Harvest Energy Trust

Financial & Operating Highlights

The table below provides a summary of Harvest's financial and operating results for the three and nine month periods ended September 30, 2006 and 2005, and the second quarter of 2006.

	Three months ended				Nine months ended		
FINANCIAL *($000s except where noted)*	**Sept. 30, 2006**	June 30, 2006	Sept. 30, 2005	2006 to 2005 Quarter Change	**Sept. 30, 2006**	Sept. 30, 2005	Year over Year Change
Revenue, net[1]	**312,864**	233,128	143,524	118%	**677,424**	262,069	158%
Cash Flow[2]	**147,471**	147,010	103,508	42%	**395,452**	213,412	85%
Per trust unit, basic[2]	**$ 1.39**	$ 1.45	$ 2.14	(35%)	**$ 4.09**	$ 4.78	(14%)
Per trust unit, diluted[2]	**$ 1.34**	$ 1.43	$ 2.09	(36%)	**$ 3.94**	$ 4.55	(13%)
Net income (loss)	**107,768**	60,682	52,862	104%	**134,513**	29,308	359%
Per trust unit, basic	**$ 1.01**	$ 0.60	$ 1.09	(7%)	**$ 1.39**	$ 0.66	111%
Per trust unit, diluted	**$ 0.99**	$ 0.60	$ 1.08	(8%)	**$ 1.38**	$ 0.64	116%
Distributions declared	**123,112**	115,889	46,691	164%	**333,813**	108,957	206%
Distributions declared, per trust unit	**$ 1.14**	$ 1.14	$ 0.95	20%	**$ 3.39**	$ 2.15	58%
Payout ratio [2][3]	**83%**	79%	45%	38%	**84%**	46%	38%
Cash capital asset additions (excluding acquisitions)	**129,054**	54,230	31,655	308%	**286,523**	81,032	254%
Bank debt	**591,189**	227,554	34,649	1,606%	**591,189**	34,649	1,606%
Production							
Light to medium oil (bbl/d)	**28,394**	28,951	18,868	50%	**27,136**	16,618	63%
Heavy oil (bbl/d)	**13,919**	13,037	13,735	1%	**14,003**	13,906	1%
Natural gas liquids (bbl/d)	**2,595**	2,016	850	205%	**2,111**	810	161%
Natural gas (mcf/d)	**103,618**	96,848	24,574	322%	**91,379**	26,839	240%
Total daily sales volumes (boe/day)	**62,178**	60,145	37,549	66%	**58,480**	35,807	63%

(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.

Message to Unitholders

Operational Update

The third quarter of 2006 was an active and successful period operationally. Production during the quarter averaged 62,178 barrels of oil equivalent per day (boe/d), which was on target and an increase of 66% over the 37,549 boe/d reported for the same period in 2005. This level reflects the impact of the Viking merger, just over 6,000 boe/d of production added in August through the acquisition of Birchill Energy Limited (Birchill), a private Canadian oil and gas company which closed during the quarter, as well as production additions gained through our drilling and optimization activities. During the quarter, production volumes were negatively impacted at Markerville, where approximately 3,500 boe/d of production was shut-in for the month of July and the first week of August following a fire at a non-operated gas processing facility. Business interruption insurance was in place (subject to a 30 day deductible period) and we will be pursuing compensation for the qualifying period during the fourth quarter.

We were very active through the third quarter, investing $129.1 million into our portfolio of drilling, optimization and enhancement activities. We drilled 76 gross (60 net) wells with a success rate of 97%, with a significant portion of our drilling activity focused on oil opportunities given very strong field prices for our mix of light / medium and heavy oil. Our most active drilling area was southeast Saskatchewan, which produces light oil (33° API) from the Tilston and Souris Valley formations. We drilled 17 gross horizontal wells in southeast Saskatchewan during the quarter, bringing our total for the year in that area to 28 gross wells. At

Lloydminster, a successful horizontal well test in 2005 was quickly translated into field development of the Lloydminster oil formation, and we drilled 6 gross horizontal wells since the middle of June. At Hayter and Suffield we continue to find incremental oil from the Dina and Glauconitic formations with a total of 16 gross infill horizontal wells drilled in the quarter in these two areas. Water handling upgrades at Suffield were also completed during the quarter, which will allow us to optimize production of both existing and newly drilled wells throughout the fourth quarter. In the first nine months of 2006 we drilled 195 gross wells, with an additional 40 to 50 gross wells planned for the balance of the year. With the acquisition of Birchill, we also increased our 2006 capital budget by $50 million to $300 million, including $25 million budgeted specifically for the new Birchill properties. Due to the success of our year to date drilling program coupled with favorable weather conditions in Western Canada, we plan to further expand our drilling and optimization budget to accelerate some of our 2007 capital projects into the fourth quarter of 2006.

We continue to be pleased with the drilling success and optimization activities within our properties, which are a significant contributor to our ongoing sustainability. This is further supported by enhanced oil recovery projects at several of our large original resource in place properties, including Hayter, Kindersley, Wainwright and Suffield. Shortly after the end of the third quarter, we began preparations for a condensate injection pilot project at Hayter, which has over 130 million barrels of original oil in place. The oil at Hayter is heavy so we blend it with condensate in order to meet the pipeline viscosity specifications for shipping. Under the pilot project, we are testing the viability of injecting condensate directly into the reservoir to reduce the viscosity of the oil, thereby improving recovery. The cost to do this is very minimal because we already have condensate on site for blending, but if successful, this could increase the ultimate recovery of that reservoir by an additional 10%. Other enhanced oil recovery projects that we are evaluating for pilot testing in 2007 include a brine flood at Kindersley, designed to improve permeability and flood sweep efficiency, and polymer injection at Wainwright and Suffield to also increase waterflood sweep efficiency. Technical work has begun on these projects, which we believe will ultimately result in incremental reserves, further contributing to our future sustainability. Our independent reserve evaluators have not yet booked any reserves associated with the enhanced oil recovery projects being undertaken on these properties, which represents future upside for Harvest.

In addition to our active internal development program, we continue to actively seek out value adding acquisition opportunities, which has become more challenging with the increased competition for assets in Western Canada. We were very pleased to be successful in acquiring the Birchill assets, which have given us just over 6,000 boe/d of production in close proximity to our existing assets in Central Alberta. As a result of this acquisition, we are a working interest owner in an active and emerging Leduc oil play in the Sylvan Lake area. These Leduc pinnacle reefs are characterized by high initial productivity with some wells capable of producing at rates in excess of 1,000 boe/d. Harvest's interest in these wells ranges between 37.5% and 50%. Associated with the Birchill acquisition, we also concluded a $200 million equity financing. This financing was increased to $230 million as the underwriters elected to exercise their overallotment option, and Harvest issued 7.0 million trust units. The equity issuance was important for preserving our balance sheet strength which improves our ability to undertake future potential acquisitions.

Value Creation

Our business strategy has always been focused on value, and since our inception, we have often found value by looking where others were not. We strive to acquire assets that have future upside potential and built-in value-optionality. We have been successful at doing this in the past, evidenced by our performance and our large inventory of internal development projects. As the competition and cost of assets in Western Canada has increased, it has become more challenging to acquire these opportunities at prices that we feel are attractive for our unitholders. Consistent with our strategy, Harvest has taken a number of steps to increase our competitive position going forward, including the merger of Harvest and Viking, retaining stronger technical and operational staff and strengthening our balance sheet. Although we continued looking for asset acquisitions that would enable us to extend our value chain, such as Birchill, we also recognized that as a producer of light / medium and heavy grades of crude oil, there was an opportunity to get involved with upgrading or refining assets to provide us with a natural hedge. During the third quarter, we successfully implemented this part of our strategy with the acquisition of North Atlantic Refining.

This acquisition gives us a high quality, medium-sour hydrocracking refinery with current capacity of 115,000 barrels per stream day situated in the Canadian province of Newfoundland and Labrador. Its strategic position along major shipping routes through the Atlantic Ocean has several advantages. We are in close proximity to crude feedstock sources such as Latin America, Russia or the Middle East, and also have ready access to large markets in the northeastern U.S. and other parts of the U.S. for refined products. Of the refinery's product slate, 75% are very high value products including reformulated gasoline (also called 'RBOB gasoline'), ultra low sulfur diesel, and jet fuel. As a result, the refinery offers strong cash flow characteristics, with annual maintenance capital estimated at approximately $40 million. Based on its current configuration and high quality product slate, the refinery does not require any additional investment beyond this maintenance capital for its continued operations. However, future enhancement opportunities do exist to upgrade the remaining 25% of the throughput from heavy fuel oil and transform it into the higher value gasoline, diesel and jet fuel products. We see very compelling economics for undertaking this type of discretionary project, and intend to pursue it in a prudent manner once the technical and financial requirements are fully understood.

In addition to the refinery, North Atlantic also includes a marketing business, with 69 retail gas stations in Newfoundland, 20,000 home heating customers, a chain of home heating stores, and a marine services division. These ancillary businesses have very strong brand recognition in the province and contribute approximately 5% - 10% to the overall cash flow from North Atlantic.

In order to finance this acquisition, we arranged a syndicated credit facility through the leading Canadian banks and several global financial institutions, and are very pleased with the strength and support received from the financial community. The credit facility consists of a $1.4 billion three year revolver, supplemented by a $350 million secured bridge with an eighteen month term, and a $450 million unsecured bridge with a six month term.

Subsequent to the end of the quarter, Harvest announced a $500 million bought deal financing; consisting of $400 million of convertible debentures and $100 million of trust units. At this time, Harvest remains in discussions with its underwriters and is assessing various alternatives to proceed with the offering. The proceeds from this financing will be used to repay the existing bridge financing and will provide Harvest with greater flexibility for recapitalizing our balance sheet over the coming months. Also after the end of the quarter, we entered into an agreement to sell two small assets totaling approximately 200 boe/d for total proceeds of $20 million. This translates into a realized price of approximately $100,000 per flowing barrel. The properties to be divested were non-operated, with one located in the Rainbow area and the other representing a small portion of our interest in Crossfield. We continue to be open to future opportunities for creating value for unitholders from the properties within our portfolio, and possibly facilitating further debt repayment. Undertaking such transactions also helps support our ongoing strategy to consolidate as well as high grade our asset base.

On October 31, the Canadian government made a surprise announcement proposing to amend the *Income Tax Act* (Canada) to apply a Distribution Tax on distributions from publicly traded income trusts. Under the proposal, newly formed trusts would be subject to tax in 2007, while existing trusts such as Harvest would benefit from a four year transition period and would not be subject to the new measures until the 2011 taxation year. Harvest intends to be active and work with our various industry associations to support the interests of our unitholders and other stakeholders. Like so many of our Canadian and non-resident unitholders, we were very disappointed by this announcement but remain committed to our strategy of creating value for our unitholders. We intend to keep our stakeholders informed regarding our efforts and activities with respect to this issue by posting updates regularly on our website at www.harvestenergy.ca.

We also want to take this opportunity to thank director Hank Swartout, who is leaving the Harvest Board effective November 8, 2006. Since our inception, Mr. Swartout has provided a great service to Harvest and our unitholders and has now decided to dedicate more time to his non-business ventures. We wish him well in his retirement and thank him for his contributions.

Outlook

Based on our success in our 2006 capital program, we have added a net $25 million to our 2006 capital program. Despite volatility in commodity prices in the latter part of 2006, Harvest has confirmed the fourth quarter 2006 monthly distributions at C$0.38 per trust unit. We believe this stable distribution level demonstrates our commitment to sustainability and the potential for increased cash flow in 2007 associated with our refinery business. Based on current price forecasts and assuming the same distribution level is maintained, we would anticipate Harvest's payout ratio will be reduced in 2007 relative to levels reported in 2006.

We have finalized our budget for 2007, and are forecasting production in our upstream business to average 65,000 boe/d based on a capital budget of $360 million which reflects $315 million in the upstream plus $45 million in the downstream and throughput in our downstream operations to be approximately 105,000 barrels per day. The downstream investment reflects maintenance capex plus $15 million of discretionary capex for enhancement opportunities. A small portion of the upstream capex may be accelerated into 2006 if the weather is supportive of starting the winter program in late 2006. We expect to be able to finance this capital spending program out of cash flow and other established financing sources. There are no major turnarounds scheduled for the refinery in 2007.

The team at Harvest is proud of the success we've achieved to date and want to thank all of our stakeholders and employees for their ongoing support. However, we intend to continue our efforts to voice concern over the government's tax plans and will seek creative and innovative ways to maximize value for our unitholders as we have successfully done in the past. With a more diversified and extended value chain, we are very well positioned to continue executing our value-creation strategy. We are determined to work together with our partners to meet the challenges facing Harvest and our industry.

Conference Call & Webcast

To provide further discussion of our third quarter 2006 financial and operating results, Harvest will be hosting a conference call and Webcast at 9:00 a.m. Mountain time (11:00 a.m. Eastern time) on November 9th, 2006. Callers may dial 1-877-888-3490 (international callers or Toronto local dial 416-695-5259) a few minutes prior to start and request the Harvest conference call. The call will also be available for replay by dialing 1-888-509-0081 (international callers or Toronto local dial 416-695-5275 and entering passcode 631699.

Webcast listeners are invited to go to the Investor Relations – Presentations & Events page of the Harvest Energy website at www.harvestenergy.ca for the live Webcast and/or a replay of the Webcast.

Harvest is one of Canada's largest energy royalty trusts offering unitholders exposure to an integrated structure with upstream and downstream operations. We are focused on identifying opportunities to create and deliver value to unitholders through monthly distributions and unit price appreciation. With an active acquisition program and the technical approach taken to maximizing our assets, we strive to grow cash flow per unit. Harvest is a sustainable trust with a combined economic life index of approximately 16 years, and current production from our oil and gas business weighted approximately 70% to crude oil and liquids and 30% to natural gas. Harvest trust units are traded on the Toronto Stock Exchange ("TSX") under the symbol "HTE.UN" and on the New York Stock Exchange ("NYSE") under the symbol "HTE".

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 and nine month periods ended September 30, 2006 and 2005. 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 November 8, 2006.

When reviewing our 2006 results and comparing them to 2005, readers are cautioned that the 2006 results include three full quarters of operations from our Hay River acquisition in the August 2005, only eight months of operations from our acquisition of Viking in February 2006, and only two months of operations from the Birchill Energy Limited ("Birchill") acquisition in August 2006. The combination of these events significantly impacts the comparability of our operations and financial results for 2006 to the results of the same period of 2005. To increase comparability, in certain instances, we have provided financial information for the second quarter of 2006, which reflects the results of operations of Harvest including a full three months of results of Viking and Hay River.

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 – Third Quarter 2006

- Cash Flows of $147.5 million for the third quarter in 2006 is relatively unchanged from the $147.0 million Cash Flow reported in the second quarter of 2006 and a 42% increase over the $103.5 million earned in the third quarter of 2005. Cash distributions declared totaled $1.14 per trust unit in both the third quarter and the second quarter of 2006 representing a payout ratio of 83% and 79%, respectively.
- Production of 62,178 boe per day (boe/d) for the third quarter, an increase in average daily production of 3% over the 60,145 boe/d reported in the second quarter of 2006 despite a temporary reduction in the third quarter related to downtime in a non-operated gas processing facility.

- Third quarter capital reinvestment of $129.1 million brings the total for year to $286.5 million. In the third quarter, 76 gross wells (60 net) were drilled resulting in 74 gross (58.3 net) successful wells with total wells drilled in 2006 totaling 195 gross (152.7 net) of which 191 gross (150.0 net) were successful.
- During the third quarter of 2006, we announced an agreement to acquire an 115,000 barrel per stream day refinery located in the Province of Newfoundland and Labrador for $1.6 billion as well as an expansion of our credit facilities to $2.2 billion, including bridge financing, to fund the acquisition. The refinery processes medium gravity sour crude and produces primarily gasoline, low sulphur diesel and jet fuel the majority of which is sold into premium markets in the United States.
- Subsequent to the end of the Third Quarter our refinery acquisition was completed and we announced a “bought deal” financing to sell $400 million of convertible debentures and 3,150,000 trust units at a price of $31.75 per trust unit. On the evening of October 31, 2006, changes to the Canadian income tax treatment of distributions from publicly traded trusts were announced by the Government of Canada. Currently, we are in discussions with our underwriters and are assessing various alternatives to proceed with this financing. The long term impact of the changes announced by the Government of Canada is being evaluated internally as well as through our active participation in the recently created coalition of Canadian energy trusts.

The table below provides a summary of our financial and operating results for the three and nine month periods ended September 30, 2006 and September 30, 2005. Detailed commentary on individual items within this table is provided elsewhere in this MD&A.

	Three months ended				**Nine months ended**		
FINANCIAL *($000s except where noted)*	**Sept. 30, 2006**	June 30, 2006	Sept. 30, 2005	2006 to 2005 Quarter Change	**Sept. 30, 2006**	Sept. 30, 2005	Year over Year Change
Revenue, net[(1)]	**312,864**	233,128	143,524	118%	**677,424**	262,069	158%
Cash Flow[(2)]	**147,471**	147,010	103,508	42%	**395,452**	213,412	85%
Per trust unit, basic[(2)]	**$ 1.39**	$ 1.45	$ 2.14	(35%)	**$ 4.09**	$ 4.78	(14%)
Per trust unit, diluted[(2)]	**$ 1.34**	$ 1.43	$ 2.09	(36%)	**$ 3.94**	$ 4.55	(13%)
Net income (loss)	**107,768**	60,682	52,862	104%	**134,513**	29,308	359%
Per trust unit, basic	**$ 1.01**	$ 0.60	$ 1.09	(7%)	**$ 1.39**	$ 0.66	111%
Per trust unit, diluted	**$ 0.99**	$ 0.60	$ 1.08	(8%)	**$ 1.38**	$ 0.64	116%
Distributions declared	**123,112**	115,889	46,691	164%	**333,813**	108,957	206%
Distributions declared, per trust unit	**$ 1.14**	$ 1.14	$ 0.95	20%	**$ 3.39**	$ 2.15	58%
Payout ratio [(2)(3)]	**83%**	79%	45%	38%	**84%**	46%	38%
Cash capital asset additions (excluding acquisitions)	**129,054**	54,230	31,655	308%	**286,523**	81,032	254%
Bank debt	**591,189**	227,554	34,649	1,606%	**591,189**	34,649	1,606%
Production							
Light to medium oil (bbl/d)	**28,394**	28,951	18,868	50%	**27,136**	16,618	63%
Heavy oil (bbl/d)	**13,919**	13,037	13,735	1%	**14,003**	13,906	1%
Natural gas liquids (bbl/d)	**2,595**	2,016	850	205%	**2,111**	810	161%
Natural gas (mcf/d)	**103,618**	96,848	24,574	322%	**91,379**	26,839	240%
Total daily sales volumes (boe/day)	**62,178**	60,145	37,549	66%	**58,480**	35,807	63%

(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

The third quarter of 2006 reflects the full impact of the acquisition of Viking Energy Royalty Trust acquired on February 3, 2006 and two months of activity from the Birchill acquisition in August 2006. A strong crude oil and heavy oil differential pricing environment benefited our Cash Flows during the quarter, despite relative weakness in natural gas prices. We generated Cash Flows of $147.5 million ($1.39 per basic trust unit) in the third quarter of 2006, compared to $103.5 million ($2.14 per basic trust unit) in the same period in 2005. This $44.0 million increase in Cash Flow is substantially attributed to the incremental impact of the Viking acquisition on our cash flows but has been partially offset by the trend of rising cost pressures in the oil and natural gas service sector.

Distributions declared during the quarter totaled $1.14 per trust unit, for a payout ratio of 83%. Distributions were consistent with those declared in the second quarter of 2006 with a slight increase in the payout ratio which was 79% for the second quarter of 2006. Per trust unit distributions are 20% higher compared to the $0.95 per trust unit declared in the third quarter of 2005. With potential increases in Cash Flow in 2007 due to the acquisition of the refinery and the increase of the floor prices of a number of price risk management contracts in 2007 and assuming a $0.38 per trust unit monthly distribution level, we anticipate a reduction in our 2007 payout ratio.

Production was 62,178 boe/d, an increase of 3.4% over second quarter of 2006. This increase is attributed to the Birchill acquisition during the quarter which was partially offset by lower production in the Markerville area, where approximately 3,500 boe/d of production was shut-in for the month of July and the first week of August following a fire at a non-operated gas processing facility. We are maintaining our forecast for annual production of approximately 60,000 boe/d and an exit production of approximately 66,000 boe/d for the year ended December 31, 2006.

During the third quarter, we invested $129.1 million in our properties, an increase of 308% over the same period in 2005. On a year to date basis, excluding acquisitions, we have invested $286.5 million which is 254% greater than in 2005. Our ability to implement a significantly larger capital program in 2006 reflects our larger size and greater opportunity portfolio. Of the total capital spent, 64% was allocated to drilling and equipping activities. In the third quarter, we drilled 17 net wells in SE Saskatchewan, 8.5 net wells in Hayter, 7 net wells in Suffield, 6 net wells in Lloydminster, 1.6 net wells in Red Earth and 2.8 net wells in Markerville, with a 97% success rate.

For the third quarter of 2006, we closed our acquisition of Birchill for $452.3 million, including working capital adjustments. At the time of acquisition Birchill was providing approximately 6,300 boe/d of production weighted to natural gas, and proved plus probable (P+P) reserves of approximately 22.6 mmboe. This acquisition was accretive to cash flow per unit, reserves per unit and production per unit, and increased Harvest's Reserve Life Index (RLI) to 9.5 years. The acquisition has been financed with a combination of bank debt and the net proceeds from our issuance of 6,110,000 trust units (7,026,500 trust units including over-allotment option) at a price of $32.75 per trust unit in August 2006.

During the third quarter of 2006, we announced an agreement to acquire an 115,000 barrel per stream day refinery located in the Province of Newfoundland and Labrador for US$1.4 billion and an expansion of our credit facilities to $2.2 billion, including bridge financing, to fund the acquisition. On August 23, 2006, we placed $111.3 million in escrow as a performance deposit in respect of our refinery acquisition. The hydrocracking refinery processes medium gravity sour crude oil to gasoline, low sulphur diesel and jet fuel the majority of which are sold into premium markets in the United States. Its strategic position along the major Atlantic Ocean shipping routes has several advantages. We are in close proximity to feedstock sources such as Middle East, Latin America or Russia and also have ready access to large markets for refined products in northeastern United States. As a result, the refinery offers attractive operating economics. We closed our refinery acquisition on October 19, 2006 and initially financed it using our $350 million secured bridge facility and our $450 million unsecured bridge facility while the remainder was financed from our three year revolving facility which was expanded from $900 million to $1.4 billion.

Subsequent to the end of the third quarter, we announced a "bought deal" agreement to sell $400 million of convertible debentures and 3,150,000 trust units at a price of $31.75 per trust unit, net proceeds from which would be used to repay our unsecured bridge facility of $450 million in full and the remainder applied against the $350 million secured bridge facility.

On the evening of October 31, 2006, changes to the Canadian income tax treatment of distributions from publicly traded trusts were announced by the Government of Canada which have resulted in considerable disruption in the valuations of all income and royalty trusts. The long term impact of these changes is being evaluated internally as well as through our active participation in the recently created coalition of Canadian energy trusts.

REVIEW OF QUARTERLY OPERATIONS

Commodity Price Environment	**Three months ended Sept. 30**			**Nine months ended Sept. 30**		
Benchmarks	**2006**	2005	Change	**2006**	2005	Change
West Texas Intermediate crude oil (US$ per barrel)	**70.58**	63.19	12%	**68.25**	55.40	23%
Edmonton light crude oil ($ per barrel)	**79.07**	76.51	3%	**75.55**	67.91	11%
Bow River blend crude oil ($ per barrel)	**58.65**	54.94	7%	**53.07**	44.80	18%
AECO natural gas daily ($ per mcf)	**5.64**	9.30	(39%)	**6.40**	7.84	(18%)
AECO natural gas monthly ($ per mcf)	**6.03**	8.17	(26%)	**7.19**	7.41	(3%)
Canadian / U.S. dollar exchange rate	**0.891**	0.833	7%	**0.883**	0.817	8%

Oil prices have increased in the third quarter of 2006 as compared to the third quarter of 2005. The West Texas Intermediate ("WTI") crude oil price increased by 12%, however this increase was not fully reflected in the Edmonton light crude oil price ("Edmonton Par") due to the 7% appreciation in value of the Canadian dollar. The Canadian dollar equivalent of WTI for the third quarter of 2006 would have been $79.21 had the dollar not appreciated by 7%. As a result, Edmonton Par only realized a 3% increase over the same period. A similar situation occurred for the nine months ended September 30, 2006 compared to the prior year as WTI increased by 23% while Edmonton Par only increased by 11%. For the nine months ended September 30, 2006, the Canadian dollar equivalent of WTI would have been $77.29, had the Canadian dollar not appreciated by 8%. In addition to the strengthening Canadian dollar, Edmonton Par was impacted by a differential to the WTI in the third quarter. For the nine months ended September 30, 2006, WTI traded at a 2% premium to Edmonton Par versus WTI and Edmonton Par trading evenly in the prior year. The combination of a strengthening Canadian dollar and the widening differential between WTI and Edmonton Par resulted in only an 11% increase in Edmonton Par over the prior year while WTI increased by 23% for the same period.

In the third quarter of 2006, prices for heavy crude oil of $58.65 were 7% higher compared to $54.94 in the same period in 2005. As shown in the table below, Bow River differentials narrowed to 25.8% of Edmonton Par in the third quarter of 2006, compared to 28.2% in the prior year. The heavy crude oil price during the nine months ending September 30, 2006 was 18% higher at $53.07 compared to $44.80 for the same period in 2005. This is due to the narrowing of the Bow River differentials to 29.8% from 34.0%.

	2006			2005			2004
Differential Benchmarks	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Bow River Blend differential to Edmonton Par	**25.8%**	22.9%	42.0%	40.0%	28.2%	39.6%	37.5%	39.1%

For the three and nine months ended September 30, 2006 compared to the same periods in 2005, AECO natural gas daily prices saw a decrease of 39% and 18%, respectively, while monthly prices for the same periods decreased by 26% and 3% respectively.

Realized Commodity Prices

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

	Three months ended			Nine months ended		
	Sept. 30, 2006	Sept. 30, 2005	Change	**Sept. 30, 2006**	Sept. 30, 2005	Change
Light to medium oil ($/bbl)	**66.64**	65.71	1%	62.13	57.05	9%
Heavy oil ($/bbl)	**55.09**	52.37	5%	48.61	39.98	22%
Natural gas liquids ($/bbl)	**61.57**	54.23	14%	60.81	46.17	32%
Natural gas ($/mcf)	**5.75**	10.69	(46%)	6.67	8.31	(20%)
Average realized price ($/boe)	**54.92**	60.39	(9%)	53.08	49.27	8%
Realized risk management losses ($/boe)[1]	**(4.96)**	(6.85)	(28%)	(3.86)	(6.76)	(43%)
Net realized price ($/boe)	**49.96**	53.45	(7%)	49.22	42.51	16%

(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 9% lower before losses on risk management contracts and 7% lower after realized losses on risk management contracts for the three months ended September 30, 2006 as compared to the same period in 2005. The WTI price increased by 12% over the same periods, however, this benefit was partially offset by a stronger Canadian dollar resulting in an increase of only 3% for Edmonton Par. This is relatively consistent with the 5% overall increase in our average realized oil price for the three months ended September 30, 2006. The change in our average realized oil price is slightly higher than the change in Edmonton Par due to a narrowing of the Bow River differential to Edmonton Par from 28.2% in the third quarter of 2005 compared to 25.8% in the third quarter of 2006. As 37% of our total production is priced off of the Bow River stream, it is expected that our average realized oil price increase would be greater than the change in Edmonton Par. For the nine months ended September 30, 2006, the Edmonton Par price increased by 11% and the Bow River price increased by 18%. The net result in the movement of these two benchmarks on our realized price for all of our oil for the nine months ended September 30, 2006 over the same period in the prior year is an increase of 17% before hedging and 25% after oil and currency exchange hedging activities.

For the third quarter of 2006, the realized price of our light to medium oil increased 1% which is relatively consistent with the Edmonton Par increase of 3% for the same period. For the nine months ended September 30, 2006, the realized price of our light to medium oil increased by 9% over the prior year while Edmonton Par increased by 11% over the same period. This increase in our realized light to medium oil price is reasonably in line with the increase in the benchmark prices.

Our realized heavy oil price differential to Edmonton Par for the three months ended September 30, 2006 was 30% compared to 32% for the three months ended September 30, 2005, a 2% improvement. This is expected as the majority of our heavy oil production is priced off of Bow River, which reflected a 2.4% narrowing to Edmonton Par from 28.2% in the third quarter of 2005 to 25.8% in the third quarter of 2006. For the nine months ended September 30, 2006 our realized heavy oil differential to Edmonton Par was 35.7% compared to 41.1% for the prior period. Bow River differentials to Edmonton Par for the nine months ended September 30, 2006 and 2005 were 29.8% and 34.0%, respectively. The narrowing in our realized heavy oil differential by 5.4% is relatively consistent with the 4.2% narrowing for the benchmark.

For the three months ended September 30, 2006, our realized natural gas price decreased by 46% compared to the same period in 2005, while the AECO daily and monthly price decreased by 39% and 26%, respectively. With approximately 85% of our natural gas sales priced off the AECO daily benchmark, 10% priced off AECO Monthly benchmark and the remainder sold to aggregators, our price decreased by more than both indices primarily due to lower production volumes at Markerville, where approximately 3,500 boe/d of production was shut in for the month of July and the first week of August following a fire at a non-operated gas processing facility. The lower production in this area had a negative impact on our realized gas price as the properties in this area typically have a higher than average heat content thus typically yielding gas prices in excess of the AECO benchmark prices. For the nine months ended September 30, 2006 our realized natural gas price decreased by 20% relative to the same period in 2005, while the AECO daily and monthly price decrease by 18% and 3% respectively. Our price decreased by more than the decrease in both indices due to the lower production in the Markerville area as noted above.

Sales Volumes

The average daily sales volumes by product were as follows:

	Three months ended						
	Sept. 30, 2006		June 30, 2006		Sept. 30, 2005		
	Volume	**Weighting**	Volume	Weighting	Volume	Weighting	% Volume 2006 to 2005 quarterly change
Light to medium oil (bbl/d)[(1)]	**28,394**	**46%**	28,951	48%	18,868	50%	50%
Heavy oil (bbl/d)	**13,919**	**22%**	13,037	22%	13,735	37%	1%
Total oil (bbl/d)	**42,313**	**68%**	41,988	70%	32,603	87%	30%
Natural gas liquids (bbl/d)	**2,595**	**4%**	2,016	3%	850	2%	205%
Total liquids (bbl/d)	**44,908**	**72%**	44,004	73%	33,453	89%	34%
Natural gas (mcf/d)	**103,618**	**28%**	96,848	27%	24,574	11%	322%
Total oil equivalent (boe/d)	**62,178**	**100%**	60,145	100%	37,549	100%	66%

	Nine months ended				
	Sept. 30, 2006		Sept. 30, 2005		
	Volume	**Weighting**	Volume	Weighting	% Volume Change
Light to medium oil (bbl/d)[(1)]	**27,136**	**46%**	16,618	46%	63%
Heavy oil (bbl/d)	**14,003**	**24%**	13,906	39%	1%
Total oil (bbl/d)	**41,139**	**70%**	30,524	85%	35%
Natural gas liquids (bbl/d)	**2,111**	**4%**	810	2%	161%
Total liquids (bbl/d)	**43,250**	**74%**	31,334	87%	38%
Natural gas (mcf/d)	**91,379**	**26%**	26,839	13%	240%
Total oil equivalent (boe/d)	**58,480**	**100%**	35,807	100%	63%

(1) Harvest classifies our oil production, except that produced from Hay River, as light to 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 third quarter of 2006, average production was higher than the same period in 2005 due to the acquisition of Viking in February of 2006 and the Hay River properties during the third quarter of 2005 plus our acquisition of Birchill in the third quarter of 2006. As a result, third quarter 2006 production is more comparable to the second quarter of 2006 than the third quarter of 2005.

Light to medium oil production is down from the second quarter of 2006 due to reduced production in the Hay River area, as the new wells, which were drilled in the first quarter, are coming off their initial production rates as expected, and in the Bellshill area due to power disruptions in the third quarter impacting production. These production decreases were partially offset by production increases attributed to the Birchill acquisition in August 2006.

Heavy oil production for the third quarter of 2006 increased by 7% to 13,919 boe/d compared to 13,037 boe/d for the second quarter of 2006, which is attributable to new wells coming on stream in the Lloydminster and Hayter areas. Heavy oil production for the three and nine months ended September 30, 2006 compared to the same period in 2005 remained relatively consistent as the incremental production added from the Viking assets and our 2006 drilling program was offset by downtime in the Suffield, Hayter and Killarney areas in the second quarter, and coupled with normal production declines.

Natural gas production in the third quarter of 2006 of 103,618 mcf/d is 322% higher compared to production of 24,574 mcf/d for the third quarter of 2005, primarily due to the acquisition of Viking in 2006 and our acquisition in August 2006, which was weighted towards natural gas. Production for the nine months ended September 30, 2006 is 240% or 64,540 mcf/d higher than it was for the nine months ended September 30, 2005. Our third quarter natural gas production was 7% higher than the second quarter of 2006 due to our Birchill acquisition in August 2006 and was partially offset by lower production volumes in the Markerville area, where approximately 3,500 boe/d of production was shut-in for the month of July and the first week of August following a fire at a non-operated gas processing facility.

Our production mix reflects the acquisition of the Viking properties and the Hay River acquisition in prior periods. Prior to these acquisitions, we were weighted 39% heavy oil with only 14% natural gas weighting. With these acquisitions and the Birchill acquisition in August 2006, our product mix changed such that approximately 22% of our production is weighted towards heavy oil and 28% 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)	**Sept. 30, 2006**	June 30, 2006	Sept. 30, 2005	2006 to 2005 Quarter Change
Light / medium oil sales	**$ 174,083**	$172,043	$ 114,060	53%
Heavy oil sales	**70,541**	67,300	66,170	7%
Natural gas sales	**54,855**	58,045	24,157	127%
Natural gas liquids sales and other	**14,701**	11,622	4,241	247%
Total sales revenue	**314,180**	309,010	208,628	51%
Realized risk management contract losses[(1)]	**(28,361)**	(24,118)	(23,652)	20%
Net revenues including realized risk management contract losses	**285,819**	284,892	184,976	55%
Realized electricity price risk management contract gains	**4,329**	258	1,470	195%
Unrealized risk management contracts (losses) / gains	**77,078**	(115)	(3,948)	(2,052%)
Net Revenues, before royalties	**367,226**	285,035	182,498	101%
Royalties	**(54,362)**	(51,907)	(38,974)	39%
Net Revenues	**$ 312,864**	$233,128	$ 143,524	118%

	Nine months ended		
(000)	**Sept. 30, 2006**	Sept. 30, 2005	Change
Light / medium oil sales	**$ 460,249**	$ 258,806	78%
Heavy oil sales	**185,828**	151,764	22%
Natural gas sales	**166,344**	60,896	173%
Natural gas liquids sales and other	**35,044**	10,206	243%
Total sales revenue	**847,465**	481,672	76%
Realized risk management contract losses[(1)]	**(61,687)**	(66,038)	(7%)
Net revenues including realized risk management contract losses	**785,778**	415,634	89%
Realized electricity price risk management contract gains	**5,064**	1,783	184%
Unrealized risk management contracts (losses) / gains	**35,966**	(73,524)	(149%)
Net Revenues, before royalties	**826,808**	343,893	140%
Royalties	**(149,384)**	(81,824)	83%
Net Revenues	**$ 677,424**	$ 262,069	158%

[(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 September 30, 2006 while relatively unchanged from the second quarter of 2006, was $60.0 million (or 53%) higher than in the prior year as a result of a 2% favourable price variance and a 51% favourable volume variance. The favorable volume variances over the prior year are primarily due to the addition of production volumes from the acquisition of Viking and Birchill in 2006 and the Hay River property in the third quarter of 2005 as well as the focus of our drilling program which is focused on light to medium oil production.

Due to our significant property acquisitions since August 2005 (Viking and Hay River) it is more relevant to compare the third quarter of 2006 to the second quarter of 2006. Light to medium oil revenue for the third quarter of 2006 increased by $2.0 million (or 1%) over the prior quarter. This increase is attributed to a $3.5 million favourable price variance and a $1.5 million unfavourable volume variance. The volume variance between the second and third quarter of 2006 is attributed to reduced production in the Hay River area due to new wells drilled in the first quarter coming off their initial production rates as expected and due to power disruptions in the Bellshill area.

For the nine months ended September 30, 2006, our light to medium oil revenue increased by $201.4 million (or 78%). The increase is attributed to a $37.6 million favourable price variance and a $163.8 million favourable volume variance due to the rising Edmonton Par and Bow River prices. Similarly, favourable volume variances are expected due to the Viking and Hay River acquisition and the Birchill acquisition in August 2006.

Heavy oil sales for the three months ended September 30, 2006 increased $4.4 million (or 7%) compared to the same period in the prior year due to a favourable price variance of $3.5 million and a favourable volume variance of $0.9 million. The rising crude oil price environment, including narrowing heavy oil differentials, resulted in higher realized prices on our heavy oil. Heavy oil revenues in the third quarter of 2006 were $3.2 million (or 5%) higher than the prior quarter as a result of an unfavourable price variance of $2.1 million and a favourable volume variance of $5.3 million. The increased in production in the third quarter is the result of downtime in Killarney and Hayter during the second quarter of 2006. For the nine months ended September 30, 2006 our heavy oil revenue increased by $34.1 million (or 22%) over the prior year due to a favourable price variance of $33.0 million and a favourable volume variance of $1.1 million.

Natural gas sales revenue increased by $30.7 million (or 127%) for the three months ended September 30, 2006 over the prior year due to an unfavourable price variance of $47.0 million and a favourable volume variance of $77.7 million. The favourable volume variance is entirely attributed to the incremental gas production from the Viking properties and the Birchill acquisition in August. For the nine months ended September 30, 2006, natural gas sales increased by $105.4 million (or 173%) over the same period in the prior year. The increase is attributed to an unfavourable price variance of $41.0 million and a favourable volume variance of $146.4 million substantially attributed to the Viking acquisition.

For the three and nine months ended September 30, 2006, natural gas liquids revenues increased by $10.5 million (or 247%) and $24.8 million (or 243%), respectively, over the same periods in the prior year with the increase generally due to a higher pricing environment and additional production volumes from the Viking properties.

Risk Management Contracts

Details of our risk management contracts at September 30, 2006, are included in Note 12 of the consolidated financial statements for the three and nine months ended September 30, 2006. The table below provides a summary of net gains and losses on risk management contracts:

	Three months ended					
	September 30, 2006					Sept. 30, 2005
(000s)	Oil	Gas	Currency	Electricity	Total	Total
Realized (losses) / gains on risk management contracts	$ (30,006)	$ 1,143	$ 502	$ 4,329	$ (24,032)	$ (22,182)
Unrealized (losses) / gains on risk management contracts	73,405	314	3,688	(361)	77,046	(3,185)
Amortization of deferred charges relating to risk management contracts	-	-	-	-	-	(1,207)
Amortization of deferred gains relating to risk management contracts	-	-	-	32	32	444
Total (losses) / gains on risk management contracts	$ 43,399	$ 1,457	$ 4,190	$ 4,000	$ 53,046	$ (26,130)

	Nine months ended					
	September 30, 2006					Sept. 30, 2005
(000s)	Oil	Gas	Currency	Electricity	Total	Total
Realized (losses) / gains on risk management contracts	$ (66,462)	$ 3,012	$ 1,763	$ 5,064	$ (56,623)	$ (64,255)
Unrealized (losses) / gains on risk management contracts	28,947	(293)	9,858	(2,911)	35,601	(65,307)
Amortization of deferred charges relating to risk management contracts	-	-	-	-	-	(9,551)
Amortization of deferred gains relating to risk management contracts	-	-	-	365	365	1,334
Total (losses) / gains on risk management contracts	$ (37,515)	$ 2,719	$ 11,621	$ 2,518	$ (20,657)	$ (137,779)

Our total realized loss on oil and gas price and currency exchange risk management contracts was $28.4 million (or $4.96 per boe) for the three months ended September 30, 2006 compared to $23.7 million (or $6.85 per boe) for the same period in 2005. For the nine months ended September 30, 2006 we recorded a realized loss on oil and gas and currency exchange risk management contracts of $61.7 million (or $3.86 per boe), a decrease of $4.3 million over the realized loss on oil and gas and currency exchange risk management contracts for the nine months ended September 30, 2005 of $66.0 million (or $6.76 per boe).

Our realized loss on oil price contracts for the third quarter of 2006 was $30.0 million compared to $24.0 million in the third quarter of 2005. The increase in our loss is primarily a result of high oil prices in the third quarter of 2006. Our total realized loss on oil contracts includes the impact of the heavy oil differential contracts in place in the third quarter of 2006, with realized losses on these contracts of $3.5 million (or $0.60 per boe) attributed to a narrowing of heavy oil differentials to 25.8% as compared to the contracted differentials of approximately 28-29%. For the three months ended September 30, 2005, we had losses of $2.3 million (or $0.66 per boe) on the heavy oil differential contracts in place when heavy oil differential averaged 28.2%. A slightly lower loss than that realized in the third quarter of 2005 due to the contracted heavy oil differential of 28-29% being approximately the same as that realized in the market. Typically, heavy oil differentials are narrower in the second and third quarter as demand for heavier oil is higher due to paving activity occurring during these times. For the third quarter of 2006, approximately 23,750 bbl/d or approximately 70%, of our net oil production was covered by oil price contracts.

Our total realized loss on oil price risk management contracts for the nine months ended September 30, 2006 was $66.5 million compared to $67.0 million for the same period in 2005. Our realized loss for the nine months ended September 30, 2006 included a $3.6 million (or $0.22 per boe) gain on our heavy oil differential contracts. For the same period in 2005 we incurred a loss of $2.2 million (or $.22 per boe), as these contracts only came into effect at the beginning of the third quarter of 2005 when heavy oil differentials are typically narrow.

We have entered into currency exchange contracts that fix the foreign exchange rate on a portion of our oil revenue. For the three months ended September 30, 2006, we realized gains on our currency exchange contracts of $502,000 or $0.09 per boe ($332,000 or $0.10 per boe for the three months ended September 30, 2005). For the nine months ended September 30, 2006, realized gains on our currency exchange contracts were $1.8 million or $0.11 per boe ($1.0 million or $0.10 per boe for the nine months ended September 30, 2005). During the third quarter we have entered into two foreign exchange contracts for 2007 and one for 2008, details of which are outlined in Note 12 to our third quarter consolidated financial statements. In the third quarter we also entered into shorter term foreign exchange contracts to fix US$750 million of the purchase price we paid for the acquisition of the refinery.

For the three and nine months ended September 30, 2006, we realized gains on our gas price risk management contracts of $1.1 million (or $0.20 per boe) and $3.0 million (or $0.19 per boe), respectively. For the third quarter of 2006, approximately 30,000 GJ/d or 29% of our gas production was covered by financial gas price risk management contracts. We did not have any gas price risk management contracts in 2005.

We have also entered into risk management contracts that provide protection from rising power costs. We realized gains on these contracts of $4.3 million (or $0.76 per boe) and $5.1 million (or $0.32 per boe) for the three and nine months ended September 30, 2006, respectively. For the same periods in 2005, our realized gain was $1.5 million (or $0.43 per boe) and a gain of $1.8 million (or $0.18 per boe), respectively. Additional details on these contracts is provided under the heading "Operating Expense" of this MD&A.

The unrealized gains on our risk management contracts for the three and nine months ended September 30, 2006, excluding amortization of deferred gains, was $77.0 million (or $13.47 per boe) and $35.6 million (or $2.23 per boe), respectively. For the three and nine months ended September 30, 2005, there was a loss of $3.2 million (or $0.92 per boe) and a loss of $65.3 million (or $6.68 per boe), respectively. Collectively, our risk management contracts had an unrealized mark-to-market deficiency of $18.1 million as at September 30, 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 gain in the nine month period ended September 30, 2006. Included within our total unrealized gains on risk management contracts for the three and nine months ended September 30, 2006 is $3.7 million and $9.9 million relating to unrealized gains on our currency exchange risk management contracts. In the third quarter we entered into three additional foreign exchange contracts to fix a portion of our exposure to fluctuations in the foreign exchange rate between the Canadian and the U.S. dollar in 2007 and 2008. In addition, in anticipation of the closing of the refinery acquisition we entered into a series of swaps and forward purchase contracts for US$750 million to be settled in October 2006. In the third quarter of 2006, the total unrealized gain of $3.7 million is comprised of a loss on foreign exchange contracts relating to 2007 and 2008 of $3.3 million and a gain on the contract entered into relating to the refinery purchase of $7.0 million. Refer to Note 12 to the consolidated financial statements for further details of the financial instruments outstanding at September 30, 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 $32,000 and $365,000 of our total unrealized gains on risk management contracts for the three and nine months ended September 30, 2006 and an expense of $444,000 and $1.3 million for the three and nine months ended September 30, 2005. These amounts are discussed further under the heading "Deferred Charges and Credits".

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.

For the three and nine months ended September 30, 2006, our net royalties as a percentage of gross revenue were 17.3% (18.7% - three months ended September 30, 2005) and aggregated to $54.4 million ($39.0 million – three months ended September 30, 2005). Royalty rates are driven by productivity and price. The decrease in the royalty rate is attributable to lower royalty rates in the Hazelwood and Hayter area in the third quarter of 2006 relative to the same period in 2005, as new wells in these areas in the third quarter of 2005 were incurring royalty rates at the upper end of the royalty scale. For the nine months ended September 30, 2006, our net royalties as a percentage of gross revenue were 17.6% (17.0% - nine months ended September 30, 2005) and aggregated to $149.4 million ($81.8 million – nine months ended September 30, 2006). An increase in the royalty rate is due to the higher rates associated with the Viking assets acquired in February 2006 (royalty rates of approximately 18%) 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 affect the first quarter of 2006 but not the first quarter in the prior year.

Operating Expense

	Three months ended			**Nine months ended**	
($000s)	**Sept. 30, 2006**	June 30, 2006	Sept. 30. 2005	**Sept. 30, 2006**	Sept. 30, 2005
Operating expense					
Power	**$ 17,491**	$ 12,227	$ 9,617	**$ 41,746**	$ 25,263
Workovers	**13,203**	12,843	6,543	**35,392**	22,405
Repairs and maintenance	**5,762**	7,317	3,158	**17,707**	8,445
Labour – internal	**5,260**	5,912	1,542	**15,105**	5,766
Processing fees	**4,991**	4,774	766	**14,094**	3,960
Fuel	**1,710**	2,382	1,382	**6,121**	3,722
Labour – external	**3,239**	3,541	1,105	**9,775**	4,604
Land leases and property tax	**6,193**	4,355	2,994	**15,119**	5,973
Other	**4,640**	7,242	5,278	**18,117**	7,984
Total operating expense	**62,489**	60,593	32,385	**173,176**	88,122
Realized gains on power risk management contracts	**(4,329)**	(258)	(1,470)	**(5,064)**	(1,783)
Net operating expense	**$ 58,160**	$ 60,335	$ 30,915	**$ 168,112**	$ 86,339
Transportation and marketing expense	**$ 3,535**	$ 4,065	$ 56	**$ 9,223**	$ 302
Net operating Expense ($/boe)	**$ 10.17**	$11.02	$ 8.95	**$ 10.53**	$ 8.83
Transportation and marketing expense ($/boe)	**$ 0.62**	$ 0.74	$ 0.02	**$ 0.58**	$ 0.03

Total operating expense increased by $30.1 million (or 93%) and $85.1 million (or 97%) respectively for the three and nine months ended September 30, 2006 compared to the same periods in the prior year. For the three months ended September 30, 2006, approximately $25.7 million of the increase ($50.1 million for the nine months ended September 30, 2006) is due to increased activity associated with the Viking properties acquired in February 2006. The remainder of the increase is attributed to increased power costs, and the continued high demand for oilfield services leading to higher costs for well servicing, workovers and well maintenance. The increases in total operating expenses for the nine months ended September 30, 2006 compared to the same period in the prior year are attributed to incremental operating costs attributed to the Viking, Hay River and the Birchill acquisition, costs associated with incremental drilling activities and generally higher costs in the industry.

Our operating expenses will benefit from our capital spending program, a portion of which is directed towards operating cost reduction initiatives such as the water disposal and fluid handling project in Suffield where we incurred approximately $10 million in capital expenditures to enable us to operate high water cut wells more economically. These projects, combined with the acquisition of Birchill in August 2006, which has lower operating costs per boe will assist in offsetting the cost pressures in the oil and gas services industry.

Our transportation costs of $2.9 million ($56,000 – three months ended September 30, 2005) and $7.4 million ($302,000 – nine months ended September 30, 2005) for the three and nine months ended September 30, 2006, respectively, are primarily related to delivering natural gas to Alberta's natural gas sales hub, the AECO Storage Hub, and to a lesser extent, our costs of trucking crude oil to pipeline receipt points. Marketing costs relate to those amounts charged for our marketing function which is outsourced.

The addition of the Viking properties and the Hay River properties to our portfolio significantly impacts comparability between the third quarter of 2006 and the third quarter of 2005. For a better comparison, our third quarter of 2006 operating expenses increased by $1.9 million compared to the second quarter of 2006. The most significant portion of the increase (approximately $1.3 million) is attributable to having two months of operating expenses related to the properties acquired in the Birchill acquisition which occurred in the third quarter of 2006, which was partially offset by lower repairs and maintenance activity as most of the servicing costs were incurred in the second quarter.

Electricity costs represent a significant portion of our total operating costs (approximately 28% in the third quarter of 2006 and 24% year to date). In the third quarter of 2006, electricity costs per megawatt hour ("MWh") were 42% higher than they were in the third quarter of 2005. These increases were offset by the Viking properties which have lower power usage per boe of production, and the Hay River properties which operate using internally generated power. The combination of these two factors, as well as the impact of our fixed price electricity contracts, has resulted in a lower per boe power cost despite rising prices. For the nine months ended September 30, 2006, we are seeing similar results. With a 25% increase in the per MWh cost of power we experienced only a 1% increase in our per boe power costs which is attributed to the same factors noted above. The following table details the power costs per boe before and after the impact of our hedging program.

	Three months ended				**Nine months ended**		
($ per boe)	**Sept. 30, 2006**	June 30, 2006	Sept. 30, 2005	2006 to 2005 Quarter Change	**Sept. 30, 2006**	Sept. 30, 2005	Change
Power costs	**$ 3.06**	$ 2.23	$ 2.78	10%	**$ 2.61**	$ 2.58	1%
Realized gains on electricity risk management contracts	**(0.76)**	(0.05)	(0.43)	77%	**(0.32)**	(0.18)	78%
Net power costs	**$ 2.30**	$ 2.18	$ 2.35	(2%)	**$ 2.29**	$ 2.40	(5%)
Alberta Power Pool electricity price ($ per MWh)	**$ 94.74**	$ 53.59	$ 66.79	42%	$ 68.36	$54.72	25%

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

	Three months ended		Nine months ended	
($ per boe)	**Sept. 30, 2006**	Sept. 30, 2005	**Sept. 30, 2006**	Sept. 30, 2005
Revenues	**$ 54.92**	$ 60.39	**$ 53.08**	$ 49.27
Realized loss on risk management contracts(1)	**(4.96)**	(6.85)	**(3.86)**	(6.76)
Royalties	**(9.50)**	(11.28)	**(9.36)**	(8.37)
As a percent of revenue	**17.30%**	18.68%	**17.63%**	16.99%
Operating expense(2)	**(10.17)**	(8.96)	**(10.53)**	(8.87)
Transportation expense	**(0.62)**	(0.02)	**(0.58)**	(0.03)
Operating netback(3)	**$ 29.67**	$ 33.28	**$ 28.75**	$ 25.24

(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 $0.76 per boe and $0.43 per boe for the three months ended September 30, 2006 and 2005 and $0.32 and $0.18 for the nine months ended September 30, 2006 and 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 $3.61 per boe lower and $3.51 per boe higher for the three and nine months ended September 30, 2006, respectively, than for the same periods of 2005. Lower natural gas prices in 2006 more than offset gains in oil prices resulting in a lower realized price per boe by $5.47/boe ($3.81/boe increase for the nine month period), which were partially offset by lower losses realized on our price risk management program of $1.89/boe ($2.90/boe for the nine month period). For the third quarter of 2006 we realized lower royalties by $1.78/boe ($0.99/boe higher for the nine month period) and higher operating costs (including transportation) of $1.81/boe ($2.21/boe for the nine month period).

General and Administrative (G&A) Expense

	Three months ended				Nine months ended		
($000s except per boe)	**Sept. 30, 2006**	June 30, 2006	Sept. 30, 2005	2006 to 2005 Quarter Change	**Sept. 30, 2006**	Sept. 30, 2005	Change
Cash G&A(1)	**$ 6,962**	$ 7,756	$ 3,773	85%	**$ 20,771**	$ 9,970	108%
Unit based compensation expense	**538**	757	9,198	(94%)	**1,054**	15,076	(93%)
Total G&A	**$ 7,500**	$ 8,513	$ 12,971	(42%)	**$ 21,825**	$ 25,046	(13%)
Cash G&A per boe ($/boe)	**1.22**	1.42	1.09	12%	**1.30**	1.02	27%
Transaction costs							
Unit based compensation expense	**-**	330	-	-	**8,974**	-	100%
Severance and other	**-**	-	-	-	**3,098**	-	100%
Total Transaction costs	**$ -**	$ 330	$ -	-	**$ 12,072**	$ -	100%

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

For the three months ended September 30, 2006, Cash G&A costs increased by $3.2 million (or 85%) compared to the same period in 2005. For the nine months ended September 30, 2006, Cash G&A increased by $10.8 million (or 108%). The increase is attributed mainly to increased staffing levels due to the Viking acquisition. Approximately $4.4 million (or 63%) of our third quarter 2006 Cash G&A and $13.5 million (or 65%) of our nine months ended September 30, 2006 Cash G&A expenses are related to salaries and other employee related costs while in the third quarter of 2005 only $1.8 million (or 48%) of our Cash G&A and $5.3 million (or 53%) of our nine months ended September 30, 2005 was made up of these costs. The acquisition of Viking in February 2006 doubled our overall staffing levels, adding approximately 100 additional employees. The remainder of the increases in the three and nine months ended September 30, 2006 compared to the same periods in 2005 are due to the work undertaken for compliance with the Sarbanes Oxley Act and generally higher costs in the industry. In particular, for the nine months ended September 30, 2006, our Cash G&A costs include $826,000 of bonus payments relating to 2005 and $560,000 of costs incurred for third party consultants incurred to evaluate acquisition opportunities that have subsequently been abandoned.

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 three months ended September 30, 2006 was $0.5 million, consisting of $1.3 million of cash compensation, $1.4 million of unit settled compensation and a $2.2 million non-cash recovery. Our total unit based compensation expense for the nine months ended September 30, 2006, including $9.0 million allocated to transaction costs, was $10.0 million, consisting of $8.3 million of cash compensation, $8.8 million of unit settled compensation and a $7.1 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 $33.21 at June 30, 2006, and at September 30, 2006 our trust unit price had decreased to $30.25. As a result, we have recorded a recovery on unexercised UARs at September 30, 2006. Our total unit based compensation expense, including that portion which has been allocated to transaction costs, decreased by $8.7 million for the three month period ended September 30, 2006 and decreased by $5.0 million for the nine month period ended September 30, 2006 over the same period in the prior year.

We have recorded transaction costs of $12.1 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 $9.0 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

	Three months ended				**Nine months ended**		
($000s except per boe)	**Sept. 30, 2006**	June 30, 2006	Sept. 30, 2005	2006 to 2005 Quarter Change	**Sept. 30, 2006**	Sept. 30, 2005	Change
Interest on short term debt	$ **-**	$ -	$ 1,083	(100%)	**$ -**	$ 3,953	(100%)
Amortization on deferred charges – short term debt	**-**	-	-	-	**-**	2,499	(100%)
Total interest on short term debt	**-**	-	1,083	(100%)	**-**	6,452	(100%)
Interest on long-term debt							
Senior notes	**5,488**	5,573	6,050	(9%)	**16,785**	18,236	(8%)
Convertible debentures	**4,674**	4,623	924	406%	**12,593**	1,730	628%
Bank loan	**5,797**	3,013	-	100%	**10,263**	-	100%
Amortization of deferred charges – long term debt	**726**	772	708	3%	**2,932**	1,494	96%
Total interest on long term debt	**16,685**	13,981	7,682	117%	**42,573**	21,460	98%
Total interest expense	**$16,685**	$ 13,981	$ 8,765	90%	**$ 42,573**	$ 27,912	53%

Interest expense for the three and nine months ended September 30, 2006 was higher by $7.9 million and $14.7 million, respectively than for the same period in the prior year primarily due to additional convertible debentures outstanding in the second half of 2005, and convertible debentures assumed with our acquisition of Viking. Compared to the second quarter of 2006, the current quarter interest expense is $2.7 million higher due to an increase in the bank loan as a result of the acquisition of Birchill.

Interest expense includes 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 determined using a floating rate based on banker's acceptances plus 65 to 115 basis points based on our Senior Debt to Cash Flow ratio. Our interest expense on bank loans has increased by approximately $4.7 million and $6.3 million respectively for the three and nine months ended September 30, 2006 as compared to the same period in 2005, due to our merger with Viking, when we assumed approximately $106.2 million and the acquisition of Birchill which resulted in additional bank debt of approximately $232.6 million.

Subsequent to September 30, 2006 we expanded our three year revolving credit facility to $1.4 billion, and arranged for a $350 million secured bridge facility and a $450 million unsecured bridge facility. The additional financing was completed in connection with the purchase of the shares of North Atlantic Refinery Limited. Further details on the expanded credit facility and the bridge financing are included under "Liquidity and Capital Resources".

At September 30, 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 and nine months ended September 30, 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 and nine months ended September 30, 2006, is $3.8 million and $10.9 million higher respectively, compared to the same period in 2005, as it includes interest expense on approximately $202.5 million of additional convertible debentures that have been assumed with the merger with Viking on February 3, 2006, as well as a full period of interest expense on approximately $37.9 million of the remaining balance of the $75 million, 6,5% convertible debentures that were issued by Harvest in the third quarter of 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 interest expense in the third quarter of 2006, as a full three months of interest expense on the convertible debentures assumed in the Viking's acquisition has been incurred in the quarter. During the quarter, $5.4 million of convertible debentures were converted into 193,186 trust units ($12.5 million convertible debentures converted to 466,466 trust units for the nine months ended September 30, 2006).

Our U.S. dollar denominated senior notes, which bear interest at 7 7/8%, mature on October 15, 2011 and have an early redemption feature, provide an offset to fluctuations in currency exchange rates. Interest expense for the three and nine months ended September 30, 2006 on these notes has remained relatively consistent with the same period in 2005, 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 $1.1 million and $4.0 million for the three and nine months ended September 30, 2006, respectively ($0.9 million and $4.3 million for the three and nine months ended September 30, 2005).

Depletion, Depreciation and Accretion Expense

	Three months ended				Nine months ended		
(000s except per boe)	**Sept. 30, 2006**	June 30, 2006	Sept. 30, 2005	Change	**Sept. 30, 2006**	Sept. 30, 2005	Change
Depletion and depreciation	**$ 106,922**	$ 88,886	$ 40,356	165%	**$ 273,203**	$109,320	150%
Depletion of capitalized asset retirement costs	**4,219**	4,230	6,228	(32%)	**12,731**	11,597	10%
Accretion on asset retirement obligation	**4,082**	4,062	2,385	71%	**11,792**	7,026	68%
Total depletion, depreciation and accretion	**$ 115,223**	$ 97,178	$ 48,969	135%	**$ 297,726**	$127,943	133%
Per boe ($/boe)	**20.14**	17.76	14.18	42%	**18.65**	13.09	42%

Our overall depletion, depreciation and accretion (DD&A) expense for the three and nine months ended September 30, 2006 is $66.3 million and $169.8 million higher compared to the same period in 2005. An increase of $32.1 million of the increase for the three months ended September 30, 2006 ($81.0 million for the nine months ended September 30, 2006) 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 $34.2 million of the increase for the three months ended September 30, 2006 ($88.8 million for the nine months ended September 30, 2006) 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

Currency 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 September 30, 2006, the Canadian dollar strengthened against the U.S. dollar compared to December 31, 2005, and we incurred an unrealized gain on our senior notes of $11.3 million, as well as realized gains on other U.S. denominated transactions of $1.0 million, which was partially offset by unrealized losses on U.S. dollar deposits of $1.0 million for a total currency exchange gain of $11.3 million reported in the first nine month of 2006.

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 relating to the issuance of the senior notes, convertible debentures and bank debt are amortized over the life of the corresponding debt. The following table provides a summary of the components of the deferred charges at September 30, 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**	**$ -**	**$ -**	**$12,768**
Additions	1,183	-	931	-	2,114
Transferred to Unit issue costs on conversion of debentures	(169)	-	-	-	(169)
Amortization	(2,925)	(222)	(149)	-	(3,296)
Balance, September 30, 2006	**$ 9,153**	**$ 1,482**	**$ 782**	**$ -**	**$ 11,417**

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 September 30, 2006 our deferred credit balance was $0.9 million of which $32,000 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 $832,000, 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 recorded when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of that acquired business. At September 30, 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 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 and nine months ended September 30, 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. For the three and nine months ended September 30, 2006 we recorded a future income tax recovery of nil and $2.3 million respectively ($1.2 million expense and $28.6 million recovery for the three and nine months ended September 30, 2005). The significant recovery in the nine months ended September 30, 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 $82.5 million in the nine months ended September 30, 2006. As a result of the merger with Viking, we added $60.5 million to our ARO, and the remainder of the increase in the year to date is due to additions resulting from the acquisition of Birchill, drilling activity in the first nine months of the year, an increased estimate of existing liabilities, and accretion expense, offset by actual asset retirement expenditures made in the period.

Non-Controlling Interest

The non-controlling interest represents the value attributed to outstanding exchangeable shares of Harvest Operations. 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 from January 1, 2006 to June 19, 2006, leaving a balance of 26,902 outstanding at June 19, 2006 compared to a balance of 182,969 at December 31, 2005.

On March 16, 2006, we announced our intent to exercise our de minimus redemption right on the remaining 26,902 exchangeable shares outstanding. As a result, each redeemed exchangeable share was purchased for a total cash payment of $1.0 million.

The net income attributed to non-controlling interest holders for the three months ended September 30, 2006 was nil ($219,000 for the three months ended September 30, 2005) versus a gain of $65,000 for the nine months ended September 30, 2006 ($156,000 gain for the nine months ended September 30, 2005).

Liquidity and Capital Resources

At the end of the Third Quarter of 2006, our bank borrowings totaled $591.2 million, an increase of $363.6 million during the quarter. The principal components of the increase in bank borrowings were the partial funding of our acquisition of Birchill accounting for $232.4 million plus the US$100 million (CDN$111.3 million) performance deposit required for our agreement to purchase a 115,000 barrel per stream day crude oil refinery and related marketing business with the residual used to fund capital expenditures.

During the three months ended September 30, 2006, our Cash Flows totaled $147.5 million, excluding $516,000 of one time cash transition costs, consistent with $147.0 million, after excluding $670,000 of one time cash transition costs, in the second quarter of 2006. Distributions, net of participation in our reinvestment plans, totaled $73.6 million while our capital expenditures totaled $129.1 million resulting in a $55.2 million deficiency which has been partially funded by bank borrowings. Our working capital deficiency of $48.4 million at the end of the third quarter 2006 as compared to a deficiency of $6.6 million at the end of June 2006 also reflects the impact of this higher level of capital spending. During the first nine months of 2006, Cash Flow totaled $395.5 million with cash distributions paid to unitholders totaling $184.7 million resulting in $210.8 million remaining to fund capital expenditures of $286.5 million. This compares with $213.4 million of Cash Flow, cash distributions paid of $74.3 million, capital expenditures of $81.0 million and debt repayments of $40.9 million for the comparable period in the prior year.

Distributions declared for the nine months ended September 30, 2006 totaled $333.8 million representing 83% of Cash Flow after excluding $6.3 million of one time cash transaction costs. Of the total distributions declared, $133.8 million have been settled with trust units as a result of unitholders choosing to participate in our distribution reinvestment plans which represents a participation rate of approximately 40%, as adjusted for the one month delay between declaration and payment of distributions. On October 4, 2006, we announced the declaration of a $0.38 per trust unit distribution for each of October, November and December based on forecasted commodity price levels and operating performance that are consistent with the current environment.

On July 26, 2006, we announced a definitive agreement to acquire Birchill for cash consideration of $451.0 million which was ultimately funded through $218.6 million of net proceeds from the issuance of 7,026,500 trust units at a price of $32.75 per trust unit and $232.4 million of bank borrowings. The operations of this acquisition have been included in Harvest consolidated results commencing July 26, 2006, the date of signing of the definitive agreement.

At the end of September 30, 2006, our Senior Debt to Cash Flow ratio was 1.1 to1.0, the Total Debt (excluding convertible debentures) was 1.7 to 1.0 while the Senior Debt to Total Capitalization was 17% and Total Debt to Total Capitalization was 24%, all within the financial covenants of our credit facilities of less than 3.0, 3.5, 50% and 55%, respectively.

On August 22, 2006, concurrent with our announcement to acquire North Atlantic Refining and related businesses for approximately US$1.4 billion, we announced an increase in our facilities from $900 million to $2.2 billion contingent on the closing of this acquisition. The $2.2 billion credit facility is comprised of a $1.4 billion Three Year Revolving Credit Facility, a $350 million Senior Secured Bridge Facility and a $450 million Senior Unsecured Bridge Facility. The $350 million Senior Secured Bridge Facility requires repayment in full with in 18 months while the $450 million Senior Unsecured Bridge Facility requires repayment in full in 6 months. During the month of September, this $2.2 billion underwritten credit facility was successfully syndicated to include Canada's six chartered banks and seven other well respected global financial institutions. An amended and restated credit agreements supports the increased $1.4 billion Three Year Revolving Credit Facility as well as establishes the $350 million Senior Secured Bridge Facility and maintains the financial covenants and pricing of the previous $900 million facility plus adds a 15 basis point administration fee for the period that the $450 million Senior Unsecured Bridge Facility is outstanding. The $350 million Senior Secured Bridge Facility and the $450 million Senior Unsecured Bridge Facility each require that net proceeds from an issuance of equity, equity-like securities (including convertible debentures) and term debt be applied to reduce these credit facilities.

On August 25, 2006, we entered into contracts to forward purchase US$750 million at a fixed rate of $1.10832 (or $0.9023) to be delivered on October 2, 2006, the then expected closing date of the North Atlantic Refining acquisition. As events unfolded, we rolled this commitment forward to October 19, 2006, the ultimate closing date. Our planned financing for this US$1.4 billion was to fund approximately $800 million from the issuance of equity and equity-like securities, typically raised in Canadian dollars, and the balance in US dollar denominated debt, initially with US dollar bank borrowings and subsequently with longer tenure fixed interest rate US dollar debt. The forward purchase enabled us to fix the currency exchange risk on the anticipated portion of the US$1.4 billion commitment to be funded from the Canadian dollar sources while anticipating that the balance would be financing in US denominated debt for the long term.

On October 19, 2006, we closed the acquisition of the refinery with the payment of approximately US$1,405 million including the release of the US$100 million deposit to the vendor. The additional US$1,305 million was funded from our credit facilities with US$554.7 million borrowed in US dollars bearing interest at the London Inter Bank Offer Rate ("LIBOR") plus 75 basis points, CDN$450 million borrowed under the Senior Unsecured Bridge Facility bearing interest at bankers acceptances plus 240 basis points, CDN$350 million borrowed under the Senior Secured Bridge Facility and CDN$428.5 million under the Three Year Revolving Facility both bearing interest at bankers acceptances plus 75 basis points.

Concurrent with the closing, North Atlantic Refining entered into a Supply and Offtake Agreement with the vendor of North Atlantic Refining which provided that the ownership of substantially all crude oil feedstock and refined product inventory at the refinery be retained by the counterparty to the agreement. The Supply and Offtake Agreement provides North Atlantic Refining with a continuous supply of crude oil feedstock and a commitment to purchase substantially all of the refined product it produces at market prices subject to a US$0.08 per barrel charge on the crude oil supplied and a time value of money fee to reflect the cost of financing the ownership of the crude oil feedstock and the refined product inventory. The cost of financing reflects a charge equivalent to LIBOR plus 350 basis points. This entire agreement may be terminated by either party at the end of an initial two year term and at any time thereafter, by providing notice of termination no later than six months prior to the desired termination date or if the refinery is sold in an arms length transaction, on 30 days notice. Should the Supply and Offtake Agreement be terminated, North Atlantic Refining would be required to purchase the crude oil feedstock committed to the refinery at that time.

On October 25, 2006, we entered into an agreement with a syndicate of underwriters to sell, on a "bought deal" basis, a combination of $400 million principal amount of 6.30% convertible unsecured subordinated debentures (the "Debentures") and 3,150,000 trust units at a price of $31.75 per trust unit to raise gross proceeds of approximately $500 million. We also granted the underwriters an over-allotment option to purchase up to an additional 15% of the Debentures and an additional 15% of trust units at the same offering prices for a period of 30 days following closing of this financing. Pursuant to the requirements of our agreement with the underwriters, we have filed the preliminary prospectus on October 31, 2006. The underwriting agreement includes a provision that entitles each underwriter to terminate and cancel their respective obligations if, among other things, prior to closing, there is announced any changes or proposed change to the income tax laws of Canada or their interpretation or administration which would, in the underwriter's opinion, be expected to have a significant adverse effect on the market price or value of the Debenture and/or trust units.

On October 31, 2006, Canada's Finance Minister announced a proposal to amend the *Income Tax Act* (Canada) to apply a tax on distributions from certain publicly-traded trusts, including Harvest. Under the proposal, certain existing trusts will be subject to the new tax measures commencing in 2011 following a four year grace period. In simplified terms, under the proposed tax amendment, income distributions from certain trusts will first be taxed at the trust level an estimated rate of 31.5%. Such income distributions to unitholders will then be treated as dividends from a taxable Canadian corporation and eligible for the applicable dividend tax credits. The net impact on taxable Canadian unitholders is expected to be minimal.

However, as a result of the 31.5% tax at the trust level, distributions to tax exempt unitholders and non-residents of Canada will be subject to tax.

As of November 8, 2006, we are in discussions with our underwriters and are assessing various alternatives to proceed with our planned issuance of convertible debentures and trust units.

Subsequent to closing our acquisition of North Atlantic Refining, our bank borrowing totaled approximately $2,088 million with $112 million of additional borrowing available under the $1.4 billion Three Year Revolving Credit Facility.

Contractual Obligations and Commitments

We have contractual obligations and commitments in the normal course of operations including purchase of assets and services, operating agreements, transportation commitments, sales commitments, royalty obligations, and land lease obligations. These obligations are of a recurring and consistent nature and impact cash flow in an ongoing manner. We also have contractual obligations and commitments that are of a less routine nature as disclosed in the following table:

		Maturity			
Annual Contractual Obligations (*000s*)	**Total**	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt	**$ 870,614**	$ -	$ -	$ 591,189	$ 279,425
Interest on long-term debt[4]	**186,290**	13,052	104,418	51,457	17,363
Interest on convertible debentures[3]	**84,213**	4,364	31,775	27,548	20,526
Operating and premise leases	**13,663**	1,508	7,076	5,079	-
Capital commitments[5]	**17,041**	5,556	11,485	-	-
Asset retirement obligations[6]	**635,910**	2,226	10,959	15,359	607,366
Total	**$ 1,807,731**	$ 26,706	$ 165,713	$ 690,632	$ 924,680

(1) As at September 30, 2006, we had entered into physical and financial contracts for production with average deliveries of approximately 23,750 barrels of oil equivalent per day in the balance of 2006, 27,500 barrels of oil equivalent per day in 2007 and 5,000 barrels of oil equivalent per day in 2008. 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 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			**Nine months ended**		
(000s)	**Sept. 30, 2006**	Sept. 30, 2005	Change	**Sept. 30, 2006**	Sept. 30, 2005	Change
Development capital expenditures excluding acquisitions and non-cash items	**$ 129,054**	$ 31,655	308%	**$ 286,523**	$ 81,032	254%
Non-cash capital additions (recoveries)	**(236)**	1,939	(112%)	**(409)**	2,974	(114%)
Total development capital expenditures	**128,818**	33,593	283%	**286,114**	84,006	241%
Net property acquisitions	**312**	(839)	(137%)	**23,984**	2,791	759%
Net business acquisitions	**563,561**	210,505	168%	**563,561**	236,505	138%
Total net capital asset expenditures	**$ 692,691**	$ 243,259	185%	**$ 873,659**	$ 323,302	170%

In the third quarter of 2006 we invested $129.1 million into our portfolio of drilling, optimization and enhancement activities compared to $31.7 million in the third quarter of 2005. Approximately 64% of our third quarter expenditures were spent on drilling 76 gross (60 net) wells with a success rate of 97%. A significant portion of our drilling activity focused on oil opportunities as we expect the current strong oil pricing environment to continue. Our most active drilling area was southeast Saskatchewan where we drilled 17 gross (17 net) horizontal wells during the quarter, bringing our total for the year to 28 gross (28 net) wells. At Lloydminster, a successful horizontal well test in 2005 was followed up with the drilling of 9 gross (9 net) horizontal wells to date in 2006, 6 gross (6 net) in the third quarter. At Hayter and Suffield we continue to find incremental oil from the Dina and Glauconitic formations with a total of 9 and 7 gross (8.5 and 7.0 net) infill horizontal wells drilled in the quarter in these two areas. Water handling upgrades at Suffield were also completed during the quarter, which will allow us to optimize production of both existing and newly drilled wells throughout the fourth quarter.

In the first nine months of 2006 we drilled 195 gross wells, with an additional 40 to 50 gross wells planned for the balance of the year. With the acquisition of Birchill in August 2006, we increased our 2006 capital budget by $50 million to $300 million, including $25 million budgeted specifically for the newly acquired properties.

The following summarizes our participation in gross and net wells drilled during the third quarter of 2006:

	Total Wells		**Successful Wells**		**Abandoned Wells**	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
South East Saskatchewan	17	17	17	17	-	-
Hayter	9	8.5	9	8.5	-	-
Suffield	7	7	7	7	-	-
Markerville	6	2.8	6	2.8	-	-
Lloydminster	6	6	6	6	-	-
Red Earth	2	1.6	2	1.6	-	-
Wainwright	-	-	-	-	-	-
Other Areas(1)	29	17.1	27	15.4	2	1.7
Total	76	60	74	58.3	2	1.7

(1) Other areas include locations such as Ferrier, Bashaw, Wilsden Green, Alexis, Parkland, Badger, and Pembina

The following summarizes our participation in gross and net wells drilled for the nine months ended 2006:

	Total Wells		**Successful Wells**		**Abandoned Wells**	
Area	**Gross[1]**	**Net**	**Gross**	**Net**	**Gross**	**Net**
South East Saskatchewan	28	28	28	28	-	-
Hay River	27	26.4	27	26.4	-	-
Markerville	17	7.7	17	7.7	-	-
Wainwright	14	14	14	14	-	-
Hayter	12	11.4	12	11.4	-	-
Suffield	13	13	13	13	-	-
Red Earth	12	10.5	12	10.5	-	-
Lloyd	9	9	9	9	-	-
Other Areas	63	32.7	59	30	4	2.7
Total	195	152.7	191	150	4	2.7

(1) Excludes 14 additional wells that we have an overriding royalty interest in.

Distributions to Unitholders and Taxability

In the third quarter of 2006, we declared distributions of $1.14 per trust unit ($123.1 million) to Unitholders. This represents a 20% increase in distributions declared over the $0.95 per trust unit declared in the third quarter of 2005. The aggregate of distributions declared during the third quarter of $123.1 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 58 million following the acquisition of Viking and the Hay River property and continued DRIP participation.

	Three months ended			Nine months ended		
(000s except per trust unit amounts)	**Sept. 30, 2006**	Sept. 30, 2005	Change	**Sept. 30, 2006**	Sept. 30, 2005	Change
Distributions declared	**$ 123,112**	$ 46,691	164%	**$ 333,813**	$ 108,957	206%
Per trust unit	**$ 1.14**	$ 0.95	20%	**$ 3.39**	$ 2.15	58%
Taxability of distributions (%)	**100%**	100%	-	**100%**	100%	-
Per trust unit	**$ 1.14**	$ 0.95	20%	**$ 3.39**	$ 2.15	58%
Payout ratio (%)[1]	**83%**	45%	38%	**84%**	46%	38%

(1) Cash flow used to calculate payout ratio 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. As such, we expect that the current year distributions to our Unitholders will be 100% taxable.

Outlook

At the end of the Third Quarter of 2006, our exit rate of production was approximately 65,000 boe/day which represents our productive capacity going into the fourth quarter of 2006. Currently, we are managing some disruptions in transportation of crude oil out of northeastern British Columbia as a third party pipeline system experiences temporary operating shutdowns and this will increase our transportation charges in the fourth quarter and will impact on our Hay River production. We anticipate that the fourth quarter production will bring our average daily production for the year to 60,000 boe/d reflecting the inclusion of the Viking Energy Royalty Trust production effective on February 3, 2006 and the acquisition of Birchill effective July 26, 2006.

Our operating costs for the fourth quarter are expected to be approximately $10.20 per boe reflecting the $4.00 per boe average operating cost of Birchill. Further, our fourth quarter unit operating costs will benefit from a higher level of continuous production partially offsetting the cost pressures driven by the record activity levels in Alberta’s oil field service industry.

We expect the WTI benchmark price of crude oil to average approximately US$60 for the fourth quarter with the heavy oil differential to be approximately 35% while the price of AECO gas to average $6.00. With these expectations, we anticipate that our crude oil price risk management contracts with floor price protection of approximately US$45 on 23,750 bbl/day during the fourth quarter to result in approximately $20 million of foregone revenues during the quarter while our natural gas collars will have no impact as our price expectations are within the collared prices.

With third quarter capital spending of $129.1 million bringing our year-to-date spending to $286.5 million, we are now forecasting that capital spending for 2006 will net approximately $325 million including the acceleration of some 2007 budgeted opportunities due to favourable weather conditions in Western Canada and equipment availability.

At the closing, the North Atlantic Refining operations were in a planned maintenance turnaround on several significant processing units. This turnaround is expected to be completed in early November. Subsequent to closing on the acquisition October 19, 2006, we anticipate that the refinery will produce 7.5 million barrels of refined products during the fourth quarter and that the refining margins will range between US$5 and US$7 while operating costs should aggregate to approximately $30 million resulting in an operating contribution of approximately $20 million which should more than offset the capital expenditures and turnaround costs incurred during the period.

We have announced a monthly distribution of $0.38 per trust unit for October, November and December based on our expectation of continued commodity price strength. Our payout ratio is expected to be approximately 85% for 2006 based on an aggregate distribution of $4.53 per trust unit. Currently, our distribution reinvestment plans enjoy a level of participation in excess of 40% and we will use this source of funding to round out the financing of our 2006 capital expenditure program.

On October 19, 2006, we completed our US$1.4 billion acquisition of North Atlantic Refining and funded 100% of the closing with proceeds from our recently increased credit facilities including a 6 month and 18 month bridge facility in the amount of $450 million and $350 million, respectively. On October 26, 2006, we entered in to a $500 million "bought deal" financing the proceeds of which were intended to repay the full amount of the 6 month bridge facility and repay some portion of the 18 month bridge. On October 31, 2006, Canada's Minister of Finance announced a proposal to amend the *Income Tax Act* (Canada) to impose a 31.5% distributions tax on certain publicly-traded trust, including Harvest. This announcement may enable the underwriters' to terminate their obligation to Harvest. As of the date of this MD&A, we remain in discussions with our underwriters and are assessing various alternatives to proceed with our planned issuance of convertible debentures and trust units. A more detailed description of this situation is provided in the Liquidity and Capital Resources section of this MD&A.

We continue to be actively evaluating our portfolio of oil and natural gas properties with an intent to dispose of properties where, in our view, their full value can be realized with the disposition proceeds. We currently have such minor dispositions in progress with aggregate proceeds of approximately $20 million expected. We also are active acquisitors of small properties that are complementary to our core properties provided the economics are supportive. Our annual expectation is that the volumetric gain (or reduction) from this activity will be modest and cash flow neutral. It is unlikely that we will be an active participant in the bidding for large scale properties in western Canada which has become very competitive with a modest supply of attractive opportunities. We anticipate that one of the outcomes of the Government's proposal to implement a 31.5% distribution tax will be to accelerate the rationalization/consolidation of the energy trust sector in western Canada and we expect to be an active participant for the appropriate opportunity.

For 2007, we are expecting upstream production volume to average 65,000 boe/d with unit operating costs of approximately $10.60 per boe supported by a $315 million capital spending program. From North Atlantic Refining, we are expecting throughput capacity to average 114,500 barrels per stream day with a crack spreads averaging US$9.30 and operating costs and capital spending of approximately $95 million and $45 million, respectively. There is no turnaround activity planned for 2007 at the refinery. Provided crude oil commodity prices remain as currently expected by the forward curve, we anticipate that our crude oil price risk management contracts will provide floor protection of approximately US$55 for the benchmark West Texas Intermediate price with a modest cost.

The following table reflects sensitivities of our expected 2007 Cash Flow to the key economic drivers of our business:

	Assumption	Change	Impact on Cash Flow
WTI oil price ($US/bbl)	$ 60.00	$ 5.00	$ 0.03 / Unit
CAD/USD exchange rate	$ 0.90	$ 0.02	$ 0.20 / Unit
AECO daily natural gas price	$ 7.00	$ 1.00	$ 0.28 / Unit
Refinery crack spread (US$/bbl)	$ 9.30	$ 1.00	$ 0.38 / Unit
Operating Expenses (per boe)	$ 10.65	$ 1.00	$ 0.19 / Unit

Summary of Historical Quarterly Results

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

Financial	**2006**			2005				2004
($000s except where noted)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Revenue, net of royalties	**$ 259,818**	$ 257,103	$ 181,160	$ 154,646	$ 169,654	$ 120,263	$ 109,931	$ 106,964
Net income (loss)	**107,768**	60,682	(33,937)	75,638	52,862	19,516	(43,070)	11,600
Per trust unit, basic[2]	**$ 1.01**	$ 0.60	$ (0.41)	$ 1.45	$ 1.09	$ 0.45	$ (1.02)	$ 0.29
Per trust unit, diluted[2]	**$ 0.99**	$ 0.60	$ (0.41)	$ 1.42	$ 1.08	$ 0.44	$ (1.02)	$ 0.27
Cash Flows[1]	**147,471**	147,010	100,971	96,431	103,508	57,217	52,687	52,870
Per trust unit, basic[1]	**$ 1.39**	$ 1.45	$ 1.23	$ 1.84	$ 2.14	$ 1.32	$ 1.25	$ 1.31
Per trust unit, diluted[1]	**$ 1.34**	$ 1.43	$ 1.22	$ 1.81	$ 2.09	$ 1.29	$ 1.19	$ 1.18
Distributions per Unit, declared	**$ 1.14**	$ 1.14	$ 1.11	$ 1.05	$ 0.95	$ 0.60	$ 0.60	$ 0.60
Total long term financial liabilities	**1,105,728**	746,840	735,896	349,074	386,124	455,163	321,534	326,250
Total assets	**4,076,771**	3,455,918	3,470,653	1,308,481	1,327,272	1,117,792	1,079,269	1,050,483
Total production (boe/d)	**62,178**	60,145	53,014	38,834	37,549	34,463	35,386	37,215

(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 as shown above. The significantly higher revenue in the second and third quarter of 2006 over the preceding quarters is due to the incremental revenue recorded from the Viking assets acquired in February of 2006 and a rising commodity price environment.

Cash flows have also steadily risen over the same period, with marked increases in the second and third quarter of 2006 due to strong commodity prices, narrower heavy oil differentials and the realization of the full benefits of the merger with Viking on our Cash Flows. We also experienced an increased in Cash Flows in the third quarter of 2005 when we benefited from higher production from the Hay River acquisition, stronger crude oil prices and narrower heavy oil differentials early in the quarter. However, this trend did not continue into the fourth quarter of 2005 as a result of decreased commodity prices, and widening heavy oil differentials, which continued into the first quarter of 2006 and also impacted Cash Flows. In the second and third quarters of 2006, Cash Flows were positively impacted by higher commodity prices, lower heavy oil differentials and a full quarter of production from the Viking Energy Royalty Trust assets acquired in February of 2006. The most significant increases in revenue occurred between the first and second quarter of 2006, due to unprecedented commodity prices and the impact of the Viking acquisition that occurred in the first quarter. The general increasing revenue trend since the third quarter of 2004 is also attributable to the strong commodity price environment through 2005 and into 2006.

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 and 2006 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 however, our review of these pronouncements and their impact is ongoing.

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 with the addition of the refinery to our business effective October 19, 2006. The incremental risk factors of the refining business are fully described on page 23 of the preliminary prospectus dated October 31, 2006 and filed on www.sedar.com. The following risk management activities are being carried relative to our refinery risks and are in addition to the activities noted on Page 26 of our Annual Information Form also filed on www.sedar.com:

Disruptions in the Supply of Crude Oil and Delivery of Refined Products

- We have entered into a Supply and Offtake agreement with Vitol Refining S.A. , a subsidiary of Vitol Refining Group B.V, one of the world's largest physical traders and marketers of crude oil and petroleum products so to minimize the risk of disruptions in supply.

Commodity Price Exposure

- Contracts will be entered into such that crude oil feedstock will be priced based on the price at or near the time of delivery to the refinery, which may be as much as 24 days subsequent to the time the feedstock initially loaded onto the shipping vessel, so to minimize the time between the pricing of the feedstock and the refined products with the objective of maintaining margins.

Environmental, Health and Safety

- The refinery is substantially compliant with existing laws and regulations in this area and keeps apprised of any changes in this area.
- Appropriate funding is allocated to environment, health and safety to invest in programs and capital initiatives to minimize the risks in this area.

Employee Relations

- A significant proportion of the employees of the refinery are unionized and resources are allocated to assist in maintaining good relations with the union to minimize operational disruptions due to strikes or work stoppage.

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 and nine months ended September 30, 2006 and 2005, Cash Flows are reconciled to its closest GAAP measure, Cash Flow from operating activities, as follows:

	Three months ended			**Nine months ended**	
($000s)	**Sept. 30, 2006**	June 30, 2006	Sept. 30, 2005	**Sept. 30, 2006**	Sept. 30, 2005
Cash Flow	**$ 147,471**	$ 147,010	$ 103,508	**$ 395,452**	$ 213,412
Cash Viking transaction costs	**(516)**	(670)	-	**(6,258)**	-
Settlement of asset retirement obligations	**(2,285)**	(625)	(1,169)	**(4,028)**	(2,333)
Changes in non-cash working capital	**(1,073)**	(10,134)	29,810	**(17,824)**	(25,867)
Cash flow from operating activities	**$ 143,597**	$ 135,581	$ 132,149	**$ 367,342**	$ 185,212

Forward-Looking Information

This MD&A highlights significant business results and statistics from our consolidated financial statements for the three and nine months ended September 30, 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)

		September 30, 2006		December 31, 2005
Assets				
Current assets				
Accounts receivable	**$**	**180,358**	$	73,766
Fair value of risk management contracts *[Note 12]*		**16,422**		21,231
Prepaid expenses and deposits		**8,046**		1,126
Future income tax		**-**		22,975
		204,826		119,098
Deferred charges *[Note 3]*		**11,417**		12,768
Fair value of risk management contracts *[Note 12]*		**15,167**		2,628
Deposit on North Atlantic Refinery Limited *[Note 15]*		**111,292**		-
Property, Plant and Equipment *[Note 4]*		**3,077,821**		1,130,155
Goodwill *[Note 2]*		**656,248**		43,832
	$	**4,076,771**	$	1,308,481
Liabilities and Unitholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities *[Note 5]*	**$**	**228,708**	$	99,576
Cash distribution payable		**42,163**		18,544
Fair value deficiency of risk management contracts *[Note 12]*		**24,850**		65,968
		295,721		184,088
Bank loan *[Note 7]*		**591,189**		13,869
Fair value deficiency of risk management contracts *[Note 12]*		**24,812**		10,449
$7^{7/8}$% Senior notes		**279,425**		290,750
Convertible debentures *[Note 8]*		**235,114**		44,455
Deferred credit		**881**		1,389
Asset retirement obligation *[Note 6]*		**193,182**		110,693
Future income tax		**-**		25,275
Non-controlling interest *[Note 11]*		**-**		3,179
Unitholders' equity				
Unitholders' capital *[Note 9]*		**2,757,381**		747,312
Equity component of convertible debentures *[Note 8]*		**24,539**		2,639
Accumulated income		**269,622**		135,665
Accumulated distributions		**(595,095)**		(261,282)
		2,456,447		624,334
	$	**4,076,771**	$	1,308,481

Commitments, contingencies, and guarantees [Note 14]
Subsequent events [Note 15]
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 Sept 30, 2006	Three Months Ended Sept 30, 2005	Nine Months Ended Sept 30, 2006	Nine Months Ended Sept 30, 2005
Revenue				
Petroleum and natural gas sales	**$ 314,180**	$ 208,628	**$ 847,465**	$ 481,672
Royalty expense	**(54,362)**	(38,974)	**(149,384)**	(81,824)
Risk management contracts				
Realized net losses	**(24,032)**	(22,182)	**(56,623)**	(64,255)
Unrealized net gains (losses)	**77,078**	(3,948)	**35,966**	(73,524)
	312,864	143,524	**677,424**	262,069
Expenses				
Operating	**62,489**	32,385	**173,176**	88,122
Transportation and marketing	**3,535**	56	**9,223**	302
General and administrative	**7,500**	12,971	**21,825**	25,046
Transaction charges	**-**	-	**12,072**	-
Interest and other financing charges on short term debt	**-**	1,083	**-**	6,452
Interest and other financing charges on long term debt	**16,685**	7,682	**42,573**	21,460
Depletion, depreciation and accretion	**115,223**	48,969	**297,726**	127,944
Foreign exchange (gain) loss	**163**	(13,974)	**(11,327)**	(8,607)
Large corporations tax and other tax	**(499)**	76	**8**	831
Future income tax (recovery)	**-**	1,195	**(2,300)**	(28,633)
Non-controlling interest *[Note 11]*	**-**	219	**(65)**	(156)
	205,096	90,662	**542,911**	232,761
Net income for the period	**107,768**	52,862	**134,513**	29,308
Accumulated income, beginning of period	**161,854**	7,165	**135,665**	30,719
Redemption of exchangeable shares	**-**	-	**(556)**	-
Accumulated income, end of period	**$ 269,622**	$ 60,027	**269,622**	$ 60,027
Net income per Trust Unit, basic *[Note 9]*	**$ 1.01**	$ 1.09	**$ 1.39**	$ 0.66
Net income per Trust Unit, diluted *[Note 9]*	**$ 0.99**	$ 1.08	**$ 1.38**	$ 0.64

Consolidated Statements of Accumulated Distributions (Unaudited)

(thousands of Canadian dollars)

	Three Months Ended Sept 30, 2006	Three Months Ended Sept 30, 2005	Nine Months Ended Sept 30, 2006	Nine Months Ended Sept 30, 2005
Accumulated distributions, beginning of period	**$ 471,983**	$ 159,376	**$ 261,282**	$ 97,110
Distributions	**123,112**	46,691	**333,813**	108,957
Accumulated distributions, end of period	**$ 595,095**	$ 206,067	**$ 595,095**	$ 206,067

See accompanying notes to these consolidated financial statements.

Harvest Energy Trust
Consolidated Statements of Cash Flows (Unaudited)

(thousands of Canadian dollars)

	Three Months Ended Sept 30, 2006	Three Months Ended Sept 30, 2005	**Nine Months Ended Sept 30, 2006**	Nine Months Ended Sept 30, 2005
Cash provided by (used in)				
Operating Activities				
Net income for the period	**$ 107,768**	$ 52,862	**$ 134,513**	$ 29,308
Items not requiring cash				
Depletion, depreciation and accretion	**115,223**	48,969	**297,726**	127,944
Unrealized foreign exchange gain	**834**	(13,829)	**(10,289)**	(8,038)
Amortization of deferred finance charges and discount on debt	**1,095**	894	**3,972**	4,334
Unrealized loss (gain) on risk management contracts *[Note 12]*	**(77,078)**	3,948	**(35,966)**	73,524
Future income tax (recovery)	**-**	1,195	**(2,300)**	(28,633)
Non-controlling interest	**-**	219	**(65)**	(156)
Unit based compensation expense	**(816)**	9,250	**1,725**	15,129
Deferred rent expense	**(127)**	-	**(271)**	-
Amortization of office lease premium	**56**	-	**149**	-
Settlement of asset retirement obligations	**(2,285)**	(1,169)	**(4,028)**	(2,333)
Change in non-cash working capital *[Note 13]*	**(1,073)**	29,810	**(17,824)**	(25,867)
	143,597	132,149	**367,342**	185,212
Financing Activities				
Issue of Trust Units, net of issue costs	**217,950**	167,595	**217,849**	167,507
Redemption of exchangeable shares	**-**	-	**(1,022)**	-
Borrowings of bank loan, net	**363,644**	(103,442)	**471,072**	(40,871)
Issuance of convertible debentures	**-**	75,000	**-**	75,000
Issue costs for convertible debentures	**-**	(3,223)	**-**	(3,223)
Financing costs	**(54)**	(1,518)	**(1,183)**	(2,052)
Cash distributions	**(73,566)**	(29,286)	**(184,734)**	(74,314)
Change in non-cash working capital *[Note 13]*	**7,879**	5,960	**(10,891)**	5,647
	515,853	111,086	**491,091**	127,694
Investing Activities				
Additions to Property, Plant and Equipment	**(129,054)**	(31,655)	**(286,523)**	(81,032)
Acquisition of Birchill Energy Limited	**(452,269)**	-	**(452,269)**	-
Acquisition of Hay River	-	(210,505)	-	(236,505)
Deposit on North Atlantic Refinery Ltd.	**(111,292)**	-	**(111,292)**	-
Property acquisitions	**(312)**	839	**(23,984)**	(2,791)
Change in non-cash working capital *[Note 13]*	**33,477**	(1,914)	**15,635**	7,422
	(659,450)	(243,235)	**(858,433)**	(312,906)
Change in cash being cash at beginning and end of period	**$ -**	$ -	**$ -**	$ -
Interest paid	**$ 6,304**	$ 13,041	**$ 23,586**	$ 17,257
Large corporation tax and other tax paid	**$ 68**	$ 1,733	**$ 880**	$ 2,079

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. Business Acquisitions

Birchill Energy Limited ("BEL")
On July 26, 2006, management signed a binding agreement to purchase all of the issued and outstanding shares of BEL on August 15, 2006 for $452.3 million net of working capital adjustments and transaction costs. The results of operations of BEL have been included in the consolidated financial statements since the time of effective control, July 26, 2006.

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

Consideration for the acquisition:		Amount
Cash paid	$	450,960
Acquisition costs		1,309
	$	452,269

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 BEL acquisition.

Consideration for the acquisition:		Amount
Net working capital	$	(2,001)
Capital assets		455,489
Asset retirement obligation		(1,219)
	$	452,269

The above amounts are estimates made by management based on currently available information. Amendments may be made to the purchase equation as the cost estimates and balances are finalized.

Viking Energy Royalty Trust ("Viking")
On February 3, 2006, the unitholders of the Trust and 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.

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

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

Consideration for the acquisition:		**Amount**
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

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

3. Deferred Charges

		September 30, 2006		December 31, 2005
Financing costs	$	**9,153**	$	11,064
Fair value of office lease *[Note 2]*		**782**		-
Discount on Senior Notes		**1,482**		1,704
	$	**11,417**	$	12,768

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

4. Property, Plant and Equipment

September 30, 2006	**Cost**	**Accumulated depletion and depreciation**	**Net book value**
Petroleum and natural gas expenditures	$ 3,663,542	$ (592,071)	$ 3,071,471
Office furniture and equipment	8,719	(2,369)	6,350
Total	$ 3,672,261	$ (594,440)	$ 3,077,821

December 31, 2005	**Cost**	**Accumulated depletion and depreciation**	**Net book value**
Petroleum and natural gas expenditures	$ 1,433,284	$ (307,384)	$ 1,125,900
Office furniture and equipment	5,377	(1,122)	4,255
Total	$ 1,438,661	$ (308,506)	$ 1,130,155

General and administrative costs of $2.4 million have been capitalized during the three month period ended September 30, 2006 (three months ended September 30, 2005- $2.6 million), of which $128,000 (three months ended September 30, 2005 - $2,080,474) relate to the Trust Unit incentive plan and the Unit award incentive plan. For the nine month period ended September 30, 2006 $9.2 million (nine months ended September 30, 2005 - $4.5 million) of general and administrative costs have been capitalized, of which $2.9 million (nine months ended September 30, 2005 - $3.2 million) relate to the Trust Unit incentive plan and the unit award incentive plan.

5. Accounts Payable and Accrued Liabilities

	September 30, 2006	December 31, 2005
Trade accounts payable	**$ 45,192**	$ 22,484
Accrued interest	**16,060**	4,959
Trust Unit Incentive Plan and Unit Award Incentive Plan *[Note 10]*	**7,623**	17,828
Premium on price risk management contract	**-**	462
Other accrued liabilities	**160,053**	53,223
Large corporation taxes payable	**(220)**	620
	$ 228,708	$ 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 $636 million which will be incurred between 2006 and 2053. 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 September 30, 2006.

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

A reconciliation of the asset retirement obligation is provided below:

	Nine months ended September 30, 2006	Year ended December 31, 2005
Balance, beginning of period	**$ 110,693**	$ 90,085
Incurred on acquisition of Viking	**60,493**	-
Incurred on acquisition of BEL	**1,219**	-
Liabilities incurred	**839**	7,328
Revision of estimates	**12,173**	8,656
Liabilities settled	**(4,028)**	(4,146)
Accretion expense	**11,793**	8,770
Balance, end of period	**$ 193,182**	$ 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 September 30, 2006, the Trust had $591.2 million drawn under the $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 Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA) Ratio as defined in the Credit Agreement. Availability under this facility is subject to quarterly financial covenants requiring that the Senior Debt to EBITDA Ratio is less than 3 to 1, the Total Debt to EBITDA Ratio is less than 3.5 to 1, Senior Debt to Capitalization Ratio is less than 50% and Total Debt to Capitalization Ratio is less than 55%, all as defined in the Credit Agreement. [See Note 15].

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	6.40%(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, including the equity component, of the 10.5% convertible debentures and the 6.40% convertible debentures at acquisition was $44.8 million and $181.5 million, respectively.

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

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)		3	300	(129)	650	824
Converted into Trust Units	(398)	(1,069)	(3,330)	(7,581)	(19)	(12,397)
As at September 30, 2006	$ 1,379	$ 2,698	$ 35,884	$ 27,811	$ 167,342	$ 235,114

	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	(398)	(1,075)	(3,544)	(7,502)	(20)	(12,539)
Outstanding at September 30, 2006	1,379	2,711	37,929	27,556	174,945	244,520

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	6.40% 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	-	(8)	(223)	(1,990)	(2)	(2,223)
As at Sept 30, 2006	**$ -**	**$ 20**	**$ 2,388**	**$ 7,311**	**$ 14,820**	**$ 24,539**

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

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
Issued for cash	7,026,500		230,118
Convertible debenture conversions-9% series	28,732		398
Convertible debenture conversions-8% series	66,883		1,077
Convertible debenture conversions-6.5% series	114,313		3,562
Convertible debenture conversions-10.5% series	256,104		9,570
Convertible debenture conversions-6.40% series	434		21
Exchangeable share retraction *[Note 11]*	184,809		2,648
Distribution reinvestment plans	3,907,825		125,470
Exercise of unit appreciation rights	347,715		11,912
Issue costs	-		(12,838)
As at September 30, 2006	110,956,670	$	2,757,381

(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 Sept 30, 2006		Three Months ended Sept 30, 2005		Nine Months ended Sept 30, 2006		Nine Months ended Sept 30, 2005
Net income, basic	$	107,768	$	52,862	$	134,513	$	29,308
Non-controlling interest		-		219		(65)		(156)
Interest on convertible debentures		4,674		-		292		-
Net income, diluted[(1)]	$	112,442	$	53,081	$	134,740	$	29,152

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

Weighted average Trust Units adjustments	**Three Months ended Sept 30, 2006**	**Three Months ended Sept 30, 2005**	**Nine Months ended Sept 30, 2006**	**Nine Months ended Sept 30, 2005**
Number of Units				
Weighted average Trust Units outstanding, basic	106,390,853	48,305,977	96,797,055	44,611,706
Effect of convertible debentures	6,380,559	-	302,484	-
Effect of exchangeable shares	-	268,398	42,507	300,830
Effect of unit appreciation rights	312,605	791,489	289,678	805,779
Weighted average Trust Units outstanding, diluted(2)	113,084,017	49,365,864	97,431,724	45,718,315

(1) Net income, diluted excludes the impact of the conversions of certain of the convertible debentures for the three month and nine month period ended September 30, 2006, of nil and $12,301,000, respectively (three and nine months ended September 30, 2005 - $924,027 and $1,730,487), as the impact was anti-dilutive.

(2) Weighted average Trust Units outstanding, diluted for the three and nine months ended September 30, 2006, does not include the impact of the units related to certain of the convertible debentures of nil and 6,167,722, respectively (three and nine months ended September 30, 2005 – 509,408 and 1,408,899, respectively), as the impact was anti-dilutive.

10. Employee Unit Incentive Plans

Trust Unit Rights Incentive Plan
As at September 30, 2006, a total of 2,080,625 (1,305,143 – December 31, 2005) Unit Appreciation Rights were outstanding under the Trust Unit Incentive Plan at an average exercise price of $32.20 ($16.73 – December 31, 2005).

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

	Nine Months ended September 30, 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	2,124,300		36.60	793,325		26.69
Exercised	(979,818)		18.24	(420,157)		9.49
Cancelled	(369,000)		37.28	(185,750)		25.70
Outstanding before exercise price reductions	2,080,625		34.54	1,305,143		19.72
Exercise price reductions	-		(2.34)	-		(2.99)
Outstanding, end of period	2,080,625	$	32.20	1,305,143	$	16.73
Exercisable before exercise price reductions	325,325	$	24.19	109,068	$	13.56
Exercise price reductions	-		(4.75)	-		(4.04)
	325,325	$	19.44	109,068	$	9.52

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

The following table summarizes information about Unit appreciation rights outstanding at September 30, 2006.

		Outstanding			Exercisable	
Exercise Price before price reductions	**Exercise Price net of price reductions**	**At Sept 30, 2006**	**Exercise Price net of price reductions[(a)]**	**Remaining Contractual Life [(a)]**	**At Sept 30, 2006**	**Exercise Price net of price reductions [(a)]**
$12.19-$13.25	$ 5.30-$ 6.63	14,100	$ 5.85	2.1	14,100	$ 5.85
$13.35-$17.84	$ 7.02-$12.41	62,375	9.48	2.8	62,375	9.48
$18.90-$25.10	$13.55-$20.15	166,550	19.19	3.5	166,550	19.19
$29.21-$37.56	$25.13-$36.22	1,837,600	34.35	4.4	82,300	29.86
$12.19-$37.56	$ 5.30-$36.22	2,080,625	$ 32.20	4.3	325,325	$ 19.45

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

Unit Award Incentive Plan
At September 30, 2006, 180,281 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	**Nine Months ended September 30, 2006**	Year ended December 31, 2005
Outstanding, beginning of period	**35,365**	10,662
Granted	**193,489**	23,466
Adjusted for distributions	**18,801**	1,237
Exercised	**(34,329)**	-
Cancelled	**(33,045)**	-
Outstanding, end of period	**180,281**	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 $0.5 million and $10.0 million for the three and nine months ended September 30, 2006 respectively ($10.0 million and $16.1 million – three and nine months ended September 30, 2005 respectively), including a non cash compensation recovery of $2.2 million and $7.1 million for the three and nine months ended September 30, 2006, respectively ($3.7 million and $9.6 million – three and nine months ended September 30, 2005 respectively), related to the Trust Unit Incentive Plan and the Unit award plan. Recoveries occur when the Trust Unit market price decreases below the previous measurement date.

Of the total compensation expense for the three and nine months ended September 30, 2006, $nil and $9.0 million, respectively, have been recorded within transaction costs, with the remaining recorded as part of general and administrative expenses. 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.

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

(b) Issued

Exchangeable shares, series 1	**Nine Months ended September 30, 2006**	Year ended December 31, 2005
Outstanding, beginning of period	**182,969**	455,547
Shareholder retractions	**(156,067)**	(272,578)
Issuer redemption	**(26,902)**	-
Outstanding , end of period	**-**	182,969
Exchange ratio	**-**	1.17475

On March 16, 2006, the Trust elected to exercise its deminimus redemption right to redeem all of the exchangeable shares outstanding. On June 20, 2006 the redemption was completed.

(c) Non-controlling interest

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

	Nine Months ended Sept 30, 2006	Year ended December 31, 2005
Non-controlling interest, beginning of period	$ **3,179**	$ 6,895
Exchanged for Trust Units	**(2,648)**	(3,865)
Redeemed for cash	**(1,022)**	-
Excess of redemption price over cost, accumulated income	**556**	-
Current period income (loss) attributable to non-controlling interest	**(65)**	149
Non-controlling interest, end of period	$ **-**	$ 3,179
Accumulated income attributed to non-controlling interest	$ **865**	$ 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 September 30, 2006.

Quantity	**Type of Contract**	**Term**	**Reference**	**Fair value**
4,000 bbl/d	Differential swap – Bow River	October – December 2006	29.58%	1,769
5,000 bbl/d	Differential swap – Bow River	October – December 2006	27.50%	1,650
1,000 bbl/d	Differential swap – Wainwright	October - December 2006	29.58%	691
1,000 bbl/d	Differential swap – Wainwright	October 2006 – April 2007	27.70%	970
5,000 GJ/d	Natural gas price collar contract	October 2006	Cdn$9.00-$13.06	741
25,000 GJ/d	Natural gas price collar contract	October 2006 – March 2007	Cdn$5.00-$13.55	1,240
25,000 GJ/d	Natural gas price collar contract	November 2006 – March 2007	Cdn$7.00-$12.50	188
$250,000,000	Foreign currency swap	October 2006	1.1066 Cdn/US(i)	2,775
$250,000,000	Foreign currency swap	October 2006	1.1091 Cdn/US(i)	2,150
$250,000,000	Foreign currency swap	October 2006	1.1093Cdn/US(i)	2,110
45 MWH	Electricity price swap contracts	October – December 2006	Cdn $51.48	2,138
Total current portion of fair value				**16,422**

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

Quantity	Type of Contract	Term	Reference	Fair value
5,000 bbl/d	Participating swap	January – December 2007	U.S.$60.00[g]	127
5,000 bbl/d	Participating swap	January – December 2007	U.S.$65.00[h]	5,429
5,000 bbl/d	Participating swap	January – June 2008	U.S.$65.00[e]	2,452
35 MWH	Electricity price swap contracts	January – December 2007	Cdn $56.69	2,472
35 MWH	Electricity price swap contracts	January – December 2008	Cdn $56.69	1,864
$416,700/mnth	Foreign currency swap	January – December 2007	1.14 Cdn/U.S.	183
$4,167,000/mnth	Foreign currency swap	January - December 2007	1.1189 Cdn/U.S.	770
$8,333,000/mnth	Foreign currency swap	January – June 2008	1.1099 Cdn/U.S.	559
$4,167,000/mnth	Foreign currency swap	January – December 2007	1.1249 Cdn/U.S.	1,311
Total long-term portion fair value				**15,167**

Quantity	Type of Contract	Term	Reference	Fair value
8,750 bbl/d	Participating swap	October – December 2006	U.S.$38.16[a]	(11,672)
5,000 bbl/d	Participating swap	October – December 2006	U.S.$45.17[a]	(4,884)
5,000 bbl/d	Participating swap	October 2006 – June 2007	U.S.$49.03[b]	(6,106)
5,000 bbl/d	Indexed put contract – bought put	October – December 2006	U.S.$55.00[c]	111
2,500 bbl/d	Indexed put contract – sold call	October – December 2006	U.S.$55.00[c]	(2,439)
2,500 bbl/d	Indexed put contract – bought call	October – December 2006	U.S.$65.00[c]	525
2,500 bbl/d	Indexed put contract – sold call	October – December 2006	U.S.$70.00[c]	(184)
2,500 bbl/d	Indexed put contract – bought call	October – December 2006	U.S.$83.00[c]	15
200 GJ/d	Fixed price - natural gas contract	October – December 2006	Cdn.$5.35[d]	(96)
76 GJ/d	Fixed price – natural gas contract	October 2006 – September 2007	Cdn.$2.23-$2.28[d]	(120)
Total current portion of fair value deficiency				**(24,850)**

Quantity	Type of Contract	Term	Reference	Fair value
10,000 bbl/d	Participating swap	January – December 2007	U.S.$55.00[e]	(13,212)
5,000 bbl/d	Participating swap	January – June 2008	U.S.$55.00[f]	(707)
5,000 bbl/d	Indexed put contract – bought put	January – December 2007	U.S.$50.00[c]	1,547
2,500 bbl/d	Indexed put contract – sold call	January – December 2007	U.S.$50.00[c]	(18,406)
2,500 bbl/d	Indexed put contract – bought call	January – December 2007	U.S.$60.00[c]	10,338
2,500 bbl/d	Indexed put contract – sold call	January – December 2007	U.S.$70.00[c]	(4,591)
2,500 bbl/d	Indexed put contract – bought call	January – December 2007	U.S.$83.00[c]	1,416
200 GJ/d	Fixed price – natural gas contract	January 2007 – December 2008	Cdn. $5.35[d]	(1,041)
76 GJ/d	Fixed price – natural gas contract	October 2007 - October 2008	Cdn. $2.28-$2.34[d]	(156)
Total long-term portion of fair value deficiency				**(24,812)**

(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.
(f) This price is a floor. The Trust realizes this price plus 80% of the difference between spot price and this price
(g) This price is a floor. The Trust realizes this price plus 77% of the difference between spot price and this price.
(h) This price is a floor. The Trust realizes this price plus 79% of the difference between spot price and this price.
(i) See Note 15

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

At September 30, 2006, the net unrealized loss position reflected on the balance sheet for all the risk management contracts outstanding at that date was approximately $18.1 million ($52.6 million – December 31, 2005).

For the three and nine months ended September 30, 2006, the total unrealized gain recognized in the consolidated statement of income, including amortization of deferred charges and gains, was $77.1 and $36.0 million (loss of $3.9 million and $73.5 million – three and nine months ended September 30, 2005 respectively). The realized gains and losses on all risk management contracts are included in the period in which they are incurred.

13. Change in Non-Cash Working Capital

	Three Months ended Sept 30, 2006	Three Months ended Sept 30, 2005	**Nine Months ended Sept 30, 2006**	Nine Months ended Sept 30, 2005
Changes in non-cash working capital items:				
Accounts receivable	**$ (382)**	$ (18,292)	**$ (10,303)**	$ (40,593)
Prepaid expenses and deposits	**(1,144)**	44,171	**(2,207)**	1,256
Current portion of risk management contracts assets	**(8,147)**	(9,596)	**4,809**	(10,544)
Current portion of future income tax asset	**-**	(20,832)	**22,975**	(27,694)
Accounts payable and accrued liabilities	**39,664**	16,613	**16,699**	42,034
Cash distribution payable	**3,330**	9,212	**1,752**	9,608
Current portion of risk management contracts liability	**(44,600)**	54,209	**(41,983)**	64,573
	$ (11,279)	$ 75,485	**$ (8,258)**	$ 38,640
Changes relating to operating activities	**$ (1,073)**	**$** 29,810	**$ (17,824)**	**$** (25,867)
Changes relating to financing activities	**7,879**	5,960	**(10,891)**	5,647
Changes relating to investing activities	**33,477**	(1,914)	**15,635**	7,422
Add: Non cash changes	**(51,562)**	41,629	**4,822**	51,438
	$ (11,279)	$ 75,485	**$ (8,258)**	$ 38,640

14. Commitments, Contingencies and Guarantees

The Trust has letters of credit outstanding in the amount of approximately $8.0 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 October 1, 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 September 30, 2006:

	Remaining Payments Due by Period						
	2006	**2007**	**2008**	**2009**	**2010**	**Thereafter**	**Total**
Debt repayments (1)	$ -	$ -	$ -	$ 591,189	$ -	$ 279,425	$ 870,614
Capital commitments (3)	5,556	8,605	2,880	-	-	-	17,041
Operating leases (2)	1,508	3,570	3,506	3,506	1,573	-	13,663
Total contractual obligations	$ 7,064	$ 12,175	$ 6,386	$ 594,695	$ 1,573	$ 279,425	$ 901,318

(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.
(3) Relating to drilling contracts.

15. Subsequent Events

a) Acquisition of Refinery

On August 22, 2006, the Trust entered into an agreement to purchase North Atlantic Refinery Limited and related businesses ("North Atlantic") for US $1.4 billion, before working capital and other adjustments. A US $100 million (CDN$111.3 million) deposit was paid into escrow upon entering into the purchase agreement and is recorded as a long term asset at September 30, 2006. In anticipation of the closing of the refinery we entered into a series of swaps and forward purchase contracts for US$750.0 million. The total gain that we realized on this hedging strategy was CDN$22.5 million. This acquisition closed on October 19, 2006, with the remaining cash payment of US $1.3 billion (CDN$1.5 billion) wired to the vendor. The Trust will include the results of North Atlantic in its consolidated results from October 19, 2006 onward.

Concurrent with the purchase of the refinery by the Trust, North Atlantic entered into a supply and offtake agreement with a division of Vitol Refining Group B.V, called Vitol Refining S.A. for a minimum period of up to two years. This agreement provides that the ownership of substantially all crude oil feedstock and refined product inventory at the refinery be retained by Vitol Refining S.A. and that during the term of the supply and offtake agreement, Vitol Refining S.A. will be granted the right and obligation to provide crude oil feedstock for delivery to the refinery as well as the right and obligation to purchase all refined products produced by the refinery. As at November 8, 2006, North Atlantic had commitments totaling approximately US$400 million in respect of future crude oil feedstock purchases from Vitol Refining S.A.

The financing for the acquisition was also finalized on October 19, 2006, when the Trust entered into an amended and restated credit agreement which increased its three year extendible revolving credit facility from $900 million to $1.4 billion and established a $350 million Senior Secured Bridge Facility. The terms and conditions of the three year extendible revolving credit facility remained unchanged except for changes to the security pledged and the addition of a 15 basis point additional fee applicable so long as the Senior Unsecured Bridge Facility is outstanding. The amended and restated credit agreement required the Trust to increase the first floating charge over all of the assets of Harvest's operating subsidiaries to $2.5 billion plus grant a first mortgage security interest on the Refinery assets of North Atlantic. The $350 million Senior Secured Bridge Facility provided Harvest with a single draw on this facility within five days of the closing of its acquisition of North Atlantic and, subject to the repayment requirements of the $450 million Senior Unsecured Bridge Facility, requires repayments equivalent to the net proceeds from an issuance of equity or equity like securities including convertible debentures and repayment in full within 18 months of the initial draw. Harvest is entitled to make additional repayments on the $350 million Senior Secured Bridge Facility without penalty or notice.

Also on October 19, 2006, Harvest entered into a credit agreement that established a $450 million Senior Unsecured Bridge Facility which provided for only a single draw on the facility within five days for the closing of its acquisition of North Atlantic and requires repayments equivalent to the net proceeds from an issuance of equity or equity like securities including convertible debentures and repayment in full within 6 months of the initial draw. Amounts borrowed under this facility bear interest at a floating rate based on bankers' acceptances plus a range of 230 to 280 basis points depending on the Harvest financial ratios as set forth in the amended and restated credit agreement.

On October 16, 2006, North Atlantic entered into an amended and restated credit agreement that provides for a $10 million demand operating line of credit to finance its receivables and inventory in the Province of Newfoundland and Labrador as well as support period cash management market transactions. This facility is secured by a guarantee from Harvest Operations Corp. with amounts borrowed bearing interest at the bank's prime lending rate.

b) Trust Unit and Debenture Offering

On October 31, 2006 we issued a preliminary prospectus in respect of a "bought deal" agreement to sell $400 million of convertible debentures and 3,150,000 Trust Units at a price of $31.75 per Trust Unit. The preliminary prospectus also included an option (the "Over-allotment Option") to the underwriters to purchase up to an additional 472,500 Trust Units at a price of $31.75 per Trust Unit and up to an additional 60,000 Debentures at a price of $1,000 per Debenture on the same terms and conditions as the offering, exercisable from time to time, in whole or in part, for a period of up to 30 days following closing of the Offering, to cover over-allotments, if any, and for market stabilization purposes. The "bought deal" agreement entitles the underwriters to terminate and cancel their respective obligation if certain standard terms and conditions are not met.

On the evening of October 31, 2006, changes to the Canadian income tax treatment of distributions from publicly traded trusts were announced by the Government of Canada which have resulted in considerable disruption of the valuations of all income and royalty trusts. In light of this announcement and the ensuing impact on capital markets, Harvest remains in discussions with its underwriters and is assessing various alternatives to proceed with this offering.

16. Comparatives

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