets less current liabilities excluding non-cash items such as future income tax assets or liabilities and unrealized financial derivative gains or losses, the principal amount of long-term debt and the balance sheet value of the convertible debentures.

The Trust's financial strategy is designed to maintain a flexible capital structure consistent with the objectives above and to respond to changes in economic conditions and the risk characteristics of its underlying assets. In order to maintain the capital structure, the Trust may adjust the amount of its distributions, adjust its level of capital spending, issue new units, issue new debt or sell assets to reduce debt.

The Trust monitors capital based on current and projected ratios of total monetary debt to cash flow, and the current and projected level of its undrawn bank credit facilities. The Trust's objectives are to maintain a total monetary debt to cash flow from operations ratio of less than two times and to have access to undrawn bank credit facilities of not less than $100 million. The total monetary debt to cash flow from operations ratio may increase beyond two times, and the undrawn credit facilities may decrease to below $100 million at certain times due to a number of factors, including acquisitions, changes to commodity prices and changes in the credit market. To facilitate management of the total monetary debt to cash flow from operations ratio and the level of undrawn bank credit facilities, the Trust continuously monitors its cash flow from operations and evaluates its distribution policy and capital spending plans.

The Trust's financial objectives and strategy as described above have remained substantially unchanged over the last two completed fiscal years. These objectives and strategy are reviewed on an annual basis. The Trust believes its financial metrics are within acceptable limits pursuant to its capital management objectives.

The Trust is subject to financial covenants relating to its bank loan, senior subordinated notes and convertible debentures. The Trust is in compliance with all financial covenants.

On June 22, 2007, new tax legislation modifying the taxation of specified investment flow-through entities, including income trusts such as the Trust, was enacted (the "New Tax Legislation"). The New Tax Legislation will apply a tax at the trust level on distributions of certain income from trusts. The New Tax Legislation permits "normal growth" for income trusts through the transitional period ending December 31, 2010. However, "undue expansion" could cause the transitional relief to be revisited, and the New Tax Legislation to be effective at a date earlier than January 1, 2011. On December 15, 2006, the Department of Finance released guidelines on normal growth for income trusts and other flow-through entities (the "Guidelines"). Under the Guidelines, trusts will be able to increase their equity capital each year during the transitional period by an amount equal to a safe harbour amount. The safe harbour amount is measured by reference to a trust's market capitalization as of the end of trading on October 31, 2006. The safe harbour amounts are 40% for the period from November 2006 to the end of 2007, and 20% per year for each of 2008, 2009 and 2010. For Baytex, the limits are approximately $730 million for 2006/2007 and $365 million for each of the subsequent three years. The safe harbour amounts are cumulative allowing amounts not used in one year to be carried forward to a future year. Two trusts can merge without being impacted by the growth limitations. Limits are not impacted by non-convertible debt-financed growth, but rather focus solely on the issuance of equity to facilitate growth. At December 31, 2008, the Trust had not exceeded its "normal growth" limits.