Harvest Energy Trust

Financial & Operating Highlights

The table below provides a summary of our financial and operating results for the three and six month periods ended June 30, 2007 and 2006. Detailed commentary on individual items within this table is provided in Harvest's Management's Discussion and Analysis, filed on SEDAR or available on our website.

	Three Months Ended June 30			**Six Months Ended June 30**		
($000s except where noted)	**2007**	2006	Change	**2007**	2006	Change
Revenue, net[1]	**1,137,638**	233,128	388%	**2,148,732**	364,560	489%
Funds From Operations	**244,461**	147,010	66%	**458,402**	247,981	85%
Per trust unit, basic	**$ 1.83**	$ 1.45	26%	**$ 3.51**	$ 2.70	30%
Per trust unit, diluted	**$ 1.62**	$ 1.43	13%	**$ 3.13**	$ 2.66	18%
Net Income[3]	**6,248**	60,682	(90%)	**76,098**	26,745	185%
Per trust unit, basic	**$ 0.05**	$ 0.60	(92%)	**$ 0.58**	$ 0.29	100%
Per trust unit, diluted	**$ 0.05**	$ 0.60	(92%)	**$ 0.58**	$ 0.29	100%
Distributions declared	**154,057**	115,889	33%	**299,327**	210,701	42%
Distributions declared, per trust unit	**$ 1.14**	$ 1.14	-%	**$ 2.28**	$ 2.25	1%
Payout ratio [2]	**63%**	79%	(16%)	**65%**	85%	(20%)
Bank debt				**1,047,965**	227,544	361%
Senior debt				**258,387**	279,050	(7%)
Convertible Debentures				**655,396**	240,246	173%
Total long-term financial liabilities				**1,961,748**	746,840	163%
Total assets				**5,613,333**	3,455,918	62%
PETROLEUM AND NATURAL GAS OPERATIONS						
Daily Production						
Light to medium oil (bbl/d)	**27,586**	28,951	(5%)	**27,311**	26,497	3%
Heavy oil (bbl/d)	**14,719**	13,037	13%	**15,164**	14,045	8%
Natural gas liquids (bbl/d)	**2,338**	2,016	16%	**2,417**	1,865	30%
Natural gas (mcf/d)	**98,078**	96,848	1%	**99,671**	85,158	17%
Total daily sales volumes (boe/d)	**60,989**	60,145	1%	**61,504**	56,600	9%
Cash capital expenditures	**48,221**	54,230	(11%)	**196,708**	157,469	25%
REFINING AND MARKETING OPERATIONS						
Average daily throughput (bbl/d)	**115,570**	-	n/a	**114,646**	-	n/a
Aggregate throughput (mbbl)	**10,517**	-	n/a	**20,751**	-	n/a
Average Refining Margin (US$/bbl)	**15.64**	-	n/a	**13.69**	-	n/a
Cash capital expenditures	**9,871**	-	n/a	**14,754**	-	n/a

(1) Revenues are net of royalties and risk management activities

(2) These are non-GAAP measures; please refer to "Non-GAAP Measures" in Harvest's Second Quarter 2007 MD&A filed on SEDAR.

(3) Net Income includes a future income tax expense of $177.7 million for the three and six months ended June 30, 2007. Please see Note 14 to the Consolidated Financial Statements for further information.

Message to Unitholders

The second quarter of 2007 clearly demonstrates the benefit of having an integrated business model. The natural financial hedge afforded by our diversified cash flow stream mitigates risk and smoothes volatility. This is key given that our two different business segments can be impacted by different variables at different times, but combined together can reduce overall volatility in Harvest's financial results.

We were very pleased with the performance of our downstream refining and marketing business in the second quarter with average throughput of 115,570 barrels per day (bbl/d) bolstered by a very strong refining margin or 'crack spread' environment. Since the time of acquisition, North Atlantic's financial performance has exceeded our original expectations and budget. The second quarter performance realized by the refining business further demonstrates its potential for value creation, as we realized a gross refining margin of US$15.64/bbl. This robust refining margin supports our belief that North American refining capacity is very tight and disruptions to the supply/demand balance can have significant impacts on refined product prices and refining margins.

Funds From Operations of $244.5 million ($1.83 per trust unit) generated in the second quarter have exceeded any other interim period in our history, and resulted in our payout ratio declining to 63% from 68% in the previous quarter and from 79% in the second quarter of 2006. Our total Funds From Operations exceeded the aggregate amount of our declared distributions plus capital investment, giving us a capital adjusted payout ratio (distributions declared plus capital expenditures divided by total Funds From Operations) of 87%. This considerable improvement in our simple and capital adjusted payout ratios reflects the addition of Funds From Operations from our refining and marketing business as well as reduced losses on 2007 commodity price risk management contracts relative to 2006.

Our strong financial performance also contributed to an improved balance sheet position at the end of the second quarter, as well as increased working capital at North Atlantic. During the period, we repaid debt with proceeds from several sources, including $218.5 million net from the equity offering that closed on June 1, $81.4 million of excess Funds From Operations, and approximately $21.8 million from net asset divestments. We experienced a 15% increase in our unit price through the second quarter, which prompted the conversion of $125.6 million of convertible debentures and resulted in a further reduction of our net debt. At the end of the quarter, we had approximately $550 million of committed undrawn bank lines, significantly increasing our flexibility. Subsequent to the end of the quarter, an additional $35.1 million of convertible debentures converted, further strengthening our balance sheet and positioning us well to take advantage of future value creation opportunities.

During the second quarter, the Canadian Government's proposed tax on income trusts (Bill C-152) received Royal Assent in the House of Commons. As a result of this enactment, we have recorded a future income tax expense of $177.7 million to reflect the impact of the 31.5% tax to be applied to trust distributions commencing in January 2011. Unitholders should keep in mind that this expense is a non-cash item which does not currently impact our Funds From Operations or distributions, but does reduce our Second Quarter 2007 net earnings.

Downstream Operations

We continue to be very pleased with the operational performance and financial contribution of our North Atlantic refining and marketing business. Second quarter refinery throughput of 115,750 bbl/d was 1.6% higher than the first quarter rate of 113,711 bbl/d. Realized per barrel refining margins or 'crack spreads' also increased 32% to US$15.64/bbl compared to the US$11.85/ bbl in the previous quarter. Operating and purchased energy costs fell to $3.84/bbl from $4.43/bbl in the prior quarter, and we are on track to meet or exceed our budgeted annual cost estimates at the refinery.

A key driver behind refinery economics are the gross margins or 'crack spreads' realized by the particular facility. As the benchmark 2-1-1 crack spread began to rise during the latter part of the first quarter and into the second quarter, our North Atlantic gross margin also increased, although not to the same degree because we use a different feedstock source and produce a slate of refined products that is different from what is included in the 2-1-1. We enjoyed robust margins during most of the second quarter, but began to experience declines late in the second quarter and into the third quarter. Our initial budget forecasts assumed refining margins in 2007 would average approximately US$10/bbl with the expectation that margins would fluctuate above and below this level throughout the year. In the first half of 2007, we have performed significantly better than this initial expectation.

One of the benefits of an integrated structure is the natural financial hedge afforded by our upstream oil production combined with our downstream oil consumption. Since we process a form of crude oil in our downstream that is very similar to that which we produce in the upstream, we have a natural financial hedge on those barrels. As a result, our risk management program going forward will aim to protect Funds From Operations across the entire integrated structure, rather than the specific business segments independently. To that end, we further enhanced our risk management program in the second quarter by entering into contracts that provide a floor price on 20,000 bbl/d of refined product through 2008, consisting of 8,000 bbl/d of heavy fuel oil and 12,000 bbl/d of heating oil (distillate or diesel products). We will continue to seek additional opportunities that reduce future downside risk and enable us to 'lock in' a floor price on a portion of our crack spread or refining margin exposure.

In light of the positive current and future anticipated environment for the refining business, we are looking for additional opportunities to grow and expand margins within our retail marketing sector and are also making progress on the visbreaker expansion project sanctioned in March. This project will effectively upgrade approximately 1,500 bbl/d of heavy fuel oil into higher value distillate products, resulting in very attractive returns and a quick payout. Over the past several months, we began undertaking a detailed review and scoping of longer-term projects that provide good value-adding growth potential. Such projects include the installation of a coker to enable upgrading of the residual heavy fuel oil (with value creating potential similar to the visbreaker project), or an expansion of the facility that would leverage off the existing infrastructure to provide cost-effective incremental processing capacity. To further support these efforts and bolster the strength of our management team, we have hired a seasoned management consultant, Mr. Brad Aldrich, who brings many years of experience in managing and growing a downstream organization. His expertise will assist us with the ongoing operation and growth of our refining and marketing business. We are very pleased to welcome Brad to our team.

Upstream Operations

At the conclusion of another very active winter drilling season through the first quarter, we turned our attention to sustainability and focused on positioning for the future. We successfully completed a series of rationalization and consolidation transactions that help create a more concentrated and efficient asset base. We successfully disposed of a small non-operated and non-core property in northwest Alberta, for which we received $25.5 million in cash and a greater working interest in some of our existing properties in Red Earth. The net effect was a positive cash injection coupled with a minor reduction in our overall production. Our teams continue to evaluate opportunities for us to consolidate our asset base, leading to more efficient operations, better use of our technical and human resources and ultimately a lower cost structure with improved returns for our unitholders.

In early June, we announced the acquisition of Grand Petroleum, a junior oil and natural gas company. Grand's first quarter 2007 production was approximately 3,400 boe/d weighted two-thirds to crude oil with reported year-end 2006 proved plus probable reserves of 6.0 million boe. The Grand assets consist of properties situated adjacent to Harvest's existing properties in Sylvan Lake / Markerville, eastern Alberta and southeast Saskatchewan, providing very good overlap and obvious synergies. For a total cost of approximately $145 million, the transaction adds production, reserves and an excellent suite of future development opportunities to our portfolio. The acquisition is anticipated to close in mid August, and will add approximately 1,000 boe/d to our 2007 annual average production.

Our portfolio of established properties gives us access to more than two billion barrels of original oil in place. During the second quarter we continued to focus on further developing the longer-term potential of these assets utilizing enhanced oil recovery schemes to increase ultimate production and recoverable reserves. We obtained positive preliminary results from an evaluation of polymer / surfactant (a form of liquid chemical) flooding in our Wainwright field, and are proceeding with project site selection, detailed cost estimates and preparation of regulatory applications. Other properties we are evaluating as candidates for implementing potential enhanced recovery technologies include Hayter in eastern Alberta, Kindersley in western Saskatchewan and Suffield in southern Alberta. At our Hay River property, we are also evaluating the impact of different pumping technologies and enhanced waterflood techniques following some steeper than expected production declines on new wells coming out of our 2007 winter drilling program. We will continue to update our unitholders in the quarters ahead on the efficacy of these enhanced oil recovery initiatives.

Subsequent to the end of the quarter, we successfully acquired 11,400 net acres of additional oilsands leases, bringing our total interest in oilsands opportunities to approximately 47,000 net acres of land with an estimated incremental one billion barrels of original oil in place on those lands. In the years ahead, the option value of our oilsands opportunities can be exercised through development and production that will enable Harvest to unlock the full potential of this asset base. In addition to our oilsands opportunities, we also remain well-positioned with respect to coal bed methane potential as that technology develops and more commercial production is developed in the future.

Similar to many of our peers in the Western Canadian Sedimentary Basin, our upstream operations team struggled through the second quarter. Production and reservoir performance issues were compounded by an extended period of wet weather, reducing production below expectations. We invested a modest $48.2 million of our $295 million annual capital budget in the second quarter, with drilling activity much lower than in the previous quarter. Production averaged just under 61,000 boe/d in the period, and we would expect these production levels to continue through the third and fourth quarters as the remaining $100 million of our capital activity budgeted for the last half of the year will not offset production declines. Given these challenges, we anticipate our 2007 annual production will average 61,000 boe/d, including the property dispositions and acquisitions discussed earlier. Although we are beginning to see some softening of the cost pressures that have affected the upstream industry over the past few years, our operating costs for the year are expected to average $12 - $13 / boe driven primarily by reduced volumes. We maintain an active effort to ensure that cost reduction opportunities are accessed with respect to operating, capital and general and administrative expenses. Across the organization, we remain committed to and are intently focused on ensuring maximum performance from our asset base.

Outlook

Generally we are pleased with the overall financial performance of the organization, and believe that the second quarter of 2007 is an excellent example of the benefits of a diversified cash flow stream afforded by our integrated structure. The different components of our business complement each other and can help to mitigate overall cash flow volatility; a key strategy for Harvest. This is further supported through the use of price risk management contracts, and we will continue to mitigate risk with the execution of our integrated risk management program. We will continue seeking favorable contracts that enable us to reduce our exposure to commodity prices, including prices for refined products, the crack spread, as well as electricity and currency exchange. Further risk mitigation is afforded by our proactive and responsible health, safety and environmental stewardship practices employed within both our upstream and downstream business segments. This is evidenced by the fact that our North Atlantic refinery has achieved over one million hours without a lost time incident, and employees in our upstream operations have recorded over 300,000 hours without a lost time incident.

Currently, the oil and natural gas industry in western Canada is undergoing a period of change. Although crude oil prices remain very strong, the impact of this is muted by a stronger Canadian dollar. Natural gas price uncertainty continues and despite some easing of cost pressures on the drilling and services side, labour costs remain very high. These impacts squeeze the margins for Canadian upstream producers. As a result, we would anticipate an active merger and acquisition market over the next few quarters as the industry restructures to produce more cost effective business models. Such challenges demonstrate the benefit we realize from having diversified operations, utilizing price risk management, and maintaining a strong balance sheet. Given our size, our strong assets, long-term approach and focus on sustainability, we believe Harvest is well positioned to participate in a rationalization of the trust sector.

As we move forward, we will continue to evaluate the opportunity to restructure our business to mitigate the impact of the royalty trust tax changes. We believe that the uniqueness of our asset base combined with our integrated structure presents good opportunities to restructure while maintaining access to competitive markets for our investors. We will continue to utilize careful management of the balance sheet and price risk management tools to reduce volatility for investors and maximize sustainability of our distribution.

Thank you for your continued interest in and support of Harvest Energy. We look forward to reporting on our future progress and direction in the quarters to come.

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, 2006 and 2005, our MD&A for the year ended December 31, 2006 as well as our interim consolidated financial statements and notes for the three and six month periods ended June 30, 2007 and 2006. The information and opinions concerning our future outlook are based on information available at August 13, 2007.

When reviewing our 2007 results and comparing them to 2006, readers should be cognizant that the 2007 results include six months of operations from our acquisition of Viking Energy Royalty Trust ("Viking") in February 2006, Birchill Energy Ltd. ("Birchill") in August 2006 and North Atlantic Refining Ltd. ("North Atlantic") in October 2006 whereas the comparative results in 2006 include only five months of operations from our acquisition of Viking. This significantly impacts the comparability of our operations and financial results for the three month and six month periods ended June 30, 2007 to the comparative period in the prior year.

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. 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.

In this MD&A, we use certain financial reporting measures that are commonly used as benchmarks within the oil and natural gas industry such as Funds From Operations, Earnings From Operations, Payout Ratio, Cash General and Administrative Expenses and Operating Netbacks and with respect to the refining industry, Gross Margin and Operating Income which are each defined in this MD&A including tables with their calculation. 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.

Consolidated Financial and Operating Highlights – Second Quarter 2007

- Funds From Operations of $244.5 million for the three month period ended June 30, 2007, an increase of $97.5 million over the prior year primarily due to our acquisitions in 2006 and continued strength in oil prices.
- North Atlantic's Funds From Operations of $138.4 million reflects the combined benefits of robust refining margins and solid refinery operating performance as throughput averaged 115,570 bbls/d.
- Funds From Operations of our petroleum and natural gas activity totaled $140.9 million with production averaging 60,989 boe/d, a narrowing of oil price differentials and reduced losses on the settlement of price risk management contracts.
- Balance sheet bolstered with a $200 million increase to our Three Year Extendible Revolving Credit Facility and the issuance of 7,302,500 Trust Units for net proceeds of $218.5 million while $125.6 million principal amount of convertible debentures were converted to 4,613,915 Trust Units.
- On June 8, 2007, we entered into a pre-acquisition agreement to acquire Grand Petroleum Inc. for aggregate consideration of approximately $145 million, an acquisition of approximately 3,400 boe/d of production and proved plus probable (P+P) reserves of 6 million boe, comprised of approximately 67% of oil. In early August 2007, we completed the acquisition and will include these operations with Harvest's in the Third Quarter.

- Maintained our monthly distributions of $0.38 per trust unit through the quarter resulting in a Payout Ratio of 63% and announced the continuation of a $0.38 per trust unit monthly distribution for the third quarter of 2007.

SELECTED INFORMATION

The table below provides a summary of our financial and operating results for the three and six month periods ended June 30, 2007 and 2006. Detailed commentary on individual items within this table is provided elsewhere in this MD&A.

	Three Months Ended June 30			**Six Months Ended June 30**		
($000s except where noted)	**2007**	2006	Change	**2007**	2006	Change
Revenue, net[1]	**1,137,638**	233,128	388%	**2,148,732**	364,560	489%
Funds From Operations	**244,461**	147,010	66%	**458,402**	247,981	85%
Per trust unit, basic	**$ 1.83**	$ 1.45	26%	**$ 3.51**	$ 2.70	30%
Per trust unit, diluted	**$ 1.62**	$ 1.43	13%	**$ 3.13**	$ 2.66	18%
Net Income[3]	**6,248**	60,682	(90%)	**76,098**	26,745	185%
Per trust unit, basic	**$ 0.05**	$ 0.60	(92%)	**$ 0.58**	$ 0.29	100%
Per trust unit, diluted	**$ 0.05**	$ 0.60	(92%)	**$ 0.58**	$ 0.29	100%
Distributions declared	**154,057**	115,889	33%	**299,327**	210,701	42%
Distributions declared, per trust unit	**$ 1.14**	$ 1.14	-%	**$ 2.28**	$ 2.25	1%
Payout ratio [2]	**63%**	79%	(16%)	**65%**	85%	(20%)
Bank debt				**1,047,965**	227,544	361%
Senior debt				**258,387**	279,050	(7%)
Convertible Debentures				**655,396**	240,246	173%
Total long-term financial liabilities				**1,961,748**	746,840	163%
Total assets				**5,613,333**	3,455,918	62%
PETROLEUM AND NATURAL GAS OPERATIONS						
Daily Production						
Light to medium oil (bbl/d)	**27,586**	28,951	(5%)	**27,311**	26,497	3%
Heavy oil (bbl/d)	**14,719**	13,037	13%	**15,164**	14,045	8%
Natural gas liquids (bbl/d)	**2,338**	2,016	16%	**2,417**	1,865	30%
Natural gas (mcf/d)	**98,078**	96,848	1%	**99,671**	85,158	17%
Total daily sales volumes (boe/d)	**60,989**	60,145	1%	**61,504**	56,600	9%
Cash capital expenditures	**48,221**	54,230	(11%)	**196,708**	157,469	25%
REFINING AND MARKETING OPERATIONS						
Average daily throughput (bbl/d)	**115,570**	-	n/a	**114,646**	-	n/a
Aggregate throughput (mbbl)	**10,517**	-	n/a	**20,751**	-	n/a
Average Refining Margin (US$/bbl)	**15.64**	-	n/a	**13.69**	-	n/a
Cash capital expenditures	**9,871**	-	n/a	**14,754**	-	n/a

(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) Net Income includes a future income tax expense of $177.7 million for the three and six months ended June 30, 2007. Please see Note 14 to the Consolidated Financial Statements for further information.

REVIEW OF SECOND QUARTER PERFORMANCE

Harvest is an integrated energy trust with our petroleum and natural gas business focused on the operation and development of quality properties in western Canada and our refining and marketing business focused on the safe operation of a medium gravity sour crude hydrocracking refinery (the "Refinery") and a petroleum marketing business both located in the province of Newfoundland and Labrador.

In the Second Quarter of 2007, we generated Funds From Operations of $244.5 million ($1.83 per basic trust unit) compared to $147.0 million ($1.45 per basic trust unit) in the second quarter of 2006. This $97.5 million increase is predominantly attributed to the incremental contribution from our North Atlantic acquisition, lower cash settlements on commodity price risk management contracts along with acquisitions in our petroleum and natural gas operations offsetting weakness in natural gas prices and production declines. During the Second Quarter of 2007, our North Atlantic business unit benefited from very strong prices for gasoline and distillate products while our refinery throughput averaged 115,570 bbls/d. During the same period, our petroleum and natural gas operations reflected a softening of production and a widening of the price differentials between western Canadian crudes (Edmonton Par and Bow River) and the West Texas Intermediate ("WTI") benchmark price as compared to the prior year. In addition, the settling of our price risk management contracts resulted in a $6.8 million loss this quarter as the floor price of our oil price contracts averaged US$55.67 compared to a floor price of US$42.11 and a $23.9 million loss in the prior year.

During the Second Quarter of 2007, North Atlantic's Funds From Operations totaled $138.4 million as compared to $94.7 million in the prior quarter. Our refinery operated at near capacity reporting 115,570 bbls/d of throughput and benefited from a 32% increase in gross margin to US$15.64 per bbl as compared to 113,711 bbls/d of throughput and a gross margin in US$11.85 per bbl in the prior quarter. During the Second Quarter of 2007, the industry benchmark "2-1-1 crack spread" averaged US$22.00, as compared to US$12.31 in the prior quarter, an 79% increase. North Atlantic's gross margin did not enjoy the full benefit of improving crack spreads as the significant narrowing of the price differential on the medium gravity sour crude oil processed by North Atlantic increased our costs relative to the WTI benchmark price, the cost of our purchased vacuum gas oil increased and our refinery produced approximately 25% heavy fuel oil which is not factored into the "2-1-1 Crack Spread" benchmark. The refinery operating costs were as anticipated.

Production from our petroleum and natural gas operations for the Second Quarter of 2007 was 60,989 boe/d, including three months of production from the assets acquired in the Birchill acquisition of August 2006, as compared to 60,145 boe/d in the Second Quarter of 2006. In 2007, our Second Quarter production is lower than our First Quarter of 62,024 boe/d as increased production from our Hay River capital program and recent acquisitions was more than offset by shortfalls in production attributed to delays in capital programs and well servicing due to an extended wet spring break-up. Further, the prices realized for our production suffered from a softening of the prices for light sweet crude oil as well as from a widening of the differential between the price received for heavy crude oil in western Canada and Edmonton Par price: prices realized on our production were 24% lower for heavy oil and 9% lower for light to medium oil as compared to the Second Quarter of 2006. During the Second Quarter of 2007, our price for natural gas was 15% higher than in the prior year with the year-to-date price 8% higher than in the prior year. Our gross revenues during the Second Quarter of 2007 were 7% lower before the impact of price risk management and royalties while our net revenues after deducting realized price risk management losses were only 2% lower than the prior year. On a year-to-date basis, our gross revenues in 2007 were up 8% before the impact of price risk management and royalties and were 14% higher after deducting realized price risk management losses. In 2007, unit operating costs of $13.13 per boe for the Second Quarter and $13.00 per boe for the year-to-date reflect the impact of the higher than anticipated cost to operate the assets acquired with the Birchill acquisition as well as the increasing cost of operating in western Canada. Overall, our operating netback during the Second Quarter of 2007 was $27.12 per boe compared to $30.81 in the comparative period in 2006 with the year-to-date netback aggregating to $28.44 in 2007 as compared to $28.24 a year earlier.

During the Second Quarter, Harvest bolstered its balance sheet with an issuance of 7,302,500 Trust Units for net proceeds of $218.5 million, an extension of the maturity date of our Three Year Extendible Revolving Credit Facility as well as an increase in the amount of the Facility from $1.4 billion to $1.6 billion. In addition, the trading value of our Trust Units has encouraged $125.6 million of principal amount of convertible debentures to convert into 4,613,915 Trust Units. At the end of June 2007, Harvest's total debt to total capitalization was 36% and its bank debt to annualized earnings before interest, taxes, depreciation and amortization ("EBITDA") was 2.3 times. Subsequent to the end of June 2007, an additional $35.1 million principal amount of convertible debentures were converted into 1,281,975 Trust Units further enhancing our balance sheet.

On June 11, 2007, Harvest and Grand Petroleum Inc. ("Grand") entered into a pre-acquisition agreement whereby Harvest agreed it would make an offer to purchase all of the outstanding shares of Grand for $3.84 per share in cash subject to there being at least 662/3% of the outstanding shares tendered to the offer. The acquisition of Grand represents an aggregate consideration of approximately $145 million consisting of $110 million for the shares of Grand and a further $35 million commitment in respect of the assumption of Grand's bank debt and estimated working capital deficiency. During the three months ended March 31, 2007, Grand's production averaged 3,409 boe/d comprised of 2,322 barrels of oil and 6,521 mcf of natural gas with estimated total proved plus probable (P+P) reserves of 6 million boe resulting in acquisition economics of approximately $42,500 per flowing boe and $24 per boe of proved plus probable reserve. In addition, Grand also has 65,000 acres (46,000 net acres) of undeveloped land and supporting seismic. In early August 2007, Harvest completed its acquisition of Grand and will commence including these operations in its results during the Third Quarter of 2007. Harvest will fund this acquisition from its existing $1.6 billion Three Year Extendible Revolving Credit Facility.

Distributions declared during the Second Quarter of 2007 totaled $1.14 per trust unit resulting in our payout ratio being 63% of Funds From Operations compared to $1.14 and 79% (before deducting $0.7 million of cash transaction costs relating to the Viking acquisition) in the prior year. For the Second Quarter of 2007, the participation in our distribution reinvestment plan ("DRIP") was approximately 29% while in the Second Quarter of 2006 the participation rate was approximately 41%. Our DRIP enables us to settle our distributions through the issue of units, allowing us to use the cash to reinvest in our capital program or for debt repayment.

During the Second Quarter of 2007, the Government of Canada enacted Bill C-52 Budget Implementation Act, 2007 ("Bill C-52") which contained the legislative provisions to apply a 31.5% tax on distributions from Canadian publicly traded income trusts. With these provisions enacted, we have recorded a future income tax provision of $177.7 million in our Second Quarter financial results to reflect a 31.5% tax rate on substantially all of the timing differences between the book value and the tax basis of assets held by our mutual fund trust. This is a non-cash item that has no current impact on our cash from operating activities: however, it has resulted in our reporting net income of $6.2 million for the three months ended June 30, 2007 as compared to net income of $60.7 million in the prior year.

Business Segments

As a result of the acquisition of North Atlantic in October of 2006, our business has two segments: petroleum and natural gas in western Canada and refining and marketing in the Province of Newfoundland and Labrador. Our petroleum and natural gas business consists of our production and development activities in western Canada and our refining and marketing business consists of a medium gravity sour crude hydrocracking refinery with a crude oil throughput capacity of 115,000 barrels per day, 61 retail gas stations, 3 cardlock locations as well as wholesale gasoline and home heating businesses. The following table presents selected financial information for our two business segments:

	Three Months Ended June 30				**Six Months Ended June 30**			
	2007			2006	**2007**			2006
(in $000's)	**Petroleum and natural gas**	**Refining and marketing**	**Total**	Total(3)	**Petroleum and natural gas**	**Refining and marketing**	**Total**	Total(3)
Revenue(1)	240,415	897,223	1,137,638	233,128	467,464	1,681,268	2,148,732	364,560
Earnings From Operations(2)	37,200	116,014	153,214	62,449	64,634	191,370	256,004	39,285
Capital expenditures	48,221	9,871	58,092	54,230	196,708	14,754	211,462	157,469
Total assets	3,952,579	1,660,754	5,613,333	3,455,918	3,952,579	1,660,754	5,613,333	3,455,918

(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) For the three and six month periods ended June 30, 2006, Harvest's operations consisted of only petroleum and natural gas operations.

PETROLEUM AND NATURAL GAS OPERATIONS

Financial and Operating Results

Throughout the Second Quarter of 2007, our production mix was approximately 49% light to medium oil and natural gas liquids, 24% heavy oil and 27% natural gas with our core areas of production located in Alberta, Saskatchewan and northeastern British Columbia.

The following summarizes the financial and operating information of our petroleum and natural gas operations for the three and six month periods ended June 30, 2007 and 2006:

(in $000's)	**Three Months Ended June 30**			**Six Months Ended June 30**		
	2007	2006	Change	**2007**	2006	Change
Revenues	**$ 286,611**	$ 309,010	(7%)	**$ 577,727**	$ 533,285	8%
Royalties	**(53,548)**	(51,907)	3%	**(103,197)**	(95,022)	9%
Realized losses on price risk management contracts[1]	**(6,266)**	(24,118)	(74%)	**(7,063)**	(33,326)	(79%)
Unrealized gains (losses) on price risk management contracts	**14,178**	(115)	12,429%	**57**	(41,112)	(100%)
Net revenues excluding realized losses on electric power fixed price contracts	**240,975**	232,870	3%	**467,524**	363,825	29%
Operating expenses	**72,333**	60,593	19%	**144,629**	110,687	31%
Realized (gains) losses on electric power fixed price contracts	**560**	(258)	317%	**60**	(735)	108%
Net operating expenses	**72,893**	60,335	21%	**144,689**	109,952	32%
General and administrative expenses	**16,061**	8,513	89%	**26,165**	14,325	83%
Transportation and marketing	**3,375**	4,065	(17%)	**6,187**	5,688	9%
Transaction costs	**-**	330	n/a	**-**	12,072	n/a
Depreciation, depletion, amortization and accretion	**111,446**	97,178	15%	**225,849**	182,503	24%
Earnings From Operations[2]	**37,200**	62,449	(40%)	**64,634**	39,285	65%
Cash capital expenditures (excluding acquisitions)	**48,221**	54,230	(11%)	**196,708**	157,469	25%
Property and business acquisitions, net of dispositions	**(21,801)**	290	(7,618%)	**9,152**	23,672	(61%)
Daily sales volumes						
Light to medium oil (bbl/d)	**27,586**	28,951	(5%)	**27,311**	26,497	3%
Heavy oil (bbl/d)	**14,719**	13,037	13%	**15,164**	14,045	8%
Natural gas liquids (bbl/d)	**2,338**	2,016	16%	**2,417**	1,865	30%
Natural gas (mcf/d)	**98,078**	96,848	1%	**99,671**	85,158	17%
Total (boe/d)	**60,989**	60,145	1%	**61,504**	56,600	9%

(1) Includes amounts realized on WTI, heavy oil price differential and currency exchange contracts and excludes amounts realized on electric power fixed price contracts.
(2) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.

Commodity Price Environment

	Three Months Ended June 30			Six Months Ended June 30		
Benchmarks	**2007**	2006	Change	**2007**	2006	Change
West Texas Intermediate crude oil (US$ per barrel)	**65.03**	70.70	(8%)	**61.60**	67.09	(8%)
Edmonton light crude oil ($ per barrel)	**71.89**	78.63	(9%)	**69.50**	73.80	(6%)
Bow River blend crude oil ($ per barrel)	**50.78**	60.59	(16%)	**50.41**	50.28	0%
AECO natural gas daily ($ per mcf)	**7.07**	6.01	18%	**7.23**	6.67	8%
AECO natural gas monthly ($ per mcf)	**7.37**	6.27	18%	**7.41**	7.77	(5%)
Canadian / U.S. dollar exchange rate	**0.911**	0.891	2%	**0.882**	0.878	0%

The West Texas Intermediate ("WTI") crude oil price was 8% lower during the three and six month periods ended June 30, 2007 than in the prior year. The reduction in the average Edmonton light crude oil price ("Edmonton Par") closely mirrors the change in the WTI price as the Canadian/U.S. dollar exchange rate was substantially unchanged during the comparative six month periods and with the three month period ended June 30, 2007 reflecting a modest appreciation of the Canadian dollar over the US dollar over the prior year. The narrowing of the differentials between WTI and Edmonton Par in 2007 has continued with the strong demand for Canadian light crude resulting in an average premium of $0.51 realized for Edmonton Par in the three month period ended June 30, 2007 as compared to a $0.72 discount in the prior year.

For the six month period ended June 30, 2007, prices for heavy crude oil of $50.41 was essentially unchanged from $50.28 in the prior year as the $4.30 reduction in the Edmonton Par price was offset by a narrowing heavy oil differential. Whereas during the three months ended June 30, 2007, the prices for heavy oil were 16% lower than in the prior year as compared to the Edmonton Par price which was 9% lower reflecting an additional $3.07 widening of the heavy oil differential from 22.9% in 2006 to 29.4% in the current year. The heavy oil differential fluctuates based on a combination of factors including the level of heavy oil inventories, pipeline capacity to deliver heavy crude to U.S. markets as well as the seasonal demand for heavy oil. In the Second Quarter of 2007, heavy oil demand was impacted by planned maintenance and unplanned disruptions in U.S. heavy oil refining as well as by a late start to the asphalt paving season in western Canada. Shown below are heavy oil differentials for the last eight quarters.

	2007		2006				2005	
Differential Benchmarks	**Q2**	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3
Bow River Blend differential to Edmonton Par	**29.4%**	**25.4%**	30.3%	25.8%	22.9%	42.0%	40.0%	28.2%

Compared to the prior year, natural gas prices during the Second Quarter were 18% higher reflecting the influence of lower natural gas storage inventories in 2007 as well as a lower level of weekly injections.

Realized Commodity Prices

The following table provides our average price realized by product as well as our net realized price before and after realized losses on price risk management contracts for the three and six month periods ended June 30, 2007 and 2006.

	Three Months Ended June 30			Six Months Ended June 30		
	2007	2006	Change	**2007**	2006	Change
Light to medium oil ($/bbl)	**59.20**	65.30	(9%)	**58.93**	59.67	(1%)
Heavy oil ($/bbl)	**43.27**	56.73	(24%)	**44.15**	45.35	(3%)
Natural gas liquids ($/bbl)	**58.67**	63.35	(7%)	**55.64**	60.26	(8%)
Natural gas ($/mcf)	**7.57**	6.59	15%	**7.81**	7.23	8%
Average realized price ($/boe)	**51.64**	56.46	(9%)	**51.90**	52.06	0%
Realized price risk management losses ($/boe)[(1)]	**(1.13)**	(4.41)	(74%)	**(0.63)**	(3.25)	(81%)
Net realized price ($/boe)	**50.51**	52.05	(3%)	**51.27**	48.81	5%

(1) Includes amounts realized on WTI, heavy oil price differential and foreign exchange contracts and excludes amounts realized on electric power fixed price contracts.

During the Second Quarter of 2007, our average realized price was 9% lower before the realized losses on our price risk management contracts but only 3% lower after deducting the realized losses on these contracts as compared to the prior year. On a year-to-date basis, our average realized price was essentially unchanged before the realized losses on our price risk management contracts and 5% higher after deducting the realized losses on these contracts as compared to the prior year. As compared to the prior year, the significant reductions in our realized losses on price risk management in 2007 is attributed to the higher contracted floor prices although the lower WTI price in the Second Quarter of 2007 was also a contributing factor.

In the Second Quarter and for the first six months of 2007, the realized price of our light to medium oil sales was 9% and 1% lower than in the comparative period in the prior year while the Edmonton Par price decreased 9% and 6% over the same periods. While the Second Quarter price changes are as expected, the year-to-date change reflects the improved quality differentials realized in the First Quarter of 2007 for our light to medium oil production relative to the Edmonton Par benchmark price as the primary reason for our higher than expected realized price.
During the Second Quarter of 2007, the realized price on our heavy oil production was 24% lower than in the prior year compared to a 16% reduction in the Bow River price reflecting the relatively heavier gravity of our recent heavy oil acquisitions in December 2006 and March 2007, as well as a lower price for the sale of this production at the wellhead. The majority of our heavy oil sales are priced off of the Bow River benchmark price. On a year-to-date basis, the realized price for our heavy oil production was 3% lower than for the first six months in the prior year as compared to a relatively unchanged price for the Bow River benchmark price for much the same reasons.

During the Second Quarter of 2007, the realized price for our natural gas production was 15% higher than in the prior year as compared to an 18% increase in the benchmark AECO prices and for the year-to-date prices, our realized price is 8% higher than in the prior year as compared to an 8% increase in the benchmark AECO price for daily pricing. Typically, we sell approximately 60% of our natural gas sales priced off the AECO daily benchmark, approximately 30% sold off the AECO monthly benchmark with the remainder sold to aggregators.

Sales Volumes

The average daily sales volumes by product were as follows:

	Three Months Ended				
	June 30, 2007		March 31, 2007		
	Volume	**Weighting**	Volume	Weighting	% Volume Change
Light to medium oil (bbl/d)(1)	**27,586**	**45%**	27,034	44%	2%
Heavy oil (bbl/d)	**14,719**	**24%**	15,614	25%	(6%)
Total oil (bbl/d)	**42,305**	**69%**	42,648	69%	(1%)
Natural gas liquids (bbl/d)	**2,338**	**4%**	2,496	4%	(6%)
Total liquids (bbl/d)	**44,643**	**73%**	45,144	73%	(1%)
Natural gas (mcf/d)	**98,078**	**27%**	101,282	27%	(3%)
Total oil equivalent (boe/d)	**60,989**	**100%**	62,024	100%	(2%)

	Six Months Ended June 30				
	2007		2006		
	Volume	**Weighting**	Volume	Weighting	% Volume Change
Light to medium oil (bbl/d)(1)	**27,311**	**44%**	26,497	47%	3%
Heavy oil (bbl/d)	**15,164**	**25%**	14,045	25%	8%
Total oil (bbl/d)	**42,475**	**69%**	40,542	72%	5%
Natural gas liquids (bbl/d)	**2,417**	**4%**	1,865	3%	30%
Total liquids (bbl/d)	**44,892**	**73%**	42,407	75%	6%
Natural gas (mcf/d)	**99,671**	**27%**	85,158	25%	17%
Total oil equivalent (boe/d)	**61,504**	**100%**	56,600	100%	9%

(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) and is classified as a light to medium oil, however, it benefits from a heavy oil royalty regime and therefore would be classified as heavy oil according to NI 51-101.

For the three month period ended June 30, 2007, average production was 2% lower than in the prior quarter as reduced volumes of heavy oil and natural gas more than offset the 2% increase in light to medium oil. Had we compared our Second Quarter production with the prior year, much of the increases would be attributed to the acquisition of Birchill in the Third Quarter of 2006 as well as two small heavy oil acquisitions in December 2006 and March 2007.

Light to medium oil production in the Second Quarter of 2007 is 552 bbl/d higher as compared to the immediately prior quarter primarily due to approximately 1,200 bbl/d of the incremental production from the Hay River area offset by modest shortfalls in other areas, attributed to delays in well servicing due to extended wet weather conditions. The Hay River area benefited from a successful acceleration of its capital program overlapping the Fourth Quarter of 2006 and the First Quarter of 2007. Second Quarter Hay River production included production from new wells and a return to normal operations after significant capital activity and routine maintenance turnarounds disrupted production in the First Quarter. Access to the Hay River area is limited to winter only and requires drilling and extensive well servicing to be concentrated during this period. In 2007, our Hay River production averaged 5,451 bbl/d in the First Quarter and 6,719 bbl/d during the Second Quarter. The more significant production shortfalls were in our Red Earth and southeast Saskatchewan areas where well servicing and new well tie-ins were delayed due to extended wet weather conditions and in Markerville where production was curtailed due to maintenance turnarounds at third party processing facilities. Year-to-date, our light to medium oil production is up 814 bbl/d primarily due to the current year including an extra month of production from the Viking acquisition completed in February 2006.

During the Second Quarter of 2007, our heavy oil production was 895 bbl/d lower than in the First Quarter primarily due to wet spring weather conditions impacting our operations at Suffield and Hayter as soft road conditions limited the movement of well servicing equipment. As well, extended "military lockouts" also reduced production at Suffield during the Second Quarter where our operations are located on a Canadian Forces Base. At our heavy oil operations in the Hayter area, production was ahead of the prior year, and our capital program for this area is planned to be executed in the Third Quarter.

Natural gas production in the Second Quarter continues to lag behind our expectations despite the addition of approximately 2,900 mcf/d from a recent discovery at Cairo in west central Alberta. We had expected significant growth in our natural gas production as compared to the prior year primarily due to the acquisition of Birchill in August 2006. This acquisition added approximately 16,500 mcf/d of incremental natural gas production at that time, but has experienced higher than anticipated decline. As well, maintenance turnarounds at third party gas processing facilities severely impacted our natural gas production during the Second Quarter of 2007. For the balance of 2007, our natural gas focus will be limited to achieving better than average production from existing assets and expediting the tie-in of wells drilled in late 2006.

Revenues

	Three Months Ended June 30		
(000s)	**2007**	2006	Change
Light to medium oil sales	**$ 148,619**	$ 172,043	(14%)
Heavy oil sales	**57,952**	67,300	(14%)
Natural gas sales	**67,563**	58,045	16%
Natural gas liquids sales and other	**12,477**	11,622	7%
Total sales revenue	**286,611**	309,010	(7%)
Realized risk management contract losses[1]	**(6,266)**	(24,118)	(74%)
Total revenues including realized risk management contract losses	**280,345**	284,892	(2%)
Realized (losses) / gains on electric power price risk management contracts	**(560)**	258	(317%)
Unrealized gains / (losses) on price risk management contracts	**14,178**	(115)	12,429%
Net Revenues, before royalties	**293,963**	285,035	3%
Royalties	**(53,548)**	(51,907)	3%
Net Revenues	**$ 240,415**	$ 233,128	3%

	Six Months Ended June 30		
(000s)	**2007**	2006	Change
Light to medium oil sales	**$ 291,290**	$ 286,166	2%
Heavy oil sales	**121,170**	115,287	5%
Natural gas sales	**140,933**	111,489	26%
Natural gas liquids sales and other	**24,334**	20,343	20%
Total sales revenue	**577,727**	533,285	8%
Realized risk management contract losses[1]	**(7,063)**	(33,326)	(79%)
Total revenues including realized risk management contract losses	**570,664**	499,959	14%
Realized gains on electric power price risk management contracts	**(60)**	735	(108%)
Unrealized losses on price risk management contracts	**57**	(41,112)	100%
Net Revenues, before royalties	**570,661**	459,582	24%
Royalties	**(103,197)**	(95,022)	9%
Net Revenues	**$ 467,464**	$ 364,560	28%

[1] Includes amounts realized on WTI, heavy oil price differential and currency exchange contracts, and excludes amounts realized on electricity contracts.

Our revenue is impacted by changes to production volumes, commodity prices, and currency exchange rates. During the Second Quarter of 2007, total sales revenue of $286.6 million was $22.4 million lower than in the prior year, of which $26.7 million is attributed to lower realized prices and is offset by $4.3 million in higher volumes. Year-to-date, total sales revenues were $577.7 million, an increase of $44.4 million over the prior year with $46.1 million of the increase attributed to increased volume primarily due to the acquisition of Birchill in August of 2006 and the acquisition of Viking in February 2006.

Light to medium oil sales revenue for the three month period ended June 30, 2007 was $23.4 million lower than in the comparative period, comprised of a $15.3 million unfavourable price variance resulting from the 9% reduction in the realized price coupled with an $8.1 million unfavourable volume variance. The unfavourable volume variance over the prior year is primarily due to the delays in well servicing as a result of extended wet weather conditions in 2007. The year-to-date light to medium oil sales revenues have increased over the prior year by $5.1 million with the impact of incremental volume from the acquisition of Birchill and Viking in 2006 substantially offset by a modest reduction in the realized price and the unfavourable volume variance in the Second Quarter of 2007.

During the Second Quarter of 2007, our heavy oil sales revenue of $58.0 million was $9.3 million lower than in the prior year comprised of an $18.0 million unfavourable price variance somewhat offset by a $8.7 million favourable volume variance as the recent acquisitions of heavy oil properties and the incremental production from recent drilling have more than offset the production shortfalls at Suffield and Hayter. Year-to-date, our heavy oil revenues are $5.9 million higher than in the six months ended June 30, 2006 as a $9.2 million favourable volume variance (again with recent acquisitions and incremental production more than offsetting shortfalls) is somewhat offset by a $3.3 million unfavourable reduction in the price realized on our heavy oil production.

Natural gas sales revenue increased by $9.5 million for the three months ended June 30, 2007 over the prior year primarily due to an $8.7 million favourable price variance coupled with a modest $800,000 favourable volume variance. Year-to-date, natural gas sales revenues are $29.4 million higher than in the first six months of 2006 with a $0.58 per mcf price increase accounting for a $10.5 million favourable variance coupled with a $18.9 million favourable volume variance primarily attributed to the incremental natural gas production for the acquisition of Birchill in August of 2006 and Viking in February of 2006.

During the Second Quarter of 2007, our natural gas liquids and other sales revenue increased by $855,000 compared to the prior year while year-to-date, our revenues increased by $4.0 million. During the Second Quarter of 2007, the increased revenues is the net result of a $1.9 million favourable volume variance being offset by lower realized prices as compared to the year-to-date increase being comprised of a $6.0 million favourable volume variance offset by a $2.0 million reduction attributed to lower realized prices in 2007. Generally, the natural gas liquids volume variance will be aligned with our production of natural gas while the price variances will be aligned with the prices realized for our oil production.

Price Risk Management

Details of our price risk management contracts outstanding at June 30, 2007 are included in Note 16 of our interim consolidated financial statements for the three and six month periods ended June 30, 2007 filed on SEDAR at www.sedar.com. Subsequent to acquiring North Atlantic, Harvest's participation in the crude oil value chain was extended to include the price of refined products produced by North Atlantic, principally gasoline, distillates (which encompasses low sulphur diesel fuel, jet fuel and heating oil) and heavy fuel oil. This results in our price protection of future cash flows including price protection on refined products and during the Second Quarter of 2007, we commenced contracting our oil price risk management contracts based on refined product pricing. For purposes of this MD&A and the segmented reporting in Note 17 of our financial statements, our price risk management contracts are presented as either relating to our petroleum and natural gas operations or our refining and marketing operations according to the price exposure that is being managed. For refined product price contracts, North Atlantic has entered into inter-company contracts with our petroleum and natural gas operation to shift the WTI price protection to our petroleum and natural gas operations.

The table below provides a summary of net gains and losses on our price risk management contracts for both the three and six month periods ended June 30, 2007 and 2006:

	Three Months Ended June 30					
	2007					2006
(000s)	Oil	Gas	Currency	Electricity	Total	Total
Realized (losses) / gains on price risk management contracts	$ (7,043)	$ 130	$ 647	$ (560)	$ (6,826)	$ (23,860)
Unrealized (losses) / gains on price risk management contracts	872	7,355	9,703	1,735	19,665	(148)
Amortization of deferred gains relating to risk management contracts	-	-	-	-	-	33
Total (losses) / gains on third party risk management contracts	$ (6,171)	$ 7,485	$ 10,350	$ 1,175	$ 12,839	$ (23,975)
Unrealized loss on WTI portion of refined product price risk management contracts	(5,487)	-	-	-	(5,487)	-
Total (losses) / gains on price risk management contracts	$ (11,658)	$ 7,485	$ 10,350	$ 1,175	$ 7,352	$ (23,975)

	Six Months Ended June 30					
	2007					2006
(000s)	Oil	Gas	Currency	Electricity	Total	Total
Realized (losses) / gains on price risk management contracts	$ (6,753)	$ 291	$ (601)	$ (60)	$ (7,123)	$ (32,591)
Unrealized (losses) / gains on price risk management contracts	(11,368)	4,539	11,065	1,308	5,544	(41,445)
Amortization of deferred gains relating to risk management contracts	-	-	-	-	-	333
Total (losses) / gains on third party risk management contracts	$ (18,121)	$ 4,830	$ 10,464	$ 1,248	$ (1,579)	$ (73,703)
Unrealized losses on WTI portion of refined product price risk management contracts	(5,487)	-	-	-	(5,487)	-
Total (losses) / gains on price risk management contracts	$ (23,608)	$ 4,830	$ 10,464	$ 1,248	$ (7,066)	$ (73,703)

During the three months ended June 30, 2007, our realized net loss on commodity price risk management contracts related to our petroleum and natural gas operations was $6.8 million as compared to a loss of $23.9 million in the Second Quarter of 2006. Year-to-date, our petroleum and natural gas price risk management program has realized a net loss of $7.1 million as compared to losses of $32.6 million during the first six months of 2006. The principal difference between 2007 and 2006 is the significant reduction in the losses on crude oil price contracts as the floor price on these participating contracts has increased from an average of US$42.11 in 2006 to an average of US$55.67 in 2007. In both 2007 and the prior year, the results of our natural gas price, currency exchange rate and electricity price contracts did not result in either a material gain or loss.

For the three months ended June 30, 2007, our oil price contracts realized losses of $7.0 million as compared to a gain of $290,000 during the First Quarter of 2007 and losses of $26.9 million in the three months ended June 30, 2006. During the Second Quarter of 2007, we had WTI price risk management contracts on 30,000 bbl/d with downside protection at an average floor price of US $55.67 per bbl and 73% participation in prices over US $55.67 as compared to 26,250 bbl/d contracted with downside protection at an average floor price of US$42.11 and 59% participation in prices above US$42.11 in the prior year. As compared to 2006, the WTI price during the Second Quarter of 2007 averaged US$65.03, a decrease of US$5.67 from US$70.70 in the prior year. The reduction of our losses on oil price risk management contracts in 2007 is the result of the higher contracted floor prices and to a lesser extent, lower WTI prices.

During the Second Quarter of 2007, North Atlantic entered into price risk management contracts with respect to an aggregate of 20,000 bbl/d of NYMEX heating oil and Platts fuel oil for the period from January 2008 through December 2008 and concurrently entered into the following inter-company contracts to shift the WTI price protection to our petroleum and natural gas operations:

Quantity	Contract Type	Contracted Price
4,000 bbls/d	Price Collar	Price Floor – US$66.00 and Price Cap – US$75.79
16,000 bbls/d	3 Way Structure	If WTI price is over US$79.57, price received is US$79.57
		If WTI price is between US$79.57 and $67.03, price received is market price
		If WTI price is between US$67.03 and US$52.33, price received is US$67.03
		If WTI price is under US$52.33, price received is market price plus US$14.70

During the Second Quarter of 2007, these are the inter-company WTI contracts that have given rise to the $5.5 million unrealized loss for the petroleum and natural gas operations while providing a $5.5 million unrealized gain for North Atlantic.

During the First Quarter of 2007, we entered into the following two natural gas price risk management contracts to protect our cash flows in the event of soft natural gas prices in the summer of 2007:

Quantity	Term	Contracted Price
20,000 GJ/d	April 2007 – March 2008	If AECO price is below \$5.00, price received is market price plus \$2.00 If AECO price is between \$5.00 and \$7.00, price received is \$7.00 If AECO price is between \$7.00 and \$10.25, price received is market price. If AECO price is over \$10.25, price received is \$10.25
10,000 GJ/d	April 2007 – March 2008	If AECO price is below \$5.00, price received is market price plus \$2.00 If AECO price is between \$5.00 and \$7.00, price received is \$7.00 If AECO price is between \$7.00 and \$10.30, price received is market price. If AECO price is over \$10.30, price received is \$10.30

During the Second Quarter of 2007, we realized a gain of $130,000 as these contracts settled and in July of 2007, we entered into contracts to unwind these positions and collected net proceeds of $5.5 million that will be reflected as realized gains of $2.5 million, $2.1 million and $900,000 in the Third and Fourth Quarters of 2007 as well as the First Quarter of 2008, respectively being the respective periods to which the gains relate. Currently, we do not have any natural gas price risk management contracts in place.

During the First and Second Quarters of 2007, we had currency exchange rate contracts in place on US$8,750,000 per month at a fixed rate of approximately $0.89 which resulted in $1.2 million of loss and a $647,000 gain, respectively, as the exchange rate averaged approximately $0.85 during the First Quarter and approximately $0.91 during the Second Quarter. For the balance of 2007, we have contracts that fix the currency exchange rate on US$8,750,000 per month at an average rate of approximately $0.89. In addition, we have benefited from our U.S. dollar denominated debt, both the 7 7/8% Senior Notes and U.S. dollar denominated bank borrowings as we have accumulated a significant decrease in the Canadian dollar equivalent as the Canadian dollar appreciates against the U.S. dollar. However, the majority of this gain is currently unrealized which is not included in Funds from Operations.

During the Second Quarter of 2007, our electric power price risk management contracts realized a loss of $560,000 as compared to a gain of $500,000 in the First Quarter of 2007 and a gain of $258,000 in the Second Quarter of the prior year. We enter into these contracts to provide protection from rising electric power prices. During the Second Quarter of 2007, Alberta's electric power price averaged $49.97 per megawatt hour ("MWh") as compared to our contracted price of $56.69 per MWh. Additional details on these contracts is provided under the heading "Operating Expenses" of this MD&A.

During the Second Quarter of 2007, we recorded a net unrealized gain on our petroleum and natural gas price risk management contracts of $14.2 million comprised of gains on our natural gas, currency exchange rate and electricity price contracts of $18.8 million offset by unrealized losses of $4.6 million on our WTI price contracts including the inter-company contracts with North Atlantic. At June 30, 2007, our price risk management contracts, including the North Atlantic refined product contracts, had an unrealized mark-to-market deficiency of $5.0 million as compared to a mark-to-market deficiency of $1.9 million at December 31, 2006.

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 six months ended June 30, 2007, our net royalties as a percentage of gross revenue were 18.7% (16.8% - three months ended June 30, 2006) and 17.9% (17.8% - six months ended June 30, 2006) respectively and aggregated to $53.5 million ($51.9 million – three months ended June 30, 2006) and $103.2 million ($95.0 million – six months ended June 30, 2006). Our year to date net royalties as a percentage of gross revenue are in line with our expectations given our current mix of properties, while the second quarter royalty rate is slightly higher due to additional crown royalties assessed by the B.C. government on our Hay River properties.

Operating Expenses

	Three Months Ended June 30				
($000s)	**2007**	**Per BOE**	2006	Per BOE	Per BOE Change
Operating expense					
Power	**$ 11,368**	**$ 2.05**	$ 12,227	$ 2.23	(8%)
Workovers	**14,856**	**2.68**	12,843	2.35	14%
Repairs and maintenance	**16,115**	**2.90**	7,317	1.34	116%
Labour – internal	**3,536**	**0.64**	5,912	1.08	(41%)
Processing fees	**8,387**	**1.51**	4,774	0.87	74%
Fuel	**2,710**	**0.49**	2,382	0.44	11%
Labour – external	**3,835**	**0.69**	3,541	0.65	6%
Land leases and property tax	**5,406**	**0.97**	3,781	0.69	41%
Other	**6,120**	**1.10**	7,816	1.42	(23%)
Total operating expense	**72,333**	**13.03**	60,593	11.07	18%
Realized (gains)/loss on electric power price risk management contracts	**560**	**0.10**	(258)	(0.05)	300%
Net operating expense	**$ 72,893**	**$ 13.13**	$ 60,335	$ 11.02	19%
Transportation and marketing expense	**$ 3,375**	**$ 0.61**	$ 4,065	$ 0.74	(18%)

	Six Months Ended June 30				
($000s)	**2007**	**Per BOE**	2006	Per BOE	Per BOE Change
Operating expense					
Power	**$25,140**	**$ 2.26**	$ 24,255	$ 2.37	(5%)
Workovers	**32,019**	**2.88**	22,189	2.17	33%
Repairs and maintenance	**29,749**	**2.67**	11,945	1.17	128%
Labour – internal	**7,154**	**0.64**	9,845	0.96	(33%)
Processing fees	**16,554**	**1.49**	9,103	0.89	67%
Fuel	**4,640**	**0.42**	4,411	0.43	(2%)
Labour – external	**7,795**	**0.70**	6,536	0.64	9%
Land leases and property tax	**8,532**	**0.77**	8,353	0.81	(6%)
Other	**13,046**	**1.16**	14,050	1.36	(15%)
Total operating expense	**144,629**	**12.99**	110,687	10.80	20%
Realized (gains)/loss on electric power price risk management contracts	**60**	**0.01**	(735)	(0.07)	114%
Net operating expense	**$ 144,689**	**$ 13.00**	$ 109,952	$ 10.73	21%
Transportation and marketing expense	**$ 6,187**	**$ 0.56**	$ 5,688	$ 0.56	-%

Total operating expense increased by $11.7 million and $33.9 million respectively for the three and six month periods ended June 30, 2007 compared to the same periods in the prior year. A significant portion of this increase is attributed to the additional production from the incremental activity associated with the assets acquired in the Birchill acquisition completed in August 2006. However, the continued high demand for oilfield services has lead to higher costs for well servicing, workovers, labour and well maintenance. We are beginning to see evidence of service costs decreasing, which should translate to lower per unit operating costs in the coming quarters.

On a per barrel basis our operating costs have increased to $13.03 and $12.99 respectively for the three and six month periods ended June 30, 2007, which represents an 18% and 20% increase over the same periods in the prior year. In addition to the general upward cost pressures in the industry, there was a significant amount of well maintenance and workovers completed in the first and second quarters of 2007 as compared to the prior year. The increased processing fees is directly related to our greater proportion of non-operated properties as a result of the acquisitions of Viking and Birchill. Generally, we incur higher processing fees on non-operated properties as although we own an interest in the well, we may not own an interest in the processing plant and are usually charged a fee for processing which is higher than the per unit cost of operating the facility.

Our transportation and marketing expense was $3.4 million or $0.61 per boe and $6.2 million or $0.56 per boe respectively for the three and six month periods ended June 30, 2007. This represents a 17% decrease and 9% increase in aggregate transportation and marketing expense for the three and six month periods ended June 30, 2007 compared to the same periods in the prior year. However, on a per barrel basis these costs have decreased 18% for the three month period ended June 30, 2007 and have remained constant for the six month period ended June 30, 2007 compared to the same periods in the prior year. These costs relate primarily to delivery of natural gas to Alberta's natural gas sales hub, the AECO Storage Hub, and to a lesser extent, our costs of trucking clean crude oil to pipeline receipt points. As compared to the prior year, our natural gas production in the second quarter of 2007 is 1% higher and the production for the first half of 2007 is 17% higher. This increase in natural gas production is mainly due to the incremental natural gas production associated with our acquisition of Viking and Birchill in 2006 and contributes to the higher transportations costs. In addition, we changed our relationship with the pipeline operators such that the transportation commitments are now a direct responsibility of Harvest rather than the independent marketer of our production in late 2006.

Electric power costs represented approximately 16% and 17% of our total operating costs during the three and six month periods ended June 30, 2007. Electric power prices per MWh for the three and six month periods ended June 30, 2007 were 7% lower and 3% higher than in the comparative periods, contributing to the 7% decrease in aggregate power costs to $11.4 million in the current quarter and a 4% increase to $25.1 million for the year to date compared to the same periods in the prior year. On a per barrel basis, lower consumption and a 1% and 9% increase in production for the three and six month periods ended June 30, 2007 resulted in a 8% and 5% decrease in electric power costs per boe respectively compared to the same periods in the prior year. Our electric power price risk management contracts resulted in a loss of $560,000 and a loss of $60,000 for the three and six month periods ended June 30, 2007, compared to gains of $258,000 and $735,000 in the same periods in the prior year, respectively. The following table details the electric power costs per boe before and after the impact of our price risk management program.

	Three Months Ended June 30			Six Months Ended June 30		
(per boe)	**2007**	2006	Change	**2007**	2006	Change
Electric power costs	**$ 2.05**	$ 2.23	(8%)	**$ 2.26**	$ 2.37	(5%)
Realized loss/(gains) on electricity risk management contracts	**0.10**	(0.05)	300%	**0.01**	(0.07)	114%
Net electric power costs	**$ 2.15**	$ 2.18	(1%)	**$ 2.27**	$ 2.30	(1%)
Alberta Power Pool electricity price (per MWh)	**$ 49.97**	$ 53.59	(7%)	**$ 56.80**	$ 55.17	3%

Approximately 52% of our estimated Alberta electricity usage is protected by fixed price purchase contracts at an average price of $56.69 per MWh through December 2008. These contracts will moderate the impact of future price swings in electric power as will capital projects undertaken that contribute to improving our efficient use of electric power.

Operating Netback

	Three Months Ended June 30		Six Months Ended June 30	
(per boe)	**2007**	2006	**2007**	2006
Revenues	**$ 51.64**	$ 56.46	**$ 51.90**	$ 52.06
Realized loss on risk management contracts(1)	**(1.13)**	(4.41)	**(0.63)**	(3.25)
Royalties	**(9.65)**	(9.48)	**(9.27)**	(9.28)
Operating expense(2)	**(13.13)**	(11.02)	**(13.00)**	(10.73)
Transportation and marketing expense	**(0.61)**	(0.74)	**(0.56)**	(0.56)
Operating netback(3)	**$ 27.12**	$ 30.81	**$ 28.44**	$ 28.24

(1) Includes amounts realized on WTI, heavy oil price differential and foreign exchange contracts, and excludes amounts realized on electricity contracts.
(2) Includes realized (losses)/gains on electric power price risk management contracts of $(0.10) per boe and $0.05 per boe for the three month periods ended June 30, 2007 and 2006 and $(0.01) per boe and $0.07 per boe for the six month periods ended June 30, 2007 and 2006.
(3) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.

Our operating netback represents the net amount realized from our production on a per boe basis after deducting the directly related costs. For the three and six month periods ended June 30, 2007, our operating netback decreased $3.69 per boe (or 12%) to $27.12 and increased $0.20 per boe (or 1%) to $28.44 respectively. The decrease in the three months ended June 30, 2007 compared to the same period in the prior year is due to lower oil prices resulting in a decrease of $4.82 per boe in our realized price, an increase of $2.11 per boe in operating costs, lower losses realized on our price risk management program of $3.28 per boe and marginally lower transportation costs and marginally higher royalties. The small increase in the operating netback for the six months ended June 30, 2007 is due to a decrease in realized price of $0.16 per boe and a $2.27 increase in operating costs that were offset by a $2.62 decrease in the realized loss on price risk management contracts.

General and Administrative ("G&A") Expense

	Three Months Ended June 30			Six Months Ended June 30		
(000s except per boe)	**2007**	2006	Change	**2007**	2006	Change
Cash G&A[(1)]	**$ 8,512**	$ 7,756	10%	**$ 15,717**	$ 13,809	14%
Unit based compensation expense	**7,549**	757	897%	**10,448**	516	1,925%
Total G&A	**$ 16,061**	$ 8,513	89%	**$ 26,165**	$ 14,325	83%
Cash G&A per boe ($/boe)	**$ 1.53**	1.42	8%	**$ 1.41**	1.35	4%

(1) Cash G&A excludes the impact of our unit based compensation expense and for the three and six months ended June 30, 2006 of nil and $3.1 million, respectively, of one time transaction costs.

For the three months ended June 30, 2007, Cash G&A costs increased by $0.8 million (or 10%) compared to the same period in 2006. This increase is mainly related to salaries, which is attributed largely to increased staffing levels from our acquisition of Birchill in August 2006. Approximately 75% of our Cash G&A expenses are related to salaries and other employee related costs, while in the prior year only 66% of our Cash G&A was staffing related. Generally, costs to retain technically qualified staff in the western Canadian petroleum and natural gas industry continue to rise.

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 being 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 month period ended June 30, 2007 was $7.5 million. Our opening trust unit market price was $28.57 at March 31, 2007 and at June 30, 2007, our trust unit price had increased to $32.95. As a result, we have recorded an expense of $6.2 million on unexercised UARs for the three month period ended June 30, 2007. Our total unit based compensation expense has increased $6.8 million for the three month period ended June 30, 2007 and $9.9 million for the six month period ended June 30, 2007 over the same period in the prior year after considering that $0.3 million of unit based compensation expense incurred in the three month period ended June 30, 2006 and $9.0 million in the six month period ended June 30, 2006 was recorded as transaction costs. In 2006, we have recorded transaction costs of $11.7 million which represent one time costs incurred by Harvest as part of the acquisition of Viking in respect of Harvest's outstanding UARs vesting on February 3, 2006 and severance payments made to Harvest employees upon merging with Viking.

Depletion, Depreciation, Amortization and Accretion Expense

	Three Months Ended June 30			Six Months Ended June 30		
(000s except per boe)	**2007**	2006	Change	**2007**	2006	Change
Depletion, depreciation and amortization	**$ 103,034**	$ 88,886	16%	**$ 208,930**	$ 166,281	26%
Depletion of capitalized asset retirement costs	**3,939**	4,230	(7%)	**8,000**	8,512	(6%)
Accretion on asset retirement obligation	**4,473**	4,062	10%	**8,919**	7,710	16%
Total depletion, depreciation, amortization and accretion	**$ 111,446**	$ 97,178	15%	**$ 225,849**	$ 182,503	24%
Per boe ($/boe)	**$ 20.08**	$ 17.76	13%	**$ 20.29**	$ 17.81	14%

Our overall depletion, depreciation, amortization and accretion ("DDA&A") expense for the three and six months ended June 30, 2007 was $14.3 million and $43.3 million higher, respectively, compared to the prior year. Of this, $1.4 million and $15.8 million respectively is due to incremental production predominantly from the merger with Viking in early 2006 and the acquisition of Birchill in August of 2006. The remaining increase is attributed to a higher depletion rate per boe, as our acquisitions in 2006 coupled with generally higher finding and development costs have increased our overall corporate DDA&A rate.

Capital Expenditures

	Three Months Ended June 30		Six Months Ended June 30	
(000s)	**2007**	2006	**2007**	2006
Land and undeveloped lease rentals	**$ 261**	$ 326	**$ 421**	$ 2,413
Geological and geophysical	**1,710**	2,027	**5,724**	3,027
Drilling and completion	**16,396**	17,955	**94,990**	84,861
Well equipment, pipelines and facilities	**27,806**	25,662	**91,151**	55,546
Capitalized G&A expenses	**2,208**	3,430	**4,451**	6,981
Furniture, leaseholds and office equipment	**(160)**	4,830	**(29)**	4,641
Development capital expenditures excluding acquisitions and non-cash items	**48,221**	54,230	**196,708**	157,469
Non-cash capital additions (recoveries)	**1,680**	(563)	**2,095**	(173)
Total development capital expenditures excluding acquisitions	**$ 49,901**	$ 53,667	**$ 198,803**	$ 157,296

During the second quarter of 2007 we invested $48.2 million in drilling, operating optimization and enhancement projects compared to $54.2 million in the second quarter of 2006. Approximately 34% of the second quarter expenditures were directly related to the drilling of 14 gross wells with a success rate of 100% as compared to 37 gross wells in the second quarter of 2006 with a success rate of 100%. With strong oil prices, we continued to focus our drilling activity on oil opportunities with 11 of the 14 wells drilled targeting oil prospects. Our most active drilling area in the second quarter was Southeast Saskatchewan, where we continued to drill horizontal wells into our new light oil discovery at Kenosee as well as infill horizontal wells at Hazelwood.

After our intensive drilling program in the first quarter, many of the capital expenditures in the second quarter relate to the equipment and facilities that were needed to bring those wells on production; approximately $27.8 million or 58% of the second quarter expenditures relate to well equipment, pipelines and facilities expenditures. This amount also includes approximately $20 million relating to a number of initiatives to improve the efficiency of our Hay River operations.

The following summarizes Harvest's participation in gross and net wells drilled during the second quarter of 2007:

	Total Wells		Successful Wells		Abandoned Wells	
Area	**Gross**[1]	**Net**	**Gross**	**Net**	**Gross**	**Net**
Hay River	-	-	-	-	-	-
Southeast Saskatchewan	4.0	4.0	4.0	4.0		
Red Earth	-	-	-	-	-	-
Suffield	3.0	3.0	3.0	3.0	-	-
Lloydminster	2.0	2.0	2.0	2.0	-	-
Markerville	-	-	-	-	-	-
Other Areas	5.0	4.3	5.0	4.3	-	-
Total	14.0	13.3	14.0	13.3	-	-

(1) Excludes 6 additional wells that we have an overriding royalty interest in.

The following summarizes Harvest's participation in gross and net wells drilled for the six months ended June 30, 2007:

	Total Wells		Successful Wells		Abandoned Wells	
Area	**Gross[1]**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Hay River	31.0	31.0	31.0	31.0	-	-
Southeast Saskatchewan	15.0	15.0	15.0	15.0	-	-
Red Earth	12.0	8.5	12.0	8.5	-	-
Suffield	8.0	8.0	7.0	7.0	1.0	1.0
Lloydminster	8.0	8.0	8.0	8.0	-	-
Markerville	5.0	1.9	5.0	1.9	-	-
Other Areas	27.0	14.0	25.0	13.4	2.0	0.6
Total	106.0	86.4	103.0	84.8	3.0	1.6

(1) Excludes 12 additional wells that we have an overriding royalty interest in.

Corporate Acquisitions

Effective March 1, 2007 we acquired a private petroleum and natural gas corporation for cash consideration of $30.3 million including $350,000 of estimated acquisition costs. This acquisition added approximately 1,500 bbl/d of western Saskatchewan heavy oil production which is immediately adjacent to our existing operations in the area.

On June 11, 2007 we entered into a pre-acquisition agreement to acquire Grand for aggregate consideration of approximately $145 million and in early August 2007 we completed this acquisition of approximately 3,400 boe/d of production with proved plus probable (P+P) reserves of 6 million boe, comprised of approximately 67% oil. Grand's assets include a significant presence in southeast Saskatchewan, the Sylvan Lake/Markerville area and eastern Alberta which are adjacent to existing Harvest operations with complimentary drilling opportunities. Grand also has 65,000 acres (46,000 net acres) of undeveloped land with supporting seismic data providing further development opportunities. This acquisition represents an acquisition cost of approximately $42,500 per flowing boe and $24 per boe of proved and probable reserves.

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 December 31, 2006, we had recorded $656.2 million of goodwill related to our petroleum and natural gas segment and this amount is unchanged at June 30, 2007. 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. To date, no charge for impairment of this goodwill has been made.

Asset Retirement Obligation ("ARO")

In connection with a property acquisition or development expenditures, 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 is adjusted at the end of each period to reflect the passage of time as well as for changes in the estimated future cash flows of the underlying obligation. Our asset retirement obligation increased by $2.5 million during the three months ended June 30, 2007. This increase is due to additions resulting from drilling activity during the quarter and accretion expense, offset by actual asset retirement expenditures made during the quarter.

REFINING AND MARKETING OPERATIONS

Our refining and marketing operations, operating under the North Atlantic trade name, are comprised of a medium gravity sour crude hydrocracking refinery with a 115,000 bbl/d capacity and a marketing division with 64 gasoline outlets, a home heating business and a commercial and wholesale petroleum products business, all located in the province of Newfoundland and Labrador. The marketing division has an average daily sales volume of approximately 11,000 barrels representing approximately a 15% to 20% share of the Newfoundland and Labrador market.

The following summarizes the North Atlantic financial and operational information for the three and six month periods ended June 30, 2007 as well as the three months ended March 31, 2007 and the period from October 19, 2006 to December 31, 2006:

(in $000's except where noted below)	Three Months Ended June 30, 2007	Three Months Ended March 31, 2007	Six Months Ended June 30, 2007	October 19, 2006 to December 31, 2006
Revenues	**900,387**	**784,045**	**1,684,432**	**460,359**
Purchased products for resale and processing	**708,642**	**632,296**	**1,340,938**	**386,014**
Gross Margin[(1)]	**191,745**	**151,749**	**343,494**	**74,345**
Costs and expenses				
Operating expense	**26,584**	**25,361**	**51,945**	**18,378**
Purchased energy expense	**18,337**	**24,000**	**42,337**	**15,685**
Marketing expense	**9,059**	**7,343**	**16,402**	**5,060**
General and Administrative	**402**	**300**	**702**	**-**
Unrealized loss on risk management contracts	**3,164**	**-**	**3,164**	**-**
Depreciation and amortization expense	**18,185**	**19,389**	**37,574**	**15,482**
Earnings from operations[(1)]	**116,014**	**75,356**	**191,370**	**19,740**
Cash capital expenditures	**9,871**	**4,883**	**14,754**	**21,411**
Feedstock volume (bbl/day)	**115,570**	**113,711**	**114,646**	**86,890**
Yield (000's barrels)				
Gasoline and related products	**3,379**	**3,310**	**6,689**	**1,875**
Ultra low sulphur diesel	**4,020**	**4,213**	**8,233**	**2,624**
Heavy fuel oil	**2,950**	**2,745**	**5,695**	**1,752**
Total	**10,349**	**10,268**	**20,617**	**6,251**
Average Refining Margin (US$bbl)	**$15.64**	**$11.85**	**$13.69**	**$9.32**

(1) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A

Overview of Refining and Marketing Operations

Since completion of an extended refinery turnaround in November 2006, North Atlantic's earnings from operations have reflected near capacity operating performance with minimal disruptions while the First Quarter and Second Quarter of 2007 have also benefited from a very strong market for refined products. North Atlantic's daily throughput has averaged approximately 114,646 barrels during the six month period ended June 30, 2007 comprised of 104,530 barrels of crude oil and 10,116 barrels of vacuum gas oil as compared to the three months ended June 30, 2007 with daily throughput averages of 115,570 barrels, 104,659 barrels and 10,911 barrels, respectively. North Atlantic's refining margins reflect the improved crack spread for gasoline and heating oil which have been impacted by both an unusual number of disruptions at North

American refineries as well as the expected seasonal increase in gasoline demand for the summer driving season offset by a narrowing of the differential between its medium gravity sour crude oil feedstock price and the North American benchmark for light sweet crude oil, West Texas Intermediate prices.

Refining Benchmark Prices

The refining industry has a few benchmark prices against which to compare refinery performance. Typically, these benchmarks include prices for refined products such as Reformulated Blendstock for Oxygenate Blending gasoline ("RBOB gasoline") and heating oil. The New York Mercantile Exchange ("NYMEX") "2-1-1 Crack Spread" is a refining benchmark calculated assuming that the processing of two barrels of light sweet crude oil (defined as a WTI quality) produces one barrel of RBOB gasoline and one barrel of heating oil delivered to the New York market where product prices are set in relation to the NYMEX gasoline and NYMEX heating oil prices. The following refining industry benchmark prices are provided as reference points with which to index the North Atlantic refinery's performance:

	Three Months Ended June 30, 2007	Three Months Ended March 31, 2007	Six Months Ended June 30, 2007	October 19, 2006 to December 31, 2006
West Texas Intermediate crude oil (US$ per barrel)	**65.03**	**58.16**	**61.60**	**60.44**
RBOB gasoline (US$ per barrel/US$ per gallon)	**93.79/2.23**	**71.08/1.69**	**82.62/1.97**	**66.78/1.59**
Heating Oil (US$ per barrel/US$ per gallon)	**80.27/1.91**	**69.86/1.66**	**75.15/1.79**	**71.82/1.71**
2-1-1 Crack Spread (US$ per barrel)	**22.00**	**12.31**	**17.29**	**8.86**
Canadian / U.S. dollar exchange rate	**0.911**	**0.854**	**0.881**	**0.883**

Although the "2-1-1 Crack Spread" is a common industry benchmark, the North Atlantic refinery's production differs in that it also produces approximately 25% to 30% heavy fuel oil not represented in the "2-1-1 Crack Spread" benchmark and also processes primarily a medium gravity sour crude oil rather than a WTI quality of light sweet crude oil. In addition, North Atlantic purchases approximately 8,000 to 10,000 bbl/d of additional vacuum gas oil to optimize the throughput of its hydrocracker unit which is a key unit in the production of gasoline and diesel fuel.

During the Second Quarter of 2007, the NYMEX price of RBOB gasoline and heating oil appreciated US$22.71/bbl and US$10.41/bbl, an increase of 32% and 15% over the prior quarter, respectively, while the WTI benchmark price increased by US$6.79/bll, a 12% increase over the prior quarter. This represents a crack spread increase during the quarter of US$15.92/bbl for RBOB gasoline and US$3.63/bbl for heating oil while the benchmark "2-1-1 Crack Spread" increased by US$9.69/bbl to US$22.00/bbl, a 79% increase over the prior quarter.

Refinery Feedstock

The cost and volume of North Atlantic's crude oil feedstocks for the three months ended June 30, 2007 and March 31, 2007 were as follows:

	Three Months Ended June 30, 2007			Three Months Ended March 31, 2007		
	Cost of Feedstock	**Volume**	**Cost per Barrel[(1)]**	**Cost of Feedstock**	**Volume**	**Cost per Barrel[(1)]**
	(000's of Cdn $)	(000s of bbls)	(US$/bbl)	(000's of Cdn $)	(000s of bbls)	(US$/bbl)
Basrah	**436,452**	**6,793**	**58.53**	**422,856**	**7,002**	**51.55**
Hamaca	**75,524**	**1,215**	**56.63**	**96,977**	**1,664**	**49.75**
Urals	**109,631**	**1,516**	**65.88**	**42,376**	**730**	**49.55**
Crude Oil Feedstock	**621,607**	**9,524**	**59.46**	**562,209**	**9,396**	**51.07**
Vacuum Gas Oil	**76,351**	**993**	**70.04**	**57,996**	**838**	**59.06**
	697,958	**10,517**	**60.46**	**620,205**	**10,234**	**51.73**
Other costs	**542**			**(819)**		
	698,500			**619,386**		

(1) Cost of feedstock includes all costs of transporting the crude oil to North Atlantic's refinery.

During the Second Quarter of 2007, the Refinery feedstock was comprised of 104,659 bbl/d of medium sour crude oil (approximately 71% Basrah Light from Iraq, 13% Hamaca from Venezula and 16% Urals from Russia) as compared to 104,400 bbl/d of medium sour crude oil (approximately 74% Basrah Light from Iraq, 18% Hamaca from Venezula and 8% Urals from Russia) in the prior quarter. During the Second Quarter, a heat exchange and fouling issue in the Refinery's crude unit vacuum tower resulted in a lower yield of vacuum gas oil and a higher consumption of purchased vacuum gas oil with 10,911 bbl/s purchased in the current quarter as compared to 9,311 bbl/d in the prior quarter. The 1,600 bbl/d increase in purchased vacuum gas oil represents an incremental feedstock cost to replace material consumed by the Refinery and a significant contributing factor to the Second Quarter's 98.40% yield as compared to the 100.33% yield of the prior quarter.

The price of North Atlantic's crude oil feedstock averaged US$59.46 per barrel during the three months ended June 30, 2007 as compared to US$51.07 for the prior three month period, a 16% increase in feedstock costs as the global demand for crude oil strengthened with discounts against the benchmark prices narrowing. Relative to the 12% increase in the WTI benchmark, North Atlantic's cost increase is driven primarily by a change in its feedstock blend to increase its consumption of Urals to 16% as compared to 8% in the prior quarter. Urals are expected to provide slightly better gasoline and distillate yields however our heat exchange and fouling issue during the Second Quarter distorted the expected benefit. During the Second Quarter, the feedstock cost for Basrah and Hamaca increased by approximately 14% over the prior quarter mirroring the 12% increase in the WTI benchmark and reflecting a stable differential between North Atlantic's cost of medium gravity sour crude oil feedstock and the WTI benchmark price which had narrowed appreciably during the First Quarter of 2007 to approximately US$7.00 per barrel.

Refined Products

Product yields are impacted by the crude oil feedstock as well as refinery performance. During the Second Quarter of 2007, North Atlantic's gasoline production was unchanged at 32% of feedstock consumed while the yield of ultra low sulphur diesel and jet fuel dropped to 39% from 41% in the prior quarter and the production heavy fuel oil increased to 29% from 27% primarily as a result of the heat exchange and fouling issue in the crude unit vacuum tower. A summary of North Atlantic's product yield, pricing and revenue for the three month periods ended June 30, 2007 and March 31, 2007 are as follows:

	Three Months Ended June 30, 2007			**Three Months Ended March 31, 2007**		
	Refinery Revenues	**Volume**	**Product Price[(1)]**	**Refinery Revenues**	**Volume**	**Product Price[(1)]**
	(000's of Cdn $)	(000s of bbls)	($ per bbl/ $ per US gal)	(000's of Cdn $)	(000s of bbls)	($ per bbl/ $ per US gal)
Gasoline and related products	**334,391**	**3,210**	**94.90/2.26**	**277,227**	**3,333**	**70.99/1.69**
Low & ultra low sulphur diesel & jet fuel	**366,846**	**3,912**	**85.43/2.03**	**360,810**	**4,154**	**74.18/1.76**
Heavy fuel oil	**177,873**	**3,066**	**52.85/1.26**	**123,300**	**2,627**	**40.08/0.95**
	879,110	**10,188**		**761,337**	**10,114**	
Inventory adjustment		**161**			**154**	
		10,349			**10,268**	
Yield (as a % of Feedstock) [(2)]		**98.40%**			**100.33%**	

(1) Product prices are based on the sales at the North Atlantic refinery loading docks.

(2) After adjusting for changes in inventory held for resale

Relative to a benchmark NYMEX RBOB gasoline price, North Atlantic received a US$0.03 per bbl premium for its gasoline during the Second Quarter of 2007 as compared to no premium in the prior quarter. For its ultra low sulphur diesel and jet fuel products, North Atlantic received a US$0.12 per gallon premium for the three months ended June 30, 2007 as compared to a US$0.10 per gallon premium in the prior three month period relative to the NYMEX heating oil benchmark price. Generally, North Atlantic's gasoline price will closely mirror the NYMEX reference price while its diesel fuel and jet fuel command a premium of approximately US$0.10 per gallon over the NYMEX heating oil price reflecting its higher product quality net of shipping costs to the New York harbour.

Relative to the average price paid for its crude oil feedstock, the selling price of North Atlantic's heavy fuel oil resulted in a negative contribution of US$6.61 per barrel and aggregated to approximately $22.2 million for the three month period ended June 30, 2007 compared to a negative contribution of US$10.39 per barrel and $33.4 million in the First Quarter of 2007. The heavy fuel oil produced by North Atlantic presents an opportunity to re-configure the Refinery to produce more gasoline and/or diesel fuel which is the objective of the $22 million visbreaker enhancement approved in March 2007.

Gross Margin

North Atlantic's gross margin is comprised of the crack spread from its refinery operations as well as the margin on its marketing and other related businesses. A summary of the gross margin contribution from the refinery and marketing operations for each three month period ended June 30, 2007 and March 31, 2007 are as follows:

	Three Months Ended June 30, 2007			**Three Months Ended March 31, 2007**		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	**Refining**	**Marketing**	**Total**
Sales revenue[(1)]	**879,110**	**115,404**	**900,387**	**761,337**	**91,290**	**784,045**
Cost of products for processing and resale[(1)]	**698,500**	**104,269**	**708,642**	**619,386**	**81,492**	**632,296**
Gross margin[(2)]	**180,610**	**11,135**	**191,745**	**141,951**	**9,798**	**151,749**
Average Refining Margin (US$/bbl)	**$15.64**			**$11.85**		

(1) The North Atlantic sales revenue and cost of products for processing and resale are net of inter-segment sales of $94,127,000 reflecting the refined products produced by the Refinery Operations and sold by the Marketing Operations for the three months ended June 30, 2007 ($68,582,000 for the three months ended March 31, 2007)

(2) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.

During the three months ended June 30, 2007, North Atlantic's crack spread of $180.6 million is comprised of $212.1 million of gross margin on the production of gasoline and ultra low sulphur diesel and jet fuel from its crude oil feedstock (including a heavy sour differential of approximately $39.0 million) and $27.3 million on the production of gasoline and ultra low sulphur diesel and jet fuel from purchased VGO offset by a $58.8 million negative contribution from the production of heavy fuel oil and other refined products. This compares to gross margin of $142.0 million comprised of $162.6 million (including $55.3 million of heavy sour differential), $15.8 million and $36.4 million, respectively, for the prior period.

As compared to the 79% appreciation in the "2-1-1 Crack Spread" benchmark during the Second Quarter of 2007 over the First Quarter, North Atlantic's average refining margin increased to US$15.64, a 32% increase over the prior quarter. North Atlantic did not fully participate in this appreciation of the "2-1-1 Crack Spread" as its average cost of medium gravity sour crude oil increased by 17% as compared to a 12% increase in the WTI benchmark price and the "2-1-1 Crack Spread" benchmark assumes no production of heavy fuel oil, while North Atlantic produced 29% heavy fuel oil at a lower US$6.61 discount to the average cost of feedstock as compared to US$10.39 in the prior quarter.

The gross margin from North Atlantic's marketing operations of $11.1 million (up $1.3 million from the prior period) is composed of the margin from both the retail and wholesale distribution of gasoline, home heating fuels and related appliances as well as the revenues from marine services including tugboat revenues.

Price Risk Management

Details of our price risk management contracts outstanding at June 30, 2007 are included in Note 16 of our interim consolidated financial statements for the three and six month periods ended June 30, 2007 filed on SEDAR at www.sedar.com. Subsequent to acquiring North Atlantic, Harvest's participation in the crude oil value chain extended through to include the price of refined products produced by North Atlantic, principally gasoline, distillates (which encompasses low sulphur diesel fuel, jet fuel and heating oil) and heavy fuel oil. This results in our price protection of future cash flows including price protection on refined products. For purposes of this MD&A and the segmented reporting in Note

17 of our financial statements, our price risk management contracts are presented as either relating to our petroleum and natural gas operations or our refining and marketing operations according to the price exposure that is being managed.

During the Second Quarter of 2007, North Atlantic entered into the price risk management contracts with respect to an aggregate of 20,000 bbl/d comprised of the following contracts on 12,000 bbl/d of NYMEX heating oil and 8,000 bbls/d of Platts fuel oil for the period from January 2008 through December 2008:

Quantity	Contract Type	Contracted Price (in $U.S. per gallon unless specified otherwise)
2,000 bbls/d	Price Collar – Heating Oil	Price Floor – US$190.00 and Price Cap – US$217.50 (in cents per US gallon)
2,000 bbls/d	Price Collar – Fuel Oil	Price Floor – US$51.00 and Price Cap – US$58.68 (US$ per bbl)
10,000 bbls/d	3 Way Structure - Heating Oil	If NYMEX price is over US$222.17, price received is US$222.17 If NYMEX price is between US$221.17 and US$193.00, price received is market price If NYMEX price is between US$193.00 and US$145.00, price received is US$193.00 If NYMEX price is under US$145.00, price received is market price plus US$48.00
6,000 bbls/d	3 Way Structure - Fuel Oil	If Platts price is over US$63.21, price received is US$63.21 If Platts price is between US$63.21 and US$51.67, price received is market price If Platts price is between US$51.67 and US$43.00, price received is US$51.67 If Platts price is under US$43.00, price received is market price plus US$8.67

Concurrently with its entering into the above price risk management contracts for refined products, North Atlantic entered into the following inter-company contracts with Harvest's petroleum and natural gas operations group to shift the WTI price protection to our petroleum and natural gas operations:

Quantity	Contract Type	Contracted Price
4,000 bbls/d	Price Collar	Price Floor – US$66.00 and Price Cap – US$75.79
16,000 bbls/d	3 Way Structure	If WTI price is over US$79.57, price paid is US$79.57 If WTI price is between US$79.57 and $67.03, price paid is market price If WTI price is between US$67.03 and US$52.33, price paid is US$67.03 If WTI price is under US$52.33, price paid is market price plus US$14.70

During the Second Quarter of 2007, the refined products contracts resulted in a net unrealized loss of $8.7 million of which $3.2 million is recognized in the North Atlantic operations as a net loss on a crack spread position and $5.5 million is recognized in the petroleum and natural gas operations as a loss on the WTI portion of the contract.

The table below provides a summary of net gains and losses on our price risk management contracts for the three month period ended June 30, 2007 and 2006:

	Three Months Ended June 30			
	2007			2006
(000s)	Heating Oil	Fuel Oil	Total	Total
Unrealized loss on refined product price risk management contracts	$ (6,156)	$ (2,495)	$ (8,651)	$ -
Unrealized gain on inter-company WTI portion of refined product price risk management contracts	3,303	2,184	5,487	-
Net unrealized loss on price risk management contracts	$ (2,853)	$ (311)	$ (3,164)	$ -

Operating Expenses

A summary of North Atlantic's operating costs for the refinery and marketing operations for the three month period ended June 30, 2007 and March 31, 2007 are as follows:

	Three Months Ended June 30, 2007			Three Months Ended March 31, 2007		
(000's of Canadian dollars)	Refining	Marketing	Total	Refining	Marketing	Total
Operating expense	22,122	4,462	26,584	21,031	4,330	25,361
Purchased energy	18,337	-	18,337	24,000	-	24,000
	40,459	4,462	44,921	45,031	4,330	49,361

The largest component of operating expense is wages and benefits which totaled $13.7 million during the Second Quarter of 2007 ($14.8 million for the three months ended March 31, 2007) while the other significant components were maintenance and repairs costs $3.0 million ($3.4 million for the three months ended March 31, 2007), insurance $1.7 million ($1.9 million for the three months ended March 31, 2007) and professional services $1.6 million ($1.1 million for the three months ended March 31, 2007), which were all in line with expectations. During the Second Quarter, refining operating expenses were $2.10 per barrel unchanged from $2.08 per barrel during the prior quarter. This is slightly lower than our expectations of approximately $2.20 to $2.40 per barrel due to the higher than anticipated throughput.

Purchased energy, consisting of low sulphur fuel oil and electric power, is required to provide heat and power to refinery operations, respectively. Our purchased energy costs dropped to $1.74 per barrel during the Second Quarter of 2007 as compared to $2.35 per barrel during the First Quarter as the refinery requires less heat during the warmer spring/summer season as well as an increase in internally produced fuel gas from the crude unit vacuum tower discussed earlier. Our expectation is that purchased energy should average approximately $2.20 for a calendar year.

Marketing Expense

During the Second Quarter of 2007, marketing expense is comprised of $1.0 million of marketing fees (based on US $0.08 per barrel of feedstock) to acquire feedstock (unchanged from the First Quarter) and $8.1 million of "Time Value of Money" charges both pursuant to the supply and offtake agreement. The "Time Value of Money" charges for the First Quarter totaled $6.3 million and reflect the lower cost of crude oil feedstock acquired in the First Quarter.

Capital Expenditures

Capital spending for the first six months of 2007 totals $14.8 million with the Second Quarter accounting for $9.9 million of the total in respect of tank recertification ($2.0 million), preliminary work on heat exchanger bundles for the hydrocracker unit that will be "cleaned out" during the planned maintenance shutdown in the Fourth Quarter ($1.0 million) along with numerous other sustaining and improvement projects.

Depreciation and Amortization Expense

North Atlantic's depreciation and amortization expense for the refinery and marketing operations for the three month ended June 30, 2007 as well as March 31, 2007 is as follows:

	Three Months Ended June 30, 2007			Three Months Ended March 31, 2007		
(000's of Canadian dollars)	Refining	Marketing	Total	Refining	Marketing	Total
Tangible assets	16,111	470	16,581	17,183	495	17,678
Intangible assets	1,221	383	1,604	1,304	407	1,711
	17,332	853	18,185	18,487	902	19,389

The process units are amortized over an average useful life of 20-30 years. The intangible assets, consisting of engineering drawings, customer lists and fuel supply contracts, are amortized over a period of 20 years, 10 years and the term of the expected cash flows, respectively.

Goodwill

On October 19, 2006, we recorded $203.9 million of goodwill in connection with the acquisition of North Atlantic as the purchase price of the acquired business exceeded the fair value of the net identifiable assets and liabilities of that acquired business. As the refining assets are held in a self-sustaining subsidiary with a U.S. dollar functional currency, the value of the goodwill will be adjusted at each period end to reflect the changing U.S. dollar currency exchange rate. Goodwill will be 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. No charge for impairment of this goodwill has been made.

FINANCING AND OTHER

Interest Expense

	Three Months Ended June 30			Six Months Ended June 30		
(000s)	**2007**	2006	Change	**2007**	2006	Change
Interest on short term debt						
Bank loan	**$ (71)**	$ 76	(193%)	**$ 1,099**	$ 226	386%
Convertible debentures	**648**	-	100%	**1,294**	-	100%
Amortization of deferred finance charges – short term debt	**-**	11	n/a	**1,811**	11	16,364%
	577	87	563%	**4,204**	237	1,674%
Interest on long-term debt						
Bank loan	**17,530**	2,937	497%	**36,706**	4,240	766%
Convertible debentures	**15,946**	4,623	245%	**30,394**	7,919	284%
$7^{7/8}$% Senior Notes	**5,659**	5,573	2%	**11,805**	11,297	4%
Amortization of deferred finance charges – long term debt	**668**	761	(12%)	**1,347**	2,195	(39%)
	39,803	13,894	186%	**80,252**	25,651	213%
Total interest expense	**$ 40,380**	$ 13,981	189%	**$ 84,456**	$ 25,888	226%

Interest expense, which includes the amortization of related financing costs, was $26.4 million and $58.6 million higher respectively for the three and six month periods ended June 30, 2007 than in the same period in the prior year. Of this increase, the amount related to bank loan interest (both short term and long term) of $14.4 million and $33.3 million for the three month and six month periods, respectively, is the result of the significant increase in the drawn amounts on our credit facilities. A further $12.0 million and $23.8 million for the three and six month periods, respectively, is related to the increase in the principal amount of convertible debentures outstanding.

At the end of the Second Quarter of 2007, we had drawn approximately $1,048.0 million of bank borrowings as compared to $1,363.2 million at the end of the First Quarter of 2007 and $1,595.7 million at the end of December 31, 2006. During the First Quarter of 2007, our bank borrowings were reduced with the net proceeds of $357.4 million from our issuance of 6,146,750 trust units and $230 million principal amount of 7.25% Debentures due 2014. During the Second Quarter of 2007, our bank borrowings were reduced by a combination of net proceeds of $218.5 million from our issuance of 7,302,500 Trust Units and surplus cash after capital spending distribution requirements. The early repayment of our Senior Secured Bridge Facilities in the First Quarter of 2007 resulted in our accelerating the expensing of $1.8 million of unamortized commitment fees related to this facility. Currently, the interest on our Three Year Extendible Revolving Facility is at a floating rate based on 70 basis points over bankers' acceptances for Canadian dollar borrowings and 70 basis points over the London Inter Bank Order Rate for US dollar borrowings. During the Second Quarter of 2007, our interest charges on bank loans aggregated to $17.5 million as compared to $20.3 million during the First Quarter of the year. Further details on our credit facilities and the bridge financing are included under "Liquidity and Capital Resources".

The interest on our convertible debentures totaled $31.7 million during the first six months of 2007 and is based on the effective yield of the debt component of the convertible debentures. Details on the convertible debentures outstanding are fully described in Note 11 to the interim consolidated financial statements for the three and six month periods ended June 30, 2007 filed on SEDAR at www.sedar.com. During the Second Quarter of 2007, there were $125.6 million of principal amount of convertible debentures converted to 4,613,915 Trust Units as compare to an aggregate of $333,000 principal amount of convertible debentures converted to 19,731 Trust Units in the First Quarter of the year.

Included in short and long term 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 amortization of commitment fees and legal costs incurred for our credit and bridge facilities, all totaling $3.2 million for the six months ended June 30, 2007.

Non-Controlling Interest

The non-controlling interest in the first quarter of 2006 represents the net income attributed to non-controlling interest holders for the period. The exchangeable shares that give rise to the non-controlling interest were issued by Harvest Operations as partial consideration for the purchase of a corporate entity in 2004. In 2006, 156,067 exchangeable shares were converted to trust units under the plan of arrangement with Viking and the remaining 26,902 exchangeable shares were purchased and cancelled for a total cash payment of $1.0 million.

Currency Exchange Gains and Losses

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 LIBOR bank loans, $7^{7/8}$% Senior Notes as well as any other U.S. dollar cash balances. Since December 31, 2006, the Canadian dollar has strengthened significantly compared to the U.S dollar. As a result we incurred an unrealized gain on our $7^{7/8}$% Senior Notes of $24.3 million and a further $55.2 million in respect of our U.S. dollar denominated LIBOR bank loans that are held in connection with the purchase of North Atlantic. The LIBOR loan balance at the beginning of the year was approximately US$650 million, but in early May we repaid approximately US$160 million of this balance and realized a $3.5 million currency exchange gain. In addition, we also incurred $0.5 million of unrealized foreign exchange losses on transactions incurred by North Atlantic and realized losses of $0.6 million.

North Atlantic is considered a self-sustaining operation with a U.S. dollar functional currency. The foreign exchange gains and losses incurred by North Atlantic relate to Canadian dollar transactions converted to U.S. dollars as their functional currency is U.S. dollars.

Future Income Tax

With the enactment of Bill C-52 in the Second Quarter of 2007, Harvest recorded a future income tax expense of $177.7 million to reflect the impact of the 31.5% tax to be applied to distributions from Canadian publicly traded income trusts commencing in January 2011. We recorded a $177.7 million future income tax expense and a corresponding future income tax liability related to the timing differences between the book value and the tax basis of assets held by our mutual fund trust. While net income in the Second Quarter of 2007 is reduced significantly by this future income tax adjustment, there is no impact on Funds From Operations.

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	**1,314,315**	-	65,000	1,249,315	-
Interest on long-term debt(4)	**253,162**	39,782	157,363	56,017	-
Interest on convertible debentures(3)	**293,208**	25,875	98,272	95,190	73,871
Operating and premise leases	**17,613**	3,447	11,331	2,577	258
Capital commitments(5)	**16,533**	13,653	2,880	-	-
Asset retirement obligations(6)	**696,003**	8,360	13,058	13,321	661,264
Transportation (7)	**4,441**	1,064	2,646	542	189
Purchase commitments	**7,275**	7,275	-	-	-
Pension contributions	**27,687**	390	3,345	4,805	19,147
Feedstock commitments	**671,642**	665,915	5,727	-	-
Total	**3,301,879**	765,761	359,622	1,421,767	754,729

(1) As at June 30, 2007, we had entered into physical and financial contracts for production with average deliveries of approximately 25,000 barrels of oil equivalent per day for the remainder of 2007, and 10,000 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 16 to the interim 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
(7) Relates to firm transportation commitment on the Nova pipeline.

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.

Related Party Transactions

During the Second Quarter of 2007, Vitol Refining S.A. purchased $131.2 million of Iraqi crude oil pursuant to the terms and conditions of the Supply and Offtake Agreement from a company in which a director of Harvest holds a minority equity interest. Management of Harvest pursues the best available terms for its crude oil supply from all available sources. As at June 30, 2007, no amounts related to these purchases are included in Harvest's accounts payable and accrued liabilities, however, there is $136.4 million included in the total feedstock commitments disclosed at the end of June 2007 and a further U.S. $65.5 million of commitments incurred after June 30, 2007 related to crude oil purchases by Vitol Refining S.A from this private company related to a Harvest director.

CHANGE IN ACCOUNTING POLICIES

Effective January 1, 2007, we have retrospectively without restatement adopted the new accounting standards of the Canadian Institute of Chartered Accountants respecting, "Financial Instruments – Recognition and Measurement"; "Comprehensive Income"; and "Financial Instruments – Disclosure and Presentation". The impact of adopting these new standards is reflected in our financial results for the six month period ended June 30, 2007 while the prior year comparative financial statements have not been restated. While the new standards change how we account for financial instruments, there were no material impacts on our results for the three and six month periods ended June 30, 2007 with the most significant difference being that the deferred charges previously presented as an asset are now netted against the respective debt and amortized to income using an effective interest rate. For a description of the new accounting standards and the impact on our financial statements of adopting such standards see Note 2 to the interim consolidated financial statements for the three and six month periods ended June 30, 2007.

LIQUIDITY AND CAPITAL RESOURCES

At the end of June 30, 2007, we had total debt and equity of $5,651.5 million, an increase of $95.3 million compared to $5,556.2 million at the end of December 2006. During the first six months of 2007, the significant changes to our capital structure were:

- The issuance of $230 million principal amount of Convertible Unsecured Subordinated Debentures and 6,146,750 Trust Units with net proceeds of $357.4 million in the First Quarter that were applied to fully repay the Senior Secured Bridge Facility with the remaining $67.7 million applied to reduce the drawn amount of our Three Year Extendible Revolving Credit Facility,
- The issuance of 7,302,500 Trust Units with net proceeds of $218.5 million in the Second Quarter that were applied to reduce the drawn amount of our Three Year Extendible Revolving Credit Facility, and
- The issuance of 3,316,725 Trust Units pursuant to our Premium Distribution™, Distribution Reinvestment and Optional trust unit Purchase Plan (the "DRIP Plans") raising $87.7 million.

(in millions)	**June 30, 2007**	December 31, 2006
DEBT		
Credit Facilities		
- Three Year Extendible Revolving Credit Facility	**$1,048.0**	$1,306.0
- Senior Secured Bridge Facility	-	289.7
Total Bank Debt	**1,048.0**	1,595.7
$7^{7/8}$ % Senior Notes Due 2011 (US$250 million) [1]	**266.4**	291.4
Convertible Debentures, at principal amount		
10.5% Debentures Due 2008	**25.5**	26.6
9% Debentures Due 2009	**1.1**	1.2
8% Debentures Due 2009	**1.8**	2.2
6.5% Debentures Due 2010	**37.9**	37.9
6.4% Debentures Due 2012	**174.6**	174.8
7.25% Debentures Due 2013	**379.4**	379.5
7.25% Debentures Due 2014	**106.0**	-
Total Convertible Debentures	**726.3**	622.2
Total Debt	**2,040.7**	2,509.3
TRUST UNITS		
143,505,858 issued at June 30, 2007	**3,610.8**	
122,096,172 issued at December 31, 2006		3,046.9
TOTAL DEBT AND TRUST UNITS	**$5,651.5**	$5,556.2
TOTAL DEBT TO TOTAL CAPITALIZATION	**36%**	45%

(1) Face value converted at the period end exchange rate.

During the six months ended June 30, 2007, our Funds From Operations totaled $458.4 million and we declared distributions to our Unitholders aggregating to $299.3 million. During this period, $203.4 million cash distributions were paid (net of $87.7 million which was reinvested through our distribution reinvestment plans) and $255.0 million of Funds From Operations was retained for our capital programs and our working capital repayment. In the six months ended June 30, 2007, our capital spending aggregated to $211.5 million while the net cash required for our acquisition/divestiture program aggregated to $9.2 million with the $26.1 million of residual Funds From Operations directed towards our increasing working capital requirements. This compares with Funds From Operations of $248.0 million ($242.3 million after including $5.7 million of one time cash transaction costs relating to the acquisition of Viking) and distributions declared of $210.7 million net of $79.3 million reinvested through our distribution reinvestment plans in the prior year with aggregate capital spending of $157.5 million.

Management, together with the Board of Directors of Harvest, continually assess distributions relative to projections of Funds From Operations, debt leverage and capital spending plans. On July 8, 2007 we announced the declaration of a $0.38 per trust unit distribution for each of July, August and September 2007 based on forecasted commodity prices and expected operating performance that are consistent with the current environment. Of the distributions declared for the first six months of 2007 totaling $299.3 million and representing 65% of Funds From Operations, $89.2 million have been settled with trust units as a result of Unitholders choosing to participate in our distribution reinvestment plans, representing a participation rate of approximately 30%.

In February 2007, we issued 6,146,750 trust units and $230 million principal amount of 7.25% Debentures due 2014 for net proceeds of $357.4 million and applied these proceeds to fully repay the remaining balance outstanding on the Senior Unsecured Bridge Facility. The residual $67.7 million of proceeds was applied to the then $1.4 billion Three Year Extendible Revolving Credit Facility thereby increasing our undrawn credit capacity. In June 2007, we issued 7,302,500 trust units for net proceeds of $218.5 million and also applied the proceeds to reduce the drawn amount of our $1.6 billion Three Year Extendible Revolving Credit Facility.

During the Second Quarter of 2007, the trading value of our trust units appreciated from an opening price of $28.57 at the beginning of the quarter to $32.95 at the end of the quarter and traded as high as $34.48 in mid June. This appreciation in the value of our Trust Units supported the conversion of $125.6 million of principle amount of 7.25% Debentures due 2014, primarily in late June. Continued strength in the trading value of our trust units in the Third Quarter is expected to encourage the conversion of more convertible debentures as all but one series of debentures have exercise prices of $32.20 per trust unit or less. While these conversions do not bring additional cash into Harvest, they do contribute to improving our credit metrics as these debt instruments transition to equity.

In the First Quarter of 2007, we requested that our lenders extend the maturity date of our Three Year Extendible Revolving Credit Facility to April 2010 from March 2009 and approve the expansion of the facility from $1.4 billion to $1.6 billion. All lenders approved the expansion of the facility to $1.6 billion and we have received consents to extend the maturity date to April 2010 from lenders representing $1,535 million of commitments, with one lender representing a $65 million commitment not consenting to an extension of the maturity date. Subsequent to the end of the Second Quarter, we received commitments from one existing lender to replace $35 million of commitments maturing March 2009, resulting in only $30 million of our $1.6 billion Three Year Extendible Revolving Credit Facility maturing March 2009. For a complete description of this covenant-based credit agreement, see Note 10 to our audited consolidated financial statements for the year ended December 31, 2006 filed on SEDAR at www.sedar.com. This credit facility contains floating interest rates that are expected to range between 65 and 115 basis points over bankers' acceptance rates depending on our secured senior debt (excluding $7^{7/8}$% Senior Notes and convertible debentures) to earnings before interest, taxes, depletion, amortization and other non-cash amounts ("EBITDA") with availability under this facility subject to:

Secured senior debt to EBITDA	3.0 to 1.0 or less
Total debt to EBITDA	3.5 to 1.0 or less
Secured senior debt to capitalization	50% or less
Total debt to capitalization	55% or less

At the end of June 30, 2007, our Bank Debt to annualized EBITDA based on the first six months of 2007 was 1.14 to 1.0, Total Debt (excluding convertible debentures) to annualized EBITDA was 1.43 to 1.0 while the Bank Debt to Total Capitalization was 19% and Total Debt to Total Capitalization was 36%.

Concurrent with the closing of the North Atlantic acquisition, North Atlantic entered into a Supply and Offtake Agreement with Vitol Refining S.A. (“Vitol”), a third party related to the vendor of North Atlantic. The agreement provides for the ownership of substantially all of the crude oil feedstock and refined product inventory at the Refinery be retained by Vitol and that Vitol will be granted the right and obligation to provide crude oil feedstock with delivery to the Refinery as well as the right and obligation to purchase all refined products produced by the Refinery. In addition to assisting North Atlantic by procuring the crude oil feedstock and marketing the refined products, this agreement also significantly reduces North Atlantic’s working capital commitments by eliminating the requirement for North Atlantic:

- to post letters of credit for crude oil feedstock purchase commitments,
- to arrange for the shipping of crude oil feedstock to the Refinery,
- to pay for crude oil feedstock purchases while in-transit to and in tankage at the Refinery,
- to finance the receivables from the sale of refined products, and
- to arrange for the shipping of refined products to customers.

In respect of this working capital requirement assumed by Vitol, the Supply and Offtake Agreement provides that North Atlantic will pay a “Time Value of Money” charge reflecting an effective interest rate of 350 basis points over the London Inter Bank Offer Rate. The Supply and Offtake Agreement may be terminated by either party at the end of the initial two year term (October 2009), and at any time thereafter by providing notice of termination no later than six months prior to the desired termination date. The potential for termination of the Supply and Offtake Agreement requires that we maintain the financial flexibility to provide the working capital capacity currently provided by Vitol as well as either develop the internal capability to perform these supply services or identify and negotiate a similar contract with another provider of such services. At the end of June 30, 2007, we estimate that the outstanding commitments under the Supply and Offtake Agreement aggregated to approximately $671.6 million.

Following the October 31, 2006 announcement by the Government of Canada which proposed to apply a 31.5% tax on the distributions from certain publicly traded mutual funds including Harvest Energy Trust, the trading value of our trust units (which closed on October 31, 2006 at $32.95) has been as follows:

	Trading Price		
Month	**High**	**Low**	**Volume**
TSX Trading			
November 2006	$ 28.60	$ 24.76	2,903,180
December 2006	$ 26.88	$ 25.70	8,828,206
January 2007	$ 26.22	$ 23.20	12,822,502
February 2007	$ 27.49	$ 24.81	10,036,635
March 2007	$ 29.22	$ 25.90	11,430,584
April 2007	$ 29.72	$ 29.24	10,244,956
May 2007	$ 31.94	$ 31.39	13,984,905
June 2007	$ 33.27	$ 32.65	19,605,824
NYSE Trading (in US$)			
November 2006	$ 25.29	$ 22.05	34,223,300
December 2006	$ 23.43	$ 22.27	16,264,800
January 2007	$ 22.20	$ 19.70	16,693,600
February 2007	$ 23.55	$ 21.18	10,059,454
March 2007	$ 25.22	$ 21.97	12,316,050
April 2007	$ 26.21	$ 25.80	10,038,123
May 2007	$ 29.25	$ 28.68	14,253,739
June 2007	$ 31.24	$ 30.66	13,474,838

Following the October 31, 2006 announcement, the trading value of our trust units sustained a significant drop in trading range and in June 2007 has surpassed the pre-announcement levels on the strength of rising commodity prices, narrowing oil quality differentials and robust refining margins. Maintaining the strength in the trading value of our trust units is critical as our trust units are the currency that enables us to optimize the accretive value of transactions, including our anticipated participation in the expected consolidation of the Canadian energy royalty trust sector, as well as minimizing the dilutive impact of issuing trust units to repay our debt.

We are authorized to issue an unlimited number of trust units. As at August 10, 2007, we had 145,299,537 trust units outstanding, 3,935,158 of Unit Appreciation Rights outstanding (of which 582,475 are exercisable) and 329,993 awards issued under the Unit Awards Incentive Plan (of which 86,497 were exercisable). In addition, we had seven series of convertible debentures outstanding that are convertible into 20,478,396 trust units.

Distributions to Unitholders and Taxability

In the Second Quarter of 2007, we declared monthly distributions of $0.38 per trust unit ($154.1 million) to Unitholders, 63% of our Funds From Operations, and have declared a monthly distribution of $0.38 per trust unit for the third quarter of 2007 as well. The $38.2 million increase in distributions declared during the Second Quarter of 2007 as compared to $115.9 million in the prior year is primarily due to an increase of approximately 41.3 million trust units outstanding following the acquisitions of Birchill and North Atlantic in 2006 along with issuance under our distribution re-investment plans.

	Three Months Ended June 30			**Six Months Ended June 30**		
(000s except per trust unit amounts)	**2007**	2006	Change	**2007**	2006	Change
Distributions declared	**$ 154,057**	$ 115,889	33%	**$ 299,327**	$ 210,701	42%
Per trust unit	**$ 1.14**	$ 1.14	-	**$ 2.28**	$ 2.25	1%
Taxability of distributions	**100%**	100%	-	**100%**	100%	-
Payout ratio(1)	**63%**	79%	(16%)	**65%**	85%	(20%)

(1) Funds From Operations used to calculate payout ratio excludes working capital changes, settlements of asset retirement obligations and in 2006, one time transaction costs associated with the Viking acquisition - see "Non-GAAP Measures".

Prior to January 1, 2011, 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 and that the Trust will have no taxable income.

OUTLOOK

During the first six months of 2007, we have benefited from stable refinery operations as well as robust refining margins and continued strength in crude oil prices while maintaining a stable monthly distribution of $0.38 per Trust Unit. As the third quarter unfolds, our focus on refining margins will shift from gasoline supplies for the summer driving season to a more balanced demand for heating oil and gasoline for the coming winter months. In our petroleum and natural gas operations, we do not attempt to forecast commodity prices although we note that natural gas prices have softened and the Canadian dollar has strengthened relative to the U.S. dollar and the crack spread on refined products has narrowed early in the Third Quarter.

For the balance of 2007, we have revised our daily production forecast to average 61,000 boe/d, including our acquisition of Grand effective in August 2007, and are adjusting our operating cost expectations to a range between $12.00 and $13.00 per boe for our petroleum and natural gas operations with our capital expenditures over the next six months to aggregate to $100 million. These production and operating cost expectations include the impact of the acquisition of Grand and anticipate that $10 million of capital spending on the Grand assets will be completed before year end. We will continue to evaluate acquisition opportunities as well as offer selected properties for divestment while striving to maintain or enhance our productive capability and improve our unit operating costs.

For our refining and marketing business, we are forecasting throughput for the Third Quarter in line with current operating performance at approximately 115,000 bbls/d of feedstock (excluding purchased fuel oil consumed by the plant). For the Fourth Quarter, we are anticipating throughput of approximately 102,000 bbls/d impacted by a planned maintenance shutdown of the Isomax unit for much of October to replace a catalyst bed and change-out its heat exchangers and this will lower the amount of gasoline and distillates produced during the Quarter. This modest turnaround may be extended to include minor modifications to the vacuum tower but this will not extend the length of the partial shutdown with current expectations being that the associated increased costs will be offset by improved distillate yields resulting in a neutral cash impact. We continue to expect our unit operating costs to be at the higher end of our $4.40 to $4.60 range with capital spending unchanged at $60 million and the cost of the turnaround estimated at $1.9 million. Should the shutdown include modifications to the vacuum tower, capital costs would be increased by $0.8 million.

Assuming a monthly distribution of $0.38 per trust unit is maintained, we continue to expect that our 2007 payout ratio will trend lower as compared to 2006 with our Funds From Operations benefiting from our acquisition of North Atlantic and a US$13.56 higher floor price in our 2007 oil price risk management contracts than in 2006.

Currently, we have entered into price risk management contracts to provide a floor price of US$55.67 (relative to the West Texas Intermediate benchmark price) with upside participation if prices rise above US$55.67 on 25,000 bbls/d for the balance of 2007. After considering our 19% average royalty rate, these risk management contracts reduce our WTI price risk exposure at prices under US$55.67 to 27% of our crude oil production, which significantly reduces the volatility of our Funds From Operations if WTI prices trend below the US$55.67 level. To complement these price risk management contracts, we have forward sold US$8,750,000 per month at an average Canadian to US dollar exchange rate of approximately US$0.89 per Canadian dollar through December 2007 and a further US$8,333,000 per month at US$0.90 per Canadian dollar for the first half of 2008, which represents approximately 20% of the US dollar value of the crude oil price risk management contracts. For the first half 2008, we have entered into price risk management contracts to provide a WTI floor price of US$55.00 with an 80% upside participation if prices rise above US$55.00 on 10,000 bbls/d, plus we have added contracts with respect to 20,000 bbls/d of refined products as more fully described in the Price Risk Management Contracts sections of this MD&A.

For 2008, we have entered into price collars on 4,000 bbl/d of refined products as well as 3-way structured contracts on a further 16,000 bbl/d of refined products as more fully described in the Price Risk management section of this MD&A's discussion of Refining and Marketing Operations.

After crystallizing a $5.5 million gain on our natural gas price contracts early in the Third Quarter of 2007, we have exposure to future changes in natural gas prices. However, our financial results will include gains of $2.5 million, $2.1 million and $900,000 in each of the next three quarters, respectively. We have also entered into contracts to fix the price of 35 megawatt hours (or approximately 50% of the anticipated electrical consumption of our petroleum and natural gas operations in Alberta) through to the end of December 2008 at a price of $56.69. Our objective with the electricity fixed price contracts is to substantially reduce the volatility of our operating costs to fluctuations in the cost of electricity which represent approximately 25% of the operating costs in our petroleum and natural gas operations.

To enhance the stability to our future cash flows, we will continue to enter into contracts to protect the future price of refined products as well as AECO natural gas prices and the currency exchange rate for US dollars to Canadian dollars along with a measured approach to negotiating fixed prices for electricity. Our objective of stabilizing our future cash flows is to fund long term sustainable cash distributions in a wide variety of pricing environments.

In addition to our petroleum and natural gas growth strategies in western Canada of focusing on properties adjacent to our existing operations, we intend to be an active participant in the consolidation of Canadian energy royalty trusts, which is dependent on the current value of our trust units as trust-on-trust mergers are expected to be negotiated based on market valuations.

In June 2007, the Federal Government of Canada substantively enacted the changes to The Income Tax Act (Canada) to apply a 31.5% tax at the mutual fund trust level on distributions of certain income from publicly traded mutual fund trusts, including Harvest Energy Trust, with an effective date of January 1, 2011, as previously announced. As of June 30, 2007, we estimate that 58% of our Unitholders are non-Canadian residents, essentially unchanged since March 31, 2007 and a significant increase since February 2006 when non-Canadian residents owned 33%. As the taxation of publicly traded mutual fund trusts unfolds, we continue to search and validate various capital structures balancing the benefits of the tax efficient distributions prior to 2011 against the longer term benefits of continuing with a growth strategy beyond the announced "normal growth" limitations.

The following table reflects the sensitivity of our last six months of operations in 2007 to changes in the following key factors to our business:

	Assumption	Change	Impact on Cash Flow
WTI oil price (US$/bbl)	$ 69.00	$ 5.00	$ 0.16 / Unit
Canadian/U.S. dollar exchange rate	$ 0.93	$ 0.02	$ 0.14 / Unit
AECO daily natural gas price ($/mcf)	$ 7.00	$ 1.00	$ 0.12 / Unit
Refinery crack spread (US$/bbl)	$ 10.00	$ 1.00	$ 0.14 / Unit
Petroleum and natural gas operating expenses (per boe)	$ 12.50	$ 1.00	$ 0.08 / Unit

SUMMARY OF QUARTERLY RESULTS

The table and discussion below highlight our second quarter 2007 performance over the preceding seven quarters on select measures:

	2007		2006				2005	
(000s except where noted)	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Revenue, net of royalties	**$ 1,133,450**	$ 1,025,512	$ 682,744	$ 259,818	$ 257,103	$ 181,160	$ 154,646	$ 169,654
Net income (loss)	**$ 6,248**	$ 69,850	$ 1,533	$ 107,768	$ 60,682	$ (33,937)	$ 75,638	$ 52,862
Per trust unit, basic[2]	**$ 0.05**	$ 0.55	$ 0.01	$ 1.01	$ 0.60	$ (0.41)	$ 1.45	$ 1.09
Per trust unit, diluted[2]	**$ 0.05**	$ 0.55	$ 0.01	$ 0.99	$ 0.60	$ (0.41)	$ 1.42	$ 1.08
Funds From Operations[1]	**$ 244,461**	$ 213,941	$ 156,270	$ 147,471	$ 147,010	$ 100,971	$ 96,431	$ 103,508
Per trust unit, basic[1]	**$ 1.83**	$ 1.68	$ 1.35	$ 1.39	$ 1.45	$ 1.23	$ 1.84	$ 2.14
Per trust unit, diluted[1]	**$ 1.62**	$ 1.52	$ 1.29	$ 1.34	$ 1.43	$ 1.22	$ 1.81	$ 2.09
Distributions per Unit, declared	**$ 1.14**	$ 1.14	$ 1.14	$ 1.14	$ 1.14	$ 1.11	$ 1.05	$ 0.95
Total long term financial liabilities	**$ 1,961,748**	$ 2,409,241	$ 2,488,524	$ 1,105,728	$ 746,840	$ 735,896	$ 349,074	$ 386,124
Total assets	**$ 5,613,333**	$ 5,800,346	$ 5,745,558	$ 4,076,771	$ 3,455,918	$ 3,470,653	$ 1,308,481	$ 1,327,272

(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 have generally increased steadily over the eight quarters with significantly higher revenue in the Second and Third Quarters of 2006 over the preceding quarters due to the incremental revenue from the Viking acquisition in February 2006 along with stronger commodity prices including narrowing crude oil differentials. In the Fourth Quarter of 2006, the significant increase in revenue over the prior quarter is attributed to the North Atlantic acquisition which is a margin business with significant revenues coupled with significant costs for crude oil feedstock. The growth in Funds From Operations is closely aligned with the growth in net revenues and is attributed to the same factors as the growth in net revenues.

Net income reflects both cash and non-cash items. Changes in non-cash items, including future income tax, DDA&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 cause net income to vary significantly from period to period. In the Second Quarter of 2007 Bill C-52 was substantively enacted, which imposed a new tax on distributions from publicly traded income trusts resulting in a large future income tax expense in the quarter. 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 and this is the primary reason why our net income (loss) does not reflect the same trends as net revenues or Funds From Operations.

Growth in total assets over the last eight quarters is directly attributed to our acquisition of Viking in the first quarter of 2006, Birchill in the Third Quarter of 2006 and North Atlantic in the Fourth Quarter of 2006. The changes in our total long term financial liabilities is primarily due to the impact of our acquisitions offset by our issuance of trust units and the net cash surplus of Funds From Operations over our distributions to Unitholders.

CRITICAL ACCOUNTING ESTIMATES

There are a number of critical estimates underlying the accounting policies applied when preparing the consolidated financial statements due to timing differences between when certain activities take place and when these activities are reported. Changes in these estimates could have a material impact on our reported results.

Reserves

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. In the process of estimating the economically recoverable oil and natural gas reserves and related future net cash flows, we incorporate many factors and assumptions, such as:

- Expected reservoir characteristics based on geological, geophysical and engineering assessments;
- Future production rates based on historical performance and expected future operating and investment activities;
- Future oil and gas prices and quality differentials; and
- Future development costs.

We follow the full cost method of accounting for our oil and natural gas activities. All costs of acquiring oil and natural gas properties and related exploration and development costs, including overhead charges directly related to these activities, are capitalized and accumulated in one cost centre. Maintenance and repairs are charged against income, and renewals and enhancements that extend the economic life of the capital assets are capitalized. The provision for depletion and depreciation of petroleum and natural gas assets is calculated on the unit-of-production method, based on proved reserves as estimated by independent petroleum engineers.

Reserve estimates impact net income through depletion, the determination of asset retirement obligations and the application of an impairment test. Revisions or changes in the reserve estimates can have either a positive or a negative impact on net income, capital assets and asset retirement obligations.

The estimates in reserves impact many of our accounting estimates including our depletion calculation. A decrease of reserves by 10% would result in an increase of approximately $70 million in our depletion expense.

Asset Retirement Obligations

In the determination of our asset retirement obligations, management is required to make a significant number of estimates with respect to activities that will occur in many years to come. In arriving at the recorded amount of the asset retirement obligation numerous assumptions are made with respect to ultimate settlement amounts, inflation factors, credit adjusted risk free discount rates, timing of settlement and expected changes in legal, regulatory, environmental and political environments. The asset retirement obligation also results in an increase to the carrying cost of capital assets. The obligation accretes to a higher amount with the passage of time as it is determined using discounted present values. A change in any one of the assumptions could impact the estimated future obligation and in return, net income. It is difficult to determine the impact of a change in any one of our assumptions. As a result, a reasonable sensitivity analysis cannot be performed.

Impairment of Capital Assets

In determining if the capital assets are impaired there are numerous estimates and judgments involved with respect to our estimates. The two most significant assumptions in determining cash flows are future prices and reserves.

The estimates of future prices require significant judgments about highly uncertain future events. Historically, oil and gas prices have exhibited significant volatility. The prices used in carrying out our impairment test are based on prices derived from a consensus of future price forecasts among industry analysts. Given the significant assumptions required and the possibility that actual conditions will differ, we consider the assessment of impairment to be a critical accounting estimate.

If forecast WTI crude oil prices were to fall by 18% to 20%, the initial assessment of impairment indicators would not change; however, below that level, we would likely experience an impairment. Although oil and natural gas prices fluctuate a great deal in the short-term, they are typically stable over a longer time horizon. This mitigates potential for impairment.

Reductions in estimated future prices may also have an impact on estimates of economically recoverable proved reserves.

Any impairment charges would reduce our net income.

It is difficult to determine and assess the impact of a decrease in our proved reserves on our impairment tests. The relationship between the reserve estimate and the estimated undiscounted cash flows is complex. As a result, we are unable to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on our assessment of impairment.

Employee Future Benefits

We maintain a defined benefit pension plan for the employees of North Atlantic. Obligations under employee future benefit plans are recorded net of plan assets where applicable. An independent actuary determines the costs of our employee future benefit programs using the projected benefit method. The determination of these costs requires management to estimate or make assumptions regarding the expected plan investment performance, salary escalation, retirement ages of employees, expected health care costs, employee turnover, discount rates and return on plan assets. The obligation and expense recorded related to our employee future benefit plans could increase or decrease if there were to be a change in these estimates. Pension expense represented less than 0.5% of our total expenses for 2006.

Purchase Price Allocations

Business acquisitions are accounted for by the purchase method of accounting. Under this method, the purchase price is allocated to the assets acquired and the liabilities assumed based on the fair values at the time of the acquisitions. The excess of the purchase price over the assigned fair values of the identifiable assets and liabilities is allocated to goodwill. In determining the fair value of the assets and liabilities we are often required to make assumptions and estimates about future events, such as future oil and gas prices, crack spreads and discount rates. Changes in any of these assumptions would impact amounts assigned to assets and liabilities and goodwill in the purchase price allocation and as a result, future net earnings.

RECENT CANADIAN ACCOUNTING AND RELATED PRONOUNCEMENTS

Convergence of Canadian GAAP with International Financial Reporting Standards

In 2006, Canada's Accounting Standards Board ("AcSB") ratified a strategic plan that will result in Canadian GAAP, as used by public companies, being converged with International Financial Reporting Standards ("IFRS") over a transitional period. In early 2007, the AcSB issued a decision summary with respect to its progress on the implementation strategy of IFRS for publicly accountable enterprises and will confirm a changeover date from Canadian GAAP to IFRS in March of 2008. Currently, it is expected that the transition date will be January 1, 2011. This convergence initiative is in its early stages as of the date of these financial statements and we have the option to adopt U.S. GAAP at any time prior to the expected conversion date. Accordingly, it would be premature to assess the impact of the initiative, if any, on our financial statements at this time.

Financial Instruments – Disclosures and Presentation

On December 1, 2006, Canada's Accounting Standards Board issued the following two new standards regarding the disclosure and presentation of financial instruments with an implementation date for annual and interim financial statements beginning on or after October 1, 2007.

- Section 3862 – *Financial Instruments – Disclosures*

This standard requires entities to provide disclosures in their financial statements that enable users to evaluate the significance of financial instruments to the entity's financial position and performance. It also requires that entities disclose the nature and extent of risks arising from financial instruments and how the entity manages those risks.

- Section 3863 – *Financial Instruments – Presentation*

This standard establishes standards for presentation of financial instruments and non-financial derivatives and deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset.

Also on December 1, 2006, Canada's Accounting Standards Board issued a new standard regarding *Capital Disclosure* requiring the disclosure of information about an entity's objectives, policies and processes for managing capital; quantitative data about what the entity regards as capital; whether the entity has complied with any externally imposed capital requirements; and if it has not complied, the consequences of such non-compliance. This standard also has an implementation date for annual and interim financial statements beginning on or after October 1, 2007.

Subsequent to June 30, 2007, new Canadian interpretive guidance has been released for the presentation and disclosure of standardized distributable cash in income trusts and other flow-through entities. This guidance is effective beginning in the Third Quarter of 2007.

OPERATIONAL AND OTHER BUSINESS RISKS

Our financial and operating performance is subject to risks and uncertainties which include, but are not limited to: oil and natural gas operations, refinery and petroleum marketing operations, reserve estimates, commodity prices, ability to obtain financing, environmental, health and safety risk, regulatory risk, disruptions in the supply of crude oil and delivery of refined products, employee relations, and other risks specifically discussed previously in this MD&A. We intend to continue executing our business plan to create value for Unitholders by paying stable monthly distributions and increasing the net asset value per trust unit. All of our risk management activities are carried out under policies approved by the Board of Directors of Harvest Operations, and are intended to mitigate the risks noted above as follows:

Operation of oil and natural gas properties:

- Applying a proactive management approach to our properties;
- Selectively adding skilled and experienced employees and providing encouragement and opportunities to maintain and improve technical competence; and

Operation of a refining and petroleum marketing business

- Maintaining a proactive approach to managing the supply of feedstock and sale of refined products (including the Supply and Offtake Agreement with Vitol Refining S.A.) to ensure the continuity of supply of crude oil to the refinery and the delivery of refined products from the refinery;
- Allocating sufficient resources to ensure good relations are maintained with our non-unionized and unionized work force; and
- Selectively adding experienced refining management to further strengthen our "in-house" management team, particularly a new leader for our refinery operations to replace the current President, Refinery Manager of North Atlantic who has committed to an orderly transition.

Estimates of the quantity of recoverable reserves:

- Acquiring oil and natural gas properties that have high-quality reservoirs combined with mature, predictable and reliable production and thus reduce technical uncertainty;
- Subjecting all property acquisitions to rigorous operational, geological, financial and environmental review; and

- Pursuing a capital expenditure program to reduce production decline rates, improve operating efficiency and increase ultimate recovery of the resource-in-place.

Commodity price exposures:

- Maintaining a risk-management policy and committee to continuously review effectiveness of existing actions, identify new or developing issues and devise and recommend to the Board of Directors of Harvest Operations action to be taken;
- Executing risk management contracts with a portfolio of credit-worthy counterparties;
- Maintaining a low cost structure to maximize product netbacks; and
- Limiting the period of exposure to price fluctuations between crude oil prices and product prices by entering into contracts 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 is initially loaded onto the shipping vessel. Thereby, minimizing the time between the pricing of the feedstock and the refined products with the objective of maintaining margins.

Financial risk:

- Monitoring financial markets to ensure the cost of debt and equity capital is kept as low as reasonably possible;
- Retaining a portion of cash flows to finance capital expenditures and future property acquisitions; and
- Carrying adequate insurance to cover property and business interruption losses.

Environmental, health and safety risks:

- Adhering to our safety programs and keeping abreast of current industry practices for both the oil and natural gas industry as well as the refining industry; and
- Committing funds on an ongoing basis toward the remediation of potential environmental issues.

Changing government policy, including revisions to royalty legislation, income tax laws, and incentive programs related to the oil and natural gas industry:

- Retaining an experienced, diverse and actively involved Board of Directors to ensure good corporate governance; and
- Engaging technical specialists when necessary to advise and assist with the implementation of policies and procedures to assist in dealing with the changing regulatory environment.

CHANGES IN REGULATORY ENVIRONMENT

The Government of Alberta has announced its intention to examine Alberta's royalty and tax regime and in February 2007, appointed an independent panel of experts to conduct a review of all aspects of the royalty system including conventional oil and gas, oil sands and coalbed methane. A final report with recommendations is expected to be presented to the Government of Alberta by August 31, 2007. It would be premature to assess the impact of the initiative, if any, on our financial statements at this time.

In 2002, the Government of Canada ratified the Kyoto Protocol which calls for Canada to reduce its greenhouse gas emissions to specified levels. On April 26, 2007, the Government of Canada released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan") which includes a regulatory framework for air emissions. This Action Plan is to regulate the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products. Meanwhile, the Government of Alberta has introduced the Climate Change and Emissions Management Amendment Act which intends to reduce greenhouse gas emissions intensity from large emitting facilities. Giving the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to assess the impact of the requirements on our operations and financial performance.

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 Funds From Operations as cash provided by operating activities before changes in non-cash working capital, settlement of asset retirement obligations and one time transaction costs. Funds From Operations as presented is not intended to represent an alternative to net earnings, cash provided by operating activities or other measures of financial performance calculated in accordance with Canadian GAAP. Management uses Funds From Operations 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 total distributions to total Funds From Operations. 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 management contracts. Cash G&A are G&A expenses excluding the effect of our unit based compensation plans. Gross Margin is commonly used in the refining industry to reflect the net cash received from the sale of refined products after considering the cost to purchase the feedstock and is calculated by deducting purchased products for resale and processing from total revenue. Earnings From Operations is also commonly used in the petroleum and natural gas and refining industries to reflect operating results before items not directly related to operations.

For the three and six months ended June 30, 2007 and 2006, Funds From Operations is reconciled to its closest GAAP measure, cash provided by operating activities, as follows:

	Three Months Ended June 30		Six Months Ended June 30	
(000s)	**2007**	2006	**2007**	2006
Funds From Operations	**$ 244,461**	$ 147,010	**$ 458,402**	$ 247,981
Cash Viking transaction costs	**-**	(670)	**-**	(5,742)
Settlement of asset retirement obligations	**(2,268)**	(625)	**(4,388)**	(1,743)
Changes in non-cash working capital	**9,025**	(10,134)	**(91,748)**	(16,751)
Cash provided by operating activities	**$ 251,218**	$ 135,581	**$ 362,266**	$ 223,745

FORWARD-LOOKING INFORMATION

This MD&A highlights significant business results and statistics from our consolidated financial statements for the three and six months ended June 30, 2007 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; risks associated with refinery 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, refinery throughput volumes, royalty rates, operating costs, commodity prices, administrative costs, commodity price risk management activity, acquisitions and dispositions, capital spending, reserve estimates, distributions, access to credit facilities, capital taxes, income taxes, Funds 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 we 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.

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(thousands of Canadian dollars)

		June 30, 2007		December 31, 2006
Assets				
Current assets				
Cash	**$**	**13,447**	$	10,006
Accounts receivable and other		**299,414**		257,131
Fair value of risk management contracts *[Note 16]*		**16,989**		17,914
Prepaid expenses and deposits		**11,356**		12,713
Inventories *[Note 4]*		**52,279**		30,512
		393,485		328,276
Deferred charges and other non-current assets *[Note 7]*		**-**		25,067
Fair value of risk management contracts *[Note 16]*		**8,859**		9,843
Property, plant and equipment *[Note 5]*		**4,256,359**		4,393,832
Intangible assets *[Note 6]*		**106,466**		122,362
Goodwill		**848,164**		866,178
	$	**5,613,333**	$	5,745,558
Liabilities and Unitholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities *[Note 8]*	**$**	**265,863**	$	294,582
Cash distribution payable		**54,532**		46,397
Current portion of convertible debentures *[Note 11]*		**25,604**		-
Fair value deficiency of risk management contracts *[Note 16]*		**21,939**		26,764
		367,938		367,743
Bank loan *[Note 10]*		**1,047,965**		1,595,663
$7^{7/8}$% Senior Notes		**258,387**		291,350
Convertible debentures *[Note 11]*		**655,396**		601,511
Fair value deficiency of risk management contracts *[Note 16]*		**8,908**		2,885
Asset retirement obligation *[Note 9]*		**210,041**		202,480
Employee future benefits *[Note 15]*		**12,219**		12,227
Deferred credit		**688**		794
Future income tax *[Note 14]*		**177,684**		-
Unitholders' equity				
Unitholders' capital *[Note 12]*		**3,610,830**		3,046,876
Equity component of convertible debentures		**41,792**		36,070
Accumulated income		**348,639**		271,155
Accumulated distributions		**(1,029,396)**		(730,069)
Accumulated other comprehensive (loss) income *[Note 2]*		**(97,758)**		46,873
		2,874,107		2,670,905
	$	**5,613,333**	$	5,745,558

Commitments, contingencies and guarantees *[Note 19]*
Subsequent events *[Note 20]*
See accompanying notes to these consolidated financial statements.

Approved by the Board of Directors:

((signed))
Hector J. McFadyen
Director

((signed))
Verne G. Johnson
Director

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE (LOSS) INCOME (UNAUDITED)

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

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	**Six Months Ended June 30, 2007**	Six Months Ended June 30, 2006
Revenue				
Petroleum, natural gas, and refined product sales	**$ 1,186,998**	$ 309,010	**$ 2,262,159**	$ 533,285
Royalty expense	**(53,548)**	(51,907)	**(103,197)**	(95,022)
Risk management contracts				
Realized net losses	**(6,826)**	(23,860)	**(7,123)**	(32,591)
Unrealized net gains (losses)	**11,014**	(115)	**(3,107)**	(41,112)
	1,137,638	233,128	**2,148,732**	364,560
Expenses				
Purchased products for processing and resale	**708,642**	-	**1,340,938**	-
Operating	**117,254**	60,593	**238,911**	110,687
Transportation and marketing	**12,434**	4,065	**22,589**	5,688
General and administrative *[Note 13]*	**16,463**	8,513	**26,867**	14,325
Transaction charges	**-**	330	**-**	12,072
Interest and other financing charges on short term debt	**577**	87	**4,204**	237
Interest and other financing charges on long term debt	**39,803**	13,894	**80,252**	25,651
Depletion, depreciation, amortization and accretion	**129,631**	97,178	**263,423**	182,503
Foreign exchange gain	**(71,098)**	(12,398)	**(82,358)**	(11,490)
Large corporations tax and other tax	**-**	169	**124**	507
Future income tax expense (recovery) *[Note 14]*	**177,684**	-	**177,684**	(2,300)
Non-controlling interest	**-**	15	**-**	(65)
	1,131,390	172,446	**2,072,634**	337,815
Net income for the period	**6,248**	60,682	**76,098**	26,745
Cumulative Translation Adjustment	**(128,491)**	-	**(144,631)**	-
Comprehensive (loss) income for the period *[Note 2]*	**(122,243)**	60,682	**(68,533)**	26,745
Net income per Trust Unit, basic *[Note 12]*	**$ 0.05**	$ 0.60	**$ 0.58**	$ 0.29
Net income per Trust Unit, diluted *[Note 12]*	**$ 0.05**	$ 0.60	**$ 0.58**	$ 0.29

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY (UNAUDITED)

(thousands of Canadian dollars)

	Unitholders' Capital	Equity Component of Convertible Debentures	Accumulated Income	Accumulated Distributions	Accumulated Other Comprehensive (Loss) Income (AOCI) *[Note 2]*	Total
At December 31, 2005	**$ 747,312**	**$ 2,639**	**$ 135,665**	**$ (261,282)**	**$ -**	**$ 624,334**
Issued in exchange for assets of Viking	1,638,131	-	-	-	-	1,638,131
Equity component of convertible debenture issuances						
10.5% Debentures Due 2008	-	9,301	-	-	-	9,301
6.40% Debentures Due 2012	-	14,822	-	-	-	14,822
Convertible debenture conversions						
9% Debentures Due 2009	318	-	-	-	-	318
8% Debentures Due 2009	824	(6)	-	-	-	818
6.5% Debentures Due 2010	3,563	(223)	-	-	-	3,340
10.5% Debentures Due 2008	3,127	(649)	-	-	-	2,478
6.40% Debentures Due 2012	21	(2)	-	-	-	19
Exchangeable share retraction	2,648	-	(556)	-	-	2,092
Exercise of unit appreciation rights and other	10,284	-	-	-	-	10,284
Issue costs	(525)	-	-	-	-	(525)
Net income	-	-	26,745	-	-	26,745
Distributions and distribution reinvestment plan	79,253	-	-	(210,701)	-	(131,448)
At June 30, 2006	**$2,484,956**	**$ 25,882**	**$ 161,854**	**$ (471,983)**	**$ -**	**$ 2,200,709**
At December 31, 2006, as restated *[Note 2]*	**$3,046,876**	**$ 36,070**	**$ 271,155**	**$ (730,069)**	**$ 46,873**	**$ 2,670,905**
Adjustment arising from change in accounting policies *[Note 2]*	(49)	-	1,386	-	-	1,337
Issued for cash						
February 1, 2007	143,834	-	-	-	-	143,834
June 1, 2007	230,029	-	-	-	-	230,029
Equity component of convertible debenture issuances						
7.25% Debentures Due 2014	-	13,100	-	-	-	13,100
Convertible debenture conversions						
9% Debentures Due 2009	168	-	-	-	-	168
8% Debentures Due 2009	416	(3)	-	-	-	413
6.5% Debentures Due 2010	-	-	-	-	-	-
10.5% Debentures Due 2008	1,426	(298)	-	-	-	1,128
6.40% Debentures Due 2012	122	(10)	-	-	-	112
7.25% Debentures Due 2013	93	(3)	-	-	-	90
7.25% Debentures Due 2014	124,302	(7,064)	-	-	-	117,238
Exercise of unit appreciation rights and other	278	-	-	-	-	278
Issue costs	(24,409)	-	-	-	-	(24,409)
Change in AOCI related to foreign currency translation adjustment	-	-	-	-	(144,631)	(144,631)
Net income	-	-	76,098	-	-	76,098
Distributions and distribution reinvestment plan	87,744	-	-	(299,327)	-	(211,583)
At June 30, 2007	**$3,610,830**	**$ 41,792**	**$ 348,639**	**$ (1,029,396)**	**$ (97,758)**	**$ 2,874,107**

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(thousands of Canadian dollars)

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	**Six Months Ended June 30, 2007**	Six Months Ended June 30, 2006
Cash provided by (used in)				
Operating Activities				
Net income for the period	**$ 6,248**	$ 60,682	**$ 76,098**	$ 26,745
Items not requiring cash				
Depletion, depreciation, amortization and accretion	**129,631**	97,178	**263,423**	182,503
Unrealized foreign exchange gain	**(68,286)**	(12,037)	**(79,022)**	(11,123)
Non-cash interest expense	**2,081**	378	**3,973**	671
Amortization of finance charges	**679**	772	**3,160**	2,206
Unrealized loss on risk management contracts *[Note 16]*	**(11,014)**	115	**3,107**	41,112
Future income tax expense (recovery) *[Note 14]*	**177,684**	-	**177,684**	(2,300)
Non-controlling interest	**-**	15	**-**	(65)
Unit based compensation expense	**6,447**	(675)	**8,877**	2,541
Amortization of office lease premium and deferred rent expense	**3**	(88)	**6**	(51)
Employee benefit obligation	**988**	-	**1,096**	-
Settlement of asset retirement obligations *[Note 9]*	**(2,268)**	(625)	**(4,388)**	(1,743)
Change in non-cash working capital *[Note 18]*	**9,025**	(10,134)	**(91,748)**	(16,751)
	251,218	135,581	**362,266**	223,745
Financing Activities				
Issue of Trust Units, net of issue costs	**218,541**	(33)	**354,557**	(101)
Issue of convertible debentures, net of issue costs *[Note 11]*	**-**	-	**220,489**	-
Redemption of exchangeable shares	**-**	(1,022)	**-**	(1,022)
Bank borrowings, net *[Note 10]*	**(266,999)**	25,892	**(492,370)**	107,428
Financing costs	**-**	(964)	**(273)**	(1,129)
Cash distributions	**(105,006)**	(65,927)	**(203,448)**	(111,168)
Change in non-cash working capital *[Note 18]*	**5,261**	(5,469)	**11,463**	(18,770)
	(148,203)	(47,523)	**(109,582)**	(24,762)
Investing Activities				
Additions to property, plant and equipment	**(58,092)**	(54,230)	**(211,462)**	(157,469)
Business acquisitions	**-**	-	**(30,264)**	-
Property acquisitions	**(7,975)**	(290)	**(11,086)**	(23,672)
Property dispositions	**29,776**	-	**32,198**	-
Change in non-cash working capital *[Note 18]*	**(53,481)**	(33,538)	**(29,478)**	(17,842)
	(89,772)	(88,058)	**(250,092)**	(198,983)
Change in cash and cash equivalents	**$ 13,243**	$ -	**$ 2,592**	$ -
Effect of exchange rate changes on cash	**204**	-	**849**	-
Cash and cash equivalents, beginning of period	**-**	-	**10,006**	-
Cash and cash equivalents, end of period	**$ 13,447**	$ -	**$ 13,447**	$ -
Interest paid	**$ 35,017**	$ 14,710	**$ 50,860**	$ 17,282
Large corporation tax and other tax paid	**$ -**	$ 206	**$ 124**	$ 812

See accompanying notes to these consolidated financial statements.

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS
Period ended June 30, 2007
(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. Except as noted below, these interim consolidated financial statements follow the same significant accounting policies as described and used in the consolidated financial statements of Harvest for the year ended December 31, 2006 and should be read in conjunction with that report.

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

2. Changes in Accounting Policies

Financial Instruments and Comprehensive Income
Effective January 1, 2007, Harvest adopted three new and revised Canadian accounting standards as issued by the Canadian Institute of Chartered Accountants respecting "Financial Instruments – Recognition and Measurement", "Financial Instruments – Presentation and Disclosure" and "Comprehensive Income".

Financial Instruments

The revised standard on Financial Instruments provides new guidance on how to recognize and measure financial instruments. It requires all financial instruments to be recorded at fair value when initially recognized. Subsequent measurement is either at fair value or amortized cost, depending on the classification of the financial instrument. Financial assets and liabilities that are held-for-trading are measured at fair value with changes in those fair values recognized in net income. Available-for-sale financial assets are measured at fair value with unrealized gains or losses recognized in other comprehensive income. Held-to-maturity assets, loans and receivables and other liabilities are all measured at amortized cost with any related expenses or income recognized in net income. Price risk management contracts are classified as held-for-trading and are measured at fair value at initial recognition and at subsequent measurement dates. Any derivatives embedded in other financial or non-financial contracts that were entered into on or after January 1, 2001 must also be measured at fair value and recorded in the financial statements if the embedded derivative is not closely related to the host contract. Fair value of financial instruments is based on market prices where available, otherwise it is calculated as the net present value of expected future cash flows. For those items measured at amortized cost, interest expense is calculated using an effective interest rate that accretes any discount or premium over the life of the instrument so that the carrying value equals the face value at maturity.

Harvest does not have any financial assets classified as available-for-sale or held-to-maturity. The only items on Harvest's balance sheet that are classified as held-for-trading and subsequently measured at fair value are cash and our price risk management contracts. The remainder of the financial instruments are measured at amortized cost. As well, there are no significant embedded derivatives that need to be recorded in the financial statements.

Transaction costs relating to financial instruments classified as held for trading are expensed in net income in the period that they are incurred. Harvest has elected to add all other transaction costs that are directly attributable to the acquisition or issue of a financial asset or liability to the amount of the financial asset or liability that is recorded on initial recognition.

The transitional provisions of the Financial Instruments standard require retrospective adoption without restatement of these standards; therefore, our prior period financial statements have not been restated. The provisions also require all financial instruments to be remeasured using the criteria of the new standard and any change in the previous carrying amount is to be recognized as an adjustment to retained earnings on January 1, 2007. As our price risk management contracts were already measured at fair value, the most significant change for Harvest was reclassifying the deferred charges relating to our senior notes and convertible debentures and netting these amounts against the respective liability. These charges are then amortized to income using an effective interest rate. The effect of applying this new standard on

January 1, 2007 was to reduce the carrying value of the following amounts as indicated with an offsetting reduction to deferred charges:

Deferred charges	$	(25,067)
7 $^{7/8}$% Senior notes		(9,522)
Convertible debentures		(16,882)
Unitholders' capital		(49)
Accumulated income		1,386

See Note 16 for the additional presentation and disclosure requirements for Financial Instruments.

Other Comprehensive Income

The new standards introduce the concept of comprehensive income, which consists of net income and other comprehensive income. Other comprehensive income represents changes in Unitholders' equity during a period arising from transactions and other events with non-owner sources. The transitional provisions of this section require that the comparative statements are restated to reflect the application of this standard only on certain items.

For Harvest, the only such item is the unrealized foreign currency translation gains or losses arising from our refining and marketing operations, which is considered a self-sustaining operation with a U.S. dollar functional currency. As the cumulative translation adjustment was presented as a separate component of Unitholders' equity already, this restatement simply required the cumulative translation adjustment to be reclassified to accumulated other comprehensive income on the balance sheet and statement of Unitholders' equity.

Future Accounting Changes

New accounting standards were issued on December 1, 2006 that effective January 1, 2008 require increased disclosure on financial instruments, particularly with regard to the nature and extent of risks arising from financial instruments and how the entity manages those risks. New capital disclosures are also required effective January 1, 2008 on an entity's objectives, policies and processes for managing capital; quantitative data about what the entity regards as capital; whether the entity has complied with any externally imposed capital requirements; and if it has not complied, the consequences of such non-compliance.

3. Business Acquisition

On March 1, 2007, Harvest acquired all of the issued and outstanding shares of a private petroleum and natural gas corporation for $30.3 million net of working capital adjustments and transaction costs. The results of operations of this acquisition have been included in the consolidated financial statements since its acquisition on March 1, 2007. An officer of Harvest was a director of this private corporation and received proceeds that are considered to be insignificant to both the officer and Harvest.

4. Inventories

		June 30, 2007		December 31, 2006
Petroleum products	**$**	**42,010**	$	19,513
Parts and supplies		**10,269**		10,999
Total inventories, net	**$**	**52,279**	$	30,512

For the three and six month period ended June 30, 2007, inventory included valuation adjustments to the lower of cost or market of $2.5 million and $3.1 million, respectively, and these adjustments were included in "purchased products for resale and processing".

5. Property, Plant and Equipment

	June 30, 2007			December 31, 2006
	Petroleum and natural gas	**Refining and marketing**	**Total**	Total
Cost	**$ 4,010,056**	**$ 1,215,329**	**$ 5,225,385**	$ 5,115,032
Accumulated depletion and depreciation	**(923,470)**	**(45,556)**	**(969,026)**	(721,200)
Net book value	**$ 3,086,586**	**$ 1,169,773**	**$ 4,256,359**	$ 4,393,832

General and administrative costs of $3.9 million have been capitalized during the three month period ended June 30, 2007 (three months ended June 30, 2006 – $2.9 million), of which $1.7 million (three months ended June 30, 2006 - $639,000) relate to the Trust Unit Rights Incentive Plan and the Unit Award Incentive Plan. For the six month period ended June 30, 2007 $6.5 million (six months ended June 30, 2006 – $6.8 million) of general and administrative costs have been capitalized, of which $2.2 million (six months ended June 30, 2006 – $2.7 million) relate to the Trust Unit Rights Incentive Plan and the Unit Award Incentive Plan.

6. Intangible Assets

	June 30, 2007			December 31, 2006
	Cost	**Accumulated Amortization**	**Net Book value**	Net Book value
Engineering drawings	**$ 94,821**	**$ 3,358**	**$ 91,463**	$ 102,641
Marketing contracts	**6,595**	**638**	**5,957**	7,109
Customer lists	**3,992**	**283**	**3,709**	4,276
Fair value of office lease	**931**	**316**	**615**	726
Financing costs	**12,113**	**7,391**	**4,722**	7,610
Total	**$ 118,452**	**$ 11,986**	**$ 106,466**	$ 122,362

7. Other Non-Current Assets

	June 30, 2007	December 31, 2006
Deferred charges, net of amortization	**$ -**	$ 23,659
Discount on senior notes, net of amortization	**-**	1,408
Total	**$ -**	$ 25,067

8. Accounts Payable and Accrued Liabilities

	June 30, 2007	December 31, 2006
Trade accounts payable	**$ 111,650**	$ 111,837
Accrued interest	**18,288**	14,367
Trust Unit Incentive Plan and Unit Award Incentive Plan *[Note 13]*	**17,155**	6,442
Other accrued liabilities	**118,770**	161,936
Total	**$ 265,863**	$ 294,582

9. Asset Retirement Obligation

Harvest's asset retirement obligations result 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. Harvest estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations to be approximately $696.0 million which will be incurred between 2007 and 2055. The majority of the costs will be incurred between 2025 and 2035. A credit-adjusted risk-free discount rate of 10% was used to calculate the fair value of the asset retirement obligations set-up before September 30, 2005. Upward revisions and new obligations after this date are discounted using a revised credit adjusted risk-free discount rate of 8%.

A reconciliation of the asset retirement obligations is provided below:

		June 30, 2007		December 31, 2006
Balance, beginning of period	**$**	**202,480**	$	110,693
Incurred on acquisition of a private corporation		**1,629**		-
Incurred on acquisition of Viking		**-**		60,493
Incurred on acquisition of Birchill		**-**		1,219
Liabilities incurred		**1,401**		2,763
Revision of estimates		**-**		20,544
Liabilities settled		**(4,388)**		(9,186)
Accretion expense		**8,919**		15,954
Balance, end of period	**$**	**210,041**	$	202,480

Harvest has gross asset retirement obligations of approximately $14.7 million relating to the refining and marketing assets that are expected to be settled after 2081. Due to the long time period prior to settlement, the discounted value today is immaterial.

10. Bank Loan

At June 30, 2007, Harvest had $1,048.0 million drawn under its Three Year Extendible Revolving Credit Facility, of which $524.9 million is payable in U.S. dollars.

On May 7, 2007, Harvest and its lenders amended the Three Year Extendible Revolving Credit Facility to increase the aggregate commitment amount from $1.4 billion to $1.6 billion and extend the maturity date of the facility from March 31, 2009 to April 30, 2010 with respect to $1,535 million of the aggregate commitment amount. Effective May 7, 2007, the Three Year Extendible Revolving Credit Facility is comprised of $1,535 million of commitments with a maturity date of April 30, 2010 and $65 million of commitments with a maturity date of March 31, 2009.

11. Convertible Debentures

Harvest has seven series of convertible unsecured subordinated debentures outstanding, the details of which have been outlined in Harvest's Consolidated Financial Statements for the year ended December 31, 2006.

The following is a summary of the seven series of convertible debentures:

Series	**Conversion price / Trust Unit**	**Maturity**	**First redemption period**	**Second redemption period**
9% Debenture Due 2009	$ 13.85	May 31, 2009	Jun. 1/07-May 31/08	Jun. 1/08-May. 30/09
8% Debenture Due 2009	$ 16.07	Sept. 30, 2009	Oct. 1/07-Sept. 30/08	Oct. 1/08-Sept. 29/09
6.5% Debenture Due 2010	$ 31.00	Dec. 31, 2010	Jan. 1/09-Dec. 31/09	Jan. 1/10-Dec. 30/10
10.5% Debenture Due 2008	$ 29.00	Jan. 31, 2008	Feb. 1/06-Jan. 31/07	Feb. 1/07-Jan. 30/08
6.40% Debenture Due 2012(1)	$ 46.00	Oct. 31, 2012	Nov. 1/08-Oct. 31/09	Nov. 1/09-Oct. 31/10
7.25% Debenture Due 2013(1)	$ 32.20	Sept. 30, 2013	Oct. 1/09-Sept. 30/10	Oct. 1/10-Sept. 30/11
7.25% Debenture Due 2014(1)	$ 27.25	Feb. 28, 2014	Mar. 1/10-Feb. 28/11	Mar. 1/11-Feb. 29/12

(1) These series of convertible debentures may also be redeemed by Harvest at a price of $1,000 per debenture after the second redemption period until maturity.

The following table summarizes the face value, carrying amount and fair value of the convertible debentures:

	June 30, 2007			December 31, 2006		
	Face Value	**Carrying Amount[(1)]**	**Fair Value**	Face Value	Carrying Amount[(1)]	Fair Value
9% Debentures Due 2009	$ 1,058	$ 1,038	$ 2,169	$ 1,226	$ 1,226	$ 2,280
8% Debentures Due 2009	1,824	1,776	3,466	2,239	2,229	3,731
6.5% Debentures Due 2010	37,929	35,111	40,360	37,929	35,988	37,925
10.5% Debentures Due 2008	25,498	25,604	28,838	26,621	26,824	28,085
6.40% Debentures Due 2012	174,626	167,787	173,735	174,743	167,401	159,485
7.25% Debentures Due 2013	379,407	353,691	398,377	379,500	367,843	375,705
7.25% Debentures Due 2014	105,970	95,993	127,185	-	-	-
	$ 726,312	**$ 681,000**	**$ 774,130**	**$ 622,258**	**$ 601,511**	**$ 607,211**

[(1)]Excluding the equity component.

12. Unitholders' Capital

(a) Authorized

The authorized capital consists of an unlimited number of Ordinary Trust Units, Special Trust Units and Special Voting Units. There are no Special Trust Units or Special Voting Units outstanding at June 30, 2007; therefore, unless otherwise noted, all references to Trust Units are deemed to be references to Ordinary Trust Units.

(b) Number of Units Issued

	Six months ended June 30, 2007	Six months ended June 30, 2006
Outstanding, beginning of period	**122,096,172**	52,982,567
Issued in exchange for assets of Viking	**-**	46,040,788
Issued for cash		
February 1, 2007	**6,146,750**	-
June 1, 2007	**7,302,500**	-
Convertible debenture conversions		
9% Debentures Due 2009	**12,128**	22,957
8% Debentures Due 2009	**25,819**	51,205
6.5% Debentures Due 2010	**-**	114,313
10.5% Debentures Due 2008	**38,721**	84,371
6.40% Debentures Due 2012	**2,542**	434
7.25% Debentures Due 2013	**2,885**	-
7.25% Debentures Due 2014	**4,551,551**	-
Exchangeable share retraction	**-**	184,809
Distribution reinvestment plan issuance	**3,316,725**	2,442,213
Exercise of unit appreciation rights and other	**10,065**	293,334
Outstanding, end of period	**143,505,858**	102,216,991

(c) Per Trust Unit Information

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

Net income adjustments	**Three months ended June 30, 2007**	Three months ended June 30, 2006	**Six months ended June 30, 2007**	Six months ended June 30, 2006
Net income, basic	**$ 6,248**	$ 60,682	**$ 76,098**	$ 26,745
Non-controlling interest	**-**	15	**-**	(65)
Interest on convertible debentures	**-**	825	**-**	-
Net income, diluted[1]	**$ 6,248**	$ 61,522	**$ 76,098**	$ 26,680

Weighted average Trust Units adjustments	**Three months ended June 30, 2007**	Three months ended June 30, 2006	**Six months ended June 30, 2007**	Six months ended June 30, 2006
Number of Units				
Weighted average Trust Units outstanding, basic	**133,815,690**	101,426,503	**130,420,556**	91,920,385
Effect of convertible debentures	**-**	1,527,476	**-**	-
Effect of exchangeable shares	**-**	28,480	**-**	64,113
Effect of Employee Unit Incentive Plans	**1,128,828**	209,575	**690,930**	168,348
Weighted average Trust Units outstanding, diluted[2]	**134,944,518**	103,192,034	**131,111,486**	92,152,846

(1) Net income, diluted excludes the impact of the conversions of certain of the convertible debentures for the three month and six month periods ended June 30, 2007 of $16,594,000 and $31,688,000 respectively (three and six months ended June 30, 2006 - $3,979,000 and $7,919,000), as the impact would be anti-dilutive.

(2) Weighted average Trust Units outstanding, diluted for the three month and six month periods ended June 30, 2007 does not include the unit impact of 25,743,388 and 25,333,076 respectively for certain of the convertible debentures (three and six months ended June 30, 2006 – 4,942,459 and 6,526,241), as the impact would be anti-dilutive.

13. Employee Unit Incentive Plans

Trust Unit Rights Incentive Plan

As at June 30, 2007, a total of 3,934,708 (3,788,125 – December 31, 2006) Unit Appreciation Rights were outstanding under the Trust Unit Rights Incentive Plan at an average exercise price of $27.51 ($29.14 – December 31, 2006).

The following table summarizes the Trust Units reserved for issuance under the Trust Unit Rights Incentive Plan:

	Six months ended June 30, 2007		Year ended December 31, 2006	
	Unit Appreciation Rights	**Weighted Average Exercise Price**	**Unit Appreciation Rights**	**Weighted Average Exercise Price**
Outstanding beginning of period	**3,788,125**	**$ 30.81**	1,305,143	$ 19.72
Granted	**412,083**	**29.81**	3,924,300	31.92
Exercised	**(65,900)**	**20.24**	(1,039,018)	18.58
Forfeited	**(199,600)**	**30.93**	(402,300)	37.25
Outstanding before exercise price reductions	**3,934,708**	**30.89**	3,788,125	30.81
Exercise price reductions	**-**	**(3.38)**	-	(1.67)
Outstanding, end of period	**3,934,708**	**$ 27.51**	3,788,125	$ 29.14
Exercisable before exercise price reductions	**560,038**	**$ 32.72**	266,125	$ 24.18
Exercise price reductions	**-**	**(5.65)**	-	(5.37)
Exercisable, end of period	**560,038**	**$ 27.07**	266,125	$ 18.81

The following table summarizes information about Unit Appreciation Rights outstanding at June 30, 2007:

		Outstanding			Exercisable	
Exercise Price before price reductions	**Exercise Price net of price reductions**	**At June 30, 2007**	**Weighted Average Exercise Price net of price reductions[1]**	**Remaining Contractual Life [1]**	**At June 30, 2007**	**Weighted Average Exercise Price net of price reductions[1]**
$12.19-$13.15	$2.69-$4.02	7,200	$ 3.61	1.4	7,200	$ 3.61
$13.35-$14.99	$4.41-$6.95	21,500	6.65	2.0	21,500	6.65
$18.90-$25.05	$10.94-$23.29	144,375	17.78	3.0	121,675	16.88
$26.17-$27.37	$23.74-$26.02	1,714,700	23.85	4.5	-	-
$28.59-$37.56	$22.82-$34.02	2,046,933	31.56	3.9	409,663	31.58
$12.19-$37.56	$2.69-$34.02	3,934,708	$ 27.51	4.1	560,038	$ 27.07

[1] Based on weighted average Unit Appreciation Rights outstanding.

Unit Award Incentive Plan
At June 30, 2007, 331,201 Units were outstanding under the Unit Award Incentive Plan (306,699 – December 31, 2006).

The following table summarizes the Trust Units reserved for issuance under the Unit Award Incentive Plan:

	Six months ended June 30, 2007	Year ended December 31, 2006
Outstanding, beginning of period	**306,699**	35,365
Granted	**42,962**	320,905
Adjusted for distributions	**22,253**	27,879
Exercised	**(28,197)**	(41,530)
Forfeited	**(12,516)**	(35,920)
Outstanding, end of period	**331,201**	306,699

Harvest has recognized compensation expense of $7.6 million and $10.5 million for the three and six months ended June 30, 2007 respectively ($1.1 million and $9.5 million – three and six months ended June 30, 2006), including non cash compensation expense of $6.3 million and $8.7 million for the three and six months ended June 30, 2007 respectively ($675,000 recovery and $2.5 million expense – three and six months ended June 30, 2006), related to the Trust Unit Rights Incentive Plan and the Unit Award Incentive Plan. This is reflected in general and administrative expense in the consolidated statements of income. Recoveries occur when the Trust Unit market price decreases below the previous measurement date.

14. Income Taxes

On June 22, 2007, Bill C-52 Budget Implementation Act, 2007 received Royal Assent which contains legislation to apply a 31.5% tax to distributions from Canadian publicly traded income trusts. The new tax is not expected to apply to Harvest until 2011 as a transition period has been established for publicly traded trusts that existed prior to November 1, 2006. As a result of the enactment of Bill C-52, we have recorded a $177.7 million future income tax expense and a future income tax liability during the three month period ended June 30, 2007. This future income tax liability represents the taxable temporary differences of the Trust, tax-effected at 31.5%, which is the rate that will be applicable in 2011 pursuant to the current legislation and Harvest's current structure.

15. Employee Future Benefit Plans

Defined Contribution Pension Plan
Total expense for the defined contribution plan is equal to Harvest's required contributions and was $0.2 million and $0.4 million for the three and six month periods ended June 30, 2007, respectively.

Defined Benefit Plans
The measurement of the accrued benefit obligation and annual expense for the defined benefit plans requires actuarial calculations and several assumptions. These assumptions, set annually on December 31, are as follows:

	June 30, 2007		December 31, 2006	
	Pension Plans	Other Benefit Plans	Pension Plans	Other Benefit Plans
Discount rate	**5.0%**	**5.0%**	**5.0%**	**5.0 %**
Expected long-term rate of return on plan assets	**7.0%**	**-**	**7.0%**	**-**
Rate of compensation increase	**3.5%**	**-**	**3.5%**	**-**
Employee contribution of pensionable income	**6.0%**	**-**	**6.0%**	**-**
Annual rate of increase in covered health care benefits	**-**	**11%**	**-**	**12 %**
Expected average remaining service lifetime (years)	**11.7**	**10.8**	**11.7**	**11.1**

The assets of the defined benefit plan are invested and maintain the following asset mix:

	June 30, 2007	December 31, 2006
Bonds/fixed income securities	**32%**	32%
Equity securities	**68%**	68%

The expected long-term rates of return are estimated based on many factors, including the expected forecast for inflation, risk premiums for each class of asset, and current and future financial market conditions.

The defined benefit pension plans were subject to an actuarial valuation on December 31, 2005 and the next valuation report is due no later than December 31, 2008. The post-retirement health care benefits plan was last subject to an actuarial valuation on December 31, 2006.

	Six Months ended June 30, 2007		Year ended December 31, 2006	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans
Employee benefit obligation, beginning of period	**$ 43,101**	**$ 6,027**	$ 38,754	$ 5,315
Current service costs	**1,521**	**184**	648	88
Interest	**1,187**	**158**	546	74
Actuarial losses	**816**	**25**	3,422	601
Plan amendment	**-**	**-**	-	-
Benefits paid	**(309)**	**(100)**	(269)	(51)
Employee benefit obligation, end of period	**46,316**	**6,294**	43,101	6,027
Fair value of plan assets, beginning of period	**36,576**	**-**	31,878	-
Expected return on plan assets	**1,334**	**-**	3,181	-
Employer contributions	**1,650**	**100**	1,306	51
Employee contributions	**815**	**-**	480	-
Benefits paid	**(309)**	**(100)**	(269)	(51)
Fair value of plan assets, end of period	**40,066**	**-**	36,576	-
Funded status	**(6,250)**	**(6,294)**	(6,525)	(6,027)
Unamortized balances:				
Net actuarial losses	**325**	**-**	325	-
Carrying amount	**$ (5,925)**	**$ (6,294)**	$ (6,200)	$ (6,027)

	June 30, 2007	December 31, 2006
Summary:		
Pension plans	**$ 5,925**	$ 6,200
Other benefit plans	**6,294**	6,027
Carrying amount	**$ 12,219**	$ 12,227

Estimated pension and other benefit payments to plan participants, which reflect expected future service, expected to be paid from 2007 to 2016 are summarized in the commitment table [see Note 19].

The table below shows the components of the net benefit plan expense:

	Three Months ended June 30, 2007		Three months ended June 30, 2006	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans
Current service cost	**$ 760**	**$ 92**	$ -	$ -
Interest costs	**594**	**79**	-	-
Expected return on assets	**(668)**	**-**	-	-
Net benefit plan expense	**$ 686**	**$ 171**	$ -	$ -

	Six Months ended June 30, 2007		Six months ended June 30, 2006	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans
Current service cost	**$ 1,521**	**$ 184**	$ -	$ -
Interest costs	**1,187**	**158**	-	-
Expected return on assets	**(1,334)**	**-**	-	-
Net benefit plan expense	**$ 1,374**	**$ 342**	$ -	$ -

A 1% change in the expected health care cost trend rate would have the following annual impacts as at December 31, 2006:

	1% Increase	1% Decrease
Impact on post-retirement benefit expense	$ 2	$ (2)
Impact on projected benefit obligation	16	(22)

16. Financial Instruments and risk management contracts

Financial instruments of Harvest consist of cash, accounts receivable, long-term receivables, accounts payable and accrued liabilities, cash distribution payable, bank loan, risk management contracts, convertible debentures and senior notes. The carrying value and fair value of these financial instruments at June 30, 2007 is disclosed below by financial instrument category, as well as any related gains or losses and interest income or expense for the six months ended June 30, 2007:

Financial Instrument	**Carrying Value**	**Fair Value**	**Gains/ (Losses)**	**Interest Income/ (Expense)**	**Other Income/ (Expense)**
Assets Held for Trading					
Cash	13,447	13,447	-	-	-
Loans and Receivables					
Accounts receivable	295,831	295,831	-	-	-
Lease payments receivable	3,583 (1)	3,583	-	110 (2)	-
Liabilites Held for Trading					
Net fair value of risk management contracts	4,999	4,999	4,188 (3)	-	-
Other Liabilities					
Accounts payable	265,863	265,863	-	-	-
Cash distributions payable	54,532	54,532	-	-	-
Bank loan	1,047,965	1,047,965	-	(37,978) (4)	(3,160) (4)
$7^{7/8}$% Senior Notes	258,387 (6)	262,355	-	(11,805) (5)	-
Convertible debentures	681,000	774,130	-	(31,688) (5)	-

(1) Included in accounts receivable on the balance sheet.
(2) Included in interest and other financing charges on short term/long term debt in the statement of income and comprehensive income.
(3) Included in risk management contracts - realized and unrealized gains/(losses) in the statement of income and comprehensive income.

(4) Included in interest and other financing charges on short term/long term debt in the statement of income and comprehensive income. The amortization of financing fees related to this liability is included in Amortization of deferred finance charges in the statement of cash flows.
(5) Included in Interest and other financing charges on short term/long term debt in the statement of income and comprehensive income. The non-cash interest expense relating to the accretion of premiums, discounts or transaction costs that are netted against these liabilities are included in non-cash interest in the statement of cash flows.
(6) The face value of the $7^{7/8}$% Senior Notes at June 30, 2007 is $266.4 million (U.S. $250 million).

The fair value of the lease payments receivable is the present value of expected future cash flows. The fair values of the convertible debentures and the $7^{7/8}$% Senior Notes are based on quoted market prices as at June 30, 2007. The risk management contracts are recorded on the balance sheet at their fair value, accordingly, there is no difference between fair value and carrying value. The bank loan is recorded at amortized cost, but there are no transaction costs associated with this and the financing costs are included in intangible assets; therefore, there is no difference between the carrying value and the fair value. Due to the short term nature of cash, accounts receivable, accounts payable and cash distributions payable, their carrying values approximate their fair values.

(a) Risk Exposure

Harvest is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Harvest is also exposed, to a lesser extent, to credit risk on accounts receivable and counterparties to price risk management contracts and to liquidity risk relating to our debt.

(i.) Credit Risk

Petroleum and Natural Gas accounts receivable

Accounts receivable in our petroleum and natural gas operations are due from crude oil and natural gas purchasers as well as joint venture partners. These balances are due from companies in the petroleum and natural gas industry and are subject to normal industry credit risks. Concentration of credit risk is mitigated by having a broad customer base, which includes a significant number of companies engaged in joint operations with Harvest. Harvest periodically assesses the financial strength of its crude oil and natural gas purchasers and will adjust its marketing plan to mitigate credit risks. This assessment involves a review of external credit ratings; however, if external ratings are not available, we try to obtain a guarantee from the parent company. If this is not possible, we perform our own internal credit review based on the purchasers past financial performance. The credit risk associated with our joint venture partners is mitigated by reviewing the credit history of partners and requiring some partners to provide cash upfront in the form of cash calls for significant capital projects. As well, most agreements have a net off provision that enables us to use the proceeds from the sale of production that would otherwise be taken in kind by the partner to net off amounts owing from the partner that are in default. Historically, the only instances of impairment or potential impairment have been when a purchaser or partner has gone bankrupt.

Risk Management Contract Counterparties

Harvest is also exposed to credit risk from the counterparties to our risk management contracts. This risk is managed by diversifying Harvest's risk management portfolio among a number of counterparties and by dealing with investment grade financial institutions. We have no history of impairment with these counterparties and therefore no impairment is recorded at June 30, 2007 or 2006.

Supply and Offtake Agreement Accounts Receivable (Vitol)

The Supply and Offtake Agreement entered into in conjunction with the purchase of the refinery exposed Harvest to the credit risk of Vitol Refining S.A. "Vitol" as all feedstock purchases and substantially all product sales are made with Vitol. Harvest mitigates this risk by requiring that Vitol maintain a minimum B+ credit rating as assessed by Standard and Poors. If the credit rating falls below this line additional security is required to be supplied to Harvest.

Other Accounts Receivable

Harvest does not have any significant exposure to any individual customer in its refining and marketing operations and its policy is to manage its credit risk by dealing with only financially sound customers. Credit is extended based on an evaluation of the customer's financial condition. The carrying amount of accounts receivable reflects management's assessment of the associated credit risks.

Harvest is also exposed to credit risk from customers due to the lease payments receivable relating to our net investment in vehicle and equipment leases. As some of the counterparties to these leases are employees or distributors, any over due amounts can be deducted from wages or commissions and therefore, the credit risk is low.

(ii.) Liquidity Risk

Harvest is exposed to liquidity risk mainly due to our outstanding bank balances and $7^{7/8}$% Senior Notes with repayment requirements. This risk is mitigated by managing the maturity dates on our obligations and complying with the covenants.

(iii.) Market Risk

Harvest is exposed to three types of market risks: interest rate risk, foreign currency exchange rate risk and commodity price risk.

Interest rate risk

Harvest is exposed to interest rate risk on its bank loans as interest rates are determined in relation to floating market rates. Harvest's convertible debentures and $7^{7/8}$% Senior Notes have fixed interest rates and therefore do not create an interest rate risk. Harvest manages its exposure to interest rate risk by maintaining its debt in a combination of floating rate debt denominated in Canadian dollars and bearing interest relative to the Canadian interest rate benchmark, floating rate debt denominated in U.S. dollars and bearing interest relative to the U.S. interest benchmark rate and fixed rate debt denominated in U.S. dollars.

In addition, Harvest manages its interest rate by targeting appropriate levels of debt relative to its expected cash flow from operations.

Foreign currency exchange rate risk

Harvest is exposed to the risk of changes in the Canadian/U.S. dollar exchange rate on its U.S. dollar denominated revenues and in respect of its refinery crude oil purchases. In addition, Harvest's $7^{7/8}$% Senior Notes are denominated in U.S. dollars (U.S.$250 million) and a portion of our credit facility is drawn in U.S. dollars. Interest is payable semi-annually in U.S. dollars on the notes; therefore, any interest payable at the balance sheet date is also subject to currency exchange rate risk. Harvest manages these exchange rate risks by occasionally entering into fixed rate currency exchange contracts on future U.S. dollar payments and U.S. dollar sales. As well, the U.S. dollar denominated debt acts as an economic hedge to help offset the impact of exchange rate movements on commodity sales during the year and the exposure on Harvest's net investment in North Atlantic as the functional currency of the refinery is U.S. dollars.

Commodity Price Risk

Harvest uses price risk management contracts for a portion of its crude oil, natural gas and refined product sales to manage its commodity price exposure and power costs. These contracts are recorded on the balance sheet at their fair value as of the balance sheet date, with changes from the prior period's fair value recorded in net income for the period. These fair values are generally determined as the difference between the stated fixed price of the contract and some expected future price of the underlying asset. Variances in expected future prices expose us to commodity price risk as they will change the gain or loss that we ultimately realize on these contracts. This risk is mitigated by continuously monitoring the effectiveness of these contracts and other risk management actions.

(b) Fair Values

At June 30, 2007, the net fair value deficiency reflected on the balance sheet for all the risk management contracts outstanding at that date was approximately $5.0 million ($1.9 million – December 31, 2006), which was included in the balance sheet as follows: Fair value of risk management contracts (current assets) $17.0 million, fair value of risk management contracts $8.9 million, fair value deficiency of risk management contracts (current liabilities) $21.9 million and fair value deficiency of risk management contracts $8.9 million.

The following is a summary of Harvest's risk management contracts outstanding, along with their fair value at June 30, 2007:

Quantity	Type of Contract	Term	Average Price	Fair value
Foreign Currency Exchange Rate Risk Management				
$8,750,667/month	U.S./Cdn dollar exchange rate swap	July – December 2007	1.1228 Cdn/U.S.	$ 3,394
$8,333,333/month	U.S./Cdn dollar exchange rate swap	January – June 2008	1.1099 Cdn/U.S.	2,362
				$ 5,756
Crude Oil Price Risk Management				
20,000 bbl/d	Participating swap	July – December 2007	U.S.$58.75[(a)]	$ (13,376)
10,000 bbl/d	Participating swap	January – June 2008	U.S.$60.00[(b)]	(2,097)
5,000 bbl/d	Indexed put contract – bought put	July – December 2007	U.S.$50.00[(d)]	60
2,500 bbl/d	Indexed put contract – sold call	July – December 2007	U.S.$50.00[(d)]	(10,271)
2,500 bbl/d	Indexed put contract – bought call	July – December 2007	U.S.$60.00[(d)]	5,690
2,500 bbl/d	Indexed put contract – sold call	July – December 2007	U.S.$70.00[(d)]	(1,999)
2,500 bbl/d	Indexed put contract – bought call	July – December 2007	U.S.$83.00[(d)]	337
				$ (21,656)
Natural Gas Price Risk Management				
276 GJ/d	Fixed price – natural gas contract	July – December 2007	Cdn$3.59[(c)]	$ (125)
276 GJ/d	Fixed price – natural gas contract	January – December 2008	Cdn$4.63[(c)]	(257)
30,000 GJ/d	Natural gas 3-way contract	July 2007 – March 2008	Cdn$5.00-10.27(7.00)[(e)]	5,308
				$ 4,926
Refined Product Price Risk Management				
10,000 bbl/d	NYMEX Heating oil 3-way contract	January – December 2008	U.S.$145.00-222.17(193.00)[(f)]	$ (5,024)
6,000 bbl/d	Platt's fuel oil 3-way contract	January – December 2008	U.S.$43.00-63.21(51.67)[(g)]	(1,741)
2,000 bbl/d	NYMEX Heating oil collar	January – December 2008	U.S.$190.00-217.50[(h)]	(1,132)
2,000 bbl/d	Platt's fuel oil collar	January – December 2008	U.S.$51.00-58.68[(i)]	(754)
				$ (8,651)
Electricity Price Risk Management				
35 MWH	Electricity price swap contracts	July – December 2007	Cdn $56.69	$ 5,767
35 MWH	Electricity price swap contracts	January – December 2008	Cdn $56.69	8,859
				$ 14,626
Total net fair value deficiency of risk management contracts				**$ (4,999)**

(a) This is the average price of the price floors. Harvest realizes this price plus 67-79%, or an average of 72%, of the difference between spot price and the given floor price.

(b) This is the average price of the price floors. Harvest realizes this price plus 67-79%, or an average of 73%, of the difference between spot price and the given floor price.

(c) This contract contains an annual escalation factor such that the fixed price is adjusted each year.

(d) Each group of puts and calls 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. This contract contains an annual escalation factor such that the fixed price is adjusted each year.

(e) If the market price is below $5.00, price received is market price plus $2.00; if the market price is between $5.00 and $7.00, the price received is $7.00; if the market price is between $7.00 and the average ceiling of $10.27, the price received is market price; if the market price is over the average ceiling of $10.27, price received is the stated ceiling price.

(f) If the market price is below $145.00, price received is market price plus $48.00; if the market price is between $145.00 and $193.00, the price received is $193.00; if the market price is between $193.00 and the average ceiling of $222.17, the price received is market price; if the market price is over the average ceiling of $222.17, price received is the stated ceiling price.

(g) If the market price is below $43.00, price received is market price plus $8.67; if the market price is between $43.00 and $51.67, the price received is $51.67; if the market price is between $51.67 and the average ceiling of $63.21, the price received is market price; if the market price is over the average ceiling of $63.21, price received is the stated ceiling price.

(h) *If the market price is below $190.00, price received is $190.00; if the market price is between $190.00 and $217.50, the price received is market price; if the market price is over the ceiling of $217.50, price received is $217.50.*
(i) *If the market price is below $51.00, price received is $51.00; if the market price is between $51.00 and the average ceiling of $56.68, the price received is market price; if the market price is over the average ceiling of $56.68, price received is the stated ceiling price.*

For the three and six months ended June 30, 2007, the total unrealized gain/loss recognized in the consolidated statement of income and comprehensive income was a gain of $11.0 million and a loss of $3.1 million respectively (a loss of $0.1 million and $41.1 million – three and six months ended June 30, 2006), which represents the change in fair value of financial assets and liabilities classified as held for trading. The realized gains and losses on all risk management contracts are included in the period in which they are incurred.

17. Segment Information

Harvest operates in Canada and has two reportable operating segments for the three and six month periods ending June 30, 2007, Petroleum and Natural Gas and Refining and Marketing. For the three and six month periods ending June 30, 2006, Harvest's only operating segment was the Petroleum and Natural Gas operations.

Petroleum and Natural Gas – Harvest's petroleum and natural gas operations consist of development, production and subsequent sale of petroleum, natural gas and natural gas liquids.

Refining and Marketing – Harvest's refining and marketing operations includes the purchase of crude oil, the refining of crude oil, the sale of the refined products including a network of retail operations, home heating business and the supply of refined products to commercial and wholesale customers.

	Three months ended June 30, 2007		
	Refining and Marketing[1]	Petroleum and Natural Gas[1]	**Total**
Revenue	$ 900,387[2]	$ 286,611	**$ 1,186,998[3]**
Royalties	-	(53,548)	**(53,548)**
Realized net loss on risk management contracts	-	(6,826)	**(6,826)**
Unrealized net gains (losses) on risk management contracts[4]	(3,164)	14,178	**11,014**
Less: expenses			
Purchased products for resale and processing	708,642	-	**708,642**
Operating	44,921	72,333	**117,254**
Transportation and marketing	9,059	3,375	**12,434**
General and administrative	402	16,061	**16,463**
Depletion, depreciation, amortization and accretion	18,185	111,446	**129,631**
	$ 116,014	$ 37,200	**$ 153,214**
Interest and other financing charges on short term debt			**577**
Interest and other financing charges on long term debt			**39,803**
Foreign exchange gain			**(71,098)**
Large corporations tax and other tax			**-**
Future income tax			**177,684**
Net income			**$ 6,248**
Total Assets[1]	$ 1,660,754	$ 3,952,579	**$ 5,613,333**
Capital Expenditures			
Development and other activity	$ 9,871	$ 48,221	**$ 58,092**
Property acquisitions	-	7,975	**7,975**
Property dispositions	-	(29,776)	**(29,776)**
Total expenditures	$ 9,871	$ 26,420	**$ 36,291**
Property, plant and equipment			
Cost	$ 1,215,329	$ 4,010,056	**$ 5,225,385**
Less: Accumulated depletion and depreciation	(45,556)	(923,470)	**(969,026)**
Net book value	$ 1,169,773	$ 3,086,586	**$ 4,256,359**

Goodwill, beginning of period	$ 207,984	$ 656,248	**$ 864,232**
Reduction to goodwill	(16,068)	-	**(16,068)**
Goodwill, end of period	$ 191,916	$ 656,248	**$ 848,164**

(1) Accounting policies for segments are the same as those described in the Significant Accounting Policies
(2) Of the total Refining and Marketing revenue for the three month period ended June 30, 2007, $784.8 million is from one customer. No other single customer within either division represents greater than 10% of Harvest's total revenue.
(3) Of the total consolidated revenue for the three months ended June 30, 2007 $402.2 million is attributable to sales in Canada, while $ 784.8 million is attributable to sales in the United States.
(4) There is no intersegment activity with the exception of intersegment risk management contracts for the period of January 1, 2008 to December 31, 2008. For the three month period ended June 30, 2007 the net unrealized mark-to-market loss on these contracts is $3.2 million for the refining and marketing segment and the net unrealized gain is $3.2 million for the petroleum and natural gas segment.

	Six months ended June 30, 2007		
	Refining and Marketing(1)	Petroleum and Natural Gas(1)	**Total**
Revenue	$ 1,684,432(2)	$ 577,727	**$ 2,262,159(3)**
Royalties	-	(103,197)	**(103,197)**
Realized net loss on risk management contracts	-	(7,123)	**(7,123)**
Unrealized net gains (losses) on risk management contracts(4)	(3,164)	57	**(3,107)**
Less: expenses			
Purchased products for resale and processing	1,340,938	-	**1,340,938**
Operating	94,282	144,629	**238,911**
Transportation and marketing	16,402	6,187	**22,589**
General and administrative	702	26,165	**26,867**
Depletion, depreciation, amortization and accretion	37,574	225,849	**263,423**
	$ 191,370	$ 64,634	**$ 256,004**
Interest and other financing charges on short term debt			**4,204**
Interest and other financing charges on long term debt			**80,252**
Foreign exchange gain			**(82,358)**
Large corporations tax and other tax			**124**
Future income tax			**177,684**
Net income			**$ 76,098**
Total Assets(1)	$ 1,660,754	$ 3,952,579	**$ 5,613,333**
Capital Expenditures			
Development and other activity	$ 14,754	$ 196,708	**$ 211,462**
Business acquisitions	-	30,264	**30,264**
Property acquisitions	-	11,086	**11,086**
Property dispositions	-	(32,198)	**(32,198)**
Total expenditures	$ 14,754	$ 205,860	**$ 220,614**
Property, plant and equipment			
Cost	$ 1,215,329	$ 4,010,056	**$ 5,225,385**
Less: Accumulated depletion and depreciation	(45,556)	(923,470)	**(969,026)**
Net book value	$ 1,169,773	$ 3,086,586	**$ 4,256,359**
Goodwill, beginning of period	$ 209,930	$ 656,248	**$ 866,178**
Reduction to goodwill	(18,014)	-	**(18,014)**
Goodwill, end of period	$ 191,916	$ 656,248	**$ 848,164**

(1) Accounting policies for segments are the same as those described in the Significant Accounting Policies
(2) Of the total Refining and Marketing revenue for the six month period ended June 30, 2007, $1,474.5 million is from one customer. No other single customer within either division represents greater than 10% of Harvest's total revenue.
(3) Of the total consolidated revenue for the six months ended June 30, 2007 $787.7 million is attributable to sales in Canada, while $1,474.5 million is attributable to sales in the United States.

[(4)] *There is no intersegment activity with the exception of intersegment risk management contracts for the period of January 1, 2008 to December 31, 2008. For the six month period ended June 30, 2007 the net unrealized mark-to-market loss on these contracts is $3.2 million for the refining and marketing segment and the net unrealized gain is $3.2 million for the petroleum and natural gas segment.*

18. Change in Non-Cash Working Capital

	Three months ended		Six months ended	
	June 30, 2007	June 30, 2006	**June 30, 2007**	June 30, 2006
Changes in non-cash working capital items:				
Accounts receivable	**$ 7,147**	$ (18,847)	**$ (40,268)**	$ (9,921)
Prepaid expenses and deposits	**2,699**	770	**2,024**	(1,063)
Current portion of risk management contract assets	**(9,008)**	1,038	**925**	12,956
Inventory	**(11,318)**	-	**(21,767)**	-
Current portion of future income tax asset	**-**	-	**-**	22,975
Accounts payable and accrued liabilities	**(20,888)**	(32,957)	**(31,709)**	(22,965)
Cash distribution payable	**5,105**	631	**8,135**	(1,578)
Current portion of risk management contract liabilities	**(8,111)**	(13,628)	**(4,825)**	2,617
	$ (34,374)	$ (62,993)	**$ (87,485)**	$ 3,021
Changes relating to operating activities	**$ 9,025**	$ (10,134)	**$ (91,748)**	$ (16,751)
Changes relating to financing activities	**5,261**	(5,469)	**11,463**	(18,770)
Changes relating to investing activities	**(53,481)**	(33,538)	**(29,478)**	(17,842)
Add: Other non-cash changes	**4,821**	(13,852)	**22,278**	56,384
	$ (34,374)	$ (62,993)	**$ (87,485)**	$ 3,021

19. Commitments, Contingencies and Guarantees

From time to time, Harvest is involved in litigation or has claims brought against it in the normal course of business operations. Management of Harvest is not currently aware of any claims or actions that would materially affect Harvest's reported financial position or results from operations. In the normal course of operations, management may also enter into certain types of contracts that require Harvest to indemnify parties against possible third party claims, particularly when these contracts relate to purchase and sale agreements. The terms of such contracts vary and generally a maximum is not explicitly stated; as such the overall maximum amount of the obligations cannot be reasonably estimated. Management does not believe payments, if any, related to such contracts would have a material effect on Harvest's reported financial position or results from operations.

The following are the significant commitments at June 30, 2007:

(a) North Atlantic has a Supply and Offtake Agreement with Vitol Refining S.A. ("Vitol"). This agreement provides that the ownership of substantially all crude oil feedstock and refined product inventory at the refinery be retained by Vitol and that for a minimum period of up to two years Vitol 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 substantially all refined products produced by the refinery. As such, at June 30, 2007, North Atlantic had commitments totaling approximately $671.6 million in respect of future crude oil feedstock purchases and related transportation from Vitol. Included in this total is approximately $143.4 million relating to the SOMO contract discussed below.

In June 2007 Vitol entered into a six month term contract with Iraq's State Oil Marketing Organization ("SOMO") for 33,000 bbl/day of Basrah crude oil at market prices on behalf of Harvest per the Supply and Offtake Agreement. Approximately one third of this commitment (2.0 million barrels) has already been scheduled for delivery and is included in the total feedstock commitment disclosed below.

The following is a summary of Harvest's contractual obligations and commitments as at June 30, 2007:

	Payments Due by Period						
	2007	**2008**	**2009**	**2010**	**2011**	**Thereafter**	**Total**
Debt repayments [(1)]	-	-	65,000	982,965	266,350	-	1,314,315
Capital commitments[(2)]	13,653	2,880	-	-	-	-	16,533
Operating leases[(3)]	3,447	6,189	5,143	2,278	299	258	17,614
Pension contributions[(4)]	390	1,510	1,835	2,219	2,586	19,147	27,687
Transportation agreements[(5)]	1,064	1,621	1,025	370	172	189	4,441
Feedstock commitments[(6)]	665,915	5,727	-	-	-	-	671,642
Contractual obligations	684,469	17,927	73,003	987,832	269,407	19,594	2,052,232

(1) Assumes that the outstanding convertible debentures either convert at the holders' option for Units or are redeemed for Units at Harvest's option.
(2) Relating to drilling contracts, AFE commitments and equipment rental contracts.
(3) Relating to building and automobile leases.
(4) Relating to expected contributions for employee benefit plans [see Note 15].
(5) Relating to oil and natural gas pipeline transportation agreements.
(6) Relating to crude oil feedstock purchases and related transportation costs [see Note 19 (a) above].

20. Subsequent Events

Subsequent to June 30, 2007, Harvest declared a distribution of $0.38 per unit for Unitholders of record on July 23, 2007, August 22, 2007 and September 24, 2007.

Between July 1, 2007 and August 10, 2007, an additional U.S. $232.0 million was committed to the purchase of feedstock inventory under the Supply and Offtake Agreement held with Vitol Refining S.A. [see table in Note 19].

On June 8, 2007, Harvest entered into a pre-acquisition agreement to acquire Grand Petroleum Inc. ("Grand") pursuant to which Harvest agreed it would make an offer to purchase all of the issued and outstanding shares of Grand for $3.84 per share with the offer open for acceptance until July 26, 2007. On July 26, 2007, Harvest purchased the 21,310,419 common shares of Grand tendered to its offer for $81.8 million and extended its offer to August 9, 2007 on the same terms and conditions. On August 9, 2007, Harvest acquired an additional 5,868,377 common shares for $22.5 million and intends to subsequently acquire the remaining common shares of Grand pursuant to the compulsory acquisition provisions of the Business Corporations Act (Alberta) for a further $5.5 million. Commencing in August 2007, Grand's operating results will be included in Harvest's revenues, expenses and capital spending.

21. Related Party Transactions

During 2007, in the normal course of operations, Vitol Refining S.A. purchased $131.2 million of Iraqi crude oil through the Supply and Offtake Agreement at fair market value for processing, which has been sourced from a private corporation of which a director of Harvest, is a director and holds a minority ownership interest. As at June 30, 2007, no amount related to these transactions is included in accounts payable and accrued liabilities and $136.4 million is included in feedstock commitments for the purchase of Iraqi crude oil [See Note 19]. Of the U.S. $232.0 million committed to the purchase of feedstock inventory under the Supply and Offtake Agreement held with Vitol Refining S.A. between July 1, 2007 and August 10, 2007 [see Note 20], U.S. $65.5 million of crude oil feedstock from Iraq was purchased from this private corporation.

22. Comparatives

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