Harvest Energy Trust

Financial & Operating Highlights
The table below provides a summary of Harvest's financial and operating results for the three month period ended March 31, 2006 and 2005.

		Three months ended		
FINANCIAL *($000s except where noted)*		March 31, 2006		March 31, 2005
Revenue, net(1)		**131,432**		16,538
Cash Flow(2)		**100,971**		52,687
Per Trust Unit, basic(2)	**$**	**1.23**	$	1.25
Per Trust Unit, diluted(2)	**$**	**1.22**	$	1.19
Net income		**(33,937)**		(43,070)
Per Trust Unit, basic	**$**	**(0.41)**	$	(1.02)
Per Trust Unit, diluted	**$**	**(0.41)**	$	(1.02)
Distributions declared(3)		**94,812**		36,126
Distributions declared, per Trust Unit	**$**	**1.11**	$	0.60
Payout ratio (2)(3)		**94%**		48%
Capital asset additions (excluding acquisitions), cash		**103,239**		23,223
Bank debt		**201,652**		103,665
Production				
Light to medium oil (bbl/d)		**23,900**		15,614
Heavy oil (bbl/d)		**15,182**		14,473
Natural gas liquids (bbl/d)		**1,709**		780
Natural gas (mcf/d)		**73,337**		27,114
Total daily sales volumes (BOE/day)		**53,014**		35,386

(1) Revenues are net of royalties and risk management activities.
(2) These are non-GAAP measures; please refer to “Non-GAAP Measures” in the first quarter 2006 MD&A.
(3) Ratio of distributions declared to Cash Flows, excluding special distribution of $10.7 million settled with the issuance of Trust Units in 2005.

Message to Unitholders

The first quarter of 2006 was an active and successful period for Harvest, as we closed the merger with Viking following approval by over 95% of the voting unitholders of each trust on February 2, and executed a capital program of over $100 million. We are pleased with the speed and efficiency of the Viking integration, and despite having only closed the transaction on February 3, benefits from the combination are already being realized.

These benefits include an expanded credit facility with more favourable lending terms, and more efficient Information Systems. In addition, combining our organizations enabled Harvest to capture annual savings of $500,000 in our transportation costs by redirecting natural gas volumes to optimize pipeline capacity charges. Further, given the size of our capital program, we benefit from greater buying power and economies of scale when procuring oilfield products and services. We expect this will lead to cost savings in excess of $5 million in 2006 alone.

Harvest’s oil-weighted commodity mix (50% light/medium oil, 25% heavy and oil sands production and 25% natural gas) is supported by our access to large, original-resource-in-place (ORIP) hydrocarbon deposits on our working interest acreage. A key element of our strategy is to enhance the ultimate recovery from these ORIP properties through drilling, fluid handling, optimization and the implementation of improved recovery technology. Based on our major assets containing ORIP of approximately 1.8 billion barrels of oil equivalent (BOE), a 1% increase in recovery could result in 18 million BOE of incremental reserves being recovered. With our efficient capital program and technical expertise, we will strive to increase recovery by an average of 5 to 10% on these major properties.

As anticipated, Harvest's first quarter payout ratio was higher than our target, but does not reflect our forecast payout ratio for subsequent quarters. This higher payout ratio is primarily due to the increased distribution level in the first quarter, lower than expected natural gas prices and wider heavy oil differentials.

Our first quarter production of 53,014 BOE/d was in-line with expectations, given that it reflected only two months of combined Harvest and Viking production, and one month of Harvest standalone production. Production was negatively impacted at the winter access only Hay River property due to the significant drilling and facility construction undertaken in the first quarter, the benefits of which are expected to be realized in subsequent quarters. As a result of this activity, production was down approximately 760 BOE/d through the quarter, but these volumes are now back on-stream. At the end of the first quarter, Harvest had approximately 2,800 BOE/d awaiting tie-in, which includes approximately 1,500 BOE/d from our Hay River winter drilling program, 1,000 BOE/d in our Markerville and Ferrier areas, and approximately 300 BOE/d from other areas. These volumes are expected to come on-stream through the second quarter. We expect that production will run relatively flat through the balance of the year, exiting the year at approximately 61,000 BOE/d, resulting in an annual average of approximately 60,000 BOE/d.

During the first quarter, we continued to execute Harvest's strategy of pursuing value creation and enhancement opportunities through our disciplined capital program, combined with ongoing cost reduction activities. To that end, we successfully delivered a substantial and successful development program of $103 million in the quarter, resulting in the drilling of 82 gross wells (69.4 net wells) with a 98% gross success rate (99% net). Executing a capital program of this size in a single quarter amidst fierce competition for rigs and services while completing a major corporate integration is a testament to the commitment and technical strengths of Harvest's team, and the ability of our organization to successfully compete in a challenging and competitive market. Of our total development capital, 78% was invested in drilling and related activities, with the remainder in projects such as optimization enhancements and operating expense reduction initiatives.

One example of our success in the capital program is the upgrading of pumping technology at our Hay River property to replace the existing jet pumps with more efficient and effective electrical submersible pumps (ESPs). The benefit of replacing the jet pumps with ESPs is to increase the ultimate recovery of oil from each horizontal well with a more reliable technology.

We remained very active through the first quarter in our business development activities to identify and pursue acquisition opportunities. A property in our Hay River area was acquired for $18.4 million, which supplements our future drilling and development inventory, and we also successfully completed several small consolidation acquisitions in other areas. With increased competition for assets in Western Canada and the experience of our team in the international arena, Harvest may consider assets or opportunities outside the Western Canadian Sedimentary Basin. However, we remain committed to our strategy of only pursuing acquisitions that create value for our unitholders.

Consistent with our strategy of sustainability, we continue to focus on medium and longer term development opportunities within our asset base. For example, during the first quarter, a third party study we commissioned identified major enhanced oil recovery (EOR) opportunities on some of our properties. We expect to conduct similar studies on other large resource-in-place properties to identify additional improved recovery projects that can further grow our RLI, extend the life of our assets, and allow us to take advantage of a large hydrocarbon base that offers significant value creation potential.

With our favourable oil-weighted commodity mix, longer RLI, opportunities within our asset base, access to a large undrawn credit facility, strong technical team, and low (33%) non-Canadian ownership, Harvest is well positioned for long-term sustainability and to continue generating value for unitholders. We appreciate the ongoing support of our unitholders, the tireless efforts of our staff members, and I look forward to reporting on our continued progress in future quarters.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") of the financial condition and results of operations of Harvest Energy Trust should be read in conjunction with our audited consolidated financial statements and accompanying notes for the years ended December 31, 2005 and 2004 as well as our unaudited consolidated financial statements and notes for the three month period ended March 31, 2006. In this MD&A, reference to "Harvest", "we", "us" or "our" refers to Harvest Energy Trust and all of its controlled entities on a consolidated basis. The information and opinions concerning our future outlook are based on information available at May 10, 2006.

When reviewing our 2006 results and comparing them to 2005, readers are cautioned that the 2006 results include a full quarter of operations from our Hay River acquisition in the third quarter of 2005 and only two months of operations from our acquisition of Viking in February 2006. The combination of these events significantly impact the comparability of our operations and financial results for 2006 to the results of for the same period of 2005. To increase comparability we have provided certain pro forma combined financial information for the three months ended December 31, 2005, which reflects the results of operations of Harvest plus the results of Viking for the fourth quarter of 2005.

All references are to Canadian dollars unless otherwise indicated. Tabular amounts are in thousands of dollars unless otherwise stated. Natural gas volumes are converted to barrels of oil equivalent ("BOE") using the ratio of six thousand cubic feet ("6 mcf") of natural gas to one (1) barrel of oil ("bbl"). BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf:1 bbl is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead.

In accordance with Canadian practice, production volumes, reserve volumes and revenues are reported on a gross basis, before deduction of crown and other royalties, unless otherwise stated.

We use certain financial reporting measures that are commonly used as benchmarks within the oil and natural gas industry in the following MD&A such as Cash Flow, Payout Ratio, Cash General and Administrative Expenses and Operating Netbacks (calculation tables within the MD&A) each as defined in this MD&A. These measures are not defined under Canadian generally accepted accounting principles ("GAAP") and should not be considered in isolation or as an alternative to conventional GAAP measures. Certain of these measures are not necessarily comparable to a similarly titled measure of another company or trust. When these measures are used, they are defined as "non-GAAP" and should be given careful consideration by the reader. Please refer to the discussion under the heading "Non-GAAP Measures" at the end of this MD&A for a detailed discussion of these reporting measures.

Financial and Operating Highlights – First Quarter 2006

- Successful integration of operations with Viking Energy Royalty Trust ("Viking") completed.
- Record capital reinvestment spending of $103.2 million directed toward enhancing the recoveries from our resource base.
- Record production of 53,014 BOE/day, an increase in average daily production of 50% over the first quarter of 2005 with estimated production behind pipe of 2,800 BOE/day at the end of the quarter.
- Cash Flows for the three months ended March 31, 2006 totaled $101.0 million ($1.23 per Trust Unit), excluding one time cash transaction costs of $5.1 million, a 92% increase over $52.7 million earned in the same period in 2005.
- Declared cash distributions of $0.35, $0.38 and $0.38 per Trust Unit in the months of January, February and March of 2006, respectively, compared to $0.20 per month in the first quarter of 2005, representing an 85% increase.
- Improved financing flexibility in 2006, with the increase in our credit facility from a $400 million reserve based loan to a three year extendable $900 million covenant based revolving loan.

The table below provides a summary of our financial and operating results for the three month periods ended March 31, 2006 and March 31, 2005. Detailed commentary on individual items within this table is provided elsewhere in this MD&A.

	Three months ended	
FINANCIAL *($000s except where noted)*	March 31, 2006	March 31, 2005
Revenue, net(1)	**131,432**	16,538
Cash Flow(2)	**100,971**	52,687
Per Trust Unit, basic(2)	**$ 1.23**	$ 1.25
Per Trust Unit, diluted(2)	**$ 1.22**	$ 1.19
Net loss	**(33,937)**	(43,070)
Per Trust Unit, basic	**$ (0.41)**	$ (1.02)
Per Trust Unit, diluted	**$ (0.41)**	$ (1.02)
Distributions declared(3)	**94,812**	36,126
Distributions declared, per Trust Unit	**$ 1.11**	$ 0.60
Payout ratio (2)(3)	**94%**	48%
Capital asset additions (excluding acquisitions), cash	**103,239**	23,223
Bank debt	**201,652**	103,665
Production		
Light to medium oil (bbl/d)	**23,900**	15,614
Heavy oil (bbl/d)	**15,182**	14,473
Natural gas liquids (bbl/d)	**1,709**	780
Natural gas (mcf/d)	**73,337**	27,114
Total daily sales volumes (BOE/day)	**53,014**	35,386

(1) Revenues are net of royalties and risk management activities
(2) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.
(3) Ratio of distributions declared to Cash Flows, excluding special distribution of $10.7 million settled with the issuance of Trust Units in 2005.

Review of Operations and Strategy

In the first quarter of 2006 we focused on integrating the Viking business and employees into our operations and executing our capital program, including a significant development drilling program in Hay River. We were committed to quickly integrating our people and systems without compromising our business operations. By the end of the first quarter of 2006, we had completely integrated organizations including the reorganization of our office space and the integration of most of our information systems. By the end of May, we expect that the remaining portions of our information systems will be aligned and we will have completed our integration process. Despite the internal challenges of merging two sizeable entities, we have continued to focus on drilling opportunities and have executed the largest drilling program in our history.

The transaction with Viking came into effect on February 3, 2006, with the issuance of 46,040,788 Trust Units to the former Viking unitholders. As part of the plan of arrangement, Harvest assumed Viking's 10.5% and 6.40% unsecured subordinated convertible debentures, with an aggregate face value of $210 million. The merged entity has an improved product mix with approximately 50 percent of our production being light to medium gravity oil, 25 percent natural gas and 25 percent heavy gravity oil. We have also acquired additional drilling opportunities supporting an increase in our capital budget from $130 million in 2005 to $250 million in 2006. With the combination of the two entities, opportunities for preferential pricing on drilling services and supplies have arisen, from which we anticipate approximate annual costs savings of $4.5 million.

Our capital development program is focused on growing and maintaining production with 78% of the costs incurred directly related to drilling and equipping activities. In the first quarter of 2006 we incurred $103.2 million of capital expenditures drilling 82 gross wells with a success rate of 98% (total net wells drilled were 69.4 with a success rate of 99%). Of the total net wells drilled, 25 were in the Hay River area, which we acquired in August of 2005. We expect to see the impacts of our first quarter drilling program in production over the remaining quarters of 2006. In addition to our capital development expenditures, we also acquired additional properties in Hay River and in Killarney for $21.9 million which provides us with additional drilling opportunities in those areas.

Production for the three months ended March 31, 2006 was 53,014 BOE/day, which includes two full months of production from the assets acquired in connection with the Viking acquisition. Our first quarter production reflects lower Hay River production volumes than can be expected for the remainder of the year due to the "winter access" only nature of the property which requires that substantially all drilling and maintenance activities be completed when the ground is frozen. As a result, we experienced periods of down time at Hay River in the first quarter of 2006 amounting to approximately 760 bbl/d of lower production. Our second quarter results should reflect the benefits of the Hay River activities undertaken in the first quarter as well as a return to normal levels of production on existing wells.

Overall, we had a solid quarter with Cash Flow for the three months ended March 31, 2006 of $101.0 million ($1.23 per Unit), excluding one time cash transaction costs of $5.1 million relating to the Viking acquisition. This represents a 92% increase in Cash Flow compared to the same period in the prior year. This $48.3 million increase is substantially attributed to higher revenues of $94.4 million and lower realized losses on commodity price risk management contracts of $10.0 million offset by higher operating expenses of $22.9 million, and higher royalties of $23.2 million.

Total declared distributions per unit for the first quarter of 2006 were $1.11 compared to $0.60 in the same period of 2005, an 85% increase. In February 2006, we increased distributions from $0.35 to $0.38. The combination of the increase in distributions per unit, wider price differentials and higher overall operating costs resulted in a payout ratio of 94% for the three months ended March 31, 2006. We expect a decrease in our payout ratio in future quarters as operations stabilize in Hay River, positive seasonal impacts on differentials are realized and we begin to capture the benefits of the merger with Viking.

Concurrent with the acquisition of Viking, we negotiated a three year extendible revolving facility and increased our borrowing capacity from $400 million to $900 million. This increase in borrowing capacity provides us with additional flexibility on the acquisitions market. We continue to evaluate potential acquisition prospects that provide us additional development opportunities.

REVIEW OF QUARTERLY OPERATIONS

Commodity Price Environment

	Three months ended March 31		
Benchmarks	**2006**	2005	Change
West Texas Intermediate crude oil (US$ per barrel)	**63.48**	49.84	27%
Edmonton light crude oil ($ per barrel)	**68.96**	61.45	12%
Bow River blend crude oil ($ per barrel)	**39.98**	38.42	4%
AECO natural gas daily ($ per mcf)	**7.52**	6.89	9%
AECO natural gas monthly ($ per mcf)	**9.27**	6.69	39%
Canadian / U.S. dollar exchange rate	**0.866**	0.815	6%

Commodity prices have increased significantly in the first quarter of 2006 as compared to the first quarter of 2005. The West Texas Intermediate ("WTI") crude oil price increased by 27%, however this increase was not fully reflected in the Edmonton light crude oil price ("Edmonton Par") for two reasons; the US/Canadian dollar exchange rate and the differential between Edmonton Par and WTI. The Canadian dollar equivalent of WTI for 2005 was $61.15, a $0.30 discount to the Edmonton Par. For the first quarter of 2006, the Canadian dollar equivalent of WTI was $73.30, a $4.34 premium to Edmonton Par and $4.58 lower than it would have been had the Canadian dollar not gained 6% over the US dollar. The combination of these two factors has resulted in only a 12% increase in Edmonton Par over the first quarter of 2005 compared to a 27% increase in WTI. This effect was further compounded for lower gravity crude oil pricing. The Bow River differential to Edmonton Par in the first quarter of 2006 widened from that realized in the first quarter of 2005. While Edmonton Par prices increased by 12%, Bow River prices only realized a 4% increase due to a widening differential as outlined below.

	2006	2005				2004		
Differential Benchmarks	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Bow River Blend differential to Edmonton Par	**42.0%**	40.0%	28.2%	39.6%	37.5%	39.1%	26.2%	26.6%

AECO natural gas daily prices saw a modest increase of 9%, however, AECO natural gas monthly prices increased by 39% compared to the first quarter of 2005.

Realized Commodity Prices

The following table provides a breakdown of our 2006 and 2005 average commodity prices by product before and after realized losses on risk management contracts.

	Three months ended		
	March 31, 2006	March 31, 2005	Change
Light to medium oil ($/bbl)	**53.06**	49.88	6%
Heavy oil ($/bbl)	**35.12**	31.67	11%
Natural gas liquids ($/bbl)	**56.69**	36.00	57%
Natural gas ($/mcf)	**8.10**	6.53	24%
Average realized price ($/BOE)	**47.01**	40.76	15%
Realized risk management losses ($/BOE)(1)	**(1.93)**	(5.93)	(67%)
Net realized price ($/BOE)	**45.08**	34.83	29%

(1) Includes amounts realized on WTI, heavy price differential and foreign exchange contracts and excludes amounts realized on electricity contracts.

Our average realized prices were 15% higher for the three months ended March 31, 2006 as compared to the same period in 2005. The WTI price for the same periods increased by US$13.64 per bbl or 27%. This increase was partially offset by a stronger Canadian dollar which resulted in a Canadian dollar increase in WTI of only 20%, which is higher than the increase in our realized price due to a widening Bow River differential to Edmonton Par. In the first quarter of 2005, the Bow River differential to Edmonton Par was 37.5% whilst in the first quarter of 2006 it was 42.0%, which has impacted our realized prices as approximately 40% of our production is priced off Bow River.

For the first quarter 2006, our light to medium realized price increased 6% as a result of the change in our production mix. For the first three months of 2005 approximately 45% of our production was priced off of the Bow River Stream, which is generally considered a medium to heavy oil stream, and approximately 11% was priced off the light oil benchmark, Edmonton Par. Subsequent to acquiring Hay River in the third quarter of 2005 and the Viking Properties in 2006, our product pricing has become more heavily weighted towards Edmonton Par pricing at approximately 22% and less heavily weighted towards Bow River pricing at approximately 40%, as the production from our Hay River property is sold at a premium price relative to our other medium oil properties. Despite this change in product mix for 2006, we realized a wider price differential to Edmonton Par for our light to medium production than that realized in the same period of 2005. This is due to a general widening of benchmark differentials for lower gravity crude oil in the first quarter of 2006 relative to 2005, as well as a lower Edmonton Par price relative to the WTI price.

Our realized heavy oil differential to Edmonton Par for the first quarter of 2006 was 49%, which is relatively consistent with the 48% differential realized in the first quarter of 2005, despite a 4.5% widening of Bow River prices to Edmonton Par for the same period. We were able to maintain a consistent differential due to lower blending costs in the first quarter of 2006 compared to the first quarter of 2005.

Our realized natural gas price has increased by 24% in the first quarter of 2006 compared to the first quarter of 2005, whilst the AECO natural gas daily price has increased by only 9% for the same period. Approximately 50% of the gas production acquired from Viking is sold at the AECO natural gas monthly price. The AECO natural gas monthly price increased by 39% in the first quarter of 2006 when compared to the first quarter of 2005, and as a result, we have realized a larger than expected increase in our realized natural gas price for the three months ended March 31, 2006 when compared to the prior year. Prior to the acquisition of Viking, the majority of our production was sold at the AECO natural gas daily price, and with the merger we have a more balanced natural gas pricing exposure.

Sales Volumes

The average daily sales volumes by product were as follows:

	Three months ended				
	March 31, 2006		March 31, 2005		
	Volume	**Weighting**	Volume	Weighting	Volume Change
Light / medium oil (bbl/d)[1]	**23,900**	**45%**	15,614	44%	53%
Heavy oil (bbl/d)	**15,182**	**29%**	14,473	41%	5%
Total oil (bbl/d)	**39,082**	**74%**	30,087	85%	30%
Natural gas liquids (bbl/d)	**1,709**	**3%**	780	2%	119%
Total liquids (bbl/d)	**40,791**	**77%**	30,867	87%	32%
Natural gas (mcf/d)	**73,337**	**23%**	27,114	13%	170%
Total oil equivalent (BOE/d)	**53,014**	**100%**	35,386	100%	50%

(1) Harvest classifies our oil production, except that produced from Hay River, as light, medium and heavy according to NI 51-101 guidance. The oil produced from Hay River has an average API of 24^{o} (medium grade), however, it benefits from a heavy oil royalty regime and therefore would be classified as heavy oil according to NI 51-101.

In the first quarter of 2006, average production was higher than the same period in 2005 due to the incremental production from the Viking properties acquired in February of 2006 and the Hay River properties acquired in the third quarter of 2005. However, first quarter 2006 average production was negatively impacted by down time at Hay River. Hay River is a "winter access" only property and, as a result, first quarter production will typically be lower for this property as compared to subsequent quarters due to routine maintenance turnarounds at production facilities and our drilling program, which also resulted in periodic shut-ins of established production. The estimated negative impact of this activity on production for Hay River was approximately 760 bbl/day.

Our production mix in 2006 was altered with the impact of the acquisition of Viking properties and the Hay River acquisition. Prior to these acquisitions, we were more weighted to heavy oil at 41% with only 13% towards natural gas. With these acquisitions, our product mix changed such that approximately 29% of our production is weighted towards heavy oil and 23% towards natural gas. With this change in product mix, we are less exposed to fluctuations in heavy oil differentials and more exposed to natural gas price volatility.

Revenues

	Three months ended		
(000)	**March 31, 2006**	March 31, 2005	Change
Light / medium oil sales	**$ 114,123**	$ 70,096	63%
Heavy oil sales	**47,987**	41,256	16%
Natural gas sales	**53,444**	15,945	235%
Natural gas liquids sales and other	**8,721**	2,529	245%
Total sales revenue	**224,275**	129,826	73%
Realized risk management contract losses[1]	**(9,208)**	(18,891)	(51%)
Net revenues including realized risk management contract losses	**215,067**	110,935	94%
Realized electricity price risk management contract gains	**477**	167	186%
Unrealized risk management contracts (losses) / gains	**(40,997)**	(74,669)	(45%)
Net Revenues, before royalties	**174,547**	36,433	379%
Royalties	**(43,115)**	(19,895)	117%
Net Revenues	**$ 131,432**	$ 16,538	695%

(1) Includes amounts realized on WTI, heavy price differential and foreign exchange contracts, and excludes amounts realized on electricity contracts.

Our revenue is impacted by production volumes, commodity prices, and currency exchange rates. Light to medium oil sales revenue for the three months ended March 31, 2006 was $44.0 million (or 63%) higher than in the same period in 2005 as a result of a 10% favourable price variance and a 53% favourable volume variance of $6.8 million and of $37.2 million, respectively. The favourable price variance relates to higher commodity prices in the quarter and an increase in our medium to light oil component. Edmonton Par increased by 12% and Bow River increased by 4% over the prior year, which contributed significantly to the higher revenues realized for the first quarter of 2006. In addition, our product mix changed primarily due to the Hay River acquisition in the third quarter of 2005. Our average realized price for our light to medium grade properties, excluding Hay River, was $52.17 per barrel for the first quarter of 2006 and our average realized price for the Hay River properties was $57.32 per barrel for the same period, which positively impacted our overall realized price. Favorable volume variances are primarily due to the addition of production volumes from the Viking properties in February of 2006 and the Hay River property in the third quarter of 2005, which together substantially increased light to medium production volumes. The Viking properties contributed an average of 8,280 bbl/day of light to medium production in February and March of 2006 (averaging 5,428 bbl/d for the quarter) and the Hay River properties contributed 4,092 bbl/day during the quarter.

Heavy oil sales for the three months ended March 31, 2006 increased $6.7 million (or 16%) compared to the same period in the prior year due to a favourable volume variance of $2.0 million and favourable price variance of $4.7 million. The rising crude oil price environment resulted in higher realized prices on our heavy oil, despite a wider Bow River differential to Edmonton par. Positive volume variances are related to the additional 1,840 bbl/day of production from the Viking properties for two months of the first quarter of 2006 (averaging 1,206 bbl/d for the quarter).

Natural gas sales revenue increased by $37.5 million (or 235%) for the three months ended March 31, 2006 over the same period in the prior year due to a favourable price variance of $10.4 million and a favourable volume variance of $27.1 million. AECO natural gas daily prices for the first quarter of 2006 increased 9% and AECO natural gas monthly prices increased by 39% over the same period in the prior year resulting in a favourable price variance. The favourable volume variance is entirely attributed to the incremental gas production of 75,822 mcf/d from the Viking properties in February and March of 2006 (averaging 49,706 mcf/d for the quarter).

Natural gas liquids do not contribute significantly to our overall sales revenues. For the three months ended March 31, 2006, natural gas liquids revenues increased by $6.2 million (or 245%) over the same period in the prior year, with the increase generally due to a higher pricing environment and additional production volumes from the Viking properties in February and March 2006.

Risk Management Contracts

Our risk management contracts at March 31, 2006 consist of: indexed puts, participating swaps, collars, fixed price heavy oil differential swaps and fixed price electricity contracts. Details of our outstanding contracts at March 31, 2006, are included in Note 12 of the consolidated financial statements for the three months ended March 31, 2006.

The table below provides a summary of net gains and losses on risk management contracts:

	Three months ended					
	March 31, 2006					March 31, 2005
(000s)	Oil	Gas	Currency	Electricity	Total	Total
Realized (losses) / gains on risk management contracts	$(9,581)	$ 239	$ 134	$ 477	$ (8,731)	$ (18,725)
Unrealized (losses) / gains on risk management contracts	(39,618)	2,232	-	(3,911)	(41,297)	(70,752)
Amortization of deferred charges relating to risk management contracts	-	-	-	-	-	(4,361)
Amortization of deferred gains relating to risk management contracts	-	-	-	300	300	445
Total (losses) / gains on risk management contracts	$(49,199)	$ 2,471	$ 134	$ (3,134)	$(49,728)	$ (93,393)

Our realized loss represents the necessary cost of price protection from commodity price downturns. Our total realized loss on oil and gas price and foreign exchange risk management contracts decreased to $9.2 million (or $1.93 per BOE) for the three months ended March 31, 2006 compared to $18.9 million (or $5.93 per BOE) for the same period in 2005.

Our total realized loss on oil contracts for the first quarter of 2006 was $9.5 million compared to $19.7 million in the first quarter of 2005. The decrease in our realized loss on oil contracts in 2006 is attributed to gains on our heavy oil differential contracts. In the first quarter of 2006 we recorded losses of $21.0 million (or $4.39 per BOE) on WTI price contracts and a gain of $11.4 million (or $2.41 per BOE) on our heavy oil differential contracts. For the three months ended March 31, 2005, we did not have any differential contracts in place. In addition, since the first quarter of 2005, our risk management strategy has changed to favour contracts with a fixed floor with upside participation. As a result, despite a 27% increase in WTI and a 7% increase in oil volumes contracted, losses on our WTI contracts increased by only 7%. Total volumes hedged in the first quarter of 2005 were 24,600 bbl compared to 26,250 bbl in the first quarter of 2006.

We have also entered into risk management contracts that provide protection from rising power costs. We realized gains on these contracts of $477,000 (or $0.10 per BOE) in the first quarter of 2006 compared to gains of $167,000 (or $0.05 per BOE) in the same period of the prior year. Additional details on these contracts is provided under the heading “Operating Expense” of this MD&A.

The unrealized losses on our risk management contracts for the three months ended March 31, 2006, excluding amortization of deferred gains, was $41.3 million (or $8.66 per BOE). For the three months ended March 31, 2005, the unrealized loss was $70.8 million (or $22.22 per BOE). Collectively, our risk management contracts had an unrealized mark-to-market deficiency of $95.0 million as at March 31, 2006. The difference between this value and the mark-to-market amount of $52.6 million at December 31, 2005 is included in our unrealized loss in the three month period ended March 31, 2006. Please refer to Note 12 to the consolidated financial statements for further details of the financial instruments outstanding at March 31, 2006.

Also included in our unrealized risk management contract losses is the amortization of the deferred charges and credits that were deferred when we ceased to apply hedge accounting principles. This represented a recovery of $300,000 of our total unrealized gains on risk management contracts for the first quarter of 2006 and an expense of $3.9 million of our total unrealized net losses for the three months ended March 31, 2005. These amounts are discussed further under the heading “Deferred Charges and Credits”.

Subsequent to March 31, 2006, we have entered into the following contracts:

Quantity	Type of Contract	Term	Reference
5,000 bbl/d	Participation swap	January 2007 – December 2007	U.S. $60.00[(a)]
5,000 bbl/d	Participation swap	January 2008 – June 2008	U.S. $55.00[(b)]
1,000 bbl/d	Differential swap – Wainwright	May 2007 – April 2007	27.7%
417,000 USD/month	Foreign currency swap	January 2007 – December 2007	1.14 Cdn/U.S.

(a) This price is a floor. The Trust realizes this price plus 76.6% of the difference between the spot price and this price.
(b) This price is a floor. The Trust realized this price plus 79.5% of the difference between the spot price and this price.

Royalties

We pay Crown, freehold and overriding royalties to the owners of mineral rights from which production is generated. These royalties vary for each property and product and our Crown royalties are based on a sliding scale dependent on production volumes and commodity prices. In certain situations, such as with some heavy oil production, the Alberta Energy and Utilities Board grants royalty 'holidays', effectively eliminating royalties on a specific well or group of wells.

For the first quarter of 2006 and 2005, our net royalties as a percentage of gross revenue were 19.2% and 15.3%, respectively, and aggregated to $43.1 million and $19.9 million, respectively. An increase in the royalty rate was expected due to the higher rates associated with the Viking assets acquired in February 2006 (historically have realized royalty rates of approximately 18-19%) and the Hay River properties acquired in August 2005 (realized royalty rates of approximately 24-25%). In addition, effective April 1, 2005 a 3.6% surcharge was applied by the Saskatchewan government on gross resource revenues earned in Saskatchewan (2% for production from wells drilled subsequent to October 2002) which effect the first quarter of 2006 but not the first quarter in the prior year.

Operating Expense

	Three months ended				
($000s)	**Harvest March 31, 2006**	Pro Forma Combined Harvest & Viking December 31, 2005	Harvest December 31, 2005	Harvest March 31, 2005	Change
Operating expense					
Power	**$ 12,028**	$ 20,323	$ 14,188	$ 8,061	49%
Workovers	**8,392**	9,539	5,871	6,995	20%
Repairs and maintenance	**4,155**	5,785	3,028	2,444	70%
Labour – internal	**4,572**	4,256	2,100	2,557	79%
Processing fees	**3,933**	5,014	2,649	1,772	122%
Fuel	**3,887**	6,421	1,201	1,291	201%
Labour – external	**2,029**	2,723	2,146	1,874	8%
Land leases and property tax	**2,995**	4,539	1,854	1,332	125%
Other	**8,103**	9,270	5,699	847	857%
Total operating expense	**50,094**	67,870	38,736	27,173	84%
Realized gains on power risk management contracts	**(477)**	(4,506)	(4,506)	(167)	186%
Net operating expense	**$ 49,617**	$ 63,364	$ 34,230	$ 27,006	84%
Transportation expense	**$ 1,623**	$ 3,025	$ 98	$ 175	827%
Net operating Expense ($/BOE)	**$ 10.40**	$ 10.96	$ 9.58	$ 8.49	22%
Transportation expense ($/BOE)	**$ 0.34**	$ 0.52	$ 0.03	$ 0.05	580%

Total operating expense increased by $22.9 million (or 84%) for the three months ended March 31, 2006 compared to the same period in the prior year. Approximately $17.9 million of the increase is due to increased activity associated with the Viking acquisition in February 2006 and the Hay River acquisition made in August 2005. The remainder of the increase is attributed to fuel and power cost increases, and the continued unprecedented demand for oilfield services leading to higher costs for well servicing, workovers and well maintenance. In addition, down time resulting from drilling activity and a turnaround in Hay River resulted in lower production volumes and higher unit operating costs. Overall, we expect higher operating costs to continue as a result of general cost pressures in the oil and natural gas industry. Our operating expenses will also benefit from a portion of our capital spending program which is directed towards operating cost reduction initiatives such as water disposal, fluid handling and power reduction projects.

Harvest's transportation costs are primarily related to our costs of delivering natural gas to Alberta's natural gas sales hub, the AECO Storage Hub, and to a much lesser extent, our costs of trucking crude oil to pipeline receipt points.

As the addition of the Viking properties and the Hay River properties to our portfolio significantly impacts comparability between the first quarter of 2006 and the first quarter of 2005, it may be more meaningful to compare the first quarter of 2006, adjusted for January operating costs for Viking of $8.8 million, to the pro forma combined information for the fourth quarter of 2005. Using this analysis, our first quarter of 2006 operating expenses decreased by $9.0 million compared to the pro forma combined operating costs for the fourth quarter of 2005. The most significant portion of the decrease, $8.8 million is attributed to lower power and fuel costs (total power and fuel costs for Viking in January were $2 million). Power prices skyrocketed to average $116/ megawatt hour ("MWh") in the fourth quarter of 2005, the highest average quarterly price since the fourth quarter of 2000. The Alberta power market saw significant softening in first quarter of 2006 compared to the fourth quarter of 2005.

As noted, electricity costs represent a significant portion of our operating costs (approximately 24% in the first quarter of 2006) and with generally rising electricity prices, particularly in Alberta, our operating expenses can be significantly impacted. In the first quarter of 2006, electricity costs per MWh were 24% higher than they were in the first quarter of 2005. These increases were offset by the impact of the Hay River and Viking acquisitions. Overall, the Viking properties have lower power usage per barrel of production, and we do not consume external power to operate the Hay River properties. The combination of these two factors, as well as the impact of our fixed price electricity contracts, have resulted in a consistent per BOE power cost despite rising prices The following table details the power costs per BOE before and after the impact of our hedging program.

	Three months ended		
($ per BOE)	**March 31, 2006**	March 31, 2005	Change
Power costs	**$ 2.52**	$ 2.53	-
Realized gains on electricity risk management contracts	**(0.10)**	(0.05)	100%
Net power costs	**$ 2.42**	$ 2.48	(2%)
Alberta Power Pool electricity price ($ per MWh)	**$56.96**	$ 45.90	24%

Approximately 65% of our estimated Alberta electricity usage is protected by fixed price purchase contracts at an average price of $51.48 per MWh through December 2006. Of our estimated 2007 and 2008 Alberta electricity usage, 52% is protected at an average price of $56.69 Per MWh These contracts will help moderate the impact of future cost swings, as will capital projects undertaken in 2006 and future periods that are dedicated to increasing our power efficiency.

Operating Netback

($ per BOE)	**Three months ended March 31, 2006**	March 31, 2005
Revenues	**$ 47.01**	$ 40.76
Realized loss on risk management contracts[1]	**(1.93)**	(5.93)
Royalties	**(9.04)**	(6.25)
As a percent of revenue	**19.22%**	15.32%
Operating expense[2]	**(10.40)**	(8.49)
Transportation expense	**(0.34)**	(0.05)
Operating netback[3]	**$ 25.30**	$ 20.04

(1) Includes amounts realized on WTI, heavy price differential and foreign exchange contracts, and excludes amounts realized on electricity contracts.
(2) Includes realized gain on electricity risk management contracts of $0.10 per BOE for the three months ended March 31, 2006 and $0.05 for the three months ended March 31, 2005.
(3) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.

Operating netback represents the total net realized price we receive for our production after direct costs. Our operating netback is $5.26 per BOE higher for the three months ended March 31, 2006 than for the same period of 2005. The increase is a result of higher commodity prices enabling us to realize a price per BOE that is $6.25 higher, lower losses realized on our hedging program of $4.00 per bbl, offset by higher royalties of $2.79 per BOE and higher operating costs (including transportation) of $2.20 per BOE.

General and Administrative (G&A) Expense

	Three months ended			
($000s except per BOE)	**Harvest March 31, 2006**	Pro Forma Combined Harvest & Viking December 31, 2005	Harvest March 31, 2005	Change
Cash G&A[1]	**$ 6,053**	$ 8,460	$ 3,249	86%
Unit based compensation expense	**(241)**	3,563	2,220	111%
Total G&A	**$ 5,812**	$ 12,023	$ 5,469	6%
Cash G&A per BOE ($/BOE)	**$ 1.27**	$ 1.46	$ 1.02	(25%)
Transaction costs				
Unit based compensation expense	**8,644**	-		
Severance and other	**3,098**	2,700		
Total Transaction costs	**$ 11,742**	2,700		

(1) Cash G&A excludes the impact of our unit based compensation expense and other one time transaction costs.

For the three months ended March 31, 2006, Cash G&A costs increased by $2.8 million (or 86%) compared to the same period in 2005. The increase is attributed to increased employee expenses, mainly a result of increased staffing levels. Approximately $4.0 million (or 66%) of our first quarter 2006 Cash G&A expenses are related to salaries and other employee related costs while in 2005 only $1.8 million (or 55%) of our Cash G&A was made up of these costs. The acquisition of Viking in February 2006, significantly increased our overall staffing levels, adding approximately 100 additional employees.

In an effort to minimize dilution, our unit based compensation plans provide the employee with the option of settling outstanding awards with cash. As a result, our unit based compensation expense is determined using the intrinsic method based on the difference between the Trust Unit trading price and the strike price of the unit appreciation rights ("UAR") adjusted for the proportion that is vested. Our total unit based compensation expense for the first quarter of 2006, including the $8.6 million allocated to transaction costs, was $8.4 million, consisting of $5.2 million of cash compensation, $6.5 million of unit settled compensation and a $3.3 million non-cash recovery. A reversal of expenses is recognized in periods where our Trust Unit price decreases from the beginning of the period to the end of the period. Our opening Trust Unit market price was $37.19 at January 1, 2006, and at March 31, 2006 our Trust Unit price had decreased to $33.95. As a result, we have recorded a recovery on unexercised UARs at March 31, 2006. Our total unit based compensation expense, including that portion which has been allocated to transaction costs, increased by $6.2 million over the same period in the prior year.

We have recorded transaction costs of $11.7 million which represent one time costs incurred as part of the acquisition of Viking. All of Harvest's outstanding UARs vested on February 3, 2006 in conjunction with the plan of arrangement. As a result, we have reflected $8.6 million, related to the additional expense incurred as a result of the accelerated vesting of our units, as a transaction cost. The remaining $3.1 million recorded as transaction costs are related to severance payments made to Harvest employees upon merging with Viking.

Interest Expense

($000s except per BOE)	Three months ended **Harvest** **March 31, 2006**	Pro Forma Combined Harvest & Viking December 31, 2005	Harvest March 31, 2005	Change
Interest on short term debt	**$ 150**	$ 135	$ 1,234	(88%)
Amortization on deferred charges – short term debt	**-**	-	1,257	(100%)
Total interest on short term debt	**150**	135	2,491	(94%)
Interest on long-term debt				
Senior notes	**5,724**	5,836	5,987	(4%)
Convertible debentures	**3,296**	4,489	494	567%
Bank loan	**1,303**	2,308	-	
Amortization of deferred charges – long term debt	**1,434**	1,183	390	268%
Total interest on long term debt	**11,757**	13,816	6,871	71%
Total interest expense	**$ 11,907**	$ 13,951	$ 9,362	27%

Interest expense for the three months ended March 31, 2006 was $2.5 million higher than for the same period in the prior year due primarily to additional interest expense on convertible debentures issued in the second half of 2005, and convertible debentures assumed in the first quarter of 2006 in connection with our acquisition of Viking. Compared to the pro forma combined interest expense of Viking and Harvest for the fourth quarter of 2005, the current quarter interest expense is $2.0 million lower, as only two months of additional interest expense on bank debt and convertible debentures assumed through our merger with Viking are included, and more favorable interest rates on bank debt have been received resulting from Harvest's new $900 million three year extendible revolving credit facility.

Interest expense reflects the charges on outstanding bank debt, convertible debentures and senior notes as well as the amortization of related financing costs. After entering into a new credit facility on February 3, 2006, interest on our bank debt is levied at a floating rate based on banker's acceptances plus 65 basis points based on our Senior Debt to Cash Flow Ratio. Compared to the first quarter of 2005, our interest expense on bank loans remained relatively unchanged, though we have primarily incurred interest expense on long term debt in the first quarter of 2006 compared with interest expense on short term debt incurred in the first quarter of 2005. In conjunction with our merger with Viking, we assumed approximately $106.2 million of additional bank debt, increasing our interest expense on bank loans a further $0.7 million compared to the fourth quarter of 2005.

At March 31, 2006, we had five series of convertible debentures outstanding, including a 10.5% and 6.40% series, which were assumed in conjunction with the Viking acquisition. Details of the terms of each convertible debenture are outlined in Note 8 of the consolidated financial statements for the three months ended March 31, 2006. Interest on the convertible debentures is reported based on the effective yield of the debt component of the convertible debentures. Interest expense on convertible debentures for the three months ended March 31, 2006, is $2.8 million higher than the first quarter of the prior year, as it includes interest expense on approximately $247.5 million of additional convertible debentures that have been issued by Harvest or assumed from the merger with Viking since March 31, 2005. Though holders of the 9%, 8%, 6.5% and 10.5% convertible debenture series have continued to convert many of their convertible debentures to Harvest Trust Units, the associated reduction in interest expense is not sufficient to offset the additional interest associated with the more recently issued or assumed convertible debentures. In future quarters, interest expense on convertible debentures, not considering future conversions, should remain relatively consistent with the pro forma combined interest in the fourth quarter of 2005, as a full three months of Viking's convertible debenture interest will be included. During the quarter, $4.8 million of convertible debentures were converted to Trust Units.

Our U.S. dollar denominated senior notes, which bear interest at 7 7/8%, mature on October 15, 2011 and have a fourth year redemption feature, provide an offset to fluctuations in currency exchange rates. Interest expense for the first quarter of 2006 on these notes has remained relatively consistent with the prior year and prior quarter, with any fluctuations attributed to volatility in the Canadian dollar to U.S. dollar exchange rate.

Included in total interest expense, is the amortization of the discount on the senior notes, the accretion on the debt component balance of the convertible debentures to face value at maturity, as well as the costs incurred to secure credit facilities, all totaling $1.8 million and $1.7 million for the three months ended March 31, 2006 and 2005, respectively.

Depletion, Depreciation and Accretion Expense

	Three months ended		
(000s except per BOE)	**March 31, 2006**	March 31, 2005	Change
Depletion and depreciation	**$ 77,395**	$ 36,456	112%
Depletion of capitalized asset retirement costs	**4,282**	2,816	52%
Accretion on asset retirement obligation	**3,648**	2,295	59%
Total depletion, depreciation and accretion	**$ 85,325**	$ 41,567	105%
Per BOE ($/BOE)	**17.88**	13.05	37%

Our overall depletion, depreciation and accretion (DD&A) expense for the three months ended March 31, 2006 is $43.8 million higher compared to the same period in 2005. $20.7 million of the increase is due to the incremental production from the acquisitions made in the latter half of 2005 and the merger with Viking in the first quarter of 2006 and $23.1 million of the increase is due to a higher depletion rate also reflecting the Hay River and Viking acquisitions. These acquisitions have increased our overall corporate DD&A rate due to their higher cost as compared to prior property acquisitions.

Foreign Exchange Gain

Foreign exchange gains and losses are attributed to the changes in the value of the Canadian dollar relative to the U.S. dollar on our U.S. dollar denominated senior notes, as well as any other U.S. dollar deposits and cash balances. At March 31, 2006, the Canadian dollar weakened slightly against the U.S. dollar compared to December 31, 2005, and we incurred unrealized losses on our senior notes of $1.3 million, which was partially offset by unrealized gains on U.S. dollar deposits of $0.4 million, as well as realized gains on other U.S. denominated transactions, for total foreign exchange losses of $0.9 million reported in the quarter.

Deferred Charges and Credits

The deferred charges balance on the balance sheet is comprised of four main components: deferred financing charges, discount on senior notes, premium on our office lease and for 2005, deferred charges related to the discontinuation of hedge accounting principles. The deferred financing charges relate primarily to the issuance of the senior notes, convertible debentures and bank debt and are amortized over the life of the corresponding debt. The following table provides a summary of the components of the deferred charges at March 31, 2006 as compared to 2005.

(000s)	Financing Costs	Discount on Senior Notes	Office Leases	Discontinuation of Hedge Accounting	Total
Balance, January 1, 2005	**$ 12,781**	**$ 2,000**	**$ -**	**$ 10,759**	**$ 25,540**
Additions	5,207	-	-	-	5,207
Transferred to Unit issue costs on conversion of debentures	(2,071)	-	-	-	(2,071)
Amortization	(4,853)	(296)	-	(10,759)	(15,908)
Balance, December 31, 2005	**$ 11,064**	**$ 1,704**	**$ -**	**$ -**	**$12,768**
Additions	168	-	931	-	1,099
Transferred to Unit issue costs on conversion of debentures	(127)	-	-	-	(127)
Amortization	(1,434)	(74)	(37)	-	(1,545)
Balance, March 31, 2006	**$ 9,671**	**$ 1,630**	**$ 894**	**$ -**	**$ 12,195**

In the first quarter of 2006, $0.9 million of deferred charges were added to our balance sheet with respect to an office lease assumed through our acquisition of Viking which had a contracted rate per square foot less than current market rates. This lease extends until February 2010 and the related deferred charge will be amortized over the remaining lease period. Additions to deferred financing costs in the first quarter of 2006 relate to the execution of our new credit agreement on February 3, 2006.

At March 31, 2006 our deferred credit balance was $1.0 million of which $97,000 related to the discontinuation of hedge accounting principles ($398,000 at December 31, 2005). This amount will be fully amortized by the end of 2006. The remaining deferred credit balance on the consolidated balance sheet includes a leasehold improvement credit of $0.9 million, relating to the leasehold improvement costs reimbursed by the landlord. The credit is amortized over the lease term as a reduction of rent expense.

Goodwill

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value for accounting purposes, of the net identifiable assets and liabilities of that acquired business. At March 31, 2006, we have recorded $656.2 million of goodwill on our balance sheet, compared with $43.8 million at December 31, 2005. In conjunction with our acquisition of Viking for total consideration of $1,975.3 million, we recorded $612.4 million of goodwill. The goodwill balance is assessed annually for impairment or more frequently if events or changes in circumstances occur that would reasonably be expected to reduce the fair value of the acquired business to a level below its carrying amount.

Future Income Tax

For the three months ended March 31, 2006, we have not recorded a future income tax balance on our balance sheet as our total deductible temporary differences exceeded our taxable temporary differences such that an asset was created. As we do not expect we will be able to recover the asset, we have not recorded it on our balance sheet. We recorded a future income tax recovery of $2.3 million for the three months ended March 31, 2006, and a recovery of $26.0 million for the three months ended March 31, 2005. The significant recovery in the first quarter of 2005 related to losses recorded in the corporate subsidiaries of the Trust.

Asset Retirement Obligation (ARO)

In connection with a property acquisition or development expenditure, we record the fair value of the ARO as a liability in the same year as the expenditure occurs. Our ARO costs are capitalized as part of the carrying amount of the assets, and are depleted and depreciated over our estimated net proved reserves. Once the initial ARO is measured, it must be adjusted at the end of each period to reflect the passage of time as well as changes in the estimated future Cash Flows of the underlying obligation.

Our asset retirement obligation increased by $75.6 million in the first quarter of 2006 relative to December 31, 2005. As a result of the merger with Viking, we added $60.5 million to our ARO, and the remainder of the increase in the quarter is due to additions resulting from drilling activity in the quarter, an increased estimate of existing liabilities, and accretion expense, offset by actual asset retirement expenditures made in the quarter.

Non-Controlling Interest

The non-controlling interest represents the value attributed to outstanding exchangeable shares of Harvest Operations at March 31, 2006 of $451,000. The exchangeable shares were originally issued by Harvest Operations as partial consideration for the purchase of a corporate entity in 2004. The exchangeable shares rank equally with the Trust Units and participate in distributions through an increase in the exchange ratio applied to the exchangeable shares when they are ultimately converted to Trust Units.

Under the plan of arrangement with Viking, exchangeable shareholders were able to convert their exchangeable shares of Harvest Operations into Trust Units. As a result 156,067 exchangeable shares were converted in the three months ended March 31, 2006, leaving a balance of 26,902 outstanding at March 31, 2006 compared to a balance of 182,969 at December 31, 2005. The exchange ratio at March 31, 2006 was 1: 1.20421, which would result in an additional 32,396 Trust Units issued if all of the exchangeable shares were converted at the end of the quarter.

On March 16, 2006, we announced our intent to exercise our de minimus redemption right on the remaining exchangeable shares. As a result, each redeemed exchangeable share will be purchased for a cash payment at a price per share equal to the amount obtained by multiplying the exchange ratio for the exchangeable shares in effect on June 19, 2006 by the weighted average trading price of our Trust Units on the Toronto Stock Exchange for the 5 trading days immediately prior to June 19, 2006.

The total net loss attributed to non-controlling interest holders for three months ended March 31, 2006 and 2005 was $80,000 and $495,000 respectively.

Liquidity and Capital Resources

At the end of the first quarter of 2006, we had bank borrowings totaling $201.7 million and an undrawn credit capacity of $698.3 million pursuant to a $900 million three year extendible revolving credit facility. On February 3, 2006, concurrent with the closing of the Viking acquisition, we entered into a new credit facility arrangement with a borrowing limit of $750 million. On March 31, 2006, the syndicate of lenders was expanded with the new syndicate agreeing to increase the revolving credit facility to $900 million. The syndicated credit facility currently matures on February 3, 2009, if not extended prior thereto.

During the first quarter of 2006, we earned Cash Flows totaling $101.0 million, excluding one time cash transaction costs of $5.1 million, and distributed $45.2 million, net of proceeds from our distribution reinvestment plan, resulting in $55.8 million of cash retained that was directed towards funding capital expenditures and acquisitions which totaled $126.6 million. Our capital program was heavily weighted to the first quarter of 2006 with $103.2 million of our $250 million annual capital program substantially completed by the end of March 2006.

Distributions declared for the three months ended March 31, 2006 totaled $94.8 million representing 94% of our Cash Flow. Of the total distributions declared, $40.4 million will be settled with Trust Units as a result of Unitholders choosing to participate in our distribution reinvestment plans, which represents a participation rate of approximately 43%. As the payment of distributions is always one month behind the declaration of the distribution, the actual equity contribution during the period was $29.9 million, which represents the participation in our distribution reinvestment plan for the months of December 2005 and January and February 2006.

The terms of our $900 million credit facility enables us to borrow funds, repay and re-borrow funds throughout the revolving three year period, unless extended by us with the consent of our lenders. The facility is secured by a $1.5 billion first floating charge over all of the assets of the operating subsidiaries and a guarantee from the Trust. Amounts borrowed under this facility bear interest at a floating rate based on bankers acceptances plus 65 basis points based on the Trust's Senior Debt to Cash Flow Ratio. Availability under this facility is subject to quarterly financial covenants requiring that the Senior Debt to Cash Flow Ratio be less than 3 to 1, the Total Debt to Cash Flow Ratio be less than 3.5 to 1, Senior Debt to Capitalization be less than 50% and Total Debt Capitalization be less than 55%, all as defined in the Credit Agreement.

As at March 31, 2006, we had 252.2 thousand convertible debentures outstanding each with a face value of $1000. During the first quarter of 2006 183,940 Trust Units were issued to convertible debenture holders upon conversion of these debentures. After the Plan of Arrangement with Viking, there are now five series of convertible debentures outstanding each with the following terms:

Issue date	Interest rate	Current face value (millions)	Conversion price / Trust Unit	Maturity	
Jan 29, 2004	9%	$1.6	$13.85	May 31, 2009	
Aug 10, 2004	8%	$3.2	$16.07	Sept. 30, 2009	
Aug 2, 2005	6.5%	$38.7	$31.00	Dec. 31, 2010	
Feb. 3, 2006	10.5%	$33.8	$29.00	Jan.31, 2008	Assumed from Viking
Feb. 3, 2006	6.40%	$174.9	$46.00	Oct. 31, 2012	Assumed from Viking

One of the key performance indicators with respect to liquidity and capitalization that we evaluate regularly is our debt as a percentage of total capitalization. Our total debt at March 31, 2006 was $745.9 million which represents 17.9% of our total capitalization (11.9% excluding the convertible debentures from total debt) compared with 15.1% (13.1% excluding the convertible debentures from total debt) at December 31, 2005. Harvest's annualized first quarter 2006 Debt to Cash Flow Ratio was 1.85 (1.22 excluding the convertible debentures from total debt). Even though our first quarter cash flow is not representative of our full year cash flow as it only includes two months of cash flow from Viking, we consider these financial metrics to be aligned with our industry peers in the conventional oil and natural gas royalty trust sector.

One of the benefits of the completion of the Arrangement with Viking is that the increased size of our entity provides us with improved access to capital whether it be bank credit (demonstrated already through the increased facility on March 31, 2006), term debt or equity. In addition, the combined entity has a more balanced production profile reducing our variability in cash flow due to fluctuation in any single commodity price. We continue to be rated as a "B+" long term credit by Standard & Poor's rating agency and continue to be on "Creditwatch Positive".

In the first quarter of 2006, liquidity remained strong with daily volumes traded on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE) of approximately 432,100 and 289,100 units respectively. At the end of the first quarter of 2006, our foreign ownership was approximately 33%.

For 2006, we anticipate that we will continue to have adequate liquidity to fund our capital spending program and our planned distributions. Unitholder participation in our distribution reinvestment plan enables us to reinvest Cash Flow in our capital spending program or debt repayment.

Contractual Obligations and Commitments

		Maturity			
Annual Contractual Obligations (*000s*)	**Total**	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt	**$ 493,652**	$ 201,652	$ -	$ -	$ 292,000
Interest on long-term debt(4)	**175,262**	24,808	66,155	66,155	18,144
Interest on convertible debentures(3)	**84,192**	13,245	32,072	27,679	11,196
Operating and premise leases	**15,010**	2,836	7,145	5,029	-
Capital commitments(5)	**28,500**	17,015	11,485	-	-
Asset retirement obligations(6)	**621,002**	6,254	10,959	15,359	588,430
Total	**$ 1,417,618**	$ 265,810	$ 127,816	$ 114,222	$ 909,770

(1) As at March 31, 2006, we had entered into physical and financial contracts for production with average deliveries of approximately 22,732 barrels of oil equivalent per day in the balance of 2006 and 21,564 barrels per day in 2007. We have also entered into financial contracts to minimize our exposure to fluctuating electricity prices. Please see Note 12 to the consolidated financial statements for further details.
(2) Assumes that the outstanding convertible debentures either convert at the holders' option or are redeemed for Units at our option.
(3) Assumes no conversions and redemption by Harvest for Trust Units at the end of the second redemption period. Only cash commitments are presented.
(4) Assumes no change in bank debt from March 31, 2006 and a constant foreign exchange rate.
(5) Relates to drilling commitments.
(6) Represents the undiscounted obligation by period

Off Balance Sheet Arrangements

We have a number of operating leases in place on moveable field equipment, vehicles and office space and our commitments under those leases are noted in our annual contractual obligations table above. The leases require periodic lease payments and are recorded as either operating costs or G&A. We also finance our annual insurance premiums, whereby a portion of the annual premium is deferred and paid monthly over the balance of the term.

Capital Expenditures

	Three months ended		
(000s)	**March 31, 2006**	March 31, 2005	Change
Development capital expenditures excluding acquisitions and non-cash items	**$ 103,239**	$ 23,223	345%
Non-cash capital additions	**390**	353	10%
Total development capital expenditures	**103,629**	23,576	340%
Net property acquisitions	**23,382**	4,659	402%
Total net capital asset expenditures	**$ 127,011**	$ 28,235	350%

(000s)	Capital Spent Three months ended March 31, 2006
Area	
Hay River	$ 40,548
Red Earth	10,973
South East Saskatchewan	8,413
Suffield	8,375
Wainwright	4,662
Other areas	30,268
Total	$ 103,239

Harvest incurred $103.2 million of expenditures to drill 82 gross (69.4 net) wells during the first three months of 2006 compared to $23.2 million and 15 net wells for the same period in the prior year. The activity reflects our increased focus on internally developed projects to exploit identified opportunities on our asset base.

In the first three months of 2006, we pursued our largest capital program ever, including the drilling of 25 wells at Hay River to exploit the opportunities identified as part of our acquisition of this property in 2005. In addition to drilling 12 multi-leg horizontal producers and 7 water injection/service wells, we were able to pre-set our intermediate casing on 6 horizontal wells which can be quickly and inexpensively drilled as part of our 2006/2007 winter drilling program. Wainwright drilling activity included 12 vertical wells into the Wainwright Sparky pool to both delineate pool boundaries, and to access unswept oil through infill drilling. Our South East Saskatchewan 7 well horizontal development program continues to expand our understanding of previously untapped hydrocarbon deposits, and we are considering increasing our drilling plans for this area for the remainder of 2006. At Red Earth, we successfully pursued the Slave Point formation, drilling 4 gross infield locations, as well as 3 step-outs that confirmed new hydrocarbon accumulations. A 3D seismic program late in the quarter will confirm further infill and delineation opportunities for the remainder of 2006 and into 2007. We also drilled 3 wells in Suffield and undertook a major facility modification to improve our water handling capacity for the area.

The following summarizes our participation in gross and net wells drilled during the first three months of 2006:

	Total Wells		**Successful Wells**		**Abandoned Wells**	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Hay River	25	25	25	25	-	-
Wainwright	12	12	12	12	-	-
South East Saskatchewan	7	7	7	7	-	-
Red Earth	7	5.9	7	5.9	-	-
Other Areas	31	19.5	29	18.5	2	1
Total	82	69.4	80	68.4	2	1

Distributions to Unitholders and Taxability

In the first quarter of 2006, we declared distributions of $1.11 per Trust Unit ($94.8 million) to Unitholders. This represents an 85% increase in distributions declared over the $0.60 per Trust Unit declared in the first quarter of 2005, and a $0.06 per Trust Unit increase from the fourth quarter of 2005. The aggregate of distributions declared during the first quarter of $94.8 million reflects an increase in distributions on a per-Trust Unit basis over 2005 as well as an increase in the number of Trust Units outstanding of approximately 46 million following the acquisition of Viking.

	Three months ended		
(000s except per Trust Unit amounts)	**March 31, 2006**	March 31, 2005	% Change
Distributions declared[1]	**$ 94,812**	$ 36,126	162%
Per Trust Unit	**$ 1.11**	$ 0.60	85%
Taxability of distributions (%)	**100%**	100%	-
Per Trust Unit	**$ 1.11**	$ 0.60	85%
Payout ratio (%)	**94%**	69%	25%

(1) Cash flow excludes working capital changes, settlements of asset retirement obligations and one time transaction costs associated with the Viking acquisition, see Non-GAAP measures.

The Trust is subject to tax on its taxable income less the portion that is paid or payable to the Unitholders at the end of each taxation year. Under the Trust indenture, an amount equal to all undistributed royalty, interest and dividend income together with taxable and non-taxable portions of any capital gains realized by the Trust in the year, net of deductible trust expenses, will be payable to the Unitholders. As such, it is unlikely that the Trust will pay income taxes, however, we expect that the current year distributions to our Unitholders will be 100% taxable.

Outlook

With the integration of the Viking business substantially complete, we anticipate that our daily production will average 60,000 to 62,000 BOE/day for the balance of 2006 as the benefits of our first quarter capital spending and routine maintenance programs combine to substantially offset our anticipated natural rate of decline. In addition, we have approximately 2,800 BOE/day behind pipe to be tied-in during the second quarter. We continue to expect that our 2006 average daily production will be approximately 60,000 BOE/day reflecting an eleven month contribution from the Viking assets.

Operating costs for the remainder of the year are anticipated to be in the $10.25 per BOE range. We expect to benefit from the lower power costs which have dropped from over $100 per MWH in the month of January to less than $50 per MWH in March 2006. We anticipate that the impact of the continuing cost pressures in the Alberta oil field service sector on our cost structure will by offset somewhat by the economies of scale afforded to larger operators and our efforts to manage costs.

The current future price curve for crude oil prices remains strong with the WTI benchmark price now expected to exceed US$70 for the balance of 2006. For the balance of 2006, our oil price risk management contracts retain some upside participation while providing a floor price of approximately US$45 on approximately 30,000 bbl/day. As a result, we expect to realize approximately US$65 on our portfolio of crude oil production for the balance of 2006 should the WTI price average US$70 over this period. In respect of natural gas prices, we have 5,000 GJ/day collared for the period from April through October with a floor price of $9.00 and a price cap of $13.06 which should provide a modest offset to the decline in natural gas prices from over $11.00 in January to less than $7.00 by the end of the first quarter.

We continue to anticipate capital spending in 2006 will total about $250 million with over $100 million spent in the first quarter. In addition, we will continue to pursue numerous incremental acquisitions/dispositions/farmouts that focus on increasing our ownership interest in existing assets while disposing of marginal interests in other properties.

We have announced a monthly distribution of $0.38 per trust unit for April, May and June and provided commodity prices remain at their current levels, our payout ratio is expected to be in the 70% to 80% range for the balance of the year, with monthly distributions at $0.38 per Trust Unit. Currently, we enjoy a participation level in our distribution reinvestment plan in excess of 40% and we will use this source of funding to round out the financing of our capital spending program and direct any surplus to debt reduction.

The following table reflects sensitivities of our anticipated 2006 Cash Flow to key assumptions in our business for the remainder of the year.

	Assumption	Change	Impact on Cash Flow
WTI oil price ($US/bbl)	$ 73.50	$ 5.00	$ 0.23 / Unit
CAD/USD exchange rate	$ 0.91	$ 0.02	$ 0.12 / Unit
AECO daily natural gas price	$ 7.00	$ 1.00	$ 0.16 / Unit
Interest rate on outstanding bank debt	5.00%	1.0%	$ 0.01 / Unit
Liquids production volume (bbl/d)	44,400	2,000	$ 0.28 / Unit
Natural gas production volume (mcf/d)	94,000	5,000	$ 0.08 / Unit
Operating Expenses (per BOE)	$ 10.25	$ 1.00	$ 0.21 / Unit

As the consolidation/rationalization of the Canadian royalty trust sector continues, we expect to be an active participant in the appropriate opportunity. In addition, we intend to maintain a strong balance sheet with significant credit capacity to support a large scale acquisition; however, the property acquisition market in the western Canadian sedimentary basin continues to be very competitive with a modest supply of attractive opportunities. With or without further acquisitions, we will continue to develop our existing assets, a very significant resource base.

Summary of Historical Quarterly Results

The table and discussion below highlight our performance over the first quarter of 2006 and the preceeding seven quarters on select measures.

Financial	**2006**	2005				2004		
($000s except where noted)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Revenue, net of royalties	**$ 181,160**	$ 154,646	$ 169,654	$ 120,263	$ 109,931	$ 106,964	$ 85,096	$ 44,461
Net income (loss)	**(33,937)**	75,638	52,862	19,516	(43,070)	11,600	1,740	151
Per Trust Unit, basic[2]	**$ (0.41)**	$ 1.45	$ 1.09	$ 0.45	$ (1.02)	$ 0.29	$ 0.06	$ 0.01
Per Trust Unit, diluted[2]	**$ (0.41)**	$ 1.42	$ 1.08	$ 0.44	$ (1.02)	$ 0.27	$ 0.06	$ 0.01
Cash Flows[1]	**100,971**	96,431	103,508	52,217	52,687	52,870	41,267	15,839
Per Trust Unit, basic[1]	**$ 1.23**	$ 1.84	$ 2.14	$ 1.32	$ 1.25	$ 1.31	$ 1.42	$ 0.91
Per Trust Unit, diluted[1]	**$ 1.22**	$ 1.81	$ 2.09	$ 1.29	$ 1.19	$ 1.18	$ 1.12	$ 0.78
Distributions per Unit, declared	**$ 1.11**	$ 1.05	$ 0.95	$ 0.60	$ 0.60	$ 0.60	$ 0.60	$ 0.60
Total long term financial liabilities	**735,896**	349,074	386,124	455,163	321,534	326,250	95,609	57,780
Total assets	**3,470,653**	1,308,481	1,327,272	1,117,792	1,079,269	1,050,459	1,070,016	488,204
Total production (BOE/d)	**53,014**	38,834	37,549	34,463	35,386	37,215	24,856	15,233

(1) This is a non-GAAP measure as referred to under "Non-GAAP Measures".
(2) The sum of the interim periods does not equal the total per year amount as there were large fluctuations in the weighted average number of Trust Units outstanding in each individual quarter.

Net revenues and Cash Flows have generally increased steadily over the eight quarters shown as above. The significantly higher revenue in the first quarter of 2006 over the preceding quarters is due to the incremental revenue recorded from the Viking assets acquired in February of 2006. Cash flows for the same period do not reflect the same increase due to higher incremental operating costs, including lower gains on our electricity price risk management contracts, higher interest expense and higher cash expense relating to our unit based compensation plan in the first quarter of 2006 compared to the previous quarter.

The significantly higher revenue and Cash Flows in the third quarter of 2005 relative to the second quarter of 2005 is primarily due to higher production from the Hay River acquisition, stronger crude oil prices and narrower heavy oil differentials early in the quarter. This trend did not continue into the fourth quarter of 2005 as a result of decreased commodity prices and widening heavy oil differentials. The most significant increases in revenue occurred through the second and third quarter of 2005, due to unprecedented commodity prices, and the third and fourth quarters of 2004, as a result of the two acquisitions completed in June and September of that year. The general increasing revenue trend since the second quarter of 2004 is also attributable to the strong commodity price environment through 2004 and 2005.

Net income reflects both cash and non-cash items. Changes in non-cash items, including depletion, depreciation and accretion (DD&A) expense, unrealized foreign exchange gains and losses, unrealized gains and losses on risk management contracts, Trust Unit right compensation expense and future income taxes can cause net income to vary significantly from period to period. However, these items do not impact the Cash Flows available for distribution to Unitholders, and therefore we believe net income to be a less meaningful measure of performance for us. The main reason for the volatility in net income (loss) between quarters in 2005 is due to the changes in the fair value of our risk management contracts. We ceased using hedge accounting for all of our risk management contracts in October 2004 and switched to a fair value accounting methodology, which has substantially increased the volatility in our reported earnings. Due primarily to the inclusion of unrealized mark-to-market gains and losses on risk management contracts, net income (loss) has not reflected the same trend as net revenues or Cash Flows.

Critical Accounting Policies and Critical Accounting Estimate

Critical accounting policies and estimates are the same as those presented in our 2005 annual MD&A.

Recent Canadian Accounting and Related Pronouncements

In an effort to harmonize Canadian GAAP with U.S. GAAP, the Canadian Accounting Standards Board has recently issued new Handbook sections:

- 1530, Comprehensive Income;
- 3855, Financial Instruments – Recognition and Measurement;
- 3861, Financial Instruments – Disclosure and Presentation; and
- 3865, Hedges.

Under these new standards, all financial assets should be measured at fair value with the exception of loans, receivables and investments that are intended to be held to maturity and certain equity investments, which should be measured at cost. Similarly, all financial liabilities should be measured at fair value when they are either derivatives or held for trading. Gains and losses on financial instruments measured at fair value will be recognized in the income statement in the periods they arise with the exception of gains and losses arising from:

- financial assets held for sale, for which unrealized gains and losses are deferred in other comprehensive income until sold or impaired; and
- certain financial instruments that qualify for hedge accounting.

Sections 3855 and 3865 make use of the term "other comprehensive income". Other comprehensive income comprises revenues, expenses, gains and losses that are excluded from net income. Unrealized gains and losses on qualifying hedging instruments, unrealized foreign exchange gains and losses, and unrealized gains and losses on financial instruments held for sale will be included in other comprehensive income and reclassified to net income when realized. Comprehensive income and its components will be a required disclosure under the new standard. Section 3861 addresses the presentation of financial instruments and non-financial derivatives, and identifies the information that should be disclosed about them. These standards are effective for interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006. As we do not apply hedge accounting to any of our derivative instruments, we do not expect these pronouncements to have a significant impact on our consolidated financial results.

Non-Monetary Transactions

The AcSB has issued Section 3831, *Non-Monetary Transactions*, which replaces Section 3830, and requires all non-monetary transactions to be measured at fair value unless:

- the transaction lacks commercial substance;
- the transaction is an exchange of production or property held for sale in the ordinary course of business for production or property to be sold in the same line of business to facilitate sales to customers other than the parties to the exchange;

- neither the fair value of the assets or services received nor the fair value of the assets or services given up is reliably measurable; or
- the transaction is a non-monetary, non-reciprocal transfer to owners that represents a spin-off or other form of restructuring or liquidation.

The new requirements apply to non-monetary transactions, initiated in periods beginning on or after January 1, 2006. Earlier adoption was permitted as of the beginning of a period beginning on or after July 1, 2005. This section did not have a material impact on our results of operations or financial position.

Operational and Other Business Risks
Our operational and other business risks are substantially the same as those presented in our 2005 annual MD&A.

Non-GAAP Measures

Throughout this MD&A we have referred to certain measures of financial performance that are not specifically defined under Canadian GAAP. Specifically, we use Cash Flow as cash flow from operating activities before changes in non-cash working capital, settlement of asset retirement obligations and one time transaction costs. Cash Flow as presented is not intended to represent an alternative to net earnings, cash flow from operating activities or other measures of financial performance calculated in accordance with Canadian GAAP. Management uses Cash Flow to analyze operating performance and leverage. Payout Ratio, Cash G&A and Operating Netbacks are additional non-GAAP measures used extensively in the Canadian energy trust sector for comparative purposes. Payout Ratio is the ratio of distributions to total Cash Flow. Operating Netbacks are always reported on a per BOE basis, and include gross revenue, royalties and operating expenses, net of any realized gains and losses on related risk managements. Cash G&A are G&A expenses excluding the effect of our unit based compensation plans.

For the three months ended March 31, 2006 and 2005, Cash Flows are reconciled to its closest GAAP measure, Cash Flow from operating activities, as follows:

	Three months ended	
($000s)	**March 31, 2006**	March 31, 2005
Cash Flow	**$ 100,971**	$ 52,687
Cash Viking transaction costs	**(5,072)**	-
Settlement of asset retirement obligations	**(1,118)**	(501)
Changes in non-cash working capital	**(6,617)**	(48,694)
Cash flow from operating activities	**$ 88,164**	$ 3,492

Forward-Looking Information
This MD&A highlights significant business results and statistics from our consolidated financial statements for the three months ended March 31, 2006 and the accompanying notes thereto. In the interest of providing our Unitholders and potential investors with information regarding Harvest, including our assessment of our future plans and operations, this MD&A contains forward-looking statements that involve risks and uncertainties. Such risks and uncertainties include, but are not limited to, risks associated with conventional petroleum and natural gas operations; the volatility in commodity prices and currency exchange rates; risks associated with realizing the value of acquisitions; general economic, market and business conditions; changes in environmental legislation and regulations; the availability of sufficient capital from internal and external sources and such other risks and uncertainties described from time to time in our regulatory reports and filings made with securities regulators.

Forward-looking statements in this MD&A include, but are not limited to, production volumes, operating costs, commodity prices, administrative costs, commodity price risk management activity, acquisitions and dispositions, capital spending, distributions, access to credit facilities, capital taxes, income taxes, Cash Flow From Operations and regulatory changes. For this purpose, any statements that are contained herein that are not statements of historical fact may be deemed to be forward-looking statements. Forward-looking statements often contain terms such as “may”, “will”, “should”, “anticipate”, “expects”, and similar expressions.

Readers are cautioned not to place undue reliance on forward-looking statements as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. Although consider such information reasonable, at the time of preparation, it may prove to be incorrect and actual results may differ materially from those anticipated. We assume no obligation to update forward-looking statements should circumstances or estimates or opinions change except as required by law. Forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

Additional Information

Further information about us, including our Annual Information Form, can be accessed under our public filings found on SEDAR at www.sedar.com or at www.harvestenergy.ca. Information can also be found by contacting our Investor Relations department at (403) 265-1178 or at 1-866-666-1178.

Harvest Energy Trust
Consolidated Balance Sheets (Unaudited)

(thousands of Canadian dollars)

		March 31, 2006		December 31, 2005
Assets				
Current assets				
Accounts receivable	**$**	**139,683**	$	73,766
Fair value of risk management contracts *[Note 12]*		**9,313**		21,231
Prepaid expenses and deposits		**7,206**		1,126
Future income tax		**-**		22,975
		156,202		119,098
Deferred charges *[Note 3]*		**12,195**		12,768
Fair value of risk management contracts *[Note 12]*		**2,902**		2,628
Capital assets *[Note 4]*		**2,643,106**		1,130,155
Goodwill *[Note 2]*		**656,248**		43,832
	$	**3,470,653**	$	1,308,481
Liabilities and Unitholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities *[Note 5]*	**$**	**198,088**	$	99,576
Cash distribution payable		**38,202**		18,544
Fair value deficiency of risk management contracts *[Note 12]*		**83,078**		65,968
		319,368		184,088
Bank loan *[Note 7]*		**201,652**		13,869
Deferred credit		**1,035**		1,389
Fair value deficiency of risk management contracts *[Note 12]*		**24,106**		10,449
Convertible debentures *[Note 8]*		**242,244**		44,455
$7^{7/8}$% Senior notes		**292,000**		290,750
Asset retirement obligation *[Note 6]*		**186,321**		110,693
Future income tax		**-**		25,275
Non-controlling interest *[Note 11]*		**451**		3,179
Unitholders' equity				
Unitholders' capital *[Note 9]*		**2,431,595**		747,312
Equity component of convertible debentures *[Note 8]*		**26,247**		2,639
Accumulated income		**101,728**		135,665
Accumulated distributions		**(356,094)**		(261,282)
		2,203,476		624,334
	$	**3,470,653**	$	1,308,481

Commitments, contingencies and guarantees [Note 14]
See accompanying notes to these consolidated financial statements.

Harvest Energy Trust
Consolidated Statements of Income and Accumulated Income (Unaudited)

(thousands of Canadian dollars, except per Trust Unit amounts)

		Three Months Ended March 31, 2006		Three Months Ended March 31, 2005
Revenue				
Petroleum and natural gas sales	**$**	**224,275**	$	129,826
Royalty expense		**(43,115)**		(19,895)
Risk management contracts				
Realized net losses		**(8,731)**		(18,724)
Unrealized net losses		**(40,997)**		(74,669)
		131,432		16,538
Expenses				
Operating		**50,094**		27,173
Transportation and marketing		**1,623**		175
General and administrative		**5,812**		5,469
Transaction charges		**11,742**		-
Interest and other financing charges on short term debt		**150**		2,491
Interest and other financing charges on long term debt		**11,757**		6,871
Depletion, depreciation and accretion		**85,325**		41,567
Foreign exchange loss		**908**		2,119
Large corporations tax and other tax		**338**		277
Future income tax recovery		**(2,300)**		(26,039)
Non-controlling interest *[Note 11]*		**(80)**		(495)
		165,369		59,608
Net loss for the period		**(33,937)**		(43,070)
Accumulated income, beginning of period		**135,665**		30,719
Accumulated income (deficit), end of period	$	**101,728**	$	(12,351)
Net loss per Trust Unit, basic *[Note 9]*	**$**	**(0.41)**	$	(1.02)
Net loss per Trust Unit, diluted *[Note 9]*	**$**	**(0.41)**	$	(1.02)

See accompanying notes to these consolidated financial statements.

Consolidated Statements of Accumulated Distributions (unaudited)

(thousands of Canadian dollars)

		Three Months Ended March 31, 2006		Three Months Ended March 31, 2005
Accumulated distributions, beginning of period	**$**	**261,282**	$	97,110
Distributions		**94,812**		36,126
Accumulated distributions, end of period	$	**356,094**	$	133,236

Harvest Energy Trust
Consolidated Statements of Cash Flows (Unaudited)

(thousands of Canadian dollars)

		Three Months Ended March 31, 2006		Three Months Ended March 31, 2005
Cash provided by (used in)				
Operating Activities				
Net loss for the period	**$**	**(33,937)**	$	(43,070)
Items not requiring cash				
Depletion, depreciation and accretion		**85,325**		41,567
Unrealized foreign exchange gain		**914**		2,110
Amortization of deferred finance charges and discount on debt		**1,727**		1,725
Unrealized loss on risk management contracts *[Note 12]*		**40,997**		74,669
Future income tax recovery		**(2,300)**		(26,039)
Non-controlling interest		**(80)**		(495)
Unit based compensation expense		**3,216**		2,220
Amortization of office lease premium		**37**		-
Settlement of asset retirement obligations		**(1,118)**		(501)
Change in non-cash working capital *[Note 13]*		**(6,617)**		(48,694)
		88,164		3,492
Financing Activities				
Issue of Trust Units, net of issue costs		**(68)**		(88)
Borrowings of bank loan, net		**81,536**		28,146
Financing costs		**(165)**		(504)
Cash distributions		**(45,241)**		(20,446)
Change in non-cash working capital *[Note 13]*		**(13,301)**		5,679
		22,761		12,787
Investing Activities				
Additions to capital assets		**(103,239)**		(23,223)
Property acquisitions		**(23,382)**		(4,659)
Change in non-cash working capital *[Note 13]*		**15,696**		11,603
		(110,925)		(16,279)
Change in cash being cash at beginning and end of period		**-**		-
Interest paid	**$**	**2,572**	$	1,338
Large corporation tax and other tax paid	**$**	**606**	$	71

See accompanying notes to these consolidated financial statements.

(Tabular amounts in thousands of Canadian dollars, except Trust Unit and per Trust Unit amounts)

1. Significant Accounting Policies

These interim consolidated financial statements of Harvest Energy Trust (the "Trust" or "Harvest") have been prepared by management in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the period. In the opinion of management, these financial statements have been prepared within reasonable limits of materiality. These interim consolidated financial statements follow the same significant accounting policies as described and used in the consolidated financial statements of the Trust for the year ended December 31, 2005 and should be read in conjunction with that report.

These consolidated financial statements include the accounts of Harvest Energy Trust, its wholly owned subsidiaries and its proportionate interest in a partnership with a third party.

2. Acquisitions

(a) Business Acquisition

On February 3, 2006, the unitholders of the Trust and Viking Energy Royalty Trust ("Viking") voted to approve a resolution to effect the Plan of Arrangement (the "Plan of Arrangement") by which unitholders of Viking received 0.25 Harvest Trust Units for every Viking Trust Unit held, and the Trust acquired all of the assets and assumed all of the liabilities of Viking for total consideration of approximately $1,638.1 million. This amount consisted of the issuance of 46,040,788 Trust Units [Note 9(b)] at an ascribed value of $35.58 per Trust Unit, based on the weighted average trading price of the Harvest Trust Units before and after the announcement date of November 28, 2005. Pursuant to the terms and conditions of Vikings' convertible debenture indenture, Harvest's acquisition of Viking's net assets resulted in Harvest assuming the obligations of Viking's convertible debentures, including the adjustment of the conversion ratio to reflect the 0.25 Harvest Trust Unit for each Viking Trust Unit exchange ratio.

The Trust's aggregate consideration for the acquisition of Viking consists of the following:

Consideration for the acquisition:		
Ascribed value of Trust Units issued	$	1,638,131
Bank debt assumed		106,247
Convertible debentures assumed		
Debt component		202,232
Equity component		24,123
Acquisition costs		4,600
	$	1,975,333

This transaction has been accounted for using the purchase method whereby the assets acquired and the liabilities assumed are recorded at their fair values with the excess of the aggregate consideration over the fair value of the identifiable net assets allocated to goodwill. The following summarizes the allocation of the aggregate consideration for the Viking acquisition.

Allocation of purchase price:		**Amount**
Net working capital deficiency	$	(31,297)
Capital assets		1,455,000
Fair value deficiency of risk management contracts		(1,224)
Fair value of office lease		931
Goodwill		612,416
Asset retirement obligation		(60,493)
	$	1,975,333

(Tabular amounts in thousands of Canadian dollars, except Trust Unit and per Trust Unit amounts)

Effective February 3, 2006, the results of Viking have been included in the consolidated financial statements.

(b) Asset Acquisition

On January 19, 2006, the Trust closed an asset acquisition in the Hay River and Killarney area for total cash consideration of $21.9 million.

3. Deferred Charges

	March 31, 2006	December 31, 2005
Financing costs	$ 9,671	$ 11,064
Fair value of office lease *[Note 2]*	894	-
Discount on Senior Notes	1,630	1,704
	$ 12,195	$ 12,768

4. Capital Assets

March 31, 2006	**Cost**	**Accumulated depletion and depreciation**	**Net book value**
Petroleum and natural gas properties	$ 2,526,899	$ (316,892)	$ 2,210,007
Production facilities and equipment	498,953	(72,039)	426,914
Office furniture and equipment	7,437	(1,252)	6,185
Total	$ 3,033,289	$ (390,183)	$ 2,643,106

December 31, 2005	**Cost**	**Accumulated depletion and depreciation**	**Net book value**
Petroleum and natural gas properties	$ 1,135,118	$ (247,652)	$ 887,466
Production facilities and equipment	298,166	(59,732)	238,434
Office furniture and equipment	5,377	(1,122)	4,255
Total	$ 1,438,661	$ (308,506)	$ 1,130,155

General and administrative costs of $3.9 million have been capitalized during the three month period ended March 31, 2006 (three months ended March 31, 2005- $1.2 million), of which $2.1million (three months ended March 31, 2005 - $353,000) relate to the Trust Unit incentive plan and the Unit award incentive plan.

(Tabular amounts in thousands of Canadian dollars, except Trust Unit and per Trust Unit amounts)

5. Accounts Payable and Accrued Liabilities

	March 31, 2006	December 31, 2005
Trade accounts payable	$ 25,794	$ 22,484
Accrued interest	16,798	4,959
Trust Unit Incentive Plan and Unit Award Incentive Plan *[Note 10]*	12,831	17,828
Premium on price risk management contracts	-	462
Accrued closing adjustments on asset acquisition	1,132	-
Other accrued liabilities	141,187	53,223
Large corporation taxes payable	346	620
	$ 198,088	$ 99,576

6. Asset Retirement Obligation

The Trust's asset retirement obligation results from its net ownership interest in petroleum and natural gas assets including well sites, gathering systems and processing facilities and the estimated costs and timing to reclaim and abandon them. The Trust estimates the total undiscounted amount of cash flows required to settle its asset retirement obligation to be approximately $621 million which will be incurred between 2006 and 2026. The majority of the costs will be incurred between 2015 and 2026. A credit-adjusted risk-free discount rate of 8% and inflation rate of approximately 1% were used to calculate the fair value of the asset retirement obligation as at March 31, 2006.

A reconciliation of the asset retirement obligation is provided below:

	Three Months ended March 31, 2006	Year ended December 31, 2005
Balance, beginning of period	$ 110,693	$ 90,085
Incurred on acquisition of Viking	60,493	-
Liabilities incurred	432	7,328
Revision of estimates	12,173	8,656
Liabilities settled	(1,118)	(4,146)
Accretion expense	3,648	8,770
Balance, end of period	$ 186,321	$ 110,693

7. Bank Loan

The Trust entered into a new credit facility agreement on February 3, 2006, that increased its borrowing capacity from $400 million to $750 million. At March 31, 2006, the Trust completed a secondary syndication of its credit facility resulting in a broadening of its banking group and an increase in its three year extendible revolving credit facility to $900 million.

At March 31, 2006, the Trust had $201.7 million drawn under a $900 million three year extendible revolving credit facility. With the consent of the lenders, the facility may be extended on an annual basis for an additional 364 days. The facility is secured by a $1.5 billion first floating charge over all of the assets of the operating subsidiaries and a guarantee from the Trust. Amounts borrowed under this facility bear interest at a floating rate based on bankers acceptances plus 65 basis points to 115 basis points depending on the Trust's Senior Debt to Cash Flow Ratio as defined in the Credit Agreement. Availability under this facility is subject to quarterly financial covenants requiring that the Senior Debt to Cash Flow Ratio is less than 3 to 1, the Total Debt to Cash Flow Ratio is less than 3.5 to 1, Senior Debt to Capitalization is less than 50% and Total Debt Capitalization is less than 55%, all as defined in the Credit Agreement.

(Tabular amounts in thousands of Canadian dollars, except Trust Unit and per Trust Unit amounts)

8. Convertible Debentures

The Trust has issued three series of unsecured subordinated debentures and has assumed two additional series as part of the Viking acquisition [Note 2]. The two additional series of debentures assumed in the Viking acquisition have the same general terms as the three series issued by Harvest, the details of which have been outlined in our December 31, 2005 annual financial statements.

The following is a summary of the five series of convertible debentures.

Issue date	Interest rate	Original face value (millions)	Conversion price / Trust Unit	Maturity	First redemption period	Second redemption period
Jan 29, 2004	9%	$ 60	$ 13.85	May 31, 2009	Jun. 1/07-May 31/08	Jun. 1/08-May. 30/09
Aug 10, 2004	8%	$ 100	$ 16.07	Sept. 30, 2009	Oct. 1/07-Sept. 30/08	Oct. 1/08-Sept. 29/09
Aug 2, 2005	6.5%	$ 75	$ 31.00	Dec. 31, 2010	Jan. 1/09-Dec. 31/09	Jan. 1/10-Dec. 30/10
Feb. 3, 2006	10.5%	$ 35(2)	$ 29.00	Jan.31, 2008	Feb. 1/06-Jan. 31/07	Feb. 1/07-Jan. 30/08
Feb. 3, 2006	6.4%(1)	$ 175(2)	$ 46.00	Oct. 31, 2012	Nov. 1/08-Oct. 31/09	Nov. 1/09-Oct. 31/10

(1) This series of convertible debentures may also be redeemed by the Trust at a price of $1,000 per debenture on or after November 1, 2009 until maturity.
(2) The fair value of the 10.5% convertible debentures and the 6.4% convertible debentures at acquisition was $44.8 million and $181.5 million, respectively.

The following table summarizes the issuance and subsequent conversions of the convertible debentures:

	9% Series	8% Series	6.5% Series	10.5% Series	6.40% Series	Total
As at December 31, 2004	$ 10,698	$ 15,052	$ -	$ -	$ -	$ 25,750
August 2, 2005 issuance	-	-	75,000	-	-	75,000
Portion allocated to equity	-	-	(4,932)			(4,932)
Accretion of non-cash interest expense	-	11	228	-	-	239
Converted into Trust Units	(8,921)	(11,299)	(31,382)	-	-	(51,602)
As at December 31, 2005	1,777	3,764	38,914	-	-	44,455
February 3, 2006 assumption	-	-	-	44,822	181,533	226,355
Portion allocated to equity	-	-	-	(9,301)	(14,822)	(24,123)
Accretion of non-cash interest expense (premium)		1	98	(31)	151	219
Converted into Trust Units	(217)	(574)	(2,568)	(1,284)	(19)	(4,662)
As at March 31, 2006	$ 1,560	$ 3,191	$ 36,444	$ 34,206	$ 166,843	$ 242,244

	Number of Debentures					
	9% Series	8% Series	6.5% Series	10.5% Series	6.40% Series	Total
Number outstanding at December 31, 2004	10,700	15,159	-	-	-	25,859
August 2, 2005 issuance	-	-	75,000	-	-	75,000
Converted into Trust Units	(8,923)	(11,373)	(33,527)	-	-	(53,823)
Outstanding at December 31, 2005	1,777	3,786	41,473	-	-	47,036
February 3, 2006 assumption	-	-	-	35,058	174,965	210,023
Converted into Trust Units	(217)	(577)	(2,735)	(1,268)	(20)	(4,817)
Outstanding at March 31, 2006	1,560	3,209	38,738	33,790	174,945	252,242

(Tabular amounts in thousands of Canadian dollars, except Trust Unit and per Trust Unit amounts)

The following table summarizes the reclassification of the equity component of convertible debentures to Unitholders' equity:

	9% Series Equity Value	8% Series Equity Value	6.5% Series Equity Value	10.5% Series Equity Value	6.4% Series Equity Value	Total
As at December 31, 2004	$ 3	$ 113	$ -	$ -	$ -	$ 116
August 2, 2005 issuance, net	-	-	4,720	-	-	4,720
Converted into Trust Units, net	(3)	(85)	(2,109)	-	-	(2,197)
As at December 31, 2005	-	28	2,611	-	-	2,639
February 3, 2006 assumption	-	-	-	9,301	14,822	24,123
Converted into Trust Units, net	-	(4)	(173)	(336)	(2)	(515)
As at March 31, 2006	**$ -**	**$ 24**	**$ 2,438**	**$ 8,965**	**$ 14,820**	**$ 26,247**

9. Unitholders' Capital

(a) Authorized

The authorized capital consists of an unlimited number of Trust Units.

(b) Issued

	Number of Units	Amount
As at December 31, 2004	**41,788,500**	$ 465,524
Conversion of subscription receipts	6,505,600	175,001
Convertible debenture conversions-9% series	643,133	8,924
Convertible debenture conversions-8% series	703,976	11,383
Convertible debenture conversion-6.5% series	1,081,497	33,585
Exchangeable share retraction *[Note 11]*	299,123	3,865
Distribution reinvestment plan issuance	1,167,109	36,217
Special distribution	465,285	10,678
Exercise of unit appreciation rights and other	328,344	12,084
Issue costs	-	(9,949)
As at December 31, 2005	**52,982,567**	$ 747,312
Issued in exchange for assets of Viking *[Note2(a)]*	46,040,788	1,638,131
Convertible debenture conversions-9% series	15,666	217
Convertible debenture conversions-8% series	35,901	578
Convertible debenture conversions-6.5% series	88,219	2,748
Convertible debenture conversions-10.5% series	43,720	1,620
Convertible debenture conversions-6.4% series	434	21
Exchangeable share retraction *[Note 11]*	184,809	2,648
Distribution reinvestment plans	905,610	29,917
Exercise of unit appreciation rights exercise	248,815	8,840
Issue costs	-	(437)
As at March 31, 2006	100,546,529	$ 2,431,595

(Tabular amounts in thousands of Canadian dollars, except Trust Unit and per Trust Unit amounts)

(c) Per Trust Unit Information

The following tables summarize the net income and Trust Units used in calculating income per Trust Unit:

Net income adjustments	**Three Months ended March 31, 2006**	Three Months ended March 31, 2005
Net loss, basic	$ (33,937)	$ (43,070)
Non-controlling interest	(80)	(495)
Net loss, diluted[(1)]	$ (34,017)	$ (43,565)

Weighted average Trust Units adjustments	**Three Months ended March 31, 2006**	Three Months ended March 31, 2005
Number of Units		
Weighted average Trust Units outstanding, basic	82,309,176	42,134,156
Effect of exchangeable shares	100,847	397,579
Weighted average Trust Units outstanding, diluted[(2)]	82,410,023	42,531,735

(1) Net income, diluted excludes the impact of the conversions of the convertible debentures for the three month period ended March 31, 2006, of $3,115,000 (three months ended March 31, 2005 - $487,000), as the impact was anti-dilutive.

(2) Weighted average Trust Units outstanding, diluted for the three months ended March 31, 2006, does not include the impact of 1,175,000 (three months ended March 31, 2005 -1,537,871) units related to the convertible debentures as the impact would be anti-dilutive. The impact of the Trust Unit incentive plans of 462,096 (three months ended March 31, 2005 - 699,350) has also been excluded as the impact would be anti-dilutive.

10. Employee Unit Incentive Plans

Trust Unit Rights Incentive Plan
As at March 31, 2006, a total of 2,150,245 (1,305,143 – December 31, 2005) Unit Appreciation Rights were outstanding under the Trust Unit Incentive Plan at an average exercise price of $31.11 ($16.73 – December 31, 2005).

The following summarizes the Trust Units reserved for issuance under the Trust Unit incentive plan:

	Three Months ended March 31, 2006		Year ended December 31, 2005	
	Unit Appreciation Rights	**Weighted Average Exercise Price**	**Unit Appreciation Rights**	**Weighted Average Exercise Price**
Outstanding beginning of period	1,305,143	$ 19.72	1,117,725	$ 11.92
Granted	1,611,500	37.34	793,325	26.69
Exercised	(659,218)	17.57	(420,157)	9.49
Cancelled	(107,000)	37.40	(185,750)	25.70
Outstanding before exercise price reductions	2,150,425	32.71	1,305,143	19.72
Exercise price reductions	-	(1.60)	-	(2.99)
Outstanding, end of period	2,150,425	$ 31.11	1,305,143	$ 16.73
Exercisable before exercise price reductions	645,925	$ 21.92	109,068	$ 13.56
Exercise price reductions	-	(3.58)	-	(4.04)
	645,925	$ 18.34	109,068	$ 9.52

The following table summarizes information about Unit appreciation rights outstanding at March 31, 2006.

(Tabular amounts in thousands of Canadian dollars, except Trust Unit and per Trust Unit amounts)

		Outstanding				Exercisable		
Exercise Price before price reductions	**Exercise Price net of price reductions**	**At March 31, 2006**		**Exercise Price net of price reductions[(a)]**	**Remaining Contractual Life [(a)]**	**At March 31, 2006**		**Exercise Price net of price reductions [(a)]**
$8.00 - $10.21	$1.79 - $4.47	13,750	$	4.33	2.2	13,750	$	4.33
$10.30 - $13.15	$4.59 - $8.19	88,425		6.18	2.3	88,425		6.18
$13.35 - $17.85	$8.58 - $13.97	118,675		10.95	3.2	118,675		10.95
$18.90 - $22.97	$15.11- $20.25	317,275		20.91	4.0	317,275		20.91
$28.90 - $37.56	$26.38- $36.64	1,612,300		36.19	4.8	107,800		30.68
$8.00 - $37.56	$1.79- $36.64	2,150,425	$	31.11	4.5	645,925	$	18.34

(a) Based on weighted average Unit appreciation rights outstanding.

Unit Award Incentive Plan
At March 31, 2006, 190,139 Units were outstanding under the Unit Award Incentive Plan.

Upon completion of the Plan of Arrangement with Viking [Note 2], Unitholders approved the issuance of up to 0.5% of outstanding Trust Units under the Unit award plan.

Number	**Three Months ended March 31, 2006**	Year ended December 31, 2005
Outstanding, beginning of period	**35,365**	10,662
Granted	**158,839**	23,466
Adjusted for distributions	**7,170**	1,237
Cancelled	**(11,235)**	-
Outstanding, end of period	**190,139**	35,365

Upon closing of the Plan of Arrangement with Viking [Note 2] all awards and rights issued under the Trusts' employee unit incentive plans vested. Subsequent to closing additional rights and awards were issued under both plans.

The Trust has recognized compensation expense of $8.4 million ($2.0 million – three months ended March 31, 2005), including non cash compensation expense of $3.2 million ($2.6 million – three months ended March 31, 2005), for the three months ended March 31, 2006, related to the Trust Unit Incentive Plan and the Unit award plan. A recovery of $0.2 million ($2.0 million – three months ended March 31, 2005) is reflected in general and administrative expense and an expense of $8.6 million is reflected in Transaction Costs in the consolidated statements of income. Recoveries occur when the Trust Unit market price decreases below the previous measurement date. The compensation expense related to the transaction with Viking, was measured based on the Trust Unit price on February 3, 2006, the effective date of the Plan of Arrangement.

11. Exchangeable Shares

(a) Authorized
Harvest Operations Corp., a subsidiary of the Trust, is authorized to issue an unlimited number of exchangeable shares without nominal or par value.

(b) Issued

Exchangeable shares, series 1	**Three Months ended March 31, 2006**	Year ended December 31, 2005
Outstanding, beginning of period	**182,969**	455,547
Shareholder retractions	**(156,067)**	(272,578)
Outstanding , end of period	**26,902**	182,969
Exchange ratio	**1.20421**	1.17475

(Tabular amounts in thousands of Canadian dollars, except Trust Unit and per Trust Unit amounts)

As a result of the completion of the Plan of Arrangement with Viking [Note 2]. There are 26,902 exchangeable shares outstanding. The Trust has elected to exercise its deminimus redemption right to redeem all of the exchangeable shares outstanding on March 16, 2006. The redemption will be completed during the second quarter of 2006.

(c) Non-controlling interest

The following is a summary of the non-controlling interest:

		Three Months ended March 31, 2006		Year ended December 31, 2005
Non-controlling interest, beginning of period	**$**	**3,179**	$	6,895
Exchanged for Trust Units		**(2,648)**		(3,865)
Current period income (loss) attributable to non-controlling interest		**(80)**		149
Non-controlling interest, end of period	**$**	**451**	$	3,179
Accumulated income attributed to non-controlling interest	**$**	**294**	$	374

12. Financial Instruments and risk management contracts

The Trust is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations as outlined in the annual consolidated financial statements for the year ended December 31, 2005 and 2004.

The following is a summary of Harvest's risk management contracts outstanding, along with their fair value at March 31, 2006.

Quantity	**Type of Contract**	**Term**	**Reference**	**Fair value**
8,750 bbl/d	Participation swap	April – December 2006	U.S$38.16[a]	$ (42,778)
5,000 bbl/d	Participation swap	July – December 2006	U.S$45.17[a]	(12,767)
5,000 bbl/d	Participating swap	April 2006 – June 2007	U.S.$49.03[b]	(12,199)
4,000 bbl/d	Differential swap – Bow River	April – June 2006	29.90%	(1,433)
5,000 bbl/d	Differential swap – Bow River	April – June 2006	27.50%	(1,144)
7,500 bbl/d	Indexed put contract – bought put	April – June 2006	U.S.$34.00[c]	(398)
3,750 bbl/d	Indexed put contract – sold call	April – June 2006	U.S.$34.00[c]	(13,588)
3,750 bbl/d	Indexed put contract – bought call	April – June 2006	U.S.$44.00[c]	9,637
5,000 bbl/d	Indexed put contract – bought put	April – December 2006	U.S.$55.00[c]	894
2,500 bbl/d	Indexed put contract – sold call	April – December 2006	U.S.$55.00[c]	(11,676)
2,500 bbl/d	Indexed put contract – bought call	April – December 2006	U.S.$65.00[c]	5,322
2,500 bbl/d	Indexed put contract – sold call	April – December 2006	U.S.$70.00[c]	(3,152)
2,500 bbl/d	Indexed put contract – bought call	April – December 2006	U.S.$83.00[c]	778
200 mcf/d	Fixed price - natural gas contract	April – December 2008	Cdn.$4.19[d]	(443)
76 mcf/d	Fixed price – natural gas contract	April – October 2008	Cdn.$2.00[d]	(131)
Total current portion of fair value deficiency				**$ (83,078)**

(Tabular amounts in thousands of Canadian dollars, except Trust Unit and per Trust Unit amounts)

Quantity	Type of Contract	Term	Reference	Fair value
10,000 bbl/d	Participating swap	January – December 2007	U.S.$55.00[(e)]	(13,115)
5,000 bbl/d	Indexed put contract – bought put	January – December 2007	U.S.$50.00[(c)]	3,026
2,500 bbl/d	Indexed put contract – sold call	January – December 2007	U.S.$50.00[(c)]	(21,218)
2,500 bbl/d	Indexed put contract – bought call	January – December 2007	U.S.$60.00[(c)]	13,584
2,500 bbl/d	Indexed put contract – sold call	January – December 2007	U.S.$70.00[(c)]	(7,702)
2,500 bbl/d	Indexed put contract – bought call	January – December 2007	U.S.$83.00[(c)]	3,304
200 Mcf/d	Fixed price – natural gas contract	April - December 2008	Cdn. $4.29[(d)]	(1,354)
76 Mcf/d	Fixed price – natural gas contract	April - October 2008	Cdn. $2.05-$2.10[(d)]	(376)
10 Mwh	Electricity price swap contract	January – December 2008	Cdn $60.90	(255)
Total long-term portion of fair value deficiency				**$ (24,106)**

(a) This price is a floor. The Trust realizes this price plus 50% of the difference between spot price and this price.
(b) This price is a floor. The Trust realizes this price plus 75% of the difference between spot price and this price.
(c) Each group of a puts and call reflect an "indexed put option". These series of puts and calls serve to fix a floor price while retaining upward price exposure on a portion of price movements above the floor price.
(d) This contract contains an annual escalation factor such that the fixed price is adjusted each year.
(e) This price is a floor. The Trust realizes this price plus 67% of the difference between spot price and this price.

Quantity	Type of Contract	Term	Reference	Fair value
4,000 bbl/d	Differential swap – Bow River	July – December 2006	29.58%	767
5,000 bbl/d	Differential swap – Bow River	July – December 2006	27.50%	2,012
1,000 bbl/d	Differential swap – Wainwright	April – June 2006	29.90%	19
1,000 bbl/d	Differential swap – Wainwright	July - December 2006	29.58%	1,134
5,000 GJ/d	Natural gas price collar contract	April - October 2006	Cdn$9.00-$13.06	2,553
45 MWH	Electricity price swap contracts	April – December 2006	Cdn $51.48	2,828
Total current portion of fair value				**$ 9,313**
35 MWH	Electricity price swap contracts	January – December 2007	Cdn $56.69	2,243
25 MWH	Electricity price swap contracts	January – December 2008	Cdn $55.00	659
Total long-term portion fair value				**$ 2,902**

At March 31, 2006, the net unrealized loss position reflected on the balance sheet for all the risk management contracts outstanding at that date was approximately $95.0 million ($52.6 million – December 31, 2005).

For the three months ended March 31, 2006, the total unrealized loss recognized in the consolidated statement of income, including amortization of deferred charges and gains, was $41.0 million ($74.7 million – three months ended March 31, 2005). The realized gains and losses on all risk management contracts are included in the period in which they are incurred.

(Tabular amounts in thousands of Canadian dollars, except Trust Unit and per Trust Unit amounts)

13. Change in Non-Cash Working Capital

	Three Months ended March 31, 2006	Three Months ended March 31, 2005
Changes in non-cash working capital items:		
Accounts receivable	**$ 8,926**	$ (17,648)
Prepaid expenses and deposits	**(1,833)**	(36,854)
Current portion of risk management contracts assets	**11,918**	3,279
Current portion of future income tax asset	**22,975**	-
Accounts payable and accrued liabilities	**9,992**	25,522
Cash distribution payable	**(2,209)**	172
Current portion of risk management contracts liability	**16,245**	27,340
	$ 66,014	$ 1,811
Changes relating to operating activities	**$ (6,617)**	$ (48,694)
Changes relating to financing activities	**(13,301)**	5,679
Changes relating to investing activities	**15,696**	11,603
Add: Non cash changes	**70,236**	33,223
	$ 66,014	$ 1,811

14. Commitments, Contingencies and Guarantees

The Trust has letters of credit outstanding in the amount of approximately $8.2 million primarily provided to electricity infrastructure providers. These letters are provided by Harvest Operations' lenders pursuant to the secured senior credit agreement [Note 7]. These letters expire between April 30, 2006 and December 31, 2006, and are expected to be renewed as required.

The following is a summary of the Trust's contractual obligations and commitments as at March 31, 2006:

	Remaining Payments Due by Period						
	2006	**2007**	**2008**	**2009**	**2010**	**Thereafter**	**Total**
Debt repayments [1]	$ -	$ 201,652	$ -	$ -	$ -	$ 292,000	$ 493,652
Capital commitments	17,015	8,605	2,880	-	-	-	28,500
Operating leases[2]	2,836	3,607	3,538	3,538	1,491	-	15,010
Total contractual obligations	$ 19,851	$ 213,864	$ 6,418	$ 3,538	$ 1,491	$ 292,000	$ 537,162

(1) Assumes that the outstanding convertible debentures either convert at the holders' option for Units or are redeemed for Units at the Trust's option.
(2) Relating to building and automobile leases.

15. Comparatives

Certain comparative figures have been reclassified to conform to the current period's presentation.