ANNUAL REPORT 2006

HARVEST

energy

DIVERSITY IN ENERGY

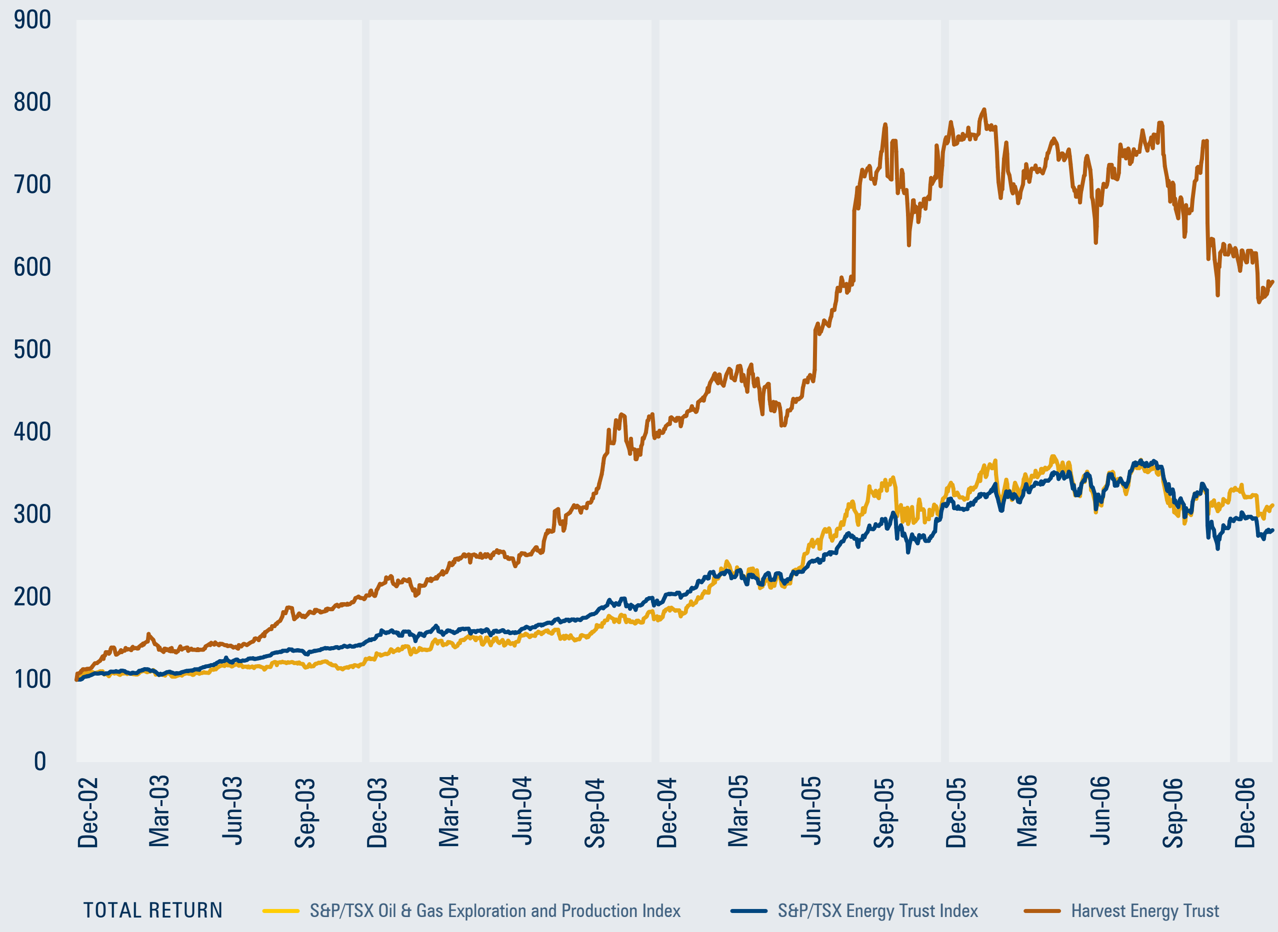
Integrated • Sustainable • Value Focused

REDEFINING HARVEST

INSIDE:
FREQUENTLY ASKED QUESTIONS ABOUT OUR
North Atlantic Refinery

Harvest Energy is an integrated oil and gas company based in Calgary, Alberta, in business since our initial public offering in December 2002.

As one of Canada's largest energy royalty trusts, Harvest offers unitholders exposure to both upstream and downstream operations. We are focused on identifying opportunities within the oil and natural gas sector to create and deliver value to unitholders through monthly distributions and unit price appreciation. With a highly technical approach taken to maximizing our assets, we strive to grow cash flow per unit. Harvest is a sustainable organization with a reserve life of 9.3 years and a refinery business providing a useful life exceeding 30 years. Within our conventional oil and natural gas operations, production is weighted approximately 70% to crude oil and liquids and 30% to natural gas, and is expected to average approximately 66,000 boe/d in 2007. Our 'Clean Fuels' hydrocracking refinery has capacity of 115,000 barrels per stream day and is currently configured to process medium sour crude oil into primarily high value products such as reformulated gasoline and ultra low sulphur diesel. Future development projects in our upstream business include the potential for over 1,000 wells on 840,000 acres of undeveloped land as well as a suite of enhanced oil recovery opportunities. In the downstream business, investment opportunities include an expansion, bottoms upgrading and ongoing throughput and reliability performance improvements.



2006
annual report

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HIGHLIGHTS

Financial ($000s except where noted)	Year ended December 31						
		2006		2005		2004	Change 2006 to 2005
Revenue, net[1]		**1,388,196**		436,452		212,118	218%
Cash Flow[2]		**551,724**		309,843		123,710	78%
Per trust unit, basic[2]	$	**5.43**	$	6.66	$	4.94	(18%)
Per trust unit, diluted[2]	$	**5.24**	$	6.35	$	3.97	(17%)
Net income (loss)		**136,046**		104,946		11,241	30%
Per trust unit, basic	$	**1.34**	$	2.25	$	0.45	(40%)
Per trust unit, diluted	$	**1.33**	$	2.19	$	0.43	(39%)
Distributions declared		**468,787**		153,494		64,563	205%
Distributions declared, per trust unit	$	**4.53**	$	3.20	$	2.40	42%
Payout ratio [2][3]		**85%**		50%		52%	35%
Bank debt		**1,595,663**		13,869		75,519	11,405%
Senior debt		**291,350**		290,750		300,500	-
Convertible Debentures		**601,511**		44,455		25,750	1,253%
Total long-term financial liabilities		**2,488,524**		349,074		401,769	613%
Total assets		**5,745,558**		1,308,481		1,050,483	339%
PETROLEUM AND NATURAL GAS OPERATIONS							
Daily Production							
Light to medium oil (bbl/d)		**27,482**		17,590		12,336	56%
Heavy oil (bbl/d)		**13,904**		13,747		8,495	1%
Natural gas liquids (bbl/d)		**2,247**		824		472	173%
Natural gas (mcf/d)		**96,578**		26,461		10,999	265%
Total daily sales volumes (boe/day)		**59,729**		36,571		23,136	63%
Cash capital expenditures		**376,881**		120,508		42,662	213%

	As at December 31, 2006		As at December 31, 2005	
Reserves (mmBOE), based on forecast prices and costs	Gross	Net	Gross	Net
Proved reserves	159.2	137.7	87.7	77.6
Probable reserves	61.1	52.2	32.0	28.0
Total proved plus probable (P+P) reserves	220.3	189.9	119.7	105.6
Total P+P Reserve Life Index[4]	9.3 years		9.4 years	

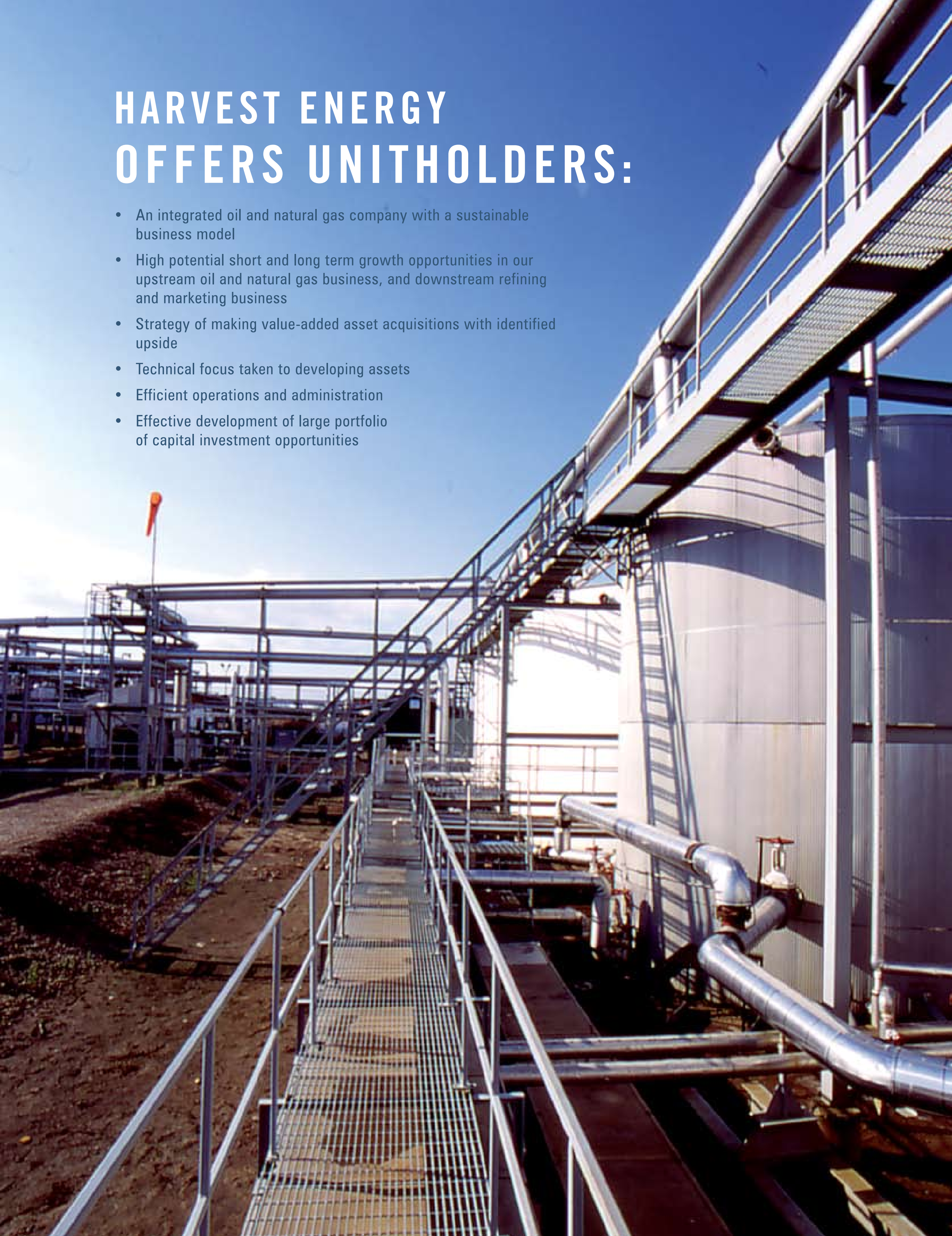
REFINING AND MARKETING OPERATIONS (from October 19, 2006 the date of acquisition to December 31, 2006)				
Average daily throughput (bbl/d)	86,890	-	-	n/a
Aggregate throughput (mbbl)	6,343	-	-	n/a
Cash capital expenditures	21,411	-	-	n/a

(1) Revenues are net of royalties and risk management activities.
(2) These are non-GAAP measures; please refer to "Non-GAAP Measures" in the MD&A beginning on page 34 of this annual report.
(3) Ratio of distributions declared to Cash Flows, excluding special distribution of $10.7 million settled with the issuance of trust units in 2005.
(4) Calculated as total P+P reserves divided by 2006 exit production of 65,000 boe/d.

		2006		2005		2004
Trust units outstanding at period end		122,096,172		52,982,567		41,788,500
Trust unit trading price at period end ($C)	$	26.23	$	37.19	$	22.95
TSX average daily trading volume		621,160		223,103		192,066
Trust unit trading price at period end ($US)	$	22.45	$	32.01		n/a
NYSE (consolidated) average daily trading volume (listed Jul. 21, 2005)		526,810		233,360		n/a

HARVEST ENERGY OFFERS UNITHOLDERS:

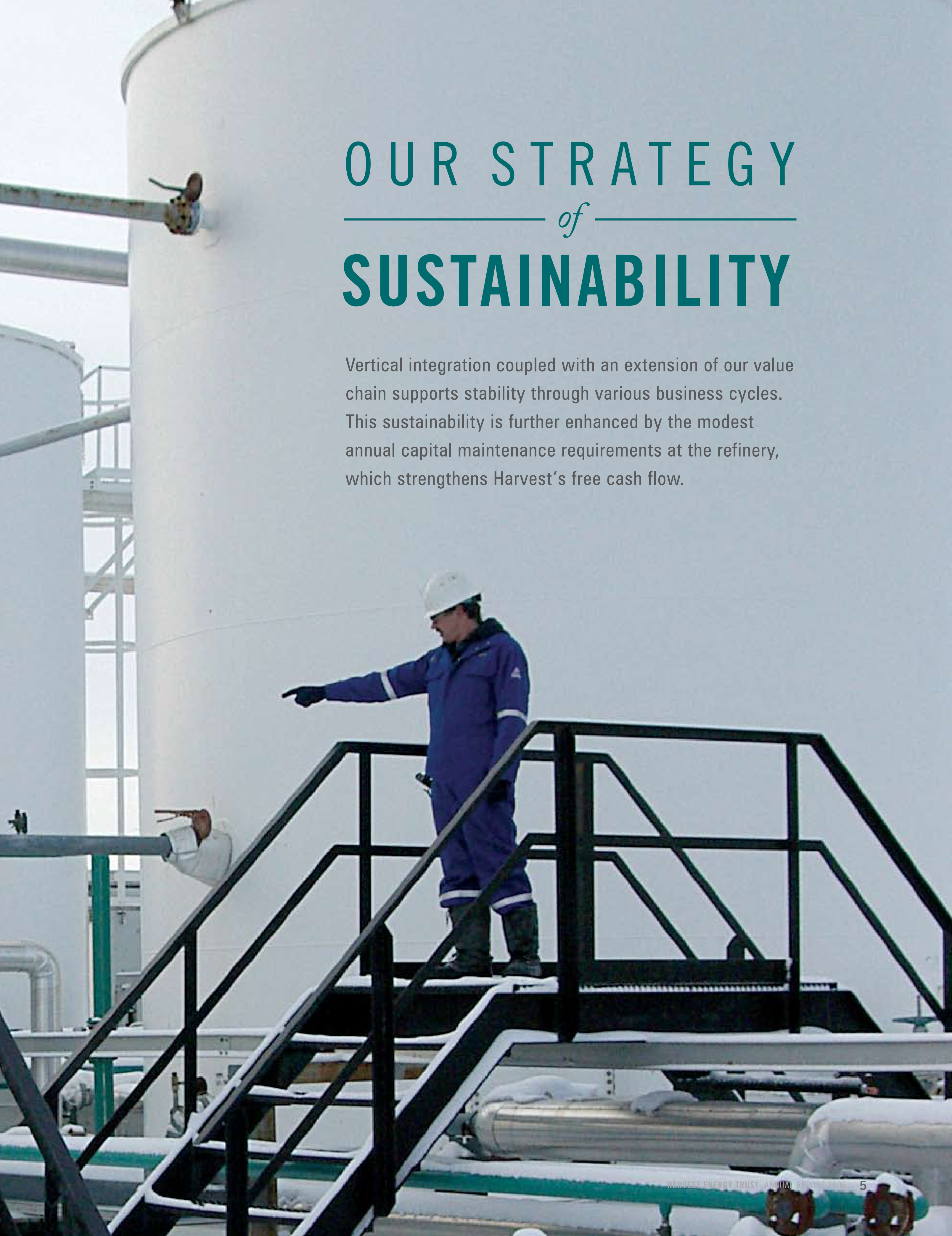
- An integrated oil and natural gas company with a sustainable business model
- High potential short and long term growth opportunities in our upstream oil and natural gas business, and downstream refining and marketing business
- Strategy of making value-added asset acquisitions with identified upside
- Technical focus taken to developing assets
- Efficient operations and administration
- Effective development of large portfolio of capital investment opportunities




Upstream Development Capex
($Cdn millions)
(excluding acquisitions)
$27.2
$42.7
$120.5
$376.9
03
04
05
06
Annual Production
(Boe/d)
11,040
23,136
36,571
59,729
03
04
05
06
OIL TA

OUR STRATEGY *of* SUSTAINABILITY

Vertical integration coupled with an extension of our value chain supports stability through various business cycles. This sustainability is further enhanced by the modest annual capital maintenance requirements at the refinery, which strengthens Harvest's free cash flow.



message to UNITHOLDERS

Harvest is one of the largest Canadian energy trusts and a significant player in the Canadian oil and natural gas industry overall. We have approximately 1,000 employees, including 700 in Newfoundland and 300 in western Canada. We exited 2006 with oil and natural gas production of approximately 65,000 boe/d, compared to our exit rate of approximately 38,800 boe/d at the end of 2005.

2006 was a busy and exciting period of change for Harvest. We recognized early the change in our business environment and have been evolving to position ourselves for continued success. Never one to follow in others' footsteps, Harvest has a proven track record of going against the grain to create value for our unitholders, and the steps we have taken over the last year are consistent with this strategy.

When Harvest was formed in 2002, we were primarily a heavy oil producer with a shorter-than-average reserve life index. Since that time, we have continued to build our portfolio and pursue under-appreciated assets that generate good value when given some technical focus and attention. The success of this strategy is evident by the industry leading rates of return generated for unitholders in each of 2003, 2004 and 2005. However, in the latter part of 2005, we recognized that the operating environment in western Canada had changed and Harvest needed to adapt with it. The number of companies competing for assets and the intensity of their interest in bidding for those assets resulted in sharply increasing acquisition prices in the western Canadian basin. As a committed value investor, we knew it would be more difficult to find assets that we could acquire at reasonable prices and invest in to create value and growth for our unitholders. We recognized that we would need to position the organization to focus more on the internal development of our asset base using industry leading technology, personnel and services. We saw the opportunity to combine two strong and successful industry performers (Harvest Energy and Viking Energy) to create an even stronger and more sustainable company. We used the strengthened organization to attract services and personnel in a period of rising service costs.

As 2006 progressed, we focused on the development of our asset base and delivered a large and successful capital investment program which has positioned the organization very well to deliver value creation in the years ahead.

We also continued to look for assets that we could acquire at reasonable prices and create value through hands-on management and investment. In the third quarter of 2006, we were pleased to announce our bold step to become an integrated oil and gas organization with the acquisition of North Atlantic Refining Limited. This refining and marketing asset extends our value chain and provides attractive financial integration with our upstream business that results in a stronger combined entity.

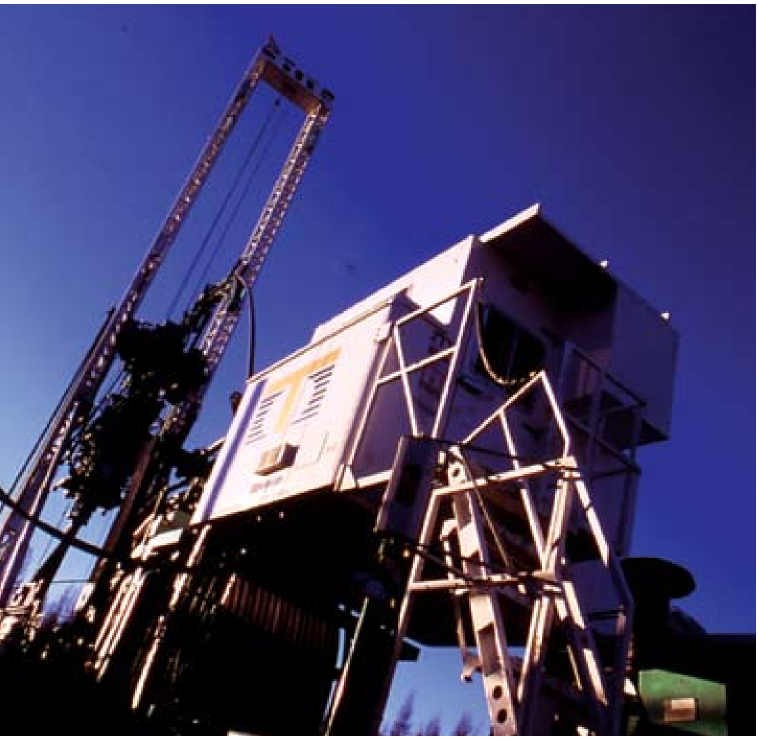
Benefits of an Integrated Structure

As a producer of light, medium and heavy grades of crude oil, getting involved with upgrading or refining assets provides us with a natural hedge to the discount that we are subject to in the upstream business on our medium and sour heavy production. Adding an infrastructure asset to our portfolio also contributes to our long term sustainability and helps offset the inherent declining cash flow base that happens over time with oil and gas production. Our sustainability is further enhanced by the refinery's minimal annual capital maintenance requirements which further improves Harvest's free cash flow.

Our practice has always been to buy assets at a good price, apply our technical and operational expertise and work those assets to enhance their value. North Atlantic is a perfect example of this. With a purchase price that was less than 4 times trailing annual cash flow, the acquisition metrics of North Atlantic support our value focus, and the transaction is accretive to cash flow. With the refinery's current configuration, we have the opportunity to invest some capital which will enhance the refined product slate, thereby generating very attractive rates of return. Having an integrated structure greatly differentiates Harvest from its peers and provides a significant competitive advantage.

Highlights of the Refinery

On October 19, 2006, we closed the acquisition of North Atlantic. Its primary asset is a medium sour hydrocracking refinery with 115,000 barrels per stream day capacity. North Atlantic is a mid-sized refinery in Canada with a current Nelson Complexity Index rating of just under 8.5. Supplementing the refinery is a marketing business in Newfoundland comprised of 69 retail and commercial gas stations, 20,000 home heat customers, six home heat stores, and a marine services division. Most importantly, the North Atlantic business comes complete with a highly skilled and experienced management team who have been



in the refining business for many years, as well as a full complement of 700 employees.

Approximately 75% of North Atlantic's refined product output consists of high value products such as reformulated gasoline (also called 'RBOB gasoline'), ultra low sulfur diesel ("ULSD"), and jet fuel that currently meet or exceed the world's most stringent specifications. For example, our ULSD is less than 10 parts per million ("ppm") sulphur, while current standards in the U.S. are 15ppm. The remaining output is heavy fuel oil, a lower value product today that presents significant future value creation opportunities through investment.

Situated on an ice-free, deep water bay on the Eastern coast of Canada in the province of Newfoundland and Labrador, North Atlantic's location offers three strategic advantages. Being located along Atlantic shipping routes enables North Atlantic to economically access crude feedstock from a variety of sources including the Middle East, Russia, and Latin America. Our primary market is the New York Boston area along the East coast of the U.S. which offers premium pricing on the sale of our refined products.

A second advantage is its location on the very deep Placentia Bay, which supports the docking of Very Large Crude Carriers (also called VLCCs); tanker vessels that can carry 2 million barrels of oil. These massive ships can dock right at North Atlantic's jetty and offload their cargo into pipes that run directly into crude holding tanks on land. Compared to most other refineries where crude must be trans-shipped or offloaded off-shore, this structure provides us with significant cost savings and reduced potential for environmental impact.

North Atlantic has been a strong supporter, significant employer and good neighbor of the local community in Newfoundland and has worked with local residents, regulatory bodies and municipalities to build the organization. As a result of this established trust and good employment record, residents in the area encourage us to make further investments to expand or grow the refinery. The supportive attitude of the local people is reflective of the great work North Atlantic has done and will continue to do in the community.

Since closing the North Atlantic acquisition part way through the fourth quarter, we have been working with the strong technical team at the refinery to manage the integration of our two businesses. We are very pleased to benefit from the extensive skills, experience and abilities of the management and staff at North Atlantic and look forward to reporting results from our combined organization as we move forward.

Highlights of the Upstream Business

While the addition of the downstream refining and marketing assets was an exciting development for Harvest, our focus throughout the year remained on our upstream oil and gas assets that have been the basis of the success that we have enjoyed over the past few years.

We started the year with the successful integration of Harvest with Viking Energy Royalty Trust following the merger of our two organizations in February. The merger placed Harvest in a better position to compete for properties, rigs and services, and talented people within western Canada. We have an experienced management team, a highly skilled complement of technical staff and a significant inventory of internal development opportunities. Through 2006, we continued to be active in assessing and bidding on properties in western Canada. Despite an environment of escalating acquisition costs throughout the year, we made several non-core acquisitions, including 27 sections of oil sands rights in Northern Alberta and the $38 million acquisition of heavy oil assets in western Saskatchewan. In July, we acquired a private oil and gas company, Birchill Energy for $447 million, adding a little over 6,000 boe/d to our production, and giving us exposure to the exciting and prolific Leduc oil play in Sylvan Lake.

In the third quarter, we created value from the high priced acquisition market and divested of approximately 200 boe/d of minor interests in two non-core assets for net proceeds of approximately $20 million. This translates to very attractive metrics of $100,000 per flowing boe. We were very pleased with these metrics, and will continue to pursue opportunities to high-grade our asset base.

We maintained a very active capital program during the year and invested $377 million, 96% of which was spent in development and exploration activities. The majority of our investments were in drilling, completion and tie-in activities and we drilled 252 gross wells with a success rate of 98%. We also made investments in several projects that are geared towards longer term results, including the initiation of an enhanced oil recovery (EOR) pilot project in Hayter, as well as research into other future potential EOR opportunities. Approximately $25 million was invested in infrastructure and maintenance enhancement projects that position Harvest for the future, including a major water handling upgrade at Suffield, and the construction of an all season access road at Hay River. Further long-term growth was supported by our $15 million investment in land, seismic and an enhanced oil recovery project at Hayter. In late 2006, the early onset of winter in Northern Alberta gave us the opportunity to begin our winter drilling program at Hay River and Red Earth sooner than expected, and we were able to accelerate $20 million of capital into 2006 that was budgeted for 2007. We will realize the benefits of this in 2007 through accelerated production and reduced costs as we will complete the projects ahead of the impact of spring break-up.

Consistent with most producers in the western Canadian Sedimentary Basin, we have experienced significant rising service costs and inflationary pressures over the past eighteen months due to rising commodity prices. However, our strong relationships with suppliers combined with our size advantage resulted in excellent cost performance on our operated drilling activity; actual costs exceeded estimates by only 2.1%. In addition, volatility of Alberta power prices continued and is reflected in our 2006 operating costs. However, this impact is reduced because we had hedges on over 50% of our Alberta power usage with an average floor price of $56.69 per megawatt hour. Cost control has always been an important part of our business, and we

HARVEST 2006 IN REVIEW

FEBRUARY 3 - Merger with Viking Energy Royalty Trust: Harvest positioned as the 5th largest conventional Canadian energy trust

SPRING - Integration of Harvest & Viking and execution of successful first quarter capital program

JULY 26 - Birchill Acquisition for $447 million adding approximately 6,000 boe/d of natural gas, liquids and light oil to production mix

JULY 26 - $230 million equity offering to repay a portion of the debt incurred in acquiring Birchill

AUGUST 22 - Acquisition of North Atlantic Refining Limited announced, C$1.6 billion purchase price funded completely with a C$2.2 billion fully underwritten credit facility

OCTOBER 19 - North Atlantic acquisition closed; refinery undergoing turnaround through mid-November

OCTOBER 25 - Announced a $400 million equity and convertible debenture financing to repay debt incurred with North Atlantic

OCTOBER 31 - Canadian government's proposed trust tax announced; billions of dollars of value single-handedly destroyed in the equity markets

NOVEMBER 9 - Despite market uncertainty, demand for Harvest securities continued and equity / convertible debenture financing was repriced

NOVEMBER 22 - Revised financing closed, gross proceeds of $638 million raised through the sale of trust units and convertible debentures. Repaid the $450 million unsecured bridge, $60 million on the secured bridge and $100 million on our credit facility

2007:

FEBRUARY 1 - Closed a $344 million trust unit and convertible debenture financing, repaying balance of the secured bridge and $40 million on the credit facility. Debt levels reduced further and balance sheet strengthened for pursuing future acquisition opportunities will continue striving to control operating costs through hedging and optimization efforts.

Income Trust Taxation

The entire income trust sector was taken by surprise on October 31 with the Canadian Government's "Tax Fairness Plan" announcement. The Plan proposes imposing a new distribution tax on income trusts beginning in 2011. This tax would reduce the amount of cash flow that a trust has available for distributions to unitholders. Like many of our income trust peers, Harvest was and continues to be frustrated by this shift in policy that was made without consultation and seemingly in the absence of facts or data to support the decision. We continue to work independently as well as with our industry associations (the Canadian Association of Income Funds - CAIF, and the Coalition of Canadian Energy Trusts - CCET) and various government representatives to raise awareness about the negative implications this new tax poses for all Canadians.

On December 15, 2006, the government provided clarity around the "Normal Growth" guidelines that were included in the original proposal and were designed to limit undue expansion for income trusts. Under the proposed growth rules, an existing trust could grow 100% over the next four years; with 40% growth permitted in 2007, and 20% permitted in each subsequent year until 2011. The growth measures are cumulative, so any unused portion can be carried forward into the following year. Although we wholeheartedly disagree with any growth restrictions being placed on business, given Harvest's size, we are well positioned in this environment relative to some smaller trusts because we have more room to grow. Also, any debt that had been incurred prior to October 31, 2006 may be repaid with equity issuances without impacting our growth limitations. The government also indicated that trusts could merge without penalty, as long as the size of the new combined trust was not greater than the sum of the individual trusts' sizes.

If unitholders wish to voice their concerns regarding this trust tax, we would encourage them to contact either their local Member of Parliament, Finance Minister Jim Flaherty and / or Prime Minister Stephen Harper. Direct email links to these government representatives are available on our website at www.harvestenergy.ca. We greatly appreciate the support we have received from unitholders to date, and the time our stakeholders have taken to get involved in this effort.

Regardless of the tax regime in which we operate, we will always be committed to our value principles and view this potential change as yet another opportunity for Harvest to demonstrate its unique value creation strategy.

Future Outlook

The past year has been an important evolutionary time for Harvest as we have positioned ourselves for the future. Today we offer unitholders a sizeable and integrated structure coupled with a strong asset base and extensive internal development opportunities. We have an attractive free cash flow profile as a result of our refining and marketing business and remain committed to maintaining a manageable balance sheet. We are prepared for future uncertainty due to our significant tax pools, ongoing hedging strategy, committed Board and skilled management team. We are not afraid to be different and will continue to seek out and take advantage of unique opportunities that others may not see.

We have greatly appreciated the continued support of our stakeholders over the past four years and we look forward to a successful future focused on value creation.

Sincerely,

John Zahary,
President and Chief Executive Officer
March 15, 2007

meet our

SENIOR MANAGEMENT TEAM

John Zahary, P.Eng
President & Chief Executive Officer

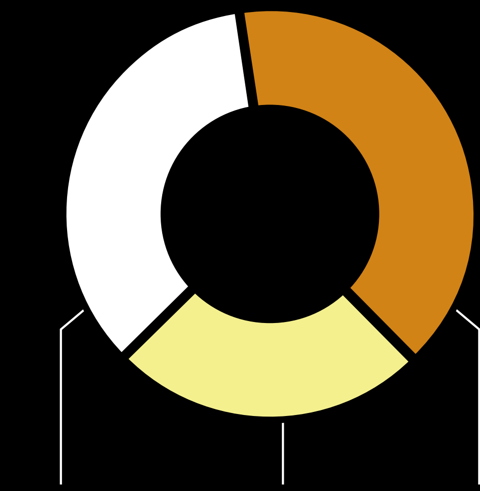
Robert Fotheringham, C.A.
Chief Financial Officer

Rob Morgan, P.Eng
Chief Operating Officer, Upstream

Jacob Roorda, P.Eng
Vice President, Corporate

OPERATIONS OVERVIEW

Our core business is to acquire oil and natural gas related assets at good prices, and employ our diligent, hands-on management to maintain, maximize and ultimately create value from those assets in an environmentally and socially responsible manner.



OPERATIONAL HIGHLIGHTS:

Upstream

- 66,000 boe/d (2007E); 70% crude oil / 30% natural gas
- 9.3 year Proved plus Probable Reserve Life Index
- Strong operational and technical team focused on high capital effectiveness and efficient operations

Downstream

- 115,000 barrels per stream day hydrocracking refinery and ancillary assets
- 69 gas stations; 20,000 home heating customers; marine logistics business
- Economic life over 30 years
- $60 million capital program in 2007 ($30 million maintenance; $30 million discretionary)
- Experienced technical and refinery operations team with record of impressive performance improvements

VALUE ENHANCEMENT OPPORTUNITIES:

Upstream

- $295 million capital program in 2007 (after accelerating $20 million into 2006)
- 840,000 acres of undeveloped land; over 1,000 future drilling locations identified;
- Short / Medium term: Solvent injection in Hayter, Polymer injection in Wainwright/Suffield, Brine injection in Kindersley
- Longer term: Oil sands development, CO_2 flooding, Coal Bed Methane (CBM)

Downstream

- Short / Medium term: Further reduce costs, improve margins and expand refinery to increase throughput, begin bottoms upgrading with visbreaker enhancement
- Longer term: complete bottoms upgrading with coker addition, consider opportunity for substantial expansion of refinery to service strong product demand

REDEFINING HARVEST

On October 19, 2006, Harvest Energy showed its leadership in the industry by acquiring a refining and marketing operation and became an integrated oil and gas company.

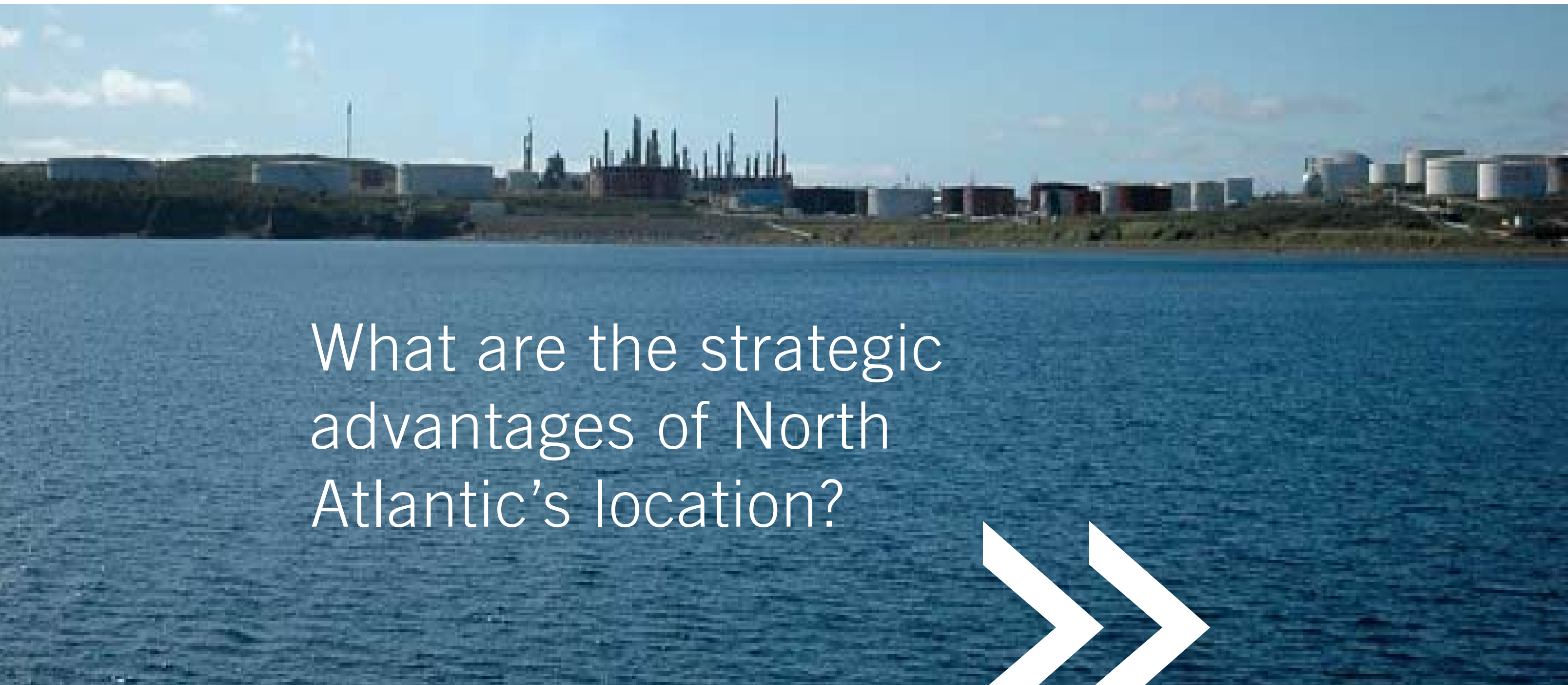
An oil refinery is a manufacturing facility that transforms crude oil into a variety of refined products. The type and mix of refined products generated depends on the facility's processing units, the quality of the crude oil feedstock put into the refinery, and the specific refining process. Examples of refined products include gasoline of different grades, diesel fuel, jet fuel, furnace oil and heavier fuel oil.

North Atlantic is a 115,000 barrel per day hydrocracking refinery, optimally configured to process medium sour crude oil (30° API, 2.5% sulphur). It has a complexity rating of just under 8.5 on the Nelson Complexity Index, an industry benchmark that measures a refinery's capacity and complexity. As a Clean Fuels refinery, 100% of its gasoline and ultra low sulphur diesel (ULSD) products meet or exceed current and future anticipated environmentally driven specifications.

How does Harvest benefit from owning North Atlantic?

One of the key features that attracted us to North Atlantic was the opportunities we identified whereby we could invest capital and further expand the refinery, as well as upgrade this lower margin #6 fuel oil into higher value products. A significant project under way is the enhancement of the existing visbreaker unit which will enable a more complete upgrade of the lower value #6 fuel oil, and provides a quick payout. Other #6 fuel oil upgrading projects, such as a new delayed coker, would enhance economic value and increase production of higher value products such as gasoline, ultra low sulphur diesel and jet fuel.

Part of our capital budget is also dedicated to our ongoing strategy of continuous improvements in yield, reliability, energy efficiency and environmental compliance.



What are the strategic advantages of North Atlantic's location?

The acquisition of North Atlantic offered us an accretive transaction at a very good price; approximately 3.7 times the trailing twelve months' cash flow. By becoming vertically integrated, Harvest's upstream expertise is complemented by North Atlantic's downstream capabilities resulting in a diversification of our business and asset base and an extension of our value chain within the hydrocarbon business. The refinery is a long life asset that requires modest annual cash flow reinvestment to maintain operations, and provides improved future cash flow stability due to the refinery's significant free cash flow characteristics. We have identified several value enhancing capital projects to improve operations, increase throughput and increase the yield of higher valued products, thereby further enhancing our long term sustainabilty.

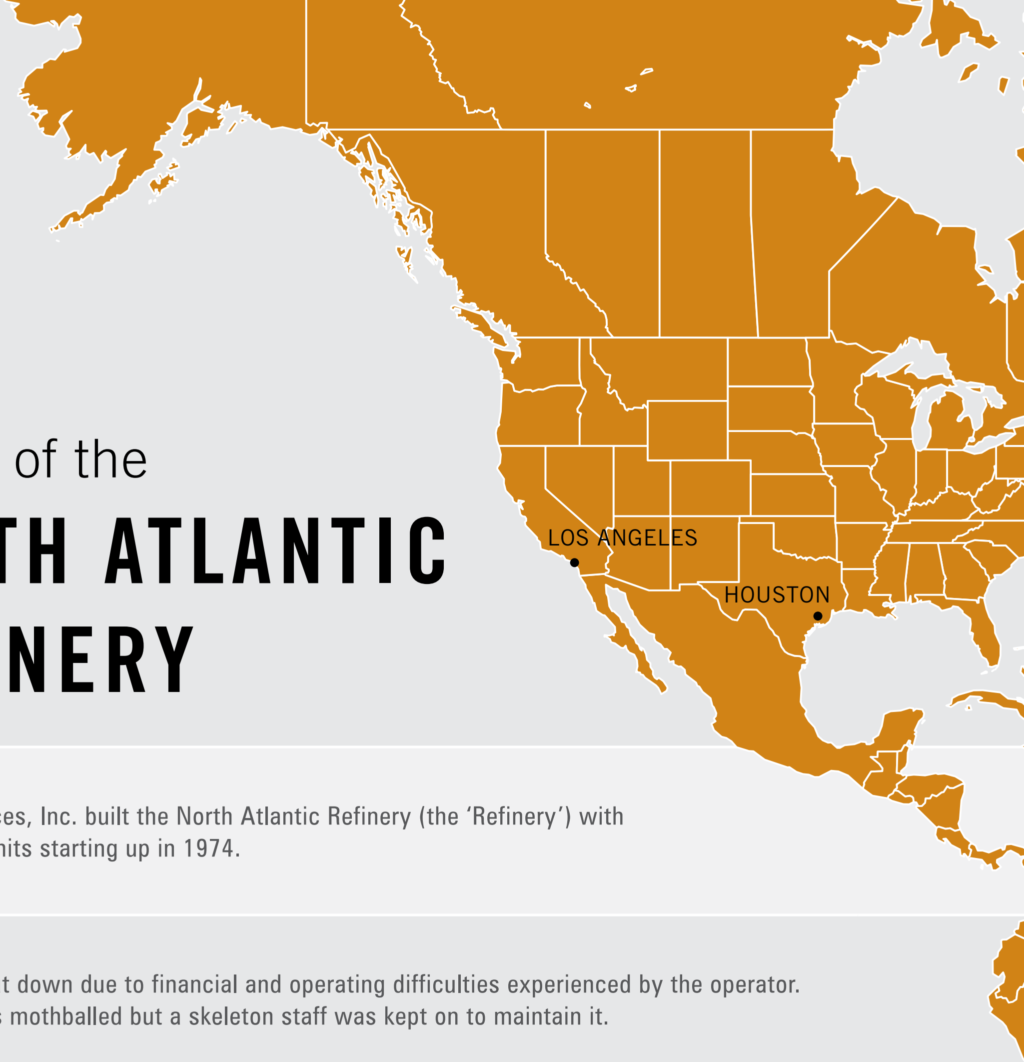
As an integrated energy trust in Canada, Harvest offers unitholders a unique, diversified and sustainable business model with strong cash flow characteristics from both our upstream oil and natural gas operations as well as the North Atlantic refining and marketing business.

A refinery's location has an important impact on its refining margins because location can influence access to crude oil feedstocks as well as efficient distribution of refined products. North Atlantic's location offers several advantages including:

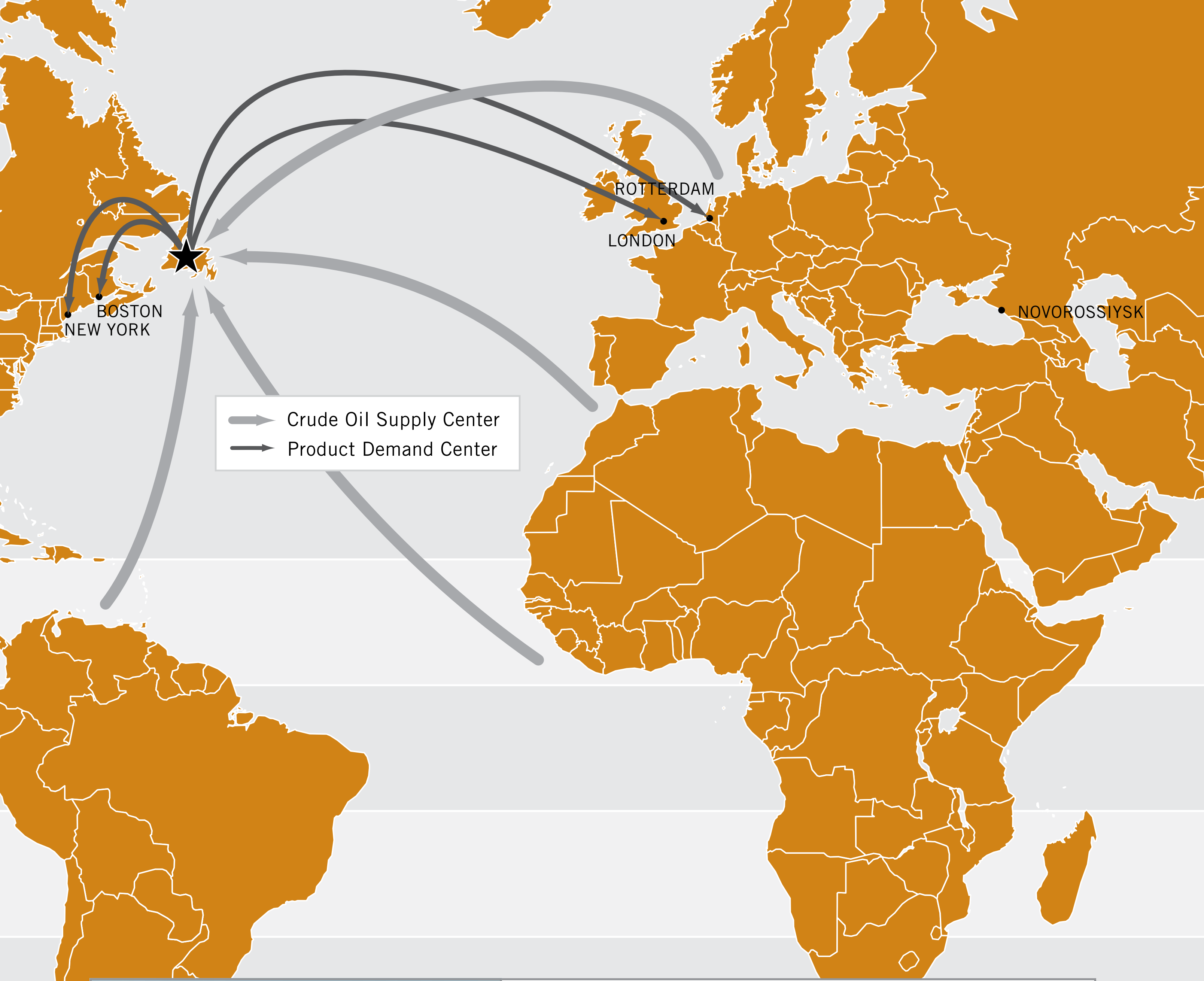
- Access to feedstock from a variety of sources (Middle East, Russia, Latin America), and good access to high quality markets in New York and Boston which are some of the largest premium transportation fuel markets.
- North American Free Trade Agreement ("NAFTA") exempts the import duties from refined product entering the United States produced by a Canadian refinery
- Situated on an ice-free, deep water port enables Very Large Crude Carriers (VLCC) to dock at North Atlantic's jetty, which reduces shipping costs and eliminates the need for crude or product transfer offshore or trans-shipping
- North Atlantic has developed strong cooperative relationships with the local communities, has a stable and dedicated work force who are actively involved in the success of the Refinery, and employees who take personal pride in the excellent reputation they have earned

History of the

NORTH ATLANTIC REFINERY



1971	Shaheen Resources, Inc. built the North Atlantic Refinery (the 'Refinery') with the majority of units starting up in 1974.
1976	Refinery was shut down due to financial and operating difficulties experienced by the operator. The Refinery was mothballed but a skeleton staff was kept on to maintain it.
JULY 1980 to LATE 1986	Petro-Canada purchased the Refinery, but did not operate it. Refinery sold in late 1986 to a wholly owned subsidiary of U.S. based Cumberland Farms Limited.
1987 to 1994	Approximately US$132 million (about C$200 million) was invested in the Refinery by Cumberland Farms' subsidiary including the construction of a new hydrogen furnace, initially operated as a hydroskimmer (the hydrocracker was brought on in 1990).
AUGUST 1994	Vitol Refining Group B.V. acquired the Refinery and commenced a major restoration. The Refinery was successfully commissioned in late 1994.
1995 to 2005	Vitol invested approximately US$600 million in capital to maintain, upgrade and expand the Refinery, which significantly improved its operating performance in terms of refinery throughput, reliability, saleable yield, product quality, safety and environmental performance.
OCTOBER 2006	Harvest Energy purchased North Atlantic.



Does Harvest refine its own oil from Western Canada?

Although the refinery could physically process Harvest's medium sour crude oil from Western Canada, it would be uneconomic to transport it to Newfoundland. As a result, all of the crude oil that is refined at North Atlantic is purchased from regions with a large supply of medium sour oil, such as Russia, the Middle East and Latin America, and delivered to Newfoundland on large tanker ships.

Harvest has an agreement with one of the world's largest physical traders and marketers of crude oil and petroleum products, Vitol Refining S.A., whereby Vitol will source and supply crude oil feedstock for the North Atlantic refinery and market the refined products outside of Newfoundland on a fee for service basis.

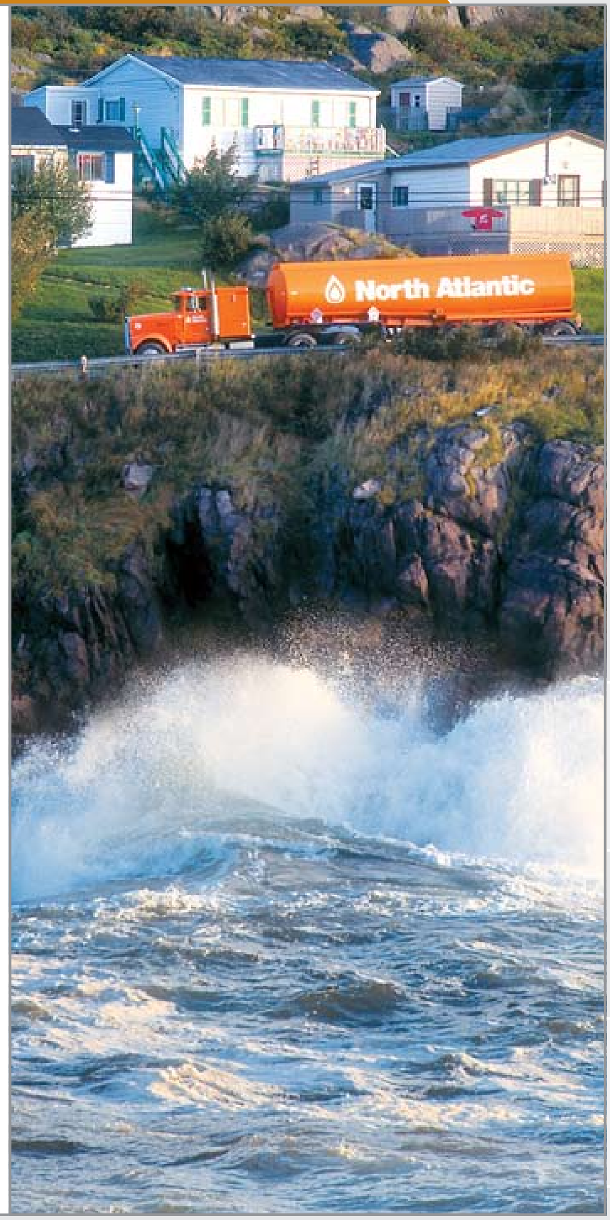
What is a 'crack spread'?

A 'crack spread' is a term used to describe a benchmark indication of a refiner's gross margin when they process a specific type of crude oil into an assumed selection of refined products. A common refining crack spread is called the 2:1:1, which mirrors the gross margin that would be realized by a refiner if they purchased two barrels of light, sweet crude oil (based on the benchmark West Texas Intermediate or WTI) as feedstock, and produced one barrel of gasoline and one barrel of diesel. Since sour crude oil traditionally sells at a discount to WTI, the margin for sour refiners tends to be more favorable and is called a "sour crack spread".

Below is a generic example of a 2:1:1 crack spread, assuming a WTI oil price of US$60 per barrel, a gasoline price of US$69 per barrel and a diesel price of US$74 per barrel.

1 barrel of WTI crude oil purchased for $60 per barrel	($60.00)
50% of one barrel of gasoline produced & sold for $69	$34.50
50% of one barrel of diesel produced & sold for $74	$37.00
Equals 2:1:1 crack spread	**$11.50**

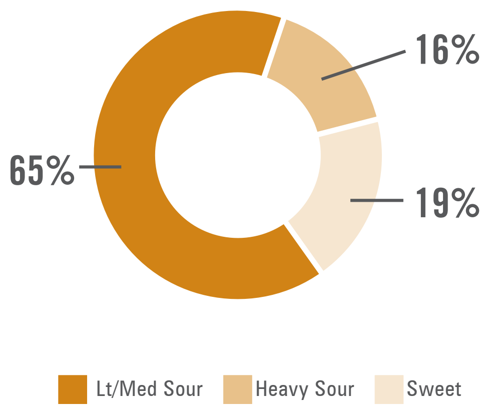
North Atlantic is a sour refinery and therefore, our margins include more products than what is included in a 2:1:1 crack spread. Each barrel of sour crude oil that we process is refined into three different products, weighted approximately as follows: 33% gasoline, 42% diesel and 25% heavy fuel oil (which trades at a discount to WTI).



What are the advantages of a medium-sour refinery?

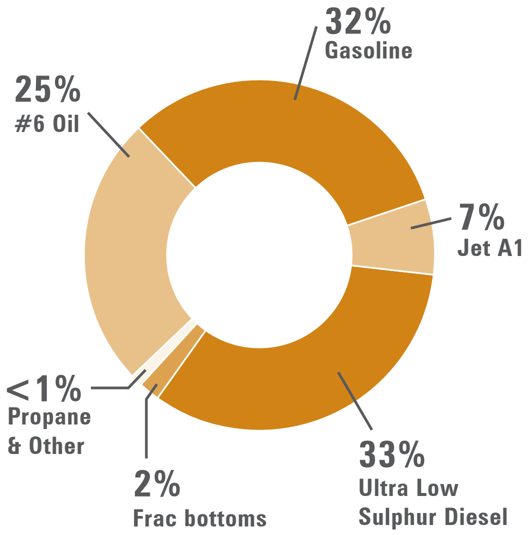
Crude oils are classified and valued by their sulphur content and their density (or gravity). Over time, the world's supply of crude oil has become heavier in quality (lower gravity) and higher in sulphur content (more sour). However, most of the global refining capacity is best suited to process a lighter oil (higher gravity) and lower sulphur ('sweeter') crude oil. Due to the quality differential between light, sweet crude oil and heavier, sour crude oil, refiners like North Atlantic who are able to process lower quality crude oil into higher value refined products have an economic advantage. North Atlantic is a sophisticated refinery that can process and upgrade medium gravity sour crude oil.

GLOBAL CRUDE RESERVES



What products does North Atlantic sell?

Approximately 75% of North Atlantic's refined products are high value, including distillates such as Ultra Low Sulphur Diesel (ULSD) and reformulate blend for oxygenate blending (RBOB) gasoline. The remaining 25% of the product is #6 fuel oil, a lower value but still heavily used product, a new grade of gasoline designed for blending with renewable fuels like ethanol. Over time, an opportunity exists for Harvest to invest additional capital in the refinery to upgrade #6 fuel oil into higher value products.



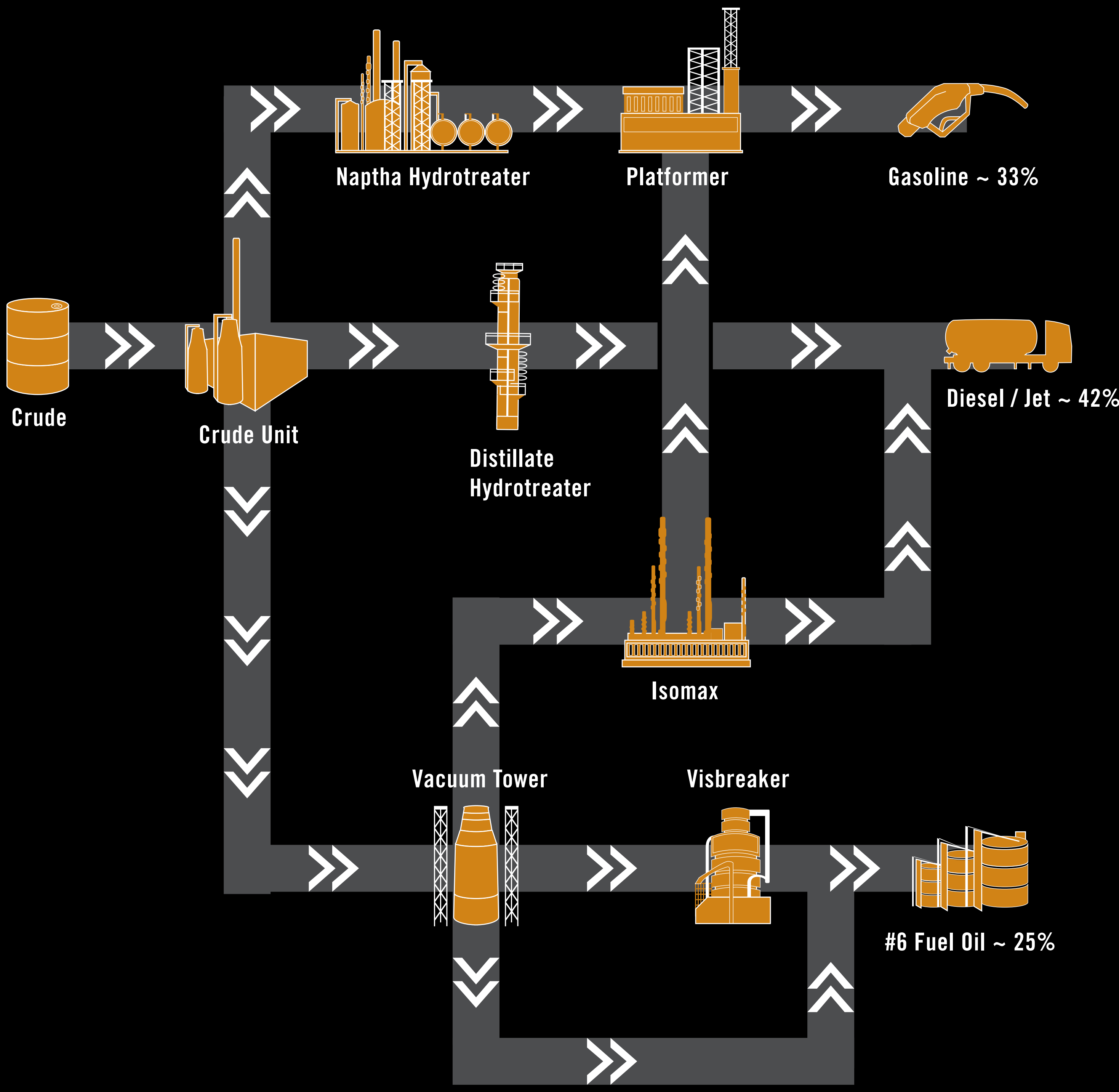
What other businesses are included in North Atlantic?

In addition to the refining business, North Atlantic has marine and marketing divisions headquartered in St. John's, Newfoundland.

Marketing Division: 69 gasoline stations; 20,000 residential heating and commercial customers throughout Newfoundland; provides product to a number of commercial and wholesale customers.

Marine Division: Manages vessel traffic in Placentia Bay; provides services to vessels entering Canadian waters, on behalf of terminals, charterers and ship owners, and owns two tugboats (one of which is equipped for fire fighting and the other for oil spill response).

SIMPLIFIED PROCESS FLOW



UPSTREAM overview

Harvest's oil and gas operations have continued to grow and evolve since our inception in 2002, with several exciting changes occurring over the past 12 months.

Following our merger with Viking Energy Royalty Trust in February 2006, production grew from approximately 38,500 boe/d to our current 2007 forecast of approximately 66,000 boe/d, including the impact of an acquisition in the first quarter. Over this time frame, we also expanded our asset base across western Canada, increased our natural gas weighting from 11% to 30%, and successfully executed the largest capital program in our history. All of these achievements took place during a period of fierce competition, volatile commodity prices and with the added challenge of integrating two significant organizations.

In 2006 we continued with our value maximization strategy of making high-quality acquisitions and pursuing good internal development opportunities. This is demonstrated by our activities through the year, including the acquisition of Birchill Energy Limited, the commencement of a pilot enhanced oil recovery (EOR) project at our Hayter field, the divestment of some non-core assets for very attractive metrics, and the bold step of becoming an integrated producer with the acquisition of a refinery.

A key benefit of the merger with Viking was the expansion of our high quality portfolio of development opportunities. In 2006, we capitalized on high oil prices and in the second quarter were one of the top ten most active drillers in Western Canada. We invested $256 million directly into drilling and related activities (68% of our total capital budget), and drilled 252 gross wells (191 net) with a 98% success rate. In addition to running a very large capital program, we also invested in projects which do not translate into immediate incremental reserves or production in 2006, but position Harvest very well to benefit in the medium and longer term. These investments include $35 million in infrastructure, including an extensive water handling upgrade in Suffield, compression addition at our Ferrier project, $15 million invested in land, seismic and enhanced oil recovery projects. Favorable weather conditions late in the fourth quarter of 2006 and our state of readiness set the stage for us to accelerate $20 million of our 2007 budgeted capital into 2006. From a production or reserves standpoint, the benefit of this shift in timing will not be realized until 2007 but it represented an excellent opportunity to more efficiently execute our 2007 program.

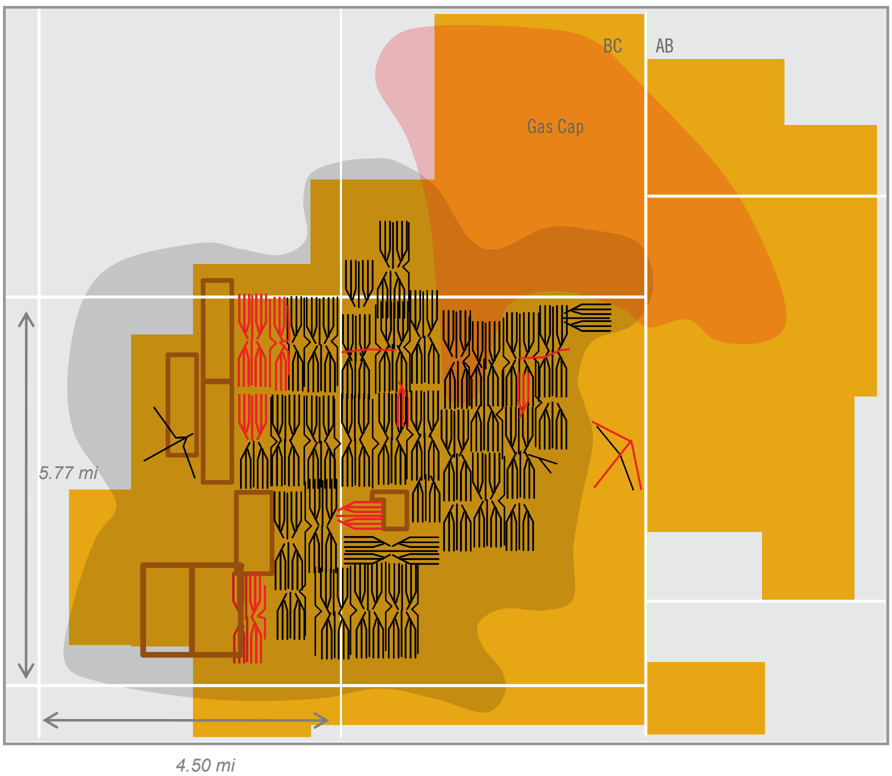
Our 2007 capital budget for the upstream oil and gas portion of our business was set at $315 million, but is now reduced to $295 million after the $20 million of capital was accelerated into 2006. In 2007 we will be focused on continued drilling in primarily oil and liquids producing areas such as Hay River ($75 million), Southeast Saskatchewan ($30 million), Provost/ Wainwright ($30 million), Suffield ($16 million) and Red Earth ($30 million). A smaller portion will be allocated to natural gas areas such as Markerville ($12 million). We will continue to focus on our existing enhanced oil recovery pilot project in Hayter as well as commencing additional pilots in Kindersley, and Wainwright/Suffield once we receive the results of engineering studies initiated in 2006.

Based on this level of capital spending, and the approximately 200 wells we plan on drilling, we estimate 2007 production will average approximately 66,000 boe/d, including the impact of an acquisition in the first quarter. Operating costs are forecast to average approximately $10.70 / boe, with royalty rates expected at 19%. Overall, our upstream oil and gas business contributes almost two thirds of our operating cash flow based on the current commodity price environment.

Bluesky's NOT the Limit in Hay River

Hay River, B.C. is a winter access only area located in Northeast British Columbia. The area's production is medium gravity crude oil, sourced from the Bluesky formation, but which sells into a light oil stream, improving its price realizations relative to medium gravity oil from other areas.

Development in Hay River is through pad drilling of multi-leg horizontal wells. The nature of the terrain has historically limited access for heavy drilling and service equipment to winter months when the ground is frozen. In the fourth quarter of 2006, an early start to the winter season combined with our state of readiness allowed us to execute our winter drilling program a full month ahead of schedule. We also commenced building an all-season access road in late 2006, which increases our flexibility to develop and access the area year round in the future.

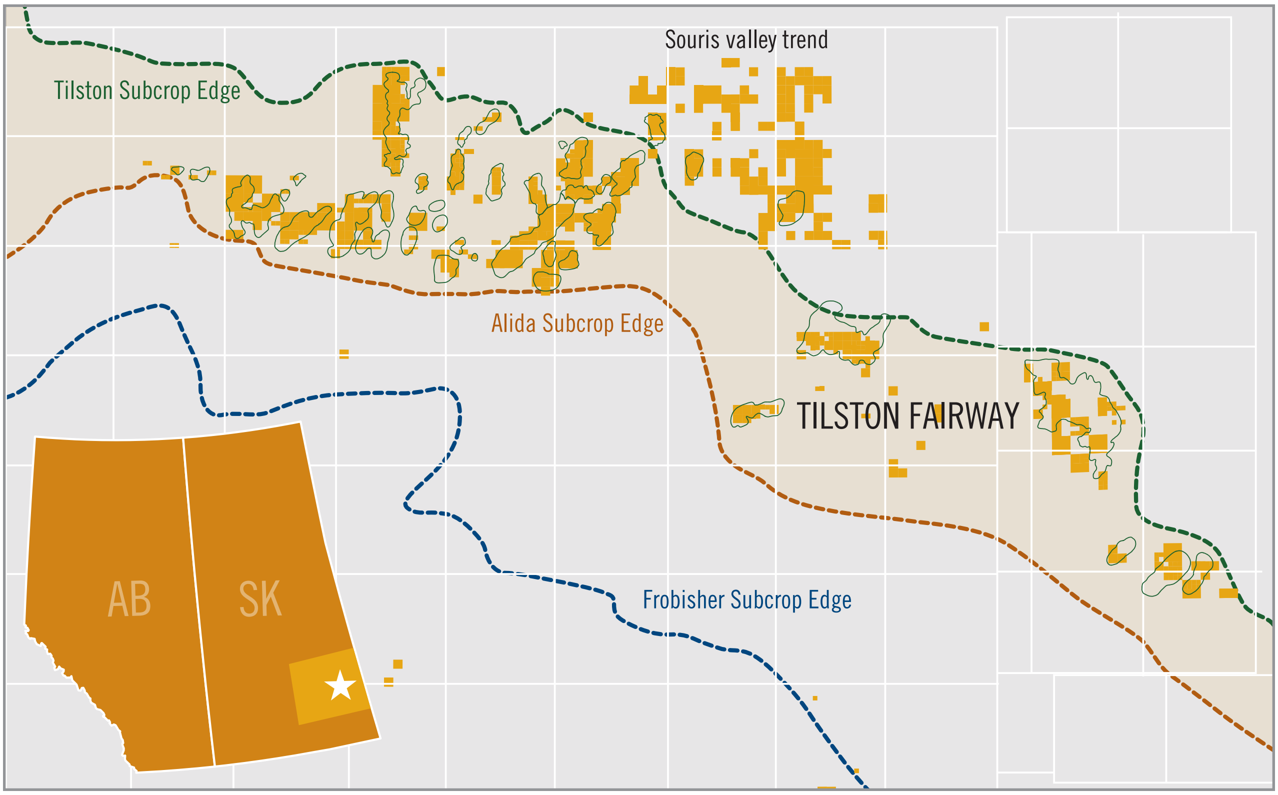


Our 2007 capital budget for Hay River is $75 million, which includes drilling 32 single and multi-leg horizontal wells, completion of our all season access road initiated in 2006, replacement of our existing on-site power generation and natural gas flaring with purchased power allowing us to sell our produced natural gas, and continued optimization of our fluid pumping and transportation infrastructure. During 2006, Hay River production averaged 5,500 boe/d and we anticipate a similar level for 2007. We view Hay River as very early in its life as an asset for Harvest, having only recovered approximately 6% of the original resource in place, and we are positioning ourselves to capture value from this asset over the near, medium and long term. In addition to oil production, a large gas cap represents future potential for development in Hay River.

Hitting it 'off the fairway' in Southeast Saskatchewan

Since Harvest's initial entry into this area in 2003, we have continued to demonstrate excellent results, both through the use of our horizontal drilling technology to effectively access oil in the Tilston formation, but also through our geological and geophysical expertise that we have used to identify new hydrocarbon deposits in existing developed fields as well as new pool discoveries. In past years, our focus had been on infill drilling our Tilston pools, but in 2006, the 37 wells drilled in SE Saskatchewan were primarily accessing light oil in the Souris Valley formation, a deeper carbonate deposit that has only recently been found to be productive.

Production in this area is predominantly light oil, with an average API gravity of approximately 33 degrees. Development is done primarily through horizontal wells and will continue to be an active area for Harvest in the future. Our 2007 capital is budgeted at approximately $30 million and will include the drilling of about 29 wells, including up to five new shallow gas wells at Monchy, a property in the southwest portion of the province with an extensive land base containing significant shallow gas development potential.

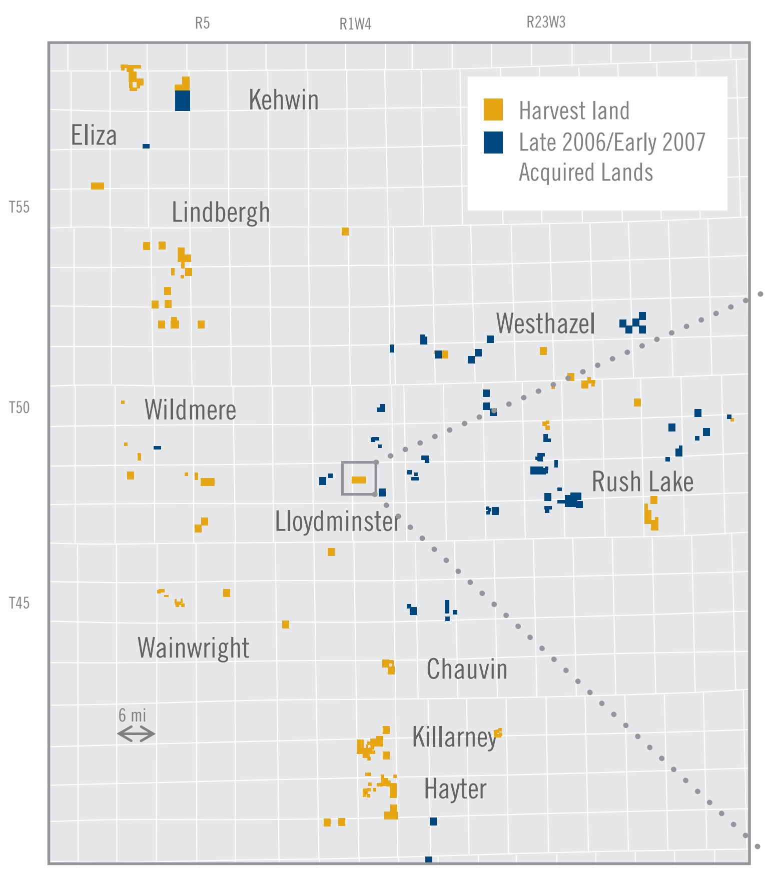


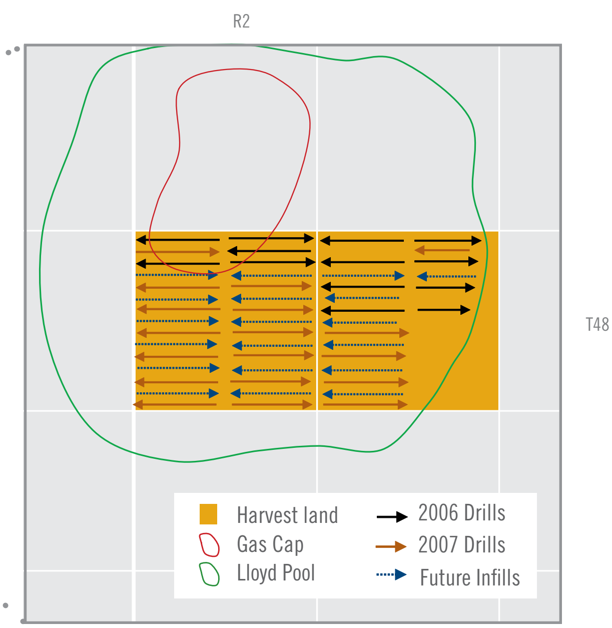
Lloydminster - 'Heavy' on Positive Results

The exciting and successful development of the Lloydminister property in eastern Alberta provides an excellent example of Harvest's strategy. Our skilled operations team identified two sections of largely undeveloped land in our portfolio at Lloydminster that appeared to contain a significant oil pool. The land was operated with 100% working interest, and contained two wells producing a combined 20 boe/d. In early 2006, the team conducted a seismic program in the area with the goal of delineating pool boundaries and improving our understanding of the play.

Following the positive results of the seismic analysis, the team commenced active well development of the area in mid 2006. Within 6 months, the team had drilled 12 horizontal wells, and production increased to approximately 850 boepd in September of 2006. In 2007, another 18 wells are planned as part of the $25 million capital program in the Lloydminster/Hayter area which will both delineate the pool boundaries to confirm our seismic interpretation, and initiate our infill drilling program which could ultimately result in approximately 40 wells being drilled on the land. With finding and development costs less than $10/boe and average netbacks in 2006 in excess of $20/boe, we have an attractive recycle ratio on a project we can quickly convert from resource in the ground to unitholder value.

In late 2006, we complemented our position in this area with the acquisition of some primarily heavy oil producing assets, and in early 2007, we purchased a private company adding further heavy oil assets to our portfolio and strengthening our position in this area. These activities have made us an important player in conventional heavy oil in this region.





RESERVES DISCLOSURE

Harvest's reserves were evaluated by the independent reserve evaluators McDaniel & Associates Consultants Ltd. ("McDaniel"), GLJ Petroleum Consultants Ltd. ("GLJ"), and Sproule Associates Limited ("Sproule") in accordance with National Instrument 51-101("NI 51-101") for the year ended December 31, 2006. The evaluation of Harvest's Proved plus Probable (P+P") reserves was completed as follows: McDaniel approximately 35%, GLJ approximately 44%, and Sproule approximately 21%. McDaniel's pricing forecasts were used in all reserve evaluations.

The information and tables listed below for Harvest constitute a combined summary of the three separate reserve reports. The full reserve disclosure information, as required under NI 51-101, will be contained in Harvest's 2006 Annual Information Form, filed on SEDAR and available on Harvest's website. Reserves data presented below is net of abandonment costs.

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

Harvest Reserves Summary as at December 31, 2006 - Forecast Prices and Costs

Gross[(1)]

Reserves Category	Light & Medium Crude Oil (mmbbl)	Heavy Crude Oil (mmbbl)	Associated & Non-Associated Gas (Bcf)	Natural Gas Liquids (mmbbl)	Total Oil Equivalent[(3)] 2006 (mmboe)	Total Oil Equivalent[(3)] 2005 (mmboe)
Proved						
Developed Producing	62.2	33.6	203.6	6.9	136.7	77.0
Developed Non-Producing	1.7	2.6	33.6	0.8	10.6	2.2
Undeveloped	4.3	3.3	22.4	0.5	11.8	8.5
Total Proved	68.2	39.5	259.5	8.2	159.1	87.7
Probable	23.2	16.7	105.1	3.6	61.1	32.0
Total Proved Plus Probable	91.4	56.2	364.6	11.8	220.2	119.7

Net[(2)]

Reserves Category	Light & Medium Crude Oil (mmbbl)	Heavy Crude Oil (mmbbl)	Associated & Non-Associated Gas (Bcf)	Natural Gas Liquids (mmbbl)	Total Oil Equivalent[(3)] 2006 (mmboe)	Total Oil Equivalent[(3)] 2005 (mmboe)
Proved						
Developed Producing	56.1	30.2	166.4	5.2	119.3	68.4
Developed Non-Producing	1.5	2.1	26.8	0.6	8.7	1.8
Undeveloped	3.6	2.7	18.0	0.3	9.7	7.4
Total Proved	61.2	35.1	211.2	6.1	137.6	77.6
Probable	20.8	14.7	85.4	2.6	52.3	28.0
Total Proved Plus Probable	82.0	49.8	296.5	8.7	189.9	105.6

(1) "Gross" reserves means the total working interest share of Harvest's remaining recoverable reserves before deductions of royalties payable to others and including royalty interests.

(2) "Net" reserves means Harvest's gross reserves less all royalties payable to others plus all royalty interests.

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

(4) Columns may not add due to rounding.

(5) The reserves attributable to Harvest's Hay River property, which is an area that produces medium gravity crude oil (average 24° API), are subject to a heavy oil royalty regime in British Columbia and would be required, under NI 51-101, to be classified as heavy oil for that reason. We have presented Hay River reserves as medium gravity crude in the following reserve tables as they would otherwise be classified in this fashion were it not for the lower rate royalty regime applied in British Columbia. If the Hay River reserves were included in the heavy crude oil category, it would increase the gross heavy oil reserves and reduce the light/medium oil reserves by the following amounts: Proved Developed Producing ("PDP"): 13.5 mmboe, Proved Undeveloped: 1.8 mmboe, Total Proved: 15.3 mmboe, Probable: 4.2 mmboe and P+P: 19.5 mmboe, and would increase the net heavy oil reserves and reduce the light/medium oil reserves by the following amounts: PDP: 11.9 mmboe, Proved Undeveloped: 1.5 mmboe, Total Proved: 13.4 mmboe, Probable: 3.7 mmboe, and P+P: 17.1 mmboe.

Net Present Value of Future Net Revenue of Reserves as at December 31, 2006 - Forecast Prices and Costs

Harvest's crude oil, natural gas and natural gas liquids reserves were evaluated using McDaniel's product price forecasts effective January 1, 2007 prior to provision for income taxes, interest, debt service charges and general and administrative expenses. Note that this presentation is on a before tax basis, and if the tax measures announced on October 31 become substantially enacted, the after tax values could be different than the pre-tax number presented herein. It should not be assumed that McDaniel's estimates of the discounted future net production revenue represent the fair market value of Harvest's reserves.

Reserves Category	0% ($millions)	5% ($millions)	10% ($millions)	15% ($millions)	20% ($millions)
Proved					
Developed Producing	3,449.4	2,718.7	2,272.1	1,968.7	1,748.3
Developed Non-Producing	320.6	224.0	174.7	144.4	123.4
Undeveloped	234.0	162.3	115.2	82.2	57.8
Total Proved	4,004.0	3,105.0	2,562.0	2,195.2	1,929.6
Probable	1,794.9	1,053.0	714.9	528.5	412.6
Total Proved Plus Probable	5,798.9	4,158.0	3,276.9	2,723.7	2,342.2

(1) Columns may not add due to rounding.

2006 Gross Reserves Reconciliation Table - Forecast Prices and Costs

	TOTAL BARREL OF OIL EQUIVALENT (boe)	
FACTORS	Gross Proved (mmboe)	Gross Proved Plus Probable (mmboe)
December 31, 2005	**87.7**	**119.7**
Technical Revisions	5.9	2.9
Extensions/Improved Recovery	6.9	10.9
Discoveries	0.5	0.6
Economic Factors	0.4	0.5
Acquisitions/Dispositions	79.5	107.4
Production	(21.8)	(21.8)
December 31, 2006	**159.1**	**220.2**

(1) Columns may not add due to rounding.

(2) A 2006 reconciliation of net reserves, compliant with NI 51-101, is available in Harvest's 2006 Annual Information Form filed on SEDAR.

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

As indicated in the table above, our P+P reserve additions (excluding acquisitions/dispositions) totaled 15.0mmboe, which includes approximately 18.9mmboe of additions from our capital program, with the balance primarily attributed to the conversion of previously booked undeveloped reserves.

McDaniel & Associates Consultants Ltd. January 1, 2007 Price Forecast

A summary of the McDaniel price forecast as at January 1, 2007 that was used in the Harvest reserves evaluation is listed below. A complete listing of the price forecast is available on the McDaniel's website at the following link http://www.mcdan.com/pricing_forecasts.html, and included in Harvet's 2006 Annual Information Form filed on SEDAR.

Year	WTI Crude Oil $US/bbl[1]	Edmonton Light Crude Oil $C/bbl[2]	Alberta Bow River Hardisty Crude Oil $C/bbl[3]	Alberta Heavy Crude Oil $C/bbl[4]	Alberta AECO Spot Price $C/GJ	US/CAN Exchange Rate $US/$CAN
2007	62.50	70.80	49.30	39.20	6.85	0.870
2008	61.20	69.30	49.60	39.80	7.05	0.870
2009	59.80	67.70	49.80	40.20	7.40	0.870
2010	58.40	66.10	49.30	40.90	7.50	0.870
2011	56.80	64.20	47.90	39.70	7.70	0.870
2012	58.00	65.60	48.90	40.60	7.90	0.870
2013	59.10	66.80	49.80	41.30	8.10	0.870
2014	60.30	68.20	50.80	42.20	8.25	0.870
2015	61.50	69.50	51.80	43.00	8.45	0.870
2016	62.70	70.90	52.90	43.80	8.60	0.870
2017	64.00	72.30	54.00	44.80	8.75	0.870
2018	65.30	73.80	55.00	45.70	8.95	0.870
2019	66.60	75.30	56.10	46.60	9.10	0.870
2020	67.90	76.80	57.20	47.50	9.30	0.870
2021	69.30	78.30	58.40	48.50	9.50	0.870
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	0.870

(1) West Texas Intermediate at Cushing Oklahoma 40 degrees API/0.5% sulphur.

(2) Edmonton Light Sweet 40 degrees API, 0.3% sulphur.

(3) Bow River at Hardisty Alberta (Heavy stream).

(4) Heavy crude oil 12 degrees API at Hardisty Alberta (after deduction of blending costs to reach pipeline quality).

2006 Reserve Life Index

The following reserve life index values were derived by dividing the total reserves by Harvest's 2006 exit production – approximately 65,000 boe/d.

Total Proved plus Probable:	**9.3**
Total Proved:	6.7
Proved Producing:	5.8

2006 Finding, Development & Acquisition Costs

In the interests of continuity and consistency, we have elected to present Finding and Development ("F&D") and Finding, Development and Acquisition ("FD&A") costs calculated both excluding and including the change in Future Development Capital ("FDC"). The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

	Total Proved	Proved plus Probable
Net reserve additions from exploration & development activities (mmboe)	13.8	15.0
Total Reserve additions including acquisitions (mmboe)	93.3	122.4
Exploration & Development Capex ($millions)	$ 363.5	$ 363.5
Total Capex Including Acquisitions ($millions)	$ 2,830.6	$ 2,830.6
F&D Before changes in FDC ($/boe)	**$ 26.41**	**$ 24.30**
FD&A Before changes in FDC ($/boe)	**$ 30.34**	**$ 23.13**
Development Capex including FDC ($millions)	$ 377.1	$ 389.5
Total Capex Including Acquisitions including FDC ($millions)	$ 2,936.3	$ 3,009.4
F&D including changes in FDC ($/boe)	**$ 27.40**	**$ 26.04**
FD&A including changes in FDC ($/boe)	**$ 31.47**	**$ 24.59**

Historical Average F&D and FD&A Costs

	Total Proved		Proved plus Probable	
	including FDC	excluding FDC	including FDC	excluding FDC
Three Year Average F&D	**$ 15.99**	**$ 14.67**	**$ 14.43**	**$ 13.22**
Three Year Average FD&A	**$ 21.20**	**$ 19.15**	**$ 17.08**	**$ 14.84**
2005 F&D ($/boe)	$ 15.17	$ 11.80	$ 13.10	$ 10.73
2005 FD&A ($/boe)	$ 17.62	$ 13.79	$ 15.56	$ 11.78

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

corporate GOVERNANCE

Harvest puts a great focus on corporate governance and we are committed to conducting all of our affairs based on a foundation of trust, integrity and ethical behavior.

Our senior executive team and independent Board of Directors are highly capable and empowered to ensure that the interests of all stakeholders are appropriately considered as the Trust executes its business strategies. We continually strive to meet the current requirements and future expectations for best practices in corporate governance.

As the corporate governance and regulatory landscape continues to change, Harvest has adopted appropriate corporate governance practices and will continue to grow and evolve accordingly to ensure that Unitholders' interests are represented and protected. Disclosure respecting our corporate governance practices in compliance with National Instrument 58-101 is contained in our 2007 Proxy Statement and Information Circular.

Although we currently fully comply with the existing corporate governance guidelines for Canadian issuers, we remain committed to further enhancing our corporate governance practices as needed. This includes ensuring that the responsibilities outlined in the mandates for the Board and its committees will meet or exceed changes to corporate governance guidelines which may occur in the future. Harvest has a whistleblower policy which allows members of the organization to anonymously report known violations of the code of ethics. Harvest also complies with the relevant internal control and disclosure certification requirements of the U.S. Sarbanes-Oxley Act, which benefits Harvest's Unitholders as it formalizes our commitment to implement processes and controls that promote sound business practices at all levels of the Trust.

Harvest's Board consists of eight independent, non-executive directors, all of whom have extensive industry experience. Directors are elected by Unitholders each year at the Annual General Meeting. Harvest's Board is responsible for stewardship and overseeing the operations of the Trust. The Board consider good corporate governance to be central to the effective and efficient operation of the Trust and believe their approach to cooperate governance is working for the benefit of the Trust and its Unitholders. The Board has established three permanent committees as follows:

Audit Committee: The members of the Audit Committee are Messrs. McFadyen (Chairman of the Committee), Johnson and Blue. Each of the Audit Committee members has many years of experience managing large organizations, and each has served on numerous boards, including internationally. The Audit Committee reviews all financial statements on a quarterly basis and makes recommendations regarding approval to the full Board. In addition, it reviews annual financial statements independently with the auditors of the Trust, prior to presentation of such statements to the Board for approval. The Audit Committee reviews the integrity of management's reporting systems and also reviews management reporting, internal financial and operating controls, policies and practices with management and the auditors of the Trust.

Compensation Committee / Corporate Governance Committee: The Compensation and Corporate Governance Committees are comprised of Messrs. Chernoff (Chairman of the Committee), Brussa and Friley. These individuals have extensive industry expirience and knowledge. The primary function of the Compensation / Corporate Governance Committee is to assist the Board in fulfilling its oversight responsibilities with respect to human resources policies, compensation, succession planning and proposing new board nominees and assessing directors. The Committee is also responsible to review and recommend to the Board management's succession plan including provisions for appointing, training and monitoring senior management, reviewing the effectiveness of the Board and its committees, and reviewing the appropriateness of the current and future organizational structure of the Trust.

Reserves, Safety & Environment Committee: The Reserves, Safety and Environment Committee is comprised of Messrs. Bennett (Chairman of the Committee), Boone and Johnson. These individuals are all registered professional engineers in the province of Alberta with substantial industry expertise and experience. The purpose of this Committee includes the review of annual independent reserve engineering evaluation reports, reviewing the qualifications, experience and independence and meeting with the independent reserve evaluators who prepare such reports. This Committee also assists directors in meeting their responsibilities (especially for accountability) in respect of Harvest's legal, industry and community obligations pertaining to the areas of health, safety and environment, as well as the establishment and implementation of appropriate environment, health and safety policies and procedures.

Environment, health & safety

Harvest is committed to conducting all of our operations in a manner that protects the health and safety of employees, contractors, and the public, as well as protecting the environment that we all share.

Our commitment to excel in the area of environment, health and safety (EH&S) makes health, safety and environmental protection an integral part of all business activities with individually tailored programs for our upstream oil and gas business, and our downstream refining and marketing business. Collectively, we strive to achieve an accident-free work place, meet or exceed all current and future expected environmental regulations, work closely with the communities in which we operate, and ensure a minimal footprint on our surroundings through responsible site reclamation in oil and gas, and commitment to programs that reduce the environmental impact of our operations.

EH&S performance is reviewed weekly by Managers, monthly by our EH&S Management Committees, and quarterly by the Reserves, Safety and Environment Committee of our Board of Directors. Our EH&S team consists of dedicated professionals with the necessary expertise to ensure that Harvest conducts business according to all regulatory requirements.

We maintain a proactive safety management program that defines key principles by which all work is to be conducted and defines specific responsibilities for all levels in the company. Harvest provides safety orientation and training for all new employees and worksite supervisors.

As part of our ongoing identification, assessment and review of potential workplace hazards, we maintain effective corporate and site specific emergency response plans, and ensure personnel are adequately trained to effectively handle emergencies and protect the public.

Through 2006, we conducted training in all of our operating areas, held a number of mock drills with staff and contractors, and will conduct further simulation exercises in 2007. We recognize that when it comes to emergency response, only superior training and commitment will ensure that we are prepared to deal with any situation.

Upstream EH&S Highlights

- Our Compliance Tracking Program provides weekly regulatory inspection results to managers and field leaders. It ensures that any identified deficiencies at field sites are corrected immediately.
- During 2006 we implemented an Approved Contractor Program, and to date have pre-qualified over 450 contractors. The Program will ensure that anyone working on a Harvest site is aware of and adheres to our strong beliefs when it comes to safety and the protection of the environment.
- During 2006, we updated our Corporate Emergency Response plan as well as 63% of our site specific Emergency Response Plans.
- We maintain internally-developed management programs to deal with environmental, regulatory, abandonment and reclamation issues, which are funded as required on an ongoing basis. Our employees conducted over 1000 scheduled site compliance inspections in 2006. We have 214 active site specific reclamation projects underway, and have processed 50 reclamation certifications in 2006 which means 50 of our field sites have been successfully restored to their natural state and returned to the landowners for their continued use.
- As a platinum level member of the Canadian Association of Petroleum Producers' Stewardship Program, we conduct regular compliance audits of our safety program, and report annually on environmental benchmarks, including Green House Gas emissions.

Downstream EH&S Highlights

Consistent with our upstream oil and natural gas business, protecting the health and safety of employees, contractors and the public and improving environmental performance are key priorities at the Refinery and in our related business. North Atlantic utilizes an Integrated Management System and the integration of health and safety into all work activities is a high priority at the Refinery as well as in our marine and other businesses. The key components of the system are core elements applicable to most large industries, and include safety, process safety environmental and health. The embedded continuous improvement program provides a structure for review and renewal. The system has assisted in reducing the refinery injury rate. Some major highlights of the North Atlantic EH&S approach are:

- North Atlantic has a long history of working with the Community Liaison Committee, representing all of the communities adjacent to the refinery. Monitoring stations continually record the air quality in three adjacent communities and the air quality in our neighboring communities continues to be well within provincial air quality standards. In 2006 new records were set with respect to oil spills; only ¼ of a liter was spilled into the water during the transfer of approximately 70 million barrels of crude oil and refined product. In 2006, there were no incidents that exceeded the Federal Refinery Effluent regulations.
- A major upgrade was completed in 2006 on the Distillate Hydrotreater to make ultra low sulphur diesel with sulphur concentrations averaging only eight parts per million (essentially sulphur-free).
- Since 1995, over $600 million has been invested in the Refinery, with a portion of that capital spent on improvements and new equipment to ensure a safe, clean, efficient, and reliable operation. Equipment upgrades and replacements, improved environmental controls and monitoring, and safety enhancements top the investment portfolio.
- Five in-house, National Board-certified inspectors have the expertise and technical tools to determine the integrity and longevity of our operating equipment.
- In 2006 the refinery was audited by the Workplace Health, Safety and Compensation Commission and received the highest rating ever provided to any company in the province of Newfoundland and Labrador. North Atlantic has received a reduction in assessment rates for five years in a row, based on continually improving performance.

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. In this MD&A, reference to "Harvest", "we", "us" or "our" refers to Harvest Energy Trust and all of its controlled entities on a consolidated basis. The information and opinions concerning our future outlook are based on information available at March 12, 2006.

When reviewing our 2006 results and comparing them to 2005, readers should be cognizant that the 2006 results include a full year of operations from our Hay River acquisition in August 2005, eleven months of operations from our acquisition of Viking Energy Royalty Trust ("Viking") in February 2006, and five months of operations from the Birchill Energy Limited ("Birchill") acquisition in August 2006. In addition, on October 19, 2006, we acquired North Atlantic Refining Ltd.("North Atlantic"), and our 2006 results include North Atlantic operations from the date of acquisition. The combination of these events significantly impacts the comparability of our operations and financial results for 2006 to the results of 2005.

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

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

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

2006 Consolidated Financial and Operating Highlights

- Cash Flows of $551.7 million for the year ended December 31, 2006 with production of 59,729 boe/d, an increase of $241.9 million and 23,158 boe/d over the prior year, respectively, primarily due to continued strength in oil prices, and the acquisition of Viking in February 2006 and Birchill in August 2006.
- Acquisition of North Atlantic Refining Ltd. for cash consideration of $1.6 billion on October 19, 2006 resulting in the addition of a 115,000 bbl/d medium gravity sour refinery to our petroleum and natural gas operations in western Canada.
- Completed a $376.9 million capital program in western Canada resulting in 252 gross petroleum and natural gas wells drilled with a success rate of 98% and incremental reserves replacing approximately 87% of 2006 production (prior to the conversion of previously booked undeveloped reserves) as well as an exit production rate at the end of the year of 65,023 boe/d.
- Maintained our monthly distributions at $0.38 per trust unit per month through the year resulting in a Payout Ratio of 85%.
- Established revolving credit facilities totaling $1.4 billion on a secured covenant based agreement with a three year extendable term as well as established an incremental $800 million of bridge facilities for the North Atlantic acquisition which have now been fully repaid.
- Raised $1.2 billion with the issuance of 22,672,250 trust units and $609.5 million principal amount of convertible debentures including the offering closed in February 2007.
- Fourth quarter Cash Flows of $156.3 million with a payout ratio of 86%.

SELECTED ANNUAL INFORMATION

The table below provides a summary of our financial and operating results for the twelve month periods ended December 31, 2006, December 31, 2005 and December 31, 2004. Detailed commentary on individual items within this table is provided elsewhere in this MD&A.

	Year ended December 31			
($000's except where noted)	**2006**	2005	2004	Change 2006 to 2005
Revenue, net[1]	**1,388,196**	436,452	212,118	218%
Cash Flow[2]	**551,724**	309,843	123,710	78%
Per trust unit, basic[2]	**$ 5.43**	$ 6.66	$ 4.94	(18%)
Per trust unit, diluted[2]	**$ 5.24**	$ 6.35	$ 3.97	(17%)
Net income (loss)	**136,046**	104,946	11,241	30%
Per trust unit, basic	**$ 1.34**	$ 2.25	$ 0.45	(40%)
Per trust unit, diluted	**$ 1.33**	$ 2.19	$ 0.43	(39%)
Distributions declared	**468,787**	153,494	64,563	205%
Distributions declared, per trust unit	**$ 4.53**	$ 3.20	$ 2.40	42%
Payout ratio [2][3]	**85%**	50%	52%	35%
Bank debt	**1,595,663**	13,869	75,519	11,405%
Senior debt	**291,350**	290,750	300,500	-
Convertible Debentures	**601,511**	44,455	25,750	1,253%
Total long-term financial liabilities	**2,488,524**	349,074	401,769	613%
Total assets	**5,745,558**	1,308,481	1,050,483	339%
PETROLEUM AND NATURAL GAS OPERATIONS				
Daily Production				
Light to medium oil (bbl/d)	**27,482**	17,590	12,336	56%
Heavy oil (bbl/d)	**13,904**	13,747	8,495	1%
Natural gas liquids (bbl/d)	**2,247**	824	472	173%
Natural gas (mcf/d)	**96,578**	26,461	10,999	265%
Total daily sales volumes (boe/d)	**59,729**	36,571	23,136	63%
Cash capital expenditures	**376,881**	120,508	42,662	213%

	As at December 31, 2006		As at December 31, 2005	
Reserves (mmboe), based on Forecast prices and costs	**Gross**	**Net**	Gross	Net
Proved reserves	**159.1**	**137.6**	87.7	77.6
Probable reserves	**61.1**	**52.3**	31.9	28.0
Total proved plus probable (P+P) reserves	**220.2**	**189.9**	119.7	105.6

REFINING AND MARKETING OPERATIONS
(from October 19, 2006 the date of acquisition to December 31, 2006)

	Year ended December 31			
($000's except where noted)	**2006**	2005	2004	Change 2006 to 2005
Average daily throughput (bbl/d)	86,890	-	-	n/a
Aggregate throughput (mbbl)	6,343	-	-	n/a
Cash capital expenditures	**21,411**	**-**	**-**	**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) Ratio of distributions declared to Cash Flows, excluding special distribution of $10.7 million settled with the issuance of trust units in 2005.

OVERALL PERFORMANCE

Subsequent to our acquisition of North Atlantic, Harvest is a fully integrated energy trust. Our petroleum and natural gas business is focused on the operation and development of quality properties in western Canada. We employ a disciplined approach to the oil and natural gas business, whereby we acquire high working interest, large resource-in-place, stable producing properties and employ "best practice" technical and field operational processes to extract maximum value. These operational processes include: diligent hands-on management to maintain and maximize production rates, the application of technology and selective capital investment to maximize reservoir recovery, and the enhancement of operational efficiencies to control and reduce expenses. Our refining and marketing business is focused on the efficient operation of a medium gravity, sour crude hydrocracking refinery and a petroleum marketing business both located in the Province of Newfoundland and Labrador. We were attracted to this asset because of its low Cash Flow multiple and relatively low level of annual capital reinvestment required relative to our petroleum and natural gas business.

We generated Cash Flows of $551.7 million ($5.43 per basic trust unit) with petroleum and natural gas production of 59,729 boe/d in the year ended December 31, 2006, compared to Cash Flows of $309.8 million ($6.66 per basic trust unit) and production of 36,571 boe/d in 2005. This $241.9 million increase in Cash Flow is substantially attributed to the incremental impact of the Viking acquisition on our Cash Flows and to a lesser degree, the impact of the Birchill and North Atlantic acquisitions. In addition, the continued strong crude oil and heavy oil differential pricing environment positively impacted our Cash Flows during the year, offsetting relative weakness in natural gas prices.

We are vulnerable to the price differentials between Edmonton Par and Bow River as our production is approximately 23% weighted towards heavy oil, which is priced off of the Bow River Stream and a portion of our light/medium production is also priced off of the Bow River Stream. For the year ended December 31, 2006 compared to December 31, 2005, heavy oil differentials were narrower overall and this is reflected in our Cash Flows. With the acquisition of the North Atlantic refinery, which processes medium gravity crude oil, our exposure to wide differentials is somewhat mitigated as our Cash Flows from the refinery are stronger when heavy oil differentials are wider. However, these positive changes to our Cash Flows have been partially offset by the rising cost pressures in the petroleum and natural gas service sector.

Production increases over the prior year are primarily attributed to the acquisitions made during 2006 as well as our successful development drilling program. These increases were offset by several production disruptions during the year: in Markerville, where approximately 3,500 boe/d of production was shut-in for the month of July and the first week of August following a fire at a non-operated gas processing facility; in Hay River, where production was impacted by first quarter maintenance turnarounds and our drilling program and in the fourth quarter due to a temporary shutdown of Rainbow pipeline; and, in Bellshill, where power disruptions impacted production. However, despite the production challenges experienced during the year we were able to exit 2006 with an average production of 65,023 boe/d. Our fourth quarter 2006 production volumes were 63,436 boe/d, compared to 38,834 boe/d in the fourth quarter of 2005, an increase of 63% attributed to acquisitions made during 2006 and our drilling program, partially offset by the shutdown of the Rainbow pipeline.

Distributions declared during the year totaled $4.53 per trust unit, for a payout ratio of 85%. Annual distributions declared were $1.33 per trust unit (or 42%) higher than those declared in the prior year, when the payout ratio was 50%. For the year ended December 31, 2006 the participation in our Distribution Reinvestment Plan ("DRIP") was approximately 38% while for the year ended December 31, 2005 the DRIP participation was 25%. Our DRIP plan enables us to settle our distributions through the issue of units and allows us to use the cash to reinvest in our capital program or for debt repayment. With potential increases in Cash Flow in 2007 due to the acquisition of the refinery and the increase of the floor prices of a number of price risk management contracts in 2007 and assuming a $0.38 per trust unit monthly distribution level, we anticipate a reduction in our 2007 payout ratio.

On February 3, 2006, Viking was acquired with the issuance of 46,040,788 trust units to former Viking unit holders, the assumption of Viking's 10.5% and 6.40% unsecured subordinated convertible debentures with an aggregate face value of $210 million and the assumption of $106.2 million of bank debt resulting in aggregate consideration of $1,975.3 million including acquisition costs. This acquisition provided us with an improved product mix, more weighted towards light/medium crude oil and natural gas and less weighted towards heavy oil. Concurrent with the acquisition of Viking, we negotiated a Three Year Extendible Revolving Credit Facility and increased our borrowing capacity from $400 million to $900 million. This increase in borrowing capacity provided us with additional flexibility for acquisitions.

Effective August 1, 2006, we acquired Birchill for $446.8 million, including working capital adjustments. Birchill was primarily weighted towards natural gas and at the time of acquisition contributed approximately 6,300 boe/d to our production. The acquisition was financed with a combination of bank debt and the net proceeds from our issuance of 7,026,500 trust units (including the over-allotment option) at a price of $32.75 per trust unit in August 2006.

On October 19, 2006, we acquired North Atlantic, its primary asset being a medium gravity sour crude hydrocracking refinery in the Province of Newfoundland and Labrador with a daily throughput capacity of 115,000 bbl/d. This refinery is strategically located on a deep water harbour which enables crude oil feedstock delivery from the Middle East, Latin America and Russia via Very Large Crude Carriers capable of delivering shipments in excess of 2 million barrels. Its location is also relatively close to the premium markets for high quality gasoline and ultra low sulphur diesel products in the northeastern United States giving it an economic advantage over certain other refiners. Our acquisition of North Atlantic created a second business segment, refining and marketing operations. The refinery's average throughput volumes were 86,890 bbl/d from the date of acquisition on October 19, 2006 to December 31, 2006 as the refinery was in the midst of a turnaround on the date of acquisition.

Concurrent with the closing of the North Atlantic acquisition we further expanded our Three Year Extendible Revolving Credit Facility from $900 million to $1.4 billion and established a $350 million Senior Secured Bridge Facility and a $450 million Senior Unsecured Bridge Facility. We initially financed the acquisition using our $350 million Secured Bridge Facility and our $450 million Unsecured Bridge Facility while the remainder was financed from our Three Year Extendible Revolving Credit Facility. On November 22, 2006, we issued 9,499,000 trust units at a price of $27.25 per trust unit and $379.5 million principal amount of 7.25% convertible unsecured subordinated debentures for net proceeds of $610.2 million, which included the full exercise of the underwriters' over-allotment option. Net proceeds from the offering were used to fully repay our $450 million Senior Unsecured Bridge Facility, pay $60.3 million of the Senior Secured Bridge facility and a $99.9 million repayment of our Three Year Extendible Revolving Credit Facility.

Our Cash Flows for the three months ended December 31, 2006 were $156.3 million compared to $96.4 million in the prior year. The increase reflects the incremental cash flow generated from the Viking and Birchill properties as well as two and a half months of operations from North Atlantic. As the refinery was acquired during the fourth quarter and was only at full capacity for the month of December, our fourth quarter Cash Flows do not fully reflect the benefits we expect to realize to our future cash flows from our North Atlantic acquisition.

For the year ended December 31, 2006, we invested $376.9 million in our oil and natural gas properties, an increase of 213% over 2005. Of the total capital spent, 57% was allocated to drilling and equipping activities resulting in a total of 252 gross wells (191.4 net) drilled with a success rate of 98%. Our finding and development ("F&D") costs for the year ended December 31, 2006 were $24.30 per boe ($10.73 per boe in 2005) on a proved plus probable ("P+P") basis excluding future development costs and $26.04 per boe ($13.10 per boe for 2005) including future development costs, reflecting a recycle ratio (operating netback divided by F&D cost) of 1.1x (3.1 for 2005). Our increased F&D costs are a result of the conversion of a larger percentage of previously booked undeveloped reserves in 2006 than in the prior year and also reflect general upward cost pressures in the industry, particularly related to the significant increase in demand for drilling rigs and the related costs to secure them which were incurred in 2006. In addition, 27% of our capital expenditures were directed towards projects that would not result in reserve additions but are included in our F&D costs for 2006; this includes $20 million of 2007 capital that was accelerated into 2006 for Hay River and Red Earth as we took advantage of favourable weather conditions in those areas. Our reserve life index (RLI) remained flat over the prior year changing from 9.4 for 2005 to 9.3 in 2006.

Subsequent to December 31, 2006, we issued $230 million principal amount of convertible debentures and 6,146,750 trust units at a price of $23.40 per trust unit for net proceeds of $357.4 million. The net proceeds from this financing were used to repay the remaining $289.7 million on the Senior Secured Bridge Facility, with the remaining $67.7 million applied to the drawn portion of our Three Year Extendible Revolving Credit Facility.

On the evening of October 31, 2006, changes to the Canadian income tax treatment of distributions from publicly traded trusts were announced by the Government of Canada which have resulted in considerable decline in the valuations of all income and royalty trusts. On December 21, 2006, the Federal Minister of Finance released draft legislation to implement the proposals originally announced on October 31, 2006. We continue to evaluate the long term impact of these changes as well as challenge them through our active participation in the recently created Coalition of Canadian Energy Trusts.

Business Segments

With the acquisition of North Atlantic, 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 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, 66 retail gas stations, 3 cardlock locations as well as a wholesale and home heating business.

	Year ended December 31, 2006		
(in 000's of Canadian dollars)	Petroleum and natural gas	Refining and marketing	Total
Revenue	1,120,575	460,359	1,580,934
Operating income[1]	200,978	19,740	220,718
Capital expenditures	376,881	21,411	398,292
Total assets	4,017,761	1,727,797	5,745,558

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

As our refining and marketing business was only acquired on October 19, 2006, the total revenue, operating income, Cash Flow, capital expenditures and total assets for the year ended December 31, 2005 as reflected in the consolidated financial statements relates only to the petroleum and natural gas business.

PETROLEUM AND NATURAL GAS OPERATIONS

Financial and Operating Results

On February 3, 2006, we completed a plan of Arrangement with Viking Energy Royalty Trust ("Viking") which provided for the merger of Harvest and Viking and resulted in the exchange of all of the issued and outstanding trust units of Viking for 46,040,788 trust units of Harvest and the assumption by Harvest of the covenants and obligations of Viking's outstanding 10.5% convertible unsecured subordinated debentures and 6.40% convertible unsecured subordinated debentures as well as Viking's bank debt for all of the crude oil and natural gas interests of Viking for an aggregate consideration of $1,975.3 million including acquisition costs. At the end of 2005, Viking's production from these properties was approximately 24,000 boe/d comprised of approximately 50% natural gas and 50% oil and natural gas liquids with its core areas of production including Markerville, Bellshill Lake, Bashaw, Channel Lake, Alexis, Tweedie/Wappau and Greater Richdale, all in Alberta, as well as Kindersley in Saskatchewan. At December 31, 2005, Viking's proved reserves, based on forecasted prices and costs, aggregated to 132.5 million mcf of natural gas, 23.5 million barrels of crude oil, 6.0 million barrels of heavy oil and 2.8 million barrels of natural gas liquids.

On July 26, 2006, we entered into an agreement to acquire all of the outstanding shares of Birchill Energy Inc., a private petroleum and natural gas producer in western Canada, for cash consideration of $446.8 million. At the time of acquisition, the production from these properties totaled approximately 6,300 boe/d weighted approximately 65% to natural gas (26 mmcf/d) and 35% to light crude oil and natural gas liquids (2,000 boe/d) with its core areas of production concentrated in the Markerville, Ferrier and Willisden Green areas of central Alberta. At April 30, 2006, Birchill's proved reserves, based on forecasted prices and costs, were estimated to be 22.6 million barrels of oil equivalent by independent reservoir engineers.

The addition of these two acquisitions significantly impacts the comparability of our 2006 results with the results of the prior year as well as provides the explanations for most of the significant year-over-year variation in our petroleum and natural gas segment.

	Year ended December 31		
(in 000's of Canadian dollars except as noted below)	**2006**	2005	Change
Revenues	**$ 1,120,575**	667,496	68%
Royalties	**(200,109)**	(113,002)	77%
Realized losses on price risk management contracts[1]	**(74,193)**	(79,271)	(6%)
Unrealized gains on price risk management contracts	**52,179**	(45,061)	216%
Net revenues excluding realized losses on electric power fixed price contracts	**898,452**	430,162	109%
Operating expenses	**242,474**	127,258	91%
Realized gains on electric power fixed price contracts	**(11,574)**	(6,290)	84%
Net operating expenses	**230,900**	120,968	91%
General and administrative expenses	**28,372**	30,697	(8%)
Transportation and marketing	**12,142**	400	-
Transaction costs	**12,072**	-	-
Depreciation, depletion and accretion	**413,988**	178,956	131%
Operating Income[2]	**200,978**	99,141	103%
Cash capital expenditures (excluding acquisitions)	**376,881**	120,508	213%
Property and Business acquisitions, net	**2,467,097**	239,658	929%
Daily sales volumes			
Light / medium oil (bbl/d)	**27,482**	17,590	56%
Heavy oil (bbl/d)	**13,904**	13,747	1%
Natural gas liquids (bbl/d)	**2,247**	824	173%
Natural gas (mcf/d)	**96,578**	26,461	265%
Total	**59,729**	36,571	63%

(1) Includes amounts realized on WTI, heavy oil price differential and currency exchange contracts and excludes amounts realized on electric power fixed price contracts and amounts realized on the series of US dollar forward purchase contracts entered into with respect to the purchase of North Atlantic.

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

Commodity Price Environment

	Year ended December 31		
Benchmarks	**2006**	2005	Change
West Texas Intermediate crude oil (US$ per barrel)	**66.24**	56.56	17%
Edmonton light crude oil ($ per barrel)	**72.79**	68.73	6%
Bow River blend crude oil ($ per barrel)	**51.04**	44.28	15%
AECO natural gas daily ($ per mcf)	**6.53**	8.71	(25%)
AECO natural gas monthly ($ per mcf)	**6.98**	8.48	(18%)
Canadian / U.S. dollar exchange rate	**0.882**	0.825	7%

Generally, the benchmark oil prices increased during the year ended December 31, 2006 compared to the prior year. The West Texas Intermediate ("WTI") crude oil price increased by 17%, however, this increase was not fully reflected in the Edmonton light crude oil price ("Edmonton Par") due to the 7% appreciation in value of the Canadian dollar. The Canadian dollar equivalent of WTI for the year ended December 31, 2006 of $75.10 would have been $80.29 (or $5.19 higher) had the Canadian dollar/US dollar exchange rate not changed. In addition to the strengthening Canadian dollar, Edmonton Par was impacted by a higher differential to WTI during the year ended December 31, 2006 compared to 2005 primarily due to the significant increase in light synthetic oils from Alberta oil sands producers as well as the decrease in local demand as western Canadian refineries convert capacity to run more medium/heavy crude oil and less light sweet crude oil. The combination of a strengthening Canadian dollar and the widening differential between WTI and Edmonton Par resulted in only a 6% increase in Edmonton Par over the prior year while WTI increased by 17% for the same period.

For the year ended December 31, 2006, prices for heavy crude oil of $51.04 were 15% higher than in 2005 with Bow River differentials narrowing to 29.9% of Edmonton Par for the year ended December 31, 2006 compared to 35.6% for 2005. As shown in the table below, heavy oil differentials during 2006 were generally narrower than those in 2005.

	2006				2005			
Differential Benchmarks	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Bow River Blend differential to Edmonton Par	**30.3%**	**25.8%**	**22.9%**	**42.0%**	40.0%	28.2%	39.6%	37.5%

For the year ended December 31, 2006 compared to the prior year, AECO natural gas daily prices saw a decrease of 25%, while monthly prices for the same periods decreased by 18%.

Realized Commodity Prices

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

	Year ended December 31		
	2006	2005	Change
Light to medium oil ($/bbl)	**59.82**	57.07	5%
Heavy oil ($/bbl)	**46.14**	39.43	17%
Natural gas liquids ($/bbl)	**58.54**	52.40	12%
Natural gas ($/mcf)	**6.76**	9.05	(25%)
Average realized price ($/boe)	**51.40**	50.01	3%
Realized price risk management losses ($/boe)[1]	**(3.40)**	(5.94)	(43%)
Net realized price ($/boe)	**48.00**	44.07	9%

(1) Includes amounts realized on WTI, heavy oil price differential and foreign exchange contracts and excludes amounts realized on electric power fixed price contracts and amounts realized on the series of US dollar forward purchase contracts entered into with respect to the purchase of the refinery.

Our average realized price was 3% higher before losses on price risk management contracts and 9% higher after deducting the realized losses on price risk management contracts for the year ended December 31, 2006 as compared to 2005. As the benefit of the increase in the WTI price was partially offset by a stronger Canadian dollar, the 12% overall increase in our average realized oil price for the year ended December 31, 2006 as compared to 2005 was as expected. The change in our average realized oil price is slightly higher than the change in Edmonton Par due to a narrowing of the Bow River differential to Edmonton Par from 35.6% for the year ended December 31, 2005 compared to 29.9% for the year ended December 31, 2006. As 38% of our total production is priced off of the Bow River stream, it is expected that our average realized oil price increase would be greater than the change in Edmonton Par.

For the year ended December 31, 2006, the realized price of our light to medium oil increased 5% which is reasonably in line with the Edmonton Par increase of 6% for the same period.

Our realized heavy oil price differential to Edmonton Par for 2006 was 36.6% compared to 42.6% for the prior year, a 6.0% improvement. This is expected as the majority of our heavy oil production is priced off of Bow River, which reflected a 5.7% narrowing to Edmonton Par from 35.6% for the year ended December 31, 2006 to 29.9% for the year ended December 31, 2006.

For the year ended December 31, 2006, our realized natural gas price decreased by 25% compared to the same period in 2005, while the AECO daily and monthly price decreased by 25% and 18%, respectively. For the majority of the year 85% of our natural gas sales were priced off the AECO daily benchmark, 10% were priced off AECO Monthly benchmark and the remainder sold to aggregators, and our price decrease is in line with the change in the benchmark prices. By the end of 2006, we decreased the amount of natural gas sales priced off the AECO daily benchmark to approximately 61% and increased the amount sold off the AECO monthly benchmark to 32%, with the remainder sold to aggregators.

Sales Volumes

The average daily sales volumes by product were as follows:

	Year ended December 31				
	2006		2005		
	Volume	**Weighting**	Volume	Weighting	% Volume Change
Light to medium oil (bbl/d)[1]	**27,482**	**46%**	17,590	48%	56%
Heavy oil (bbl/d)	**13,904**	**23%**	13,747	38%	1%
Total oil (bbl/d)	**41,386**	**69%**	31,337	86%	32%
Natural gas liquids (bbl/d)	**2,247**	**4%**	824	2%	173%
Total liquids (bbl/d)	**43,633**	**73%**	32,161	88%	36%
Natural gas (mcf/d)	**96,578**	**27%**	26,461	12%	265%
Total oil equivalent (boe/d)	**59,729**	**100%**	36,571	100%	63%

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

For the year ended December 31, 2006, average production was higher than in the prior year due to the acquisition of Viking in February of 2006, our acquisition of Birchill in the third quarter of 2006 and the Hay River properties during the third quarter of 2005.

Light to medium oil production is 9,892 bbl/d higher compared to the prior year. The acquisition of Viking contributed 7,197 bbl/d while Birchill contributed 481 bbl/d and Hay River contributed an additional 3,420 bbl/d. The incremental production from the Hay River property also includes production from a $21.9 million property acquisition closed on January 19, 2006 as well as new wells from our first quarter drilling program. These increases were partially offset by disruptions in Hay River in the first and fourth quarter of 2006 as a result of routine maintenance turnarounds at production facilities, disruptions attributed to our drilling program in first quarter and a halt of production and subsequent production restrictions due to a shutdown of the Rainbow pipeline in the fourth quarter. In addition, we experienced decreases in production in the third quarter at Bellshill Lake due to power disruptions.

Heavy oil production for the year ended December 31, 2006 of 13,904 bbl/d remained relatively consistent with the prior year production of 13,747 bbl/d. The incremental production added from our 2006 drilling program and from the Viking acquisition (1,581 bbl/d) was offset by downtime in the Suffield, Hayter and Killarney areas in the second quarter and downtime in Hayter in the fourth quarter. This downtime is attributable to processing limitations at a non-operated plant as well as the installation of an acid gas compressor.

Natural gas production for the year ended December 31, 2006 of 96,578 mcf/d is significantly higher compared to average production of 26,461 mcf/d in 2005, again primarily due to the acquisition of Viking in February 2006 and our Birchill acquisition in August 2006, a natural gas weighted acquisition. The increase was partially offset by lower production volumes in the Markerville area, where approximately 3,500 boe/d of production was shut-in for the month of July and the first week of August following a fire at a non-operated gas processing facility.

Following our acquisition of Viking and Birchill, our production is weighted 45% light/medium oil, 25% heavy oil and 30% natural gas compared to 34% heavy oil and an 11% natural gas weighting in the fourth quarter of 2005. With these acquisitions, we are less exposed to fluctuations in heavy oil differentials and more exposed to natural gas price volatility.

Revenues

	Year ended December 31		
($000's)	**2006**	2005	Change
Light / medium oil sales	**$ 600,061**	$ 366,432	64%
Heavy oil sales	**234,144**	197,863	18%
Natural gas sales	**238,367**	87,437	173%
Natural gas liquids sales and other	**48,003**	15,764	205%
Total sales revenue	**1,120,575**	667,496	68%
Realized risk management contract losses[1]	**(74,193)**	(79,271)	(6%)
Total revenues including realized risk management contract losses	**1,046,382**	588,225	78%
Realized gains on electric power price risk management contract	**11,574**	6,290	84%
Unrealized gains/(losses) on risk management contracts	**52,179**	(45,061)	(216%)
Net Revenues, before royalties	**1,110,135**	549,454	102%
Royalties	**(200,109)**	(113,002)	77%
Net Revenues	**$ 910,026**	$ 436,452	109%

(1) Includes amounts realized on WTI, heavy oil price differential and currency exchange contracts, and excludes amounts realized on electricity contracts and amounts realized on the series of swaps and forwards entered into with respect to the purchase of the refinery.

Our revenue is impacted by production volumes, commodity prices, and currency exchange rates. Light to medium oil sales revenue for the year ended December 31, 2006 was $233.6 million (or 64%) higher than for the prior year as a result of a $27.6 million favourable price variance due to the 6% increase in the Edmonton Par price and a $206.0 million favourable volume variance. The favourable volume variances over the prior year are primarily due to the acquisition of Viking (7,197 bbl/d) and Birchill (481 boe/d) in 2006 and the Hay River (3,420 bbl/d) property in the third quarter of 2005, as well as the focus of our drilling program which is focused on light to medium oil production.

Heavy oil sales revenue for the year ended December 31, 2006 increased $36.3 million (or 18%) compared to the same period in the prior year due to a favourable price variance of $34.0 million and a favourable volume variance of $2.3 million. The rising crude oil price environment, including the narrowing of heavy oil differentials, resulted in higher realized prices on our heavy oil. The volume variance is primarily attributed to the Viking assets and new wells drilled in Hayter and Suffield. These volume additions were partially offset by natural declines and higher water cuts in a portion of our heavy oil production.

Natural gas sales revenue increased by $150.9 million (or 173%) for the year ended December 31, 2006 over the prior year due to an unfavourable price variance of $80.7 million and a favourable volume variance of $231.6 million. Natural gas prices during the current year have been relatively weak compared to the prior year with the AECO daily price showing a 25% year over year reduction. The favourable volume variance is entirely attributed to the annualized incremental gas production of 65,955 mcf/d from the Viking properties and 6,799 mcf/d from the Birchill properties both acquired in 2006.

For the year ended December 31, 2006 natural gas liquid sales and other increased by $32.2 million (or 205%) compared to the year ended December 31, 2005. The increase is due to a $5.0 million favourable price variance and a $27.2 million favourable volume variance which is generally due to a higher pricing environment and additional production volumes from the Viking and Birchill properties.

Price Risk Management Contracts

Details of our price risk management contracts outstanding at December 31, 2006 are included in Note 18 of our audited consolidated financial statements for the year ended December 31, 2006 filed on SEDAR at www.sedar.com. The table below provides a summary of net gains and losses on risk management contracts:

	Year ended December 31					
	2006					2005
($000's)	Oil	Gas	Currency	Electricity	Total	Total
Realized (losses) / gains on price risk management contracts	$ (80,832)	$ 4,838	$ 1,801[1]	$ 11,574	$ (62,619)	$ (72,981)
Unrealized (losses) / gains on price risk management contracts	53,820	(662)	(5,309)	3,932	51,781	(36,081)
Amortization of deferred charges relating to risk management contracts	-	-	-	-	-	(10,759)
Amortization of deferred gains relating to risk management contracts	-	-	-	398	398	1,779
Total (losses) / gains on risk management contracts	$ (27,012)	$ 4,176	$ (3,508)	$ 15,904	$ (10,440)	$ (118,042)

(1) Excludes amounts realized on the series of US dollar forward purchase contracts entered into with respect to the purchase of North Atlantic.

Our total realized loss on oil and gas price and currency exchange risk management contracts was $74.2 million for the year ended December 31, 2006 compared to $79.3 million for the same period in 2005.

Our realized loss on oil price contracts for the year ended December 31, 2006 of $80.8 million was relatively unchanged from the $80.7 million realized in the prior year. In 2006, we had WTI price risk management contracts on approximately 25,000 bbl/d with downside protection at an average floor price of US $43.80 per bbl and 60% participation in prices over US $43.80 as compared to price risk management contracts that had fixed price caps in 2005. As compared to 2005, the average WTI price increased by US $9.68 to US $66.24 in 2006 but our participating price risk contracts limited our participation in prices over US$43.80 resulting in the losses on WTI oil price contracts, in U.S. dollars, being 9% higher than in the prior year. This increase in losses due to WTI pricing contracts in 2006 was offset by the strengthening of the Canadian dollar and to a lesser extent an increase in the realized gains from fixed price contracts for heavy oil price differentials.

Realized gains on our heavy oil differential contracts for the year ended December 31, 2006 totaled $6.8 million (or $0.31 per boe) compared to $3.9 million (or $0.29 per boe) in the prior year. During the first and fourth quarter of 2006 when heavy oil differentials averaged 42.0% and 30.3%, respectively, we realized gains on these contracts which were partially offset by losses during the second and third quarters of 2006 when heavy oil differentials averaged 22.9% and 25.8%, respectively. Our heavy oil differential contracts result in a contractual average differential from WTI of 28-29% for 2006 and 2005. For the year ended December 31, 2005, we only had heavy oil differential contracts in place from July 1, 2005 onwards.

In early 2006, we acquired Viking which significantly changed our production mix from 11% natural gas in the prior year to approximately 30% for the year ended December 31, 2006. In anticipation of soft natural gas prices in the summer of 2006, we entered into one natural gas price risk management contract for the period from April 2006 through March 2007 for 25,000 GJ/d with a floor price of $7.00 and a price cap of approximately $12.50 and another contract for the same period for 25,000 GJ/d with a floor price of $5.00 and a price cap of $13.55. We also entered into a contract for 5,000 GJ/d for the period from April 2006 through October 2006 with a floor price of $9.00 and a price cap of $13.06. The contracts with floor prices of $7.00 and $9.00 resulted in favourable settlements aggregating to a gain of $4.8 million in 2006. There were no natural gas price risk management contracts in place for 2005.

In 2006, we settled currency exchange rate contracts and accumulated a net gain of $1.8 million compared to $1.4 million in the prior year. The gain in 2006 is primarily the result of our participation in an oil sales contract which entitles us to elect on a monthly basis to accept settlement of the prior month's sales proceeds in US currency or to fix the currency exchange rate for a Canadian dollar settlement. In 2006, we also settled fixed rate currency exchange contracts on US $12.9 million at an average rate of $0.86 resulting in a nominal gain. For 2007, we have entered into contracts to fix the currency exchange rate on US $105.0 million at an average rate of approximately $0.89.

We have also entered into risk management contracts that provide protection from rising electric power prices. We realized gains on these contracts of $11.6 million (or $0.53 per boe) for the year ended December 31, 2006 and $6.3 million (or $0.47 per boe) for the prior year. Additional details on these contracts is provided under the heading "*Operating Expense*" of this MD&A.

The unrealized gains on our risk management contracts for the year ended December 31, 2006, excluding amortization of deferred gains, was $51.8 million compared to a loss of $36.1 million for the prior year. Collectively, our risk management contracts had an unrealized mark-to-market deficiency of $1.9 million as at December 31, 2006 compared to a mark-to-market deficiency of $52.6 million at December 31, 2005. Refer to Note 18 to the consolidated financial statements for the year ended December 31, 2006 filed on SEDAR at www.sedar.com for further details of the price risk management contracts outstanding at December 31, 2006.

Also included in our unrealized gains on risk management contracts is the amortization of the deferred charges and credits that were deferred when we ceased to apply hedge accounting principles. This represented a recovery of $398,000 for the year ended December 31, 2006 and $1.8 million for the year ended December 31, 2005. These amounts are discussed further under the heading "*Deferred Charges and Credits*".

Subsequent to December 31, 2006, we have entered into the following natural gas price risk management contracts:

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

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 year ended December 31, 2006, our net royalties as a percentage of gross revenue were 17.8% (16.9% - year ended December 31, 2005) and aggregated to $200.1 million ($113.0 million – year ended December 31, 2005). The increase in the royalty rate is due to the higher rates associated with the Viking assets acquired in February 2006 (royalty rates of approximately 18%) and the Hay River properties acquired in August 2005 (royalty rates of approximately 24-25%). In addition, effective April 1, 2005 a 3.6% surcharge was applied by the Saskatchewan government on gross resource revenues earned in Saskatchewan (2% for production from wells drilled subsequent to October 2002) which affects the first quarter of 2006 but not the first quarter in the prior year.

Operating Expense

	Year ended December 31				
($000's)	**2006**	**Per Boe**	2005	Per Boe	Per Boe Change
Operating expense					
Power	**$ 61,056**	**$ 2.80**	$ 39,452	$ 2.96	(5%)
Workovers	**51,151**	**2.34**	29,099	2.18	7%
Repairs and maintenance	**38,969**	**1.79**	17,316	1.30	38%
Labour – internal	**20,719**	**0.95**	7,631	0.57	67%
Processing fees	**15,311**	**0.70**	4,268	0.32	119%
Fuel	**7,442**	**0.34**	6,451	0.48	(29%)
Labour – external	**13,012**	**0.60**	5,917	0.44	36%
Land leases and property tax	**19,319**	**0.89**	11,998	0.90	(1%)
Other	**15,495**	**0.71**	4,726	0.35	103%
Total operating expense	**242,474**	**11.12**	126,858	9.50	17%
Realized gains on electric power price risk management contracts	**(11,574)**	**(0.53)**	(6,290)	(0.47)	13%
Net operating expense	**$ 230,900**	**$ 10.59**	$ 120,568	$ 9.03	17%
Transportation and marketing expense	**$ 12,142**	**$ 0.56**	$ 400	$ 0.03	1767%

Total operating expense increased by $115.6 million to $242.5 million for the year ended December 31, 2006 compared to the prior year. For the year ended December 31, 2006, approximately $90.6 million of the increase is due to increased activity associated with the Viking properties acquired in February 2006 and the remainder of the increase is attributed to Birchill acquisition in August 2006 and Hay River in August 2005 along with continued high demand for oilfield services leading to higher costs for well servicing, workovers, labour and well maintenance.

On a per barrel basis our operating costs have increased to $10.59 per boe, 17% over the prior year. In addition to the general upward cost pressures in the industry, the increase is partially attributed to higher processing fees as we have a greater proportion of non-operated properties in our portfolio as a result of the acquisition of Viking. We incur higher processing fees on non-operated properties as in most cases, although we own an interest in the well, we do not own an interest in the processing plant and we are charged a fee associated with processing.

Our operating expenses will benefit from our 2006 capital spending program, a portion of which was directed towards operating cost reduction initiatives such as the water disposal and fluid handling project in Suffield where we incurred approximately $13 million in capital expenditures to lower power costs to operate high water cut wells. These projects, combined with the acquisition of Birchill in August 2006 which has lower average operating costs per boe, will assist in offsetting the upwards cost pressures in the oil and gas services industry.

Our transportation costs of $12.1 million ($400,000 – year ended December 31, 2005) are primarily related to delivering natural gas to Alberta's natural gas sales hub, the AECO Storage Hub, and to a lesser extent, our costs of trucking crude oil to pipeline receipt points. The increase in our 2006 transportation costs over the prior year is substantially related to the incremental natural gas production with our acquisition of Viking and Birchill which added over 70,000 mcf/d of natural gas production. In addition we also 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. As to the $2.2 million of marketing costs included in our 2006 transportation and marketing expense, we have built an "in-house" marketing capability during the fourth quarter of 2006 and have concurrently terminated our agreement with the independent marketer.

Electricity costs represent approximately 25% of our total operating costs (approximately 31% for the year ended December 31, 2005). For the year ended December 31, 2006, electricity costs per megawatt hour ("MWh") were 14% higher than they were in the prior year. These increases were offset by the Viking properties which have lower electric power usage per boe of production and the Hay River properties, which operate using internally generated electric power. The combination of these two factors, as well as the impact of our fixed price electricity contracts, has resulted in a lower per boe electric power cost despite rising prices. The following table details the electric power costs per boe before and after the impact of our hedging program.

	Year ended December 31		
($ per boe)	**2006**	2005	Change
Electric power costs	**$ 2.80**	$ 2.96	(5%)
Realized gains on electricity risk management contracts	**(0.53)**	(0.47)	13%
Net electric power costs	**$ 2.27**	$ 2.49	(9%)
Alberta Power Pool electricity price ($ per MWh)	**$ 80.48**	$ 70.35	14%

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

Operating Netback

	Year ended December 31	
($ per boe)	**2006**	2005
Revenues	**$ 51.40**	$ 50.01
Realized loss on risk management contracts[1]	**(3.40)**	(5.94)
Royalties	**(9.18)**	(8.47)
Operating expense[2]	**(10.59)**	(9.03)
Transportation and marketing expense	**(0.56)**	(0.03)
Operating netback[3]	**$ 27.67**	$ 26.54

(1) Includes amounts realized on WTI, heavy price differential and foreign exchange contracts, and excludes amounts realized on electricity contracts and amounts realized on the series of swaps and forwards entered into with respect to the purchase of the refinery.

(2) Includes realized gain on electricity risk management contracts of $0.53 per boe and $0.47 per boe for the year ended December 31, 2006 and 2005.

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

Operating netback represents the total net realized price we receive for our production after direct costs. Our operating netback is $1.13 per boe higher for the year ended December 31, 2006 than for the prior year. Higher oil prices more than offset lower natural gas prices in 2006 compared to 2005 resulting in a higher realized price per boe by $1.39/boe, which was positively impacted by a further $2.54/boe due to lower losses realized, on a per boe basis, on our price risk management program. Gains in revenues were offset by higher royalties by $0.71/boe, higher operating costs of $1.56/boe, and higher transportation costs of $0.53/boe.

General and Administrative ("G&A") Expense

	Year ended December 31		
($000's except per boe)	**2006**	2005	Change
Cash G&A[(1)]	**$ 27,485**	$ 13,571	103%
Unit based compensation expense	**887**	17,126	(95%)
Total G&A	**$ 28,372**	$ 30,697	(8%)
Cash G&A per boe ($/boe)	**1.26**	1.02	24%
Transaction costs			
Unit based compensation expense	**8,974**	-	
Severance and other	**3,098**	-	
Total Transaction costs	**$ 12,072**	$ -	

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

For the year ended December 31, 2006, Cash G&A costs increased by $13.9 million (or 103%) compared to the same period in 2005 which is attributed mainly to increased staffing levels with our integration of the staff from our acquisition of Viking. Approximately $21.4 million (or 78%) of our year end Cash G&A expenses are related to salaries and other employee related costs while in the prior year only $8.5 million (or 62%) of our Cash G&A was made up of these costs. In addition to the rising costs for technically qualified staff, the acquisition of Viking in February 2006 doubled our overall staffing levels, adding approximately 100 additional employees. The remainder of the increases for the year ended December 31, 2006 compared to 2005, are due to the work undertaken for compliance with the Sarbanes Oxley Act, higher office rental costs required for the additional staff, increased travel costs related to the refinery acquisition and $600,000 of costs incurred for third party consultants used to evaluate acquisition opportunities that have subsequently been abandoned.

Our unit based compensation plans provide the employee with the option of settling outstanding awards with cash. As a result, our unit based compensation expense is determined using the intrinsic method 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 year ended December 31, 2006, was $9.9 million, of which $9.0 million was allocated to transaction costs and $0.9 million was allocated to G&A expense. A reversal of expenses is recognized in periods where our trust unit price decreases from the beginning of the period to the end of the period. Our opening trust unit market price was $37.19 at January 1, 2006 and at December 31, 2006 our trust unit price had decreased to $26.23. As a result, we have recorded a recovery of $8.1 million on unexercised UARs for the year ended December 31, 2006. Our total unit based compensation expense, including that portion which has been allocated to transaction costs, decreased by $7.3 million for the year ended December 31, 2006 compared to the prior year.

We have recorded transaction costs of $12.1 million which represent one time costs incurred as part of the acquisition of Viking. All of Harvest's outstanding UARs vested on February 3, 2006 in conjunction with the plan of arrangement and we have reflected $9.0 million as a result of the accelerated vesting of our units as a transaction cost. In addition, the remaining $3.1 million recorded as transaction costs are related to severance payments made to Harvest employees upon merging with Viking.

Depletion, Depreciation, Amortization and Accretion Expense

	Year ended December 31		
($000's except per boe)	**2006**	2005	Change
Depletion, depreciation and amortization	**$ 381,085**	$ 155,841	145%
Depletion of capitalized asset retirement costs	**16,950**	14,345	18%
Accretion on asset retirement obligation	**15,953**	8,770	82%
Total depletion, depreciation and accretion	**$ 413,998**	$ 178,956	131%
Per boe ($/boe)	**18.99**	13.41	42%

Our overall depletion, depreciation, amortization and accretion ("DDA&A") expense for the year ended December 31, 2006 is $235.0 million higher compared to 2005. Of this, $113.3 million is due to the incremental production from the Hay River acquisition made in the latter half of 2005 and the merger with Viking in early 2006 and the remaining $121.7 million of the increase is attributed to a higher depletion rate per boe as acquisitions have increased our overall corporate DDA&A rate due to their higher cost as compared to prior property acquisitions.

Capital Expenditures

	Year ended December 31	
($000's)	**2006**	2005
Land and undeveloped lease rentals	**$ 9,756**	$ 1,838
Geological and geophysical	**6,709**	285
Drilling and completion	**214,964**	80,170
Well equipment, pipelines and facilities	**124,518**	32,644
Capitalized G&A expenses	**13,141**	3,830
Furniture, leaseholds and office equipment	**7,793**	1,741
Development capital expenditures excluding acquisitions	**$ 376,881**	$ 120,508
Non-cash capital additions (recoveries)	**(553)**	3,275
Total development capital expenditures excluding acquisitions and non-cash items	**376,348**	123,783

In 2006 we invested $376.9 million into our portfolio of drilling, optimization and enhancement activities compared to $120.5 million in 2005. Approximately 57% of annual expenditures were spent on drilling 252 gross wells with a success rate of 98%, compared to 94 gross wells drilled in 2005 with a success rate of 95%. We continued to focus our drilling activity on oil opportunities as we expect the current strong oil pricing environment to continue. The WTI benchmark price for crude oil averaged US$66.24 in 2006 compared to US$56.56 in 2005.

The following summarizes Harvest's participation in gross and net wells drilled during 2006:

	Total Wells		Successful Wells		Abandoned Wells	
Area	Gross[1]	Net	Gross	Net	Gross	Net
South East Saskatchewan	37.0	36.8	37.0	36.8	-	-
Hay River	27.0	27.0	27.0	27.0	-	-
Markerville	26.0	11.5	26.0	12.1	-	-
Wainwright	14.0	14.0	14.0	14.0	-	-
Hayter	16.0	15.2	16.0	15.2	-	-
Suffield	16.0	16.0	16.0	16.0	-	-
Red Earth	19.0	16.8	19.0	16.8	-	-
Lloyd	12.0	12.0	12.0	12.0	-	-
Parkland	8.0	1.9	8.0	1.9	-	-
Red Deer	7.0	2.1	7.0	2.1	-	-
Other Areas	70.0	38.1	65.0	33.9	5.0	3.6
Total	252.0	191.4	247.0	187.8	5.0	3.6

(1) Excludes 23 additional wells that we have an overriding royalty interest in.

Our most active drilling area was southeast Saskatchewan where we drilled 37 gross horizontal and vertical wells during the year, accessing both infill potential on our existing pools, and previously untapped hydrocarbon deposits. A vertical stratigraphic test in the Kenosee area discovered a significant new oil pool, which we expect to begin exploiting with horizontal wells in early 2007. The majority of the 27 gross wells that were drilled at Hay River in 2006 were drilled in the first quarter to continue our development of this large Bluesky oil pool which we acquired in August 2005. Production at Hay River peaked at just over 7,300 boe/d in May of 2006 following the successful completion of our winter program. At Markerville, 26 gross wells were drilled in the year with 4 horizontal wells targeting liquids rich sweet natural gas in the Pekisko formation, and the remainder of the wells accessing natural gas in the shallow Edmonton sands formation. After confirming new hydrocarbon accumulations in the Slave Point formation, a total of 19 gross wells were drilled at Red Earth in 2006, including a new pool discovery. At Hayter, we continue to drill infill horizontal wells with a total of 16 gross wells drilled seeking to further increase the recovery factor from this large Dina heavy oil pool. Similarly at Suffield, we continue to find incremental oil from the Glauconitic formations with a total of 16 gross infill horizontal wells drilled.

The $124.5 million of well equipment, pipelines and facilities expenditures includes approximately $13 million for water handling upgrades at Suffield to increase total fluid handling capacity from this field, to improve the overall efficiency of our water separation and extraction processes, and to accommodate the recent and future year drilling programs. At Hay River we started the construction of an all season access road with an expenditure of $6.6 million. This will enable us to access our Hay River operations year round for well servicing and optimization activity. Prior to the initial construction of the access road, Hay River was a winter access only property. We also completed a tie-in of compression at our Ferrier project during the year for an expenditure of $5 million, and we were able to bring on approximately 400 boe/d at the end of August.

As a result of our 2006 drilling program we added 18.9 mmboe of proved plus probable reserves (prior to the conversion of previously booked undeveloped reserves) replacing approximately 87% of 2006 production and resulting in finding and development costs ("F&D") before changes in future development capital ("FDC") of $24.30 per boe on a proved plus probable basis and $26.04 per boe after FDC. This represents an increase of $13.57 per boe and $12.94 per boe over the prior year F&D costs of $10.73 per boe excluding FDC and $13.10 per boe including FDC, respectively. Finding Development and Acquisition ("FD&A") costs per boe on a proved plus probable basis for the year ended December 31, 2006 were $23.13 per boe before FDC and $24.59 per boe after FDC, compared to FD&A costs for 2005 before FDC of $11.78 per boe and $15.56 per boe including FDC costs. Our increased F&D costs are a result of the conversion of a larger percentage of previously booked undeveloped reserves in 2006 than in the prior year and also reflect general upward cost pressures in the industry, particularly related to the significant increase in demand for drilling rigs and the related costs to secure them which were incurred in 2006. In addition, 27% of our capital expenditures were directed towards projects that would not result in reserve additions but are included in our F&D costs for 2006, this includes $20 million of 2007 capital that was accelerated into 2006 for Hay River and Red Earth as we took advantage of favourable weather conditions in those areas.

Property Acquisitions and Divestitures

Cash property acquisitions (net of dispositions) year-to-date are $44.9 million including $38.0 million on heavy oil properties acquired in Saskatchewan in the fourth quarter, $18.4 million for an acquisition in the Hay River area, $3.5 million in the South Killarney area and $3.1 million in the Crossfield East area. These acquisitions were offset by the disposition of $13.3 million and $6.7 million in the Crossfield and Rainbow areas respectively, as well as other small acquisitions and dispositions. The dispositions allowed us to take advantage of an attractive market condition as we were able to sell these minor interests at a producing metric of approximately of $100,000 per boe/d. We also acquired a total of 70,200 net acres of undeveloped land during 2006 at an average price of $131/acre. Two major land parcels were acquired, including 27 sections (17,280 acres) of oilsands rights in Red Earth for total consideration of $2 million, and almost 13,000 acres of petroleum and natural gas rights at Red Earth for a total consideration of $1.5 million.

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 have recorded $656.2 million of goodwill related to our petroleum and natural gas segment compared with $43.8 million at December 31, 2005. In conjunction with our acquisition of Viking we recorded $612.4 million of goodwill. The goodwill balance is assessed annually for impairment or more frequently if events or changes in circumstances occur that would reasonably be expected to reduce the fair value of the acquired business to a level below its carrying amount.

Asset Retirement Obligation ("ARO")

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

Our asset retirement obligation increased by $91.8 million in the year ended December 31, 2006. As a result of the merger with Viking, we added $60.5 million to our ARO, and the remainder of the increase in the year to date is due to additions resulting from the acquisition of Birchill, drilling activity in the year, an increased estimate of existing liabilities, and accretion expense, offset by actual asset retirement expenditures made in the period.

REFINING AND MARKETING OPERATIONS

Financial and Operating Results

On October 19, 2006 Harvest completed its acquisition of all of the shares of North Atlantic Refining Limited ("North Atlantic") and related businesses and North Atlantic concurrently entered into a supply and off take agreement with Vitol Refining, S.A. (the "Supply and Offtake Agreement") (collectively, the "Acquisition").

The principal asset of North Atlantic is a medium gravity sour crude hydrocracking refinery with a 115,000 bbl/d capacity located in the Province of Newfoundland and Labrador (the "Refinery"), and a marketing division with 69 gas stations, a home heating business and a commercial and wholesale petroleum products business, all located in the Province of Newfoundland and Labrador. The Refinery is capable of processing a wide range of crude oils and feedstocks with a sulphur content as high as 3.5% and API gravity in the range of 25° to 40°, has approximately seven million barrels of tankage including six 575,000 barrel crude tanks and has a dock facility capable of handling vessels in excess of 330,000 dwt that carry up to 2 million barrels of crude oil which typically results in significantly lower per barrel transportation charges. The Refinery's feedstocks are primarily from the Middle East, Russia and Latin America. The Refinery's product slate is weighted towards high quality diesel fuel, jet fuel and gasoline that are currently compliant with product specifications (including sulphur, cetane and aromatic content) that are becoming increasingly restrictive and constraining supply. Approximately 10% of North Atlantic's refined products are sold in the Province of Newfoundland and Labrador while approximately 90% are sold in the U.S. east coast markets, primarily Boston and New York City. Through its marketing division, North Atlantic operates a petroleum marketing and distribution business in the Province of Newfoundland and Labrador with average daily sales over 11,000 barrels. The North Atlantic brand has been positioned in the Newfoundland marketplace as a local company with its retail gasoline business operating 66 retail gas stations and 3 cardlock locations capturing a market share of approximately 15% to 20%.

Concurrent with our acquisition of North Atlantic, North Atlantic entered into the Supply and Offtake Agreement with Vitol Refining S.A. The Supply and Offtake Agreement provides that the ownership of substantially all crude oil feedstock and refined product inventory at the Refinery be retained by Vitol Refining S.A. and that during the term of the Supply and Offtake Agreement, Vitol Refining S.A. will be granted the right and obligation to provide crude oil feedstock for delivery to the Refinery as well as the right and obligation to purchase all refined products produced by the refinery. The Supply and Offtake Agreement also provides that Vitol Refining S.A. will also receive a time value of money amount reflecting the cost of financing the crude oil feedstock and sale of refined products. Further, the Supply and Offtake Agreement provides North Atlantic with the opportunity to share the incremental profits and losses resulting from the sale of products beyond the U.S. east coast markets.

Effective with the closing of this acquisition on October 19, 2006, the operating results of North Atlantic are included in the operations of Harvest with segmented reporting for each of the petroleum and natural gas operations in western Canada and the refining and marketing business in the Province of Newfoundland and Labrador. The operating results of North Atlantic for the period from October 19, 2006 through December 31, 2006 reflect the impact of an extended turnaround that commenced October 1, 2006 with the Refinery returning to full operations near the end of November. While December's operations are more reflective of normal operations, North Atlantic did experience an unplanned disruption with its naptha hydrotreater due to a pipe rupture and additional downtime due to a disruption in electric power service from Newfoundland and Labrador Hydro which impacted December's throughput by approximately 3,000 bbl/d. The following table summarizes the North Atlantic financial and operational information for the period from October 19, 2006 to December 31, 2006:

(in 000's of Canadian dollars unless otherwise noted)	
Revenues	**460,359**
Purchased products for resale and processing	**386,014**
Gross Margin[1]	**74,345**
Costs and expenses	
Operating expense	**18,378**
Purchased energy expense	**15,685**
Marketing expense	**5,060**
Depreciation and amortization expense	**15,482**
Operating income[1]	**19,740**
Cash capital expenditures	**21,411**
Feedstock volume (bbl/day)[2]	**86,890**
Yield (000's barrels)	
Gasoline and related products	**1,875**
Ultra low sulphur diesel	**2,624**
Heavy fuel oil	**1,752**
Total	**6,251**

[1] These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.

[2] Barrels per stream day are calculated using total barrels of crude oil feedstock and Vacuum Gas Oil (VGO) divided by 73 days.

Refining Benchmark Prices

An oil refinery is a manufacturing facility that uses crude oil and other feedstocks as a raw material and produces a wide variety of refined products. The actual mix of refined products from a particular refinery varies according to the refinery's processing units, the specific refining process utilized and the nature of the crude oil feedstock. The refinery processing units generally perform one of three functions: the different types of hydrocarbons in crude oil are separated, the separated hydrocarbons are converted into more desirable or higher value products or chemicals treat the products to remove unwanted elements and components such as sulphur, nitrogen and metals. Refined products are typically differing grades of gasoline, diesel fuel, jet fuel, furnace oil and heavier fuel oil.

Similar to the petroleum and natural gas industry, the refining industry has a few benchmark prices from which to assess a particular refinery's performance. Typically, these benchmarks include prices for refined products such as Reformulated Blendstock for Oxygenate Blending gasoline ("RBOB gasoline") and heating oil. As a benchmark indicator of refining margins, The New York Mercantile Exchange ("NYMEX") "2-1-1 Crack Spread" is a refining benchmark calculated by assuming that the processing of two barrels of light sweet crude oil (defined as a WTI quality) produces one barrel of gasoline and one barrel of diesel into the New York market where product prices are set in relation to the NYMEX gasoline and NYMEX heating oil prices. The following table provides the average prices for the period from October 19, 2006 to December 31, 2006 for a few refining industry benchmark prices:

West Texas Intermediate crude oil (US$/barrel)	**60.44**
RBOB gasoline (US$/barrel)	**66.78**
Heating Oil (US$/barrel)	**71.82**
2-1-1 Crack (US$/barrel)	**8.86**
Canadian / U.S. dollar exchange rate	**0.883**

Although the "2-1-1 Crack Spread" is a reasonable benchmark, the North Atlantic refinery differs in that it produces a significant amount of heavy fuel oil relative to 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 VGO to optimize the throughput of its Isomax unit which is a key unit in the production of gasoline and diesel fuel and this further differentiates the North Atlantic refinery gross margin from the "2-1-1 Crack Spread" benchmark.

North Atlantic's Refinery Feedstock

During the period from October 19, 2006 to December 31, 2006, North Atlantic's crude oil feedstocks were as follows:

(in 000's of Canadian dollars unless noted)	Cost of Goods Sold	Volume (in 000's bbls)	US$/barrel
Basrah	305,396	5,372	50.21
Hamaca	28,826	524	48.59
Total Crude Feedstock	334,222	5,896	50.07
Vacuum Gas Oil purchased	26,645	446	52.77
Total Feedstock/Throughput	360,867	6,342	50.26
Other additives	6,834		
Total of Feedstock and Other Additives	367,701		

During the period from October 19, 2006 to December 31, 2006, the Refinery feedstock was comprised of 80,767 bbl/d of crude oil, approximately 91% Basrah (a medium sour crude) from Iraq in the Middle East and 9% Hamaca crude from Venezuela in South America, and 6,100 bbl/d of VGO with prices per barrel, including all costs of transporting to the North Atlantic site, of approximately US$50.07 and US$52.77, respectively. Relative to the average price of the WTI benchmark, the medium gravity sour crude purchased by North Atlantic represents a US$10.37 per barrel price differential on feedstock.

North Atlantic's Refined Products

Product yields are impacted by the crude oil feedstock as well as refinery performance and with its feedstock being primarily Basrah for the period from October 19, 2006 to December 31, 2006, North Atlantic anticipated a refined product yield of approximately 31% gasoline, 41% ultra low sulphur diesel and jet fuel and 27% heavy fuel oil. North Atlantic's actual yields for this period were as follows:

(in 000's of Canadian dollars unless noted)	Refinery Revenues	Volume (in 000's bbls)	US$ per bbl/US$ per gal
Gasoline and related products	131,643	1,875	62.01/1.48
Ultra low sulphur diesel and jet fuel	216,435	2,624	72.85/1.73
Heavy fuel oil	78,969	1,752	39.81/0.95
	427,047	6,251	
Other	7,617		
Total refined products	434,664		
Total Yield (as a % of feedstock)	99%		

For the period from October 19, 2006 to December 31, 2006, North Atlantic's actual yields were as expected with 1% more heavy fuel oil and 1% less gasoline. Relative to the benchmark prices, North Atlantic received US$62.01 per bbl (US$1.48 per gallon) for its gasoline as compared to US$1.59 per gallon for NYMEX RBOB gasoline and US$72.85 (US$1.73 per gallon) for its ultra low sulphur diesel and jet fuel products compared to US$1.71 for NYMEX heating oil. The gasoline price is slightly less than the NYMEX reference price due to shipping costs to New York harbour. The US$0.02 per gallon premium over the NYMEX heating oil price reflects the higher product quality of North Atlantic's diesel fuel and jet fuel less shipping costs to New York harbour.

The value of the heavy fuel oil produced by North Atlantic will fluctuate over the longer term as "bottoms upgrading" projects come online reducing the supply of heavy fuel oil while shipping companies and electric utilities continue to burn high and low sulphur heavy fuel oil. Relative to the average price North Atlantic paid for its Basrah feedstock, the selling price for its heavy fuel oil results in a negative contribution to North Atlantic of US$10.40 per barrel. The amount of heavy fuel oil produced by North Atlantic presents an opportunity to change its refinery configuration to produce more gasoline and diesel by upgrading its heavy fuel oil.

North Atlantic's 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. For the period from October 19, 2006 to December 31, 2006, contribution from the refinery and marketing operations were as follows:

(in 000's of Canadian dollars unless noted)	Refinery Operations	Marketing Operations	North Atlantic [(1)]
Sales revenue	434,665	68,099	460,359
Cost of products for processing and resale	367,701	60,718	386,014
Gross margin[(2)]	66,964	7,381	74,345

(1) The North Atlantic sales revenue and cost of products for processing and resale are net of inter-segment sales of $42,405 reflecting the refined products produced by the Refinery Operations and sold by the Marketing Operations.

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

North Atlantic's crack spread is comprised of the following: $83.7 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 $47.4million) and 9.7 million on the production of gasoline and ultra low sulphur diesel and jet fuel from purchased VGO offset by a $26.4 million negative contribution from the production of heavy fuel oil and other refined products. Overall, relative to the industry "2-1-1 Crack Spread" benchmark of US$8.86 during the period, North Atlantic's crack spread averaged US$9.32 per barrel of throughput.

The $7.4 million of gross margin from the Marketing Operations is composed of the margin from the both retail and wholesale distribution of gasoline, home heating fuels and related appliances as well as the revenues from marine services including tugboat revenues.

Operating Expenses

For the period from October 19, 2006 to December 31, 2006, North Atlantic's operating costs were as follows:

(in 000's of Canadian dollars unless noted)		$/bbl
Operating expense	18,378	2.90
Purchased energy expense	15,685	2.47
Total	34,063	5.37
Marketing expense	5,060	0.80

The largest component of operating expense is wages and benefits which totaled $11.2 million (approximately 61% of operating expense) while the other significant components were maintenance and repairs costs ($2.1 million), insurance ($1.4 million) and chemicals ($0.9 million). The wages and benefits and maintenance costs are higher than normal due to the electrical power outage in December while the unplanned shutdown on the naptha hydrotreater unit during November and December resulted in a greater than normal amount of chemicals used in the operations. Other operating expenses are in line with expectations. Overall operating expenses were $2.90 per barrel during the period as compared to our expectations during a normal operations period of approximately $2.20 to $2.40 per barrel.

Purchased energy is required to provide heat and to operate the refinery which consists of purchased low sulphur fuel oil and electric power, respectively. During the period from October 19, 2006 to December 31, 2006, our energy usage was higher than expected due to the power failure and the energy consumption during the subsequent unit start-up following both the planned and unplanned maintenance. Our energy costs were $2.47 per barrel for the period, however, during a normal operating period, we would expect our purchased energy cost to be on average less than $2.20.

Marketing expense is comprised of $0.5 million of marketing fees (US $0.08 per barrel of feedstock) to acquire feedstock and $4.6 million of "*Time Value of Money*" incurred pursuant to the supply and offtake agreement entered into with Vitol Refining S.A.

Capital Expenditures

During the period from October 19, 2006 to December 31, 2006, capital spending totaled $21.4 million with $5.8 million incurred for the replacement of Heater 1501 convection section, $4.6 million for ongoing tank recertification and $4.4 million to complete the naphtha hydrotreater platformer turnaround. There was also $1.7 million spent to complete the construction of a new truck loading facility.

Depreciation and Amortization Expense

(in 000's of Canadian dollars)	2006
Tangible assets	14,243
Intangible assets	1,239
Total	15,482

The process units are amortized over an average useful life of 20-30 years. The intangible assets consist of engineering drawings, customer lists and fuel supply contracts which are being 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 the refinery 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.

FINANCING AND OTHER

Interest Expense

	Year ended December 31		
($000's except per boe)	**2006**	2005	Change
Interest on short term debt	**$ 1,489**	$ 4,089	(64%)
Amortization on deferred charges – short term debt	**3,375**	2,498	35%
Total interest on short term debt	**4,864**	6,587	(26%)
Interest on long-term debt			
Senior notes	**22,624**	23,952	(6%)
Convertible debentures	**20,229**	2,865	606%
Bank loan	**30,967**	651	4657%
Amortization of deferred charges – long term debt	**5,073**	2,356	115%
Total interest on long term debt	**78,893**	29,824	165%
Total interest expense	**$ 83,757**	$ 36,411	130%

Interest expense, which includes the charges on outstanding bank debt, convertible debentures and senior notes as well as the amortization of related financing costs, was $47.3 million higher for the year ended December 31, 2006 than the prior year. Of this increase, $27.7 million is due to increases in short term and long term bank loan interest from the significant increase in the amounts drawn on our credit facilities resulting from the assumption of approximately $106.2 million of bank debt in the acquisition of Viking and incremental borrowings to finance the acquisition of Birchill and North Atlantic.

On February 3, 2006 we entered into a new credit agreement that established a Three Year Extendible Revolving Credit Facility that increased our borrowing capacity to $900 million with interest calculated using a floating rate based on banker's acceptances plus 65 to 115 basis points based on our Senior Debt to Cash Flow ratio as defined in the credit agreement. On October 19, 2006, and concurrent with our acquisition of North Atlantic, this facility was amended and restated to increase our Three Year Extendible Revolving Credit Facility from $900 million to $1.4 billion, and we established a $350 million Senior Secured Bridge Facility. At the same time we established a $450 million Senior Unsecured Bridge Facility. The terms and conditions of the Three Year Extendible Revolving Credit Facility remained unchanged except for changes to the security pledged and the addition of a 15 basis point fee applicable so long as the $450 million Senior Unsecured Bridge Facility was outstanding. The amounts borrowed under the $450 million Senior Unsecured Bridge Facility bear interest at a floating rate based on bankers' acceptances plus a range of 230 to 280 basis points depending on Harvest's financial ratios. Further details on the expanded credit facility and the bridge financing are included under "*Liquidity and Capital Resources*".

The $17.4 million increase in convertible debenture interest is due to the additional convertible debentures outstanding in the second half of 2005 and outstanding for the full year in 2006, the convertible debentures assumed with our acquisition of Viking and the convertible debentures issued in November 2006 partially offset by conversions of convertible debentures to trust units occurring during the year. A full year of interest expense was incurred on approximately $37.9 million of the remaining balance of the $75 million 6.5% convertible debentures that were issued by Harvest in the third quarter of 2005. Approximately $202.2 million of additional convertible debentures were assumed with the merger with Viking and approximately $379.5 million of additional convertible debentures were issued in November. Although holders of the 9%, 8%, 6.5%, 10.5% and 6.40% convertible debenture series have converted $14.3 million of the convertible debentures into 546,086 trust units, the associated reduction in interest expense is not sufficient to offset the additional interest associated with the more recently issued or assumed convertible debentures. Interest on the convertible debentures is reported based on the effective yield of the debt component of the convertible debentures.

Our U.S. dollar denominated 7 7/8 Senior Notes, which bear interest at 7 7/8%, mature on October 15, 2011 and have an early redemption feature. Interest expense for the year ended December 31, 2006 on these notes has remained relatively consistent with the same period in 2005, with any fluctuations attributed to volatility in the Canadian dollar to U.S. dollar exchange rate.

Included in 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 $8.4 million for the year ended December 31, 2006. This $3.5 million increase from the $4.9 million expensed in 2005 is due mainly to the increased bank borrowings throughout the year in 2006 as well as the increase in convertible debentures outstanding.

Non-Controlling Interest

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

Under the plan of arrangement with Viking, exchangeable shareholders were able to convert their exchangeable shares of Harvest Operations into trust units. As a result 156,067 exchangeable shares were converted from January 1, 2006 to June 19, 2006, leaving a balance of 26,902 outstanding at June 19, 2006 compared to a balance of 182,969 at December 31, 2005.

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

The net income attributed to non-controlling interest holders for the year ended December 31, 2006 was a gain of $65,000 compared to an expense of $149,000 for the year ended December 31, 2005.

Currency Exchange Loss

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 deposits and cash balances. At December 31, 2006, the Canadian dollar weakened slightly as compared to the U.S. dollar at December 31, 2005, as a result we incurred an unrealized loss on our senior notes of $600,000. In connection with the purchase of the refinery, we incurred U.S. denominated LIBOR bank loans, which contributed $23.4 million to the unrealized foreign exchange losses for the year ended December 31, 2006. In addition, we also incurred $1.0 million of unrealized foreign exchange gains on transactions incurred by the refinery and realized losses of $371,000. The refinery is considered a self-sustaining operation with a U.S. dollar functional currency. The foreign exchange gains incurred in the refinery relate to Canadian dollar transactions converted to U.S. dollars as their functional currency is U.S. dollars. Unrealized foreign exchange losses were partially offset by realized gains of $3.2 million attributed to gains on the initial deposit of US$100 million for the purchase of North Atlantic and U.S. dominated cash and working capital.

Future Income Tax

On October 31, 2006, the Canadian government announced plans to introduce a tax on publicly traded income trusts. For existing income trusts, the new tax measures would be effective for 2011, provided we comply with the "normal growth" parameters regarding equity growth until that time. A "*Notice of Ways and Means Motion*" was passed in Parliament shortly after the government announcement. This notice was a summary of the government's proposal and did not specify the particular amendments to the Income Tax Act.

On December 15, 2006, the government announced safe harbour guidance regarding "normal growth" for equity capital. The safe harbour amount will be measured by reference to the individual trust's market capitalization as of the end of trading on October 31, 2006 (which was approximately $3.7 billion for Harvest). For the period from November 1, 2006 to December 31, 2007 a trust's safe harbour amount will be 40% of the October 31, 2006 market capitalization benchmark and for each of the years 2008 through and including 2010 will be 20% of the benchmark, cumulatively allowing growth of up to 100% until 2011. In addition, we understand that trusts will be able to issue equity to retire debt existing on October 31, 2006 without eroding their safe harbour limits.

On December 21, 2006, the government released more detailed draft legislation with respect to the proposed amendments to the Income Tax Act and requested comments from stakeholders. In late January 2007, the House of Commons Standing Committee on Finance held special hearings on the proposed tax and the draft legislation. At this time we are unable to determine the impact, if any, these hearings may have on the proposed legislation or the timing of when the proposed legislation could be passed in Parliament.

Should the tax legislation become substantially enacted, future income taxes may be adjusted to include temporary difference between the accounting and tax bases of the Trust's assets and liabilities. In addition, reserves reported under NI 51-101 may be adjusted to include an estimate of the tax effect on our estimated future revenues from our reserves. We will assess alternative organizational structures during the four-year transition period, however, we are confident that regardless of the final tax legislation or our structure we will continue to provide value to our unitholders.

During 2006, we have integrated Viking and Birchill into the Harvest organization in such a fashion that much of the value of these acquisitions is attributed to the net profits interests on the respective petroleum and natural gas properties created subsequent to their acquisition. The value of the net profits interest resides within the Trust while the tax basis associated with these acquisitions is retained by our corporate entities. The net result of this approach to integration for income tax purposes is that the book basis and the tax basis of our petroleum and natural gas assets held in corporate entities are approximately equal resulting in no recorded future income taxes beyond the recovery of $2.3 million in the current year. The significant recovery of $32.4 million for the year ended December 21, 2005 is related to net losses for income tax purposes recorded in corporate subsidiaries.

Risk Management Contracts

In connection with the acquisition of the North Atlantic we entered into a series of U.S. dollar forward purchase contracts to protect a portion of the U.S. dollar denominated purchase price from currency exchange rate fluctuations. We realized a gain on these contracts of $17.8 million. No similar arrangements were entered into in 2005. Our total realized loss on price risk management contracts, including those incurred by our petroleum and natural gas operations, are $44.8 million consisting of $76.0 million losses on commodity price risk contracts, $19.6 million gains on currency exchange contracts and $11.6 million gains on electric power fixed price contracts.

Deferred Charges and Other Non-Current Assets

The deferred charges and other non-current assets balance on the balance sheet is comprised of four main components: deferred financing charges, discount on senior notes, long-term leases and for 2005, deferred charges related to the discontinuation of hedge accounting principles. The deferred financing charges relating to the issuance of the senior notes, convertible debentures and bank debt are amortized over the life of the corresponding debt. Other non-current assets include the long-term leases of $3.0 million (net of the current portion of $1.4 million), which are related to vehicles provided to the distributors of refined products for the local Newfoundland and Labrador market. These leases are provided under direct financing leases with the majority having terms of 2-5 years. The following table provides a summary of the components of the deferred charges, excluding other non-current assets, at December 31, 2006 as compared to 2005.

($000's)	Financing Costs	Discount on Senior Notes	Discontinuation of Hedge Accounting	Total
Balance, January 1, 2005	**$ 12,781**	**$ 2,000**	**$ 10,759**	**$ 25,540**
Additions	5,207	-	-	5,207
Transferred to Unit issue costs on conversion of debentures	(2,071)	-	-	(2,071)
Amortization	(4,853)	(296)	(10,759)	(15,908)
Balance, December 31, 2005	**$ 11,064**	**$ 1,704**	**$ -**	**$ 12,768**
Additions	28,830	-	-	28,830
Transferred to Unit issue costs on conversion of debentures	(193)	-	-	(193)
Amortization	(8,432)	(296)	-	(8,728)
Balance, December 31, 2006	**$ 31,269**	**$ 1,408**	**$ -**	**$ 32,677**

Additions to deferred financing costs relate to execution of our new credit agreements and costs relating to the issue of our convertible debentures during the year.

At December 31, 2006 our deferred credit balance was $794,000 ($398,000 at December 31, 2005) all of which relates to leasehold improvement costs incurred by us and reimbursed by the landlord. The credit is amortized over the lease term as a reduction of rent expense.

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 ($000's)	**Total**	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt	**1,887,013**	-	1,595,663	291,350	-
Interest on long-term debt[4]	**299,649**	112,037	146,565	41,047	-
Interest on convertible debentures[3]	**264,499**	44,247	83,023	79,853	57,376
Operating and premise leases	**19,990**	6,476	10,845	2,411	258
Capital commitments[5]	**37,410**	34,530	2,880	-	-
Asset retirement obligations[6]	**686,915**	12,748	13,058	13,321	647,788
Transportation [7]	**4,738**	2,080	2,441	217	-
Purchase commitments	**8,215**	8,215	-	-	-
Pension contributions	**28,077**	780	3,345	4,805	19,147
Feedstock commitment	**550,230**	550,230	-	-	-
Total	**3,786,736**	771,343	1,857,820	433,004	724,569

(1) As at December 31, 2006, we had entered into physical and financial contracts for production with average deliveries of approximately 27,480 barrels of oil equivalent per day for 2007, and 5,000 barrels of oil equivalent per day in 2008. We have also entered into financial contracts to minimize our exposure to fluctuating electricity prices. Please see Note 18 to the consolidated financial statements for further details.

(2) Assumes that the outstanding convertible debentures either convert at the holders' option or are redeemed for Units at our option.

(3) Assumes no conversions and redemption by Harvest for trust units at the end of the second redemption period. Only cash commitments are presented.

(4) Assumes constant foreign exchange rate.

(5) Relates to drilling commitments.

(6) Represents the undiscounted obligation by period.

(7) Relates to firm transportation commitment on the Nova pipeline.

Off Balance Sheet Arrangements

We also 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.

LIQUIDITY AND CAPITAL RESOURCES

At the end of December 2006, we had total debt and equity capital of $5,556.2 million compared to $1,099.0 million at the end of the prior year. As presented in the following table, the substantial portion of this $4,457.2 million increase is comprised of:

- $1,581.8 million additional bank debt related to the acquisition of Birchill and North Atlantic,
- The assumption of $202.2 million principal amount of Convertible Unsecured Subordinated Debentures and issuance of 46,040,788 trust units at an ascribed value of $1,638.1 million relating to the acquisition of Viking,
- The issuance of 7,026,500 trust units with net proceeds of $218.6 million in connection with the Birchill acquisition and a further 9,499,000 trust units for net proceeds of $610.2 million to refinance the North Atlantic acquisition, and
- The issuance of 5,464,917 trust units pursuant to Harvest's Premium Distribution™, Distribution Reinvestment and Optional trust unit Purchase Plan (the "DRIP Plans") raising $167.6 million.

	As At December 31	
(in millions $)	**2006**	2005
DEBT		
Credit Facilities		
- Three Year Extendible Revolving Credit Facility	**$ 1,306.0**	$ -
- Senior Secured Credit Facility	**289.7**	-
- 364 day Extendible Revolving Credit Facility	-	13.9
Total Bank Debt	**1,595.7**	13.9
7 7/8% Senior Notes due 2011 (US$250 million)	**291.4**	290.8
Convertible Debentures, at principal amount		
10.5% Debentures Due 2008	**26.6**	-
9% Debentures Due 2009	**1.2**	1.8
8% Debentures Due 2009	**2.2**	3.8
6.5% Debentures Due 2010	**37.9**	41.4
6.4% Debentures Due 2012	**174.8**	-
7.25% Debentures Due 2013	**379.5**	-
Total Convertible Debentures	**622.2**	47.0
Total Debt	**2,509.3**	351.7
TRUST UNITS		
122,096,172 issued at end of 2006	**3,046.9**	
52,982,567 issued at end of 2005		747.3
TOTAL OF DEBT AND TRUST UNITS	**$ 5,556.2**	$ 1,099.0

Our approach to managing our capital resources is comprised of three objectives: (1) to fund distributions to unitholders and the internal development of our assets from annual Cash Flow; (2) to maintain a sufficient balance sheet strength to continue development activities and acquiring petroleum and natural gas assets to replace production and add reserves; and (3) to permanently fund significant acquisitions with some combination of term debt and equity, such that acquisitions further strengthen our balance sheet capability.

For the year ended December 2006, our Cash Flow totaled $545.2 million ($551.7 million after excluding $6.5 million of one time cash transaction costs relating to the acquisition of Viking) compared to $309.8 million in the prior year. In 2006, we paid distributions to unitholders aggregating to $440.9 million, with $167.5 million reinvested through our DRIP Plans, with $273.4 million remaining to fund our combined $398.3 million capital program. This compares with distributions paid to Unitholders totaling $143.2 million (excluding the $10.7 million special distribution settled with the issue of trust units), with $36.2 million reinvested through the DRIP plans, resulting in $107.0 million to fund $120.5 million of capital spending.

Management, together with the Board of Harvest continually assess distributions relative to cash flow projections, debt leverage and capital spending plans. Distributions declared for 2006 totaled $468.8 million representing 85% of Cash Flow excluding $6.5 million of one time cash transaction costs. Of the distributions declared, $175.8 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 38%. On January 10, 2007, we announced the declaration of a $0.38 per trust unit distribution for each of January, February and March 2007 based on forecasted commodity price levels and operating performance that are consistent with the current environment.

Concurrent with the closing to the arrangement with Viking, we entered into a credit agreement establishing a $750 million Three Year Extendible Revolving Credit Facility with improved borrowing margins and more flexible covenant-based terms.

On March 31, 2006, this credit agreement was syndicated to a group of thirteen lenders and expanded to $900 million. This bank facility carries 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
Senior debt to capitalization	50% or less
Total debt to capitalization	55% or less

With the consent of the lenders, this facility may be extended on an annual basis for an additional 364 days.

On August 15, 2006, we closed the acquisition of Birchill for cash consideration of $446.8 million and funded this acquisition with the $218.6 million of net proceeds from an issuance of 7,026,500 trust units and $228.2 million of incremental bank borrowings. The results of operations from this acquisition have been included in our consolidated results commencing July 26, 2006, the date of the definitive agreement.

On August 22, 2006, we entered into a purchase and sale agreement to acquire North Atlantic Refining Limited for a total cash consideration of US$1,385 million and provided the vendors with a US$100 million escrowed deposit and on October 19, 2006, closed the transaction. To fund this acquisition, we entered into credit agreements upsizing our Three Year Extendible Revolving Credit Facility to $1.4 billion as well as establishing a $350 million Senior Secured Bridge Facility and a $450 million Senior Unsecured Bridge Facility concurrent with the signing of the purchase and sale agreement. For a complete description of these credit agreements, see Note 10 to our audited consolidated financial statements for the year ended December 31, 2006 filed on SEDAR at www.sedar.com. On August 25, 2006, we entered into contracts to forward purchase US$750 million at a fixed rate of $1.10832 (or $0.9023) to be delivered on October 2, 2006, the then expected closing date of the North Atlantic acquisition. As events unfolded, these forward purchase commitments were rolled forward to October 19, 2006, the ultimate closing date. The intention of these forward purchase contracts was to fix the Canadian dollars required to fund US$750 million of the purchase price at approximately $830 million with the residual US$635 million to be financed with US dollar borrowings. The $830 million represented the expected refinancing from future public equity issuances to be raised in Canadian dollars.

Concurrent with the closing of the North Atlantic acquisition, North Atlantic entered into a Supply and Offtake Agreement with Vitol Refining S.A., a third party related to the vendor of North Atlantic. The Supply and Offtake Agreement provides that ownership of substantially all of the crude oil feedstock and refined product inventory at the Refinery be retained by Vitol Refining S.A. and that during the term of the Supply and Offtake Agreement, Vitol Refining S.A. will be granted the right and obligation to provide crude oil feedstock for delivery to the Refinery as well as the right and obligation to purchase all refined products produced by the Refinery. 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,
- arranging for the delivery of crude oil feedstock to the Refinery,
- to pay for crude oil feedstock purchases in-transit to the Refinery,
- to provide working capital for:
    - crude oil feedstock inventories sufficient for stable Refinery operations,
    - refined product inventories prior to shipping to market,
    - receivables related to the sale of refined products, and
- arranging for the delivery of refined products to customers.

The Supply and Offtake Agreement significantly reduces the working capital requirements of North Atlantic as the vessels delivering the crude oil feedstock may carry in excess of 2 million barrels (value approximately - $120 million) and the inventories of refined products and crude oil feedstock at any time may be substantial (currently approximately valued at $400 million). In respect of this working capital requirement assumed by Vitol Refining S.A., 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 termination of the Supply and Offtake Agreement requires that we develop the financial flexibility to provide the working capital requirements currently funded by Vitol Refining S.A. as well as either develop the internal capability to provide these supply services for the Refinery or negotiate a similar contract with another provider of such services. At the end of December 31, 2006 we estimate that the outstanding commitments under the Supply and Offtake Agreement aggregated to approximately $550.2 million.

On October 25, 2006, we entered into an agreement with a syndicate of underwriters to issue a $400 million principal amount of 6.30% convertible unsecured subordinated debentures (convertible at $38.50 per trust unit) and 3,150,000 trust units (to be issued at $31.75 per trust unit) for net proceeds, before election of the underwriters' Over-Allotment Option, of approximately $479 million and on October 31, 2006, filed the preliminary short form prospectus supporting this issuance. Also on that day, the Minister of Finance of the Government of Canada proposed to apply a 31.5% tax at the mutual fund trust level on distributions from certain publicly traded mutual funds which definition includes Harvest Energy Trust and to treat such distributions as dividends to the unitholders (the "October 31, 2006 Proposal"). The announcement of the October 31, 2006 Proposal triggered a termination clause in our agreement with the syndicate of underwriters as the proposed change in income tax laws had a significant material adverse effect on the market price of Harvest's trust units. On October 31, 2006, the Harvest trust units traded between $33.06 and $32.39 closing at $32.95 and on November 1, 2006, traded between $29.90 and $26.80 closing at $28.60 with subsequent days trading trending stabilizing in the $26 to $27 range representing a drop of 18% in trading price.

On November 9, 2006, we amended the terms of our agreement with the syndicate of underwriters to an issuance of $330 million principal amount of 7.25% convertible unsecured subordinated debentures and 8,260,000 trust units for net proceeds, before election of the underwriters' Over-Allotment Option, of approximately $530 million. On November 22, 2006, this offering closed with $379.5 million principal amount of 7.25% convertible unsecured subordinated debentures (convertible at $32.20 per trust unit) and 9,499,000 trust units (issued at $27.25 per trust unit), which included the underwriters' election to fully exercise their Over-Allotment Option, for net proceeds of $610.2 million. The impact of the October 31, 2006 Proposal was a $4.50 reduction in the issue price for the trust units and an increase of 0.95% interest rate on the convertible unsecured subordinated debentures as well as a reduction of $6.30 per trust unit in the conversion feature. The net proceeds from this offering were used to fully repay the $450 million of Senior Unsecured Bridge Facility, repay $60.3 million of the Senior Secured Bridge Facility and reduce the drawn portion of its Three Year Extendible Revolving Credit Facility by $99.9 million.

On November 20, 2006, we amended the credit agreement with our lenders to enable the first $100 million of net proceeds on November 22, 2006 to be retained for general corporate purposes to improve our liquidity.

At the end of December 31, 2006, our Bank Debt to Cash Flow ratio was 2.9 to1.0, Total Debt (excluding convertible debentures) to Cash Flow was 3.5 to 1.0 while the Bank Debt to Total Capitalization was 31% and Total Debt to Total Capitalization was 37%.

Subsequent to the end of 2006, we issued 6,146,750 trust units and $230 million principal amount of 7.25% Debenture Due 2014 for net proceeds of $357.4 million. After applying $289.7 million of these proceeds to fully repay the remaining balance outstanding on the $350 million Senior Unsecured Bridge Facility, the residual $67.7 million of proceeds was applied to the $1.4 billion Three Year Extendible Revolving Facility increasing our undrawn credit capacity to approximately $167.1 million

On a pro forma basis reflecting this issuance of $230 million principal amount of 7.25% Debentures Due 2013 and 6,146,750 trust units for net proceeds of $357.4 million, our Bank Debt to Cash Flow ratio would be 2.3 to 1.0 while the Total Debt (excluding convertible debentures) to Total Capitalization would be 30%.

In 2007, we plan to extend the maturity date of this credit facility from March 2009 to March 2010 and may consider the issue of additional term debt to replenish the capacity of our term facility.

Disclosure of Outstanding Trust Unit Data

We are authorized to issue an unlimited number of trust units. As at March 12, 2007, we had 129,470,352 number of trust units outstanding, 3,800,675 of Unit Appreciation Rights outstanding (of which 538,550 are exercisable) and 274,384 number of awards issued under the Unit Awards Incentive Plan (of which 93,945 were excercisable). In addition we had seven series of convertible debentures outstanding that are convertible into 26,382,215 trust units.

Distributions to Unitholders and Taxability

In the year ended December 31, 2006, we declared distributions of $4.53 per trust unit ($468.8 million) to Unitholders. This represents a 42% increase in distributions declared over the $3.20 per trust unit declared in 2005. The aggregate distributions declared during 2006 of $468.8 million reflects an increase in distributions on a per-trust unit basis over 2005 as well as an increase in the number of trust units outstanding of 69,113,605 trust units to 122,096,172 following the acquisition of North Atlantic Refining, Viking and Birchill and continued DRIP participation.

	Year end December 31		
($000's except per trust unit amounts)	**2006**	2005	Change
Distributions declared	**$ 468,787**	$ 153,494	205%
Per trust unit	**$ 4.53**	$ 3.20	42%
Taxability of distributions (%)	**100%**	100%	-
Per trust unit	**$ 4.53**	$ 3.20	42%
Payout ratio (%)[1]	**85%**	50%	35%

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

The Trust is subject to tax on its taxable income less the portion that is paid or payable to the Unitholders at the end of each taxation year. As such, we expect that the current year distributions to our Unitholders will be 100% taxable.

OUTLOOK

Unitholders should benefit from the addition of the North Atlantic refining and marketing business to our petroleum and natural gas operations in western Canada with distributions funded by a more diversified cash flow. Refining is primarily a margin business where the crude oil feedstocks and refined products are both commodities which react to differing regional supply/demand and transportation pressures. Accordingly, refining margins should not be as sensitive to changes in commodity prices as our petroleum and natural gas operations, however, the demand for refined products is also a contributor to the general level of global crude oil prices. We anticipate that increases in heavy oil price differentials will have a favourable impact on our refining margins while the price realizations of our petroleum and natural gas operations in western Canada will suffer: this internal and offsetting impact should result in a more stable Cash Flow.

The following summarizes our 2007 guidance relative to its 2006 performance. There is no attempt to forecast commodity prices and accordingly do not forecast Cash Flow or the level of cash distributions. This 2007 guidance includes the modest impact of our acquisition of Reveal Resources Ltd. for $29.9 million of cash consideration. Reveal's production consists of approximately 1,600 boe/d of primarily heavy oil in west central Saskatchewan.

	2007 Forecast	2006
Petroleum and Natural Gas Operations		
Average Production in boe/d	**66,000**	59,729
Operating Costs in $/boe	**$ 10.70**	$ 10.59
Average Royalty Rate	**19%**	18%
Production mix		
Light/medium oil in bbls/d	**28,000**	27,482
Heavy oil in bbls/d	**16,800**	13,904
Natural gas in mcf/d	**112,000**	96,578
Natural gas liquids in bbls/d	**2,700**	2,247
Capital expenditures (in millions)[1]	**$ 295**	$ 377
Refining and Marketing		
Throughput in bbls/d	**116,100**	n/a
Operating costs in $/bbl, including purchased energy	**$ 4.40-4.60**	n/a
Capital expenditure (in millions)	**$ 60**	n/a
Payout Ratio	**55% to 80%**	85%

(1) 2007 reflects the acceleration of $20 million of 2007 capital into 2006.

At the end of 2006, we had entered into price risk management contracts to provide a floor price of approximately US$56 (relative to the West Intermediate Texas benchmark price) on 27,500 bbls/d throughout 2007 with upside participation in prices higher than US$56. After considering our 19% average royalty rate, these risk management contracts reduce our WTI price risk exposure at prices under US$56 to 25% of our crude oil production. This significantly reduces the volatility of our cash flows to WTI prices if prices trend below the US$56 price level. To complement these price risk management contracts, we have forward sold US$8,750,000 per month at an average Canadian dollar 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.

At the end of 2006, we had entered into price risk management contracts to collar AECO based natural gas prices on 50,000 GJ/d with an average floor price of $6.00 and an average price cap of $13.00 for the period through March 2007. In early 2007, we added contracts that provided the following three way price structure on 30,000 GJ/d for the period from April 2007 through March 2008:

For market prices below $5, a price equal to the market price plus $2;

For market prices between $5 and $7, a fixed price of $7;

For market prices between $7 and $10.27, market prices; and,

For market prices higher than $10.27, a price of $10.27.

After considering an 18% average royalty rate, we have reduced our AECO natural gas price exposure at prices less than $7 to 55% of its natural gas production. We may add a further 20,000 GJ/d of natural gas price protection.

In addition, we have also entered in to contracts to fix the price of 35 megawatthours (or approximately 50% of the anticipated electrical consumption of its petroleum and natural gas operations in Alberta) through to the end of December 2008 at price of $56.69. Our objective with these fixed price contracts is to substantially reduce the volatility of our operating costs to fluctuations in cost of electricity which represent approximately 25% of the operating costs in our petroleum and natural gas operations.

We are currently evaluating the impact of the North Atlantic acquisition on our overall corporate risk management profile with a goal of adding stability to our ability to fund sustainable cash distributions in a wide variety of pricing environments. Currently, the most likely outcome appears to be that we will commence contracting for price protection on refined products (rather than crude oil prices) and continue to contract for protection on 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 growth strategies for the petroleum and natural gas operations in western Canada will be to continue to acquire properties immediately adjacent to our existing operations on favourable terms as well as develop our extensive resource position with a 2007 capital spending plan of $295 million. While down from $376.9 million in 2006, the 2007 capital plan reflects the acceleration of $20 million of 2007 planned activity forward to December 2006 at Hay River and Red Earth due to favourable weather conditions. In our refining and marketing business for 2007, we expect to invest approximately $30 million in maintenance capital with discretionary capital spending ranging from $15 million to $30 million for visbreaker unit upgrade as well as other discretionary projects. The visbreaker project will enable a further upgrading of approximately 1,500 bbl/d of heavy fuel oil to higher valued refined products with an on-stream date during the fourth quarter of 2008 expected. In addition, we intend to be an active participant in the consolidation of Canadian energy royalty trusts which is dependent on the currency value of our trust units as trust-on-trust mergers are expected to be negotiated based on market valuation with premiums, if any, being nominal.

Following the announcement by the Minister of Finance for the Government of Canada on October 31, 2006 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, we will continue to explore the most efficient capital structure for its Unitholders balancing the benefits of the remaining four years of tax efficient distributions against the longer term benefits of continuing with a growth strategy beyond the "normal growth." At this time, the absence of firm guidelines and proposed Tax Act changes limits our ability to properly evaluate alternative structures and future plans.

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

	Assumption	Change	Impact on Cash Flow
WTI oil price ($US/bbl)	$ 60.00	$ 5.00	0.37/ Unit
CAD/USD exchange rate	$ 0.90	$ 0.05	0.54/ Unit
AECO daily natural gas price	$ 7.00	$ 1.00	0.26/ Unit
Refinery crack spread (US$/bbl)	$ 9.30	$ 1.00	0.34/ Unit
Operating Expenses (per boe)	$ 10.65	$ 1.00	0.18/ Unit

For Canadian income tax purposes, unitholders should anticipate that our distributions will continue to be 100% taxable with no "return of capital".

SUMMARY OF FOURTH QUARTER RESULTS

	Three months ended December 31				
	Petroleum and natural gas 2006	**Refining and marketing 2006**	**Total 2006**	2005	Change
Revenues	**273,110**	**460,359**	**733,469**	185,824	295%
Royalties	**(50,725)**	**-**	**(50,725)**	(31,178)	63%
Realized losses on risk management contracts[3]	**(12,506)**	**-**	**(12,506)**	(13,233)	5%
Unrealized gains on risk management contracts	**16,213**	**-**	**16,213**	28,463	(43%)
Net revenues	**226,092**	**460,359**	**680,451**	169,876	304%
Purchased product for resale and processing	**-**	**386,014**	**386,014**	-	n/a
Operating expenses	**69,298**	**34,063**	**103,361**	38,736	167%
Realized gains on electric power hedge	**(6,510)**	**-**	**(6,510)**	(4,507)	44%
Net operating expenses	**62,788**	**34,063**	**96,851**	34,229	183%
General and administrative expenses	**6,714**	**-**	**6,714**	4,083	19%
Less: Unit based compensation expenses	**(167)**	**-**	**(167)**	1,568	(89%)
Total cash general and administrative expenses	**6,547**	**-**	**6,547**	5,651	60%
Transportation and marketing	**2,919**	**5,060**	**7,979**	98	8,042%
Depreciation, depletion and accretion	**116,262**	**15,482**	**131,744**	51,012	158%
Net income per segment	**37,576**	**19,740**	**57,316**	78,886	(27%)
Interest expense			**41,184**	8,499	385%
Corporate costs[4]			**14,599**	(5,251)	(378%)
Net income			**1,533**	75,638	(98%)
Payout ratio		**-**	**86%**	57%	29%
Cash capital asset additions (excluding acquisitions)	**90,358**	**21,411**	**111,769**	39,476	183%
Refinery Throughput (mbbl)	**-**	**6,343**	**6,343**	-	n/a
OPERATING					
Daily sales volumes					
Light / medium oil (bbl/d)	**28,152**			20,471	38%
Heavy oil (bbl/d)	**13,967**			13,273	5%
Natural gas liquids (bbl/d)	**2,649**			867	205%
Natural gas (mcf/d)	**112,006**			25,339	342%
	63,436			38,834	63%
OPERATING NETBACK[1] ($/Boe)					
Revenue	**46.80**			52.01	(10%)
Realized loss on risk management contracts	**(2.14)**			(3.70)	(42%)
Royalties as percent of revenue	**(8.69)**			(8.73)	-
As a percent of revenue	**18.6%**			16.8%	2%
Operating expense[2]	**(10.76)**			(9.58)	12%
Transportation expense	**(0.50)**			(0.03)	1,567%
Operating Netback[1]	**24.71**			29.97	(18%)

(1) This is a non-GAAP measure, please refer to "*Non-GAAP Measure*" in this MD&A.

(2) Includes realized gain on electricity risk management contract of $1.12/boe and $1.26/boe for the three months ended December 31, 2006 and 2005 respectively.

(3) Includes amounts realized on WTI, heavy oil differential and currency exchange contracts and excludes amounts on electricity contracts and amounts realized on the series of US dollar forward purchase contracts entered into with respect to the purchase of North Atlantic.

(4) Includes foreign exchange losses, taxes and amounts realized on the series of US dollar forward purchase contracts entered into with respect to the purchase of North Atlantic.

Our 2006 fourth quarter is not directly comparable to our 2005 fourth quarter as a result of the acquisition of the refinery during the fourth quarter of 2006. As a result it is more applicable to compare our petroleum and natural gas segment fourth quarter results to our 2005 fourth quarter results. Results of our refining and marketing division have been discussed in other sections of our MD&A.

Our 2006 fourth quarter revenues have increased over the fourth quarter in 2005 as a result of increased production volumes due to the Viking and Birchill acquisitions and higher heavy oil prices, these increases were partially offset by lower gas and light to medium oil prices during the fourth quarter. Light / medium oil sales revenue for the three month period ended December 31, 2006 was $31.3 million (or 29%) higher than in same period in the prior year due to a favourable volume variance of $40.7 million and an unfavourable price variance of $9.4 million. Heavy oil revenues for the three months ended December 31, 2006 increased by $2.2 million (or 5%) due to an unfavourable price variance of $0.2 million and a favourable volume variance of $2.4 million. Natural gas sales revenue increased by $45.5 million (or 171%) for the three months ended December 31, 2006 over the same period in 2005, which reflects a favourable volume variance of $90.8 million and an unfavourable price variance of $45.3 million. The increase in our natural gas volumes are related to the acquisition of Viking which significantly increased our natural gas production as well as the acquisition of Birchill, which was predominantly gas. During 2006, natural gas prices were relatively weaker than in 2005 resulting in a significant unfavourable price variance.

Our fourth quarter 2006 production volumes are higher than in 2005 as production in the fourth quarter of 2006 reflects a full quarter of production from Viking and Birchill as well as added production from our drilling activity in the year.

For the three months ended December 31, 2006, our net royalties as a percentage of revenue were 18.6% ($50.7 million), compared to 16.8% ($31.2 million) in the same period in 2005. This increase in the royalty rate is mainly due to higher royalty rates associated with the Viking acquisition.

Operating expenses increased by $64.6 million (or 167%) for the three months ended December 31, 2006 compared to the same period in the prior year. Of this increase, $27.2 million relates to the acquisition of Viking, $34.1 million relates to the acquisition of the refinery, while the remaining increase reflects inflationary cost pressures in the western Canadian oil and natural gas sector.

For the three months ended December 31, 2006, Cash G&A increased by $0.9 million (or 16%) compared to the same period in the prior year. This increase is reflective of additional staffing costs relating to the Viking acquisition and generally higher costs for our external service providers.

Interest expense increased by $32.7 million for the three months ended December 31, 2006 relative to the same period in the prior year due to the acquisition of the refinery, which was initially financed with debt resulting in a significantly higher average debt balances on the credit facility in 2006.

After capital spending of $103.2 million, $54.2 million and $129.1 million in the first, second, and third quarter of 2006, respectively, capital spending in our petroleum and natural gas segment in the fourth quarter totaled $90.4 million including approximately $20 million of capital accelerated from the 2007 capital plan to take advantage of favourable weather conditions at our Hay River and Red Earth operations.

SUMMARY OF HISTORICAL QUARTERLY RESULTS

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

Financial	2006				2005			
($000's except where noted)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Revenue, net of royalties	**$682,744**	$ 259,818	$ 257,103	$ 181,160	$ 154,646	$ 169,654	$ 120,263	$ 109,931
Net income (loss)	**1,533**	107,768	60,682	(33,937)	75,638	52,862	19,516	(43,070)
Per trust unit, basic[2]	**$ 0.01**	$ 1.01	$ 0.60	$ (0.41)	$ 1.45	$ 1.09	$ 0.45	$ (1.02)
Per trust unit, diluted[2]	**$ 0.01**	$ 0.99	$ 0.60	$ (0.41)	$ 1.42	$ 1.08	$ 0.44	$ (1.02)
Cash Flows[1]	**156,270**	147,471	147,010	100,971	96,431	103,508	57,217	52,687
Per trust unit, basic[1]	**$ 1.35**	$ 1.39	$ 1.45	$ 1.23	$ 1.84	$ 2.14	$ 1.32	$ 1.25
Per trust unit, diluted[1]	**$ 1.29**	$ 1.34	$ 1.43	$ 1.22	$ 1.81	$ 2.09	$ 1.29	$ 1.19
Distributions per Unit, declared	**$ 1.14**	$ 1.14	$ 1.14	$ 1.11	$ 1.05	$ 0.95	$ 0.60	$ 0.60
Total long term financial liabilities	**2,478,518**	1,105,728	746,840	735,896	349,074	386,124	455,163	321,534
Total assets	**5,745,558**	4,076,771	3,455,918	3,470,653	1,308,481	1,327,272	1,117,792	1,079,269
Total production (boe/d)	**63,436**	62,178	60,145	53,014	38,834	37,549	34,463	35,386

(1) This is a non-GAAP measure as referred to under "*Non-GAAP Measures*".

(2) The sum of the interim periods does not equal the total per year amount as there were large fluctuations in the weighted average number of trust units outstanding in each individual quarter.

Net revenues and Cash Flows have generally increased steadily over the eight quarters as shown above. The significantly higher revenue in the second and third quarter of 2006 over the preceding quarters is due to the incremental revenue recorded from the Viking assets acquired in February of 2006 and a rising commodity price environment. In the fourth quarter of 2006, another significant increase in revenue is realized due to the acquisition of the refinery which will result in significantly higher revenues in this quarter and future quarters.

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

Net income reflects both cash and non-cash items. Changes in non-cash items, including 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 can cause net income to vary significantly from period to period. However, these items do not impact the Cash Flows available for distribution to Unitholders, and therefore we believe net income to be a less meaningful measure of performance for us. The main reason for the volatility in net income (loss) between quarters in 2005 and 2006 is due to the changes in the fair value of our risk management contracts. We ceased using hedge accounting for all of our risk management contracts in October 2004 and switched to a fair value accounting methodology, which has substantially increased the volatility in our reported earnings. Due primarily to the inclusion of unrealized mark-to-market gains and losses on risk management contracts, net income (loss) has not reflected the same trend as net revenues or Cash Flows.

CRITICAL ACCOUNTING 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 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 pension plan related to employees of the refinery. Obligations under employee future benefits plans are recorded net of plan assets where applicable. An independent actuary determines the costs of our employee future benefits 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 benefits 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 ratified a strategic plan that will result in Canadian GAAP, as used by public companies, being converged with International Financial Reporting Standards over a transitional period. The Accounting Standards Board (AcSB) is expected to develop and publish a detailed implementation plan with a transition period expected to be approximately five years. This convergence initiative is in its early stages as of the date of these annual consolidated 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, Comprehensive Income and Hedges

The AcSB has issued five new accounting standards relating to the recognition, measurement, disclosure and presentation of financial instruments. The new standards comprise five handbook sections:

- CICA Section 3855 – *Financial Instruments – Recognition and Measurement*

This standard establishes the criteria for recognizing and measuring financial assets, financial liabilities and non-financial derivatives. It also specifies how financial instrument gains and losses are to be presented. Financial liabilities will be classified as either held-for-trading or other. Held-for-trading instruments will be recorded at fair value with realized and unrealized gains and losses reported in net income. Other instruments will be accounted for at amortized cost with gains and losses reported in net income in the period that the liability is derecognized.

Derivatives will be classified as held-for-trading unless designated as hedging instruments. All derivatives, including embedded derivatives that must be separately accounted for, will be recorded at fair value on the consolidated balance sheet. For derivatives that hedge the changes in fair value of an asset or liability, changes in the derivatives' fair value will be reported in net income and be substantially offset by changes in the fair value of the hedged asset or liability attributable to the risk being hedged. For derivatives that hedge variability in cash flows, the effective portion of the changes in the derivatives' fair value will be initially recognized in other comprehensive income and the ineffective portion will be recorded in net income. The amounts temporarily recorded in other comprehensive income will subsequently be reclassified to net income in the periods when net income is affected by the variability in the cash flows of the hedged item.

- CICA Section 3865 – *Hedges*

This standard provides optional alternative treatment to Section 3855 for entities which choose to designate qualifying transactions as hedges for accounting purposes. It will replace Accounting Guideline 13 (AcG 13) – *Hedging Relationships,* and build on Section 1560 – *Foreign Currency Translation*, by specifying how hedge accounting is applied and what disclosures are necessary when it is applied. Retroactive application of this Section is not permitted.

- CICA Section 1530 – *Comprehensive Income*

This standard introduces a new requirement to temporarily present certain gains and losses as part of a new earnings measurement called comprehensive income.

- CICA 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.

- CICA 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.

CICA sections 3855, 3865 and 1530 are effective for annual and interim periods in fiscal years beginning on or after October 1, 2006. A presentation reclassification of amounts previously recorded in "Foreign currency translation adjustment" to "Accumulated other comprehensive income" will be made upon adoption of Section 1530. In addition, deferred charges associated with the bank debt will be expensed and those incurred related to convertible debentures and the 7 7/8% Senior Notes will be recorded net of the debt balance. We do not expect there to be any other material impact on the consolidated financial statements upon adoption of the new standards.

CICA sections 3862 and 3863 are effective for annual and interim periods beginning on or after October 1, 2007.

Accounting changes

The AcSB issued CICA Section 1506, *Accounting Changes*. The standard prescribes the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies and estimates, and correction of errors. The standard requires the retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impractical to determine either the period-specific effects or the cumulative effect of the change. Application is on a prospective basis and is effective for changes in accounting policies and estimates and correction of errors made in fiscal years beginning on or after January 1, 2007.

Variable Interest Entities

The Emerging Issues Committee (EIC) issued EIC Abstract 163 – *Determining the Variability to be Considered in Applying AcG 15*. This Abstract, which is harmonized with the equivalent United States FASB Staff Position (FSP) FIN 46(R) – 6 – *Determining the Variability to be Considered in Applying FASB Interpretation No. 46(R)*, provides guidance on how an enterprise should determine the variability to be considered in applying AcG 15 – *Consolidation of Variable Interest Entities*. The Abstract is to be applied prospectively to all entities with which an enterprise first becomes involved and to all entities previously required to be analyzed under AcG 15 when a reconsideration event has occurred beginning the first day of the first reporting period beginning on or after January 1, 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 risk 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
- Remunerating employees with a combination of average industry salary and benefits combined with a merit based bonus plan to reward success in execution of our business plan.

Operation of a refining and petroleum marketing business:

- Maintaining a proactive approach to managing the Supply and Offtake Agreement 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 unionized work force to minimize operational disruptions due to strikes or work stoppages; and
- Selectively adding experienced refining management to strengthen our "in-house" management team, particularly a new leader for our refinery operations to replace the current President and 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 products 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.

Disruptions in the supply of crude oil and delivery of refined products:

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

Non-GAAP Measures

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

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

	Three months ended December 31		Year ended December 31	
($000's)	**2006**	2005	**2006**	2005
Cash Flow	**$ 156,270**	$ 96,431	**$ 551,724**	$ 309,843
Cash Viking transaction costs	**(243)**	-	**(6,501)**	-
Settlement of asset retirement obligations	**(5,158)**	(1,813)	**(9,186)**	(4,146)
Changes in non-cash working capital	**(10,327)**	3,348	**(28,152)**	(22,519)
Cash flow from operating activities	**$ 140,542**	$ 97,966	**$ 507,885**	$ 283,178

Disclosure Controls and Procedures

Under the supervision of our Chief Executive Office and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures as of the end of December 31, 2006 as defined under the rules adopted by the Canadian securities regulatory authorities and by the U.S. Securities and Exchange Commission. On October 19, 2006, we acquired North Atlantic and our evaluation of disclosure controls and procedures was expanded to include a review of their design and effectiveness.

Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that as of the end of the fiscal year, the design and operation of our disclosure controls and procedures were effective to ensure that information required to be disclosed by Harvest in reports it files or submits under Canadian and US securities regulatory authorities was recorded, processed, summarized and reported within the time periods specified in Canadian and US Security laws and was accumulated and communicated to Harvest's management, including its Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

Internal Controls Over Financial Reporting

Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of financial statements for external purposes in accordance with Generally Accepted Accounting Principles. On October 19, 2006, we acquired North Atlantic and expanded our review of internal control over financial reporting to include the review of the design of North Atlantic's controls over their internal reporting of financial information. Our evaluation of the design and effectiveness of our internal control over financial reporting as of the end of December 31, 2006 was based on the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). There were no changes in our internal controls over financial reporting during the year ending December 31, 2006 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

We have completed our review of the design of North Atlantic's control over their internal reporting of financial information but have not completed an evaluation as to its effectiveness which is planned to be completed in 2007. North Atlantic's total assets, net sales and earnings before interest expense and income taxes constitute 30%, 29% and 9% of Harvest's consolidated total assets, net sales and income, respectively, as of and for the fiscal year ended December 31, 2006.

Based on our evaluation which was completed under the supervision of our Chief Executive Officer and Chief Financial Officer, we have concluded that as of December 31, 2006, we had effective controls over financial reporting. This conclusion excludes an evaluation of North Atlantic's control over their internal reporting of financial information.

Because of their inherent limitations, disclosure controls and procedures and internal controls over financial reporting may not prevent or detect misstatements, errors, or fraud. Control systems, no matter how well conceived or operated can provide only reasonable, not absolute assurance that the objectives of the control systems are met.

Forward-Looking Information

This MD&A highlights significant business results and statistics from our consolidated financial statements for year ended December 31, 2006 and the accompanying notes thereto. In the interest of providing our Unitholders and potential investors with information regarding Harvest, including our assessment of our future plans and operations, this MD&A contains forward-looking statements that involve risks and uncertainties. Such risks and uncertainties include, but are not limited to, risks associated with conventional petroleum and natural gas operations; 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, Cash Flow From Operations and regulatory changes. For this purpose, any statements that are contained herein that are not statements of historical fact may be deemed to be forward-looking statements. Forward-looking statements often contain terms such as "may", "will", "should", "anticipate", "expects", and similar expressions.

Readers are cautioned not to place undue reliance on forward-looking statements as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. Although 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.

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Harvest Energy Trust (the "Trust") is responsible for establishing and maintaining adequate internal control over financial reporting for the Trust. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). On October 19th, 2006 Harvest acquired North Atlantic Refining Limited ("North Atlantic") and we expanded our review of internal control over financial reporting to include a review of the design of North Atlantic's controls over their internal reporting of financial information. North Atlantic's total assets, net sales and earning before interest expense and income taxes constitute 30%, 29% and 9% of Harvest's consolidated total assets, net sales, and income respectively as of and for the fiscal year ended December 31, 2006. Based on our assessment, and excluding an assessment of the effectiveness of North Atlantic's control over their internal reporting of financial information which is planned for 2007, we have concluded that as of December 31, 2006, our internal controls over financial reporting were effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

Management's assessment of the effectiveness of the Trust's internal control over financial reporting as of December 31, 2006, has been audited by KPMG LLP, the Trust's Independent Registered Public Accountants, who also audited the Trust's Consolidated Financial Statements for the year ended December 31, 2006.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Harvest Operations Corp. on behalf of Harvest Energy Trust and the Unitholders of Harvest Energy Trust,

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Harvest Energy Trust ("the Trust") maintained effective internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Trust's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Trust's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

An entity's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. An entity's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the entity; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the entity are being made only in accordance with authorizations of management and directors of the entity; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the entity's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Trust maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

The Trust acquired North Atlantic Refining Limited during 2006, and management excluded from its assessment of the effectiveness of the Trust's internal control over financial reporting as of December 31, 2006, North Atlantic Refining Limited's internal control over financial reporting associated with total assets of $1,727.8 million and total refined product sales of $460 million included in the consolidated financial statements of the Trust as of and for the year ended December 31, 2006. Our audit of internal control over financial reporting of the Trust also excluded an evaluation of the internal control over financial reporting of North Atlantic Refining Limited.

We also have conducted our audits on the consolidated financial statements in accordance with Canadian generally accepted auditing standards. With respect to the year ended December 31, 2006, we also have conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our report dated March 12, 2007, expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Chartered Accountants
Calgary, Canada
March 12, 2007

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

In management's opinion, the accompanying consolidated financial statements of Harvest Energy Trust (the "Trust") have been prepared within reasonable limits of materiality and in accordance with Canadian generally accepted accounting principles. Since a precise determination of many assets and liabilities is dependent on future events, the preparation of financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgment and with all information available up to March 12, 2007. Management is responsible for all information in the annual report and for the consistency, therewith, of all other financial and operating data presented in this report.

To meet its responsibility for reliable and accurate financial statements, management has established and monitors systems of internal control which are designed to provide reasonable assurance that financial information is relevant, reliable and accurate, and that assets are safeguarded and transactions are executed in accordance with management's authorization.

The consolidated financial statements have been examined by KPMG LLP, Independent Registered Public Accountants. Their responsibility is to express a professional opinion on the fair presentation of the consolidated financial statements in accordance with Canadian generally accepted accounting principles. The Independent Registered Public Accountants Report outlines the scope of their examination and sets forth their opinion.

The Audit Committee, consisting exclusively of independent directors, has reviewed these statements with management and the Independent Registered Public Accountants and has recommended their approval to the Board of Directors. The Board of Directors has approved the consolidated financial statements of the Trust.

John E. Zahary
President and Chief Executive Officer

Robert W. Fotheringham
Vice President, Finance and Chief Financial Officer

Calgary, Alberta
March 12, 2007

AUDITORS' REPORT

To the Unitholders of Harvest Energy Trust,

We have audited the consolidated balance sheets of Harvest Energy Trust (the "Trust") as at December 31, 2006 and 2005 and the consolidated statements of income, unitholders' equity and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. With respect to the consolidated financial statements for the year ended December 31, 2006, we also conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2006 and 2005 and the results of its operations and its cash flow for the years then ended in accordance with Canadian generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Trust's internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 12, 2007 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

Chartered Accountants
Calgary, Canada
March 12, 2007

COMMENTS BY AUDITORS FOR UNITED STATES READERS ON CANADA – UNITED STATES REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Trust's financial statements, such as the change described in note 22 to the consolidated financial statements as at December 31, 2006 and 2005 and for the years then ended. Our report to the unitholders dated March 12, 2007, is expressed in accordance with Canadian reporting standards, which do not require a reference to such a change in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

KPMG LLP

Chartered Accountants
Calgary, Canada
March 12, 2007

CONSOLIDATED BALANCE SHEETS

As at December 31

(thousands of Canadian dollars)	2006	2005
Assets		
Current assets		
Cash	$ 10,006	$ -
Accounts receivable and other	254,151	73,766
Fair value of risk management contracts [Note 18]	17,914	21,231
Prepaid expenses and deposits	12,713	1,126
Inventories [Note 4]	30,512	-
Future income tax [Note 16]	-	22,975
	325,296	119,098
Deferred charges and other non-current assets [Note 7]	35,657	12,768
Fair value of risk management contracts [Note 18]	9,843	2,628
Property, plant and equipment [Notes 3 and 5]	4,393,832	1,130,155
Intangible assets [Note 6]	114,752	-
Goodwill [Note 3]	866,178	43,832
	$ 5,745,558	$ 1,308,481
Liabilities and Unitholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities [Note 8]	$ 294,582	$ 99,576
Cash distribution payable	46,397	18,544
Fair value deficiency of risk management contracts [Note 18]	26,764	65,968
	367,743	184,088
Bank loan [Note 10]	1,595,663	13,869
$7^{7/8}$% Senior notes [Note 12]	291,350	290,750
Convertible debentures [Notes 3 and 11]	601,511	44,455
Fair value deficiency of risk management contracts [Note 18]	2,885	10,449
Asset retirement obligation [Note 9]	202,480	110,693
Employee future benefits [Note 17]	12,227	-
Deferred credit	794	1,389
Future income tax [Note 16]	-	25,275
Non-controlling interest [Note 15]	-	3,179
Unitholders' equity		
Unitholders' capital [Note 13]	3,046,876	747,312
Equity component of convertible debentures	36,070	2,639
Accumulated income	271,155	135,665
Accumulated distributions	(730,069)	(261,282)
Cumulative translation adjustment	46,873	-
	2,670,905	624,334
	$ 5,745,558	$ 1,308,481

Commitments, contingencies and guarantees [Note 21]
Subsequent events [Note 23]
See accompanying notes to these consolidated financial statements.

Approved by the Board of Directors:

Hector J. McFadyen
Director

Verne G. Johnson
Director

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31

(thousands of Canadian dollars, except per trust unit amounts)	2006	2005
Revenue		
Petroleum, natural gas, and refined product sales	**$ 1,580,934**	$ 667,496
Royalty expense	**(200,109)**	(113,002)
Risk management contracts		
Realized net losses	**(44,808)**	(72,981)
Unrealized net gains (losses)	**52,179**	(45,061)
	1,388,196	436,452
Expenses		
Purchased products for processing and resale	**386,014**	-
Operating	**276,537**	126,858
Transportation and marketing	**17,202**	400
General and administrative [Note 14]	**28,372**	30,697
Transaction costs	**12,072**	-
Interest and other financing charges on short term debt, net	**4,864**	6,587
Interest and other financing charges on long term debt	**78,893**	29,824
Depletion, depreciation, amortization and accretion	**429,470**	178,956
Foreign exchange loss (gain)	**21,100**	(9,728)
Large corporations tax and other tax	**(9)**	134
Future income tax recovery [Note 16]	**(2,300)**	(32,371)
Non-controlling interest [Note 15]	**(65)**	149
	1,252,150	331,506
Net income for the year	**$ 136,046**	$ 104,946
Net income per trust unit, basic [Note 13]	**$ 1.34**	$ 2.25
Net income per trust unit, diluted [Note 13]	**$ 1.33**	$ 2.19

See accompanying Notes to these Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY

For the Years Ended December 31

(thousands of Canadian dollars)	Unitholders' Capital	Equity Component of Convertible Debentures	Accumulated Income	Accumulated Distributions	Cumulative Translation Adjustment	Total
At December 31, 2004	**$ 465,524**	**$ 116**	**$ 30,719**	**$ (97,110)**	**$ -**	**$ 399,249**
Issued for cash	175,001	-	-	-	-	175,001
Equity component of 6.5% series of convertible debentures issuance	-	4,720	-	-	-	4,720
Convertible debenture conversions						
9% Debentures Due 2009	8,924	(3)	-	-	-	8,921
8% Debentures Due 2009	11,383	(85)	-	-	-	11,298
6.5% Debentures Due 2010	33,585	(2,109)	-	-	-	31,476
Exchangeable share retraction [Note 15]	3,865	-	-	-	-	3,865
Exercise of unit appreciation rights and other	12,084	-	-	-	-	12,084
Issue costs	(9,949)	-	-	-	-	(9,949)
Net income	-	-	104,946	-	-	104,946
Distributions	46,895	-	-	(164,172)	-	(117,277)
At December 31, 2005	**747,312**	**2,639**	**135,665**	**(261,282)**	**-**	**624,334**
Issued in exchange for assets of Viking [Note 3(c)]	1,638,131	-	-	-	-	1,638,131
Issued for cash						
August 17, 2006	230,118	-	-	-	-	230,118
November 22, 2006	258,848	-	-	-	-	258,848
Equity component of convertible debenture issuances						
10.5% Debentures Due 2008	-	9,301	-	-	-	9,301
6.40% Debentures Due 2012	-	14,822	-	-	-	14,822
7.25% Debentures Due 2013	-	11,800	-	-	-	11,800
Convertible debenture conversions						
9% Debentures Due 2009	551	-	-	-	-	551
8% Debentures Due 2009	1,550	(12)	-	-	-	1,538
6.5% Debentures Due 2010	3,563	(223)	-	-	-	3,340
10.5% Debentures Due 2008	10,761	(2,238)	-	-	-	8,523
6.40% Debentures Due 2012	231	(19)	-	-	-	212
Exchangeable share retraction [Note 15]	2,648	-	(556)	-	-	2,092
Exercise of unit appreciation rights and other	12,034	-	-	-	-	12,034
Issue costs	(26,414)	-	-	-	-	(26,414)
Foreign currency translation adjustment	-	-	-	-	46,873	46,873
Net income	-	-	136,046	-	-	136,046
Distributions and distribution reinvestment plan	167,543	-	-	(468,787)	-	(301,244)
At December 31, 2006	**$ 3,046,876**	**$ 36,070**	**$ 271,155**	**$ (730,069)**	**$ 46,873**	**$ 2,670,905**

See accompanying Notes to these Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31

(thousands of Canadian dollars)	2006	2005
Cash provided by (used in)		
Operating Activities		
Net income for the year	$ 136,046	$ 104,946
Items not requiring cash		
Depletion, depreciation, amortization and accretion	429,470	178,956
Unrealized foreign exchange loss (gain)	23,956	(8,588)
Non-cash interest expense	1,577	535
Amortization of deferred finance charges	8,432	4,853
Unrealized loss (gain) on risk management contracts [Note 18]	(52,179)	45,061
Future income tax recovery	(2,300)	(32,371)
Non-controlling interest	(65)	149
Unit based compensation expense	775	16,302
Amortization of office lease premiums and deferred rent expense	(161)	-
Employee benefit obligation	(328)	-
Settlement of asset retirement obligations [Note 9]	(9,186)	(4,146)
Change in non-cash working capital [Note 20]	(28,152)	(22,519)
	507,885	283,178
Financing Activities		
Issue of trust units, net of issue costs	463,160	167,256
Issue of convertible debentures, net of issue costs [Note 11]	363,742	71,777
Redemption of exchangeable shares [Note 15]	(1,022)	-
Bank borrowings, net [Note 10]	1,452,138	(61,650)
Financing costs	(13,071)	(2,196)
Cash distributions	(273,391)	(107,091)
Change in non-cash working capital [Note 20]	(12,604)	(1,035)
	1,978,952	67,061
Investing Activities		
Additions to property, plant and equipment	(398,292)	(120,508)
Business acquisitions	(2,044,640)	(237,783)
Property acquisitions	(65,773)	(4,052)
Property dispositions	20,856	2,177
Increase in other non-current assets	(165)	-
Change in non-cash working capital [Note 20]	10,886	9,927
	(2,477,128)	(350,239)
Change in cash and cash equivalents	9,709	-
Effect of exchange rate changes on cash	297	-
Cash and cash equivalents, beginning of year	-	-
Cash and cash equivalents, end of year	$ 10,006	$ -
Interest paid	$ 53,434	$ 30,771
Large corporation tax and other tax paid	$ 862	$ 2,079

See accompanying Notes to these Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2006 and 2005

(tabular amounts in thousands of Canadian dollars, except trust units, and per trust unit amounts)

1. STRUCTURE OF THE TRUST

Harvest Energy Trust (the "Trust") is an open-ended, unincorporated investment trust established under the laws of the Province of Alberta on July 10, 2002 and is governed pursuant to the Amended and Restated Trust Indenture dated February 3, 2006 between Harvest Operations Corp. ("Harvest Operations"), a wholly owned subsidiary and manager of the Trust, and Valiant Trust Company as Trustee (the "Trust Indenture"). The purpose of the Trust is to indirectly exploit, develop and hold interests in petroleum and natural gas properties and refining and marketing assets through investments in the securities of its subsidiaries and net profits interests in petroleum and natural gas properties. The beneficiaries of the Trust are the holders of its trust units (the "Unitholders") who receive monthly distributions from the Trust's net cash flow from its various investments after the provision for interest due to the holders of convertible debentures. Pursuant to the Trust Indenture, the Trust is required to distribute 100% of its taxable income to its Unitholders each year and to comply with the mutual fund trust requirements of the Income Tax Act (Canada). The Trusts' activities are limited to holding and administering permitted investments and making distributions to its Unitholders.

The business of the Trust is carried on by Harvest Operations and other operating subsidiaries of the Trust, including North Atlantic Refining General Partnership. The activities of Harvest Operations and the Trust's subsidiaries are financed through interest bearing notes from the Trust, net profit interests issued to the Trust, and third party debt such as the bank debt and the $7^{7/8}$% senior notes.

The net profit interests are determined pursuant to the terms of each respective net profit interest agreement. The Trust is entitled to net profit interests equal to the amount by which 99% of the gross proceeds from the sale of production from petroleum and natural gas properties exceed 99% of certain deductible expenditures. Under the terms of the net profits interests agreements, deductible expenditures may include discretionary amounts to fund capital expenditures, to repay third party debt and to provide for working capital required to carry out the operations of the operating subsidiaries.

References to "Harvest" refers to the Trust on a consolidated basis. References to "North Atlantic" refers to North Atlantic Refining General Partnership and it subsidiaries, all of which are 100% owned by Harvest.

2. SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). These principles differ in certain respects from accounting principles generally accepted in the United States of America ("U.S. GAAP") and to the extent that the differences materially affect Harvest, they are described in Note 22.

(a) Consolidation

These consolidated financial statements include the accounts of Harvest and its subsidiaries. All inter-entity transactions and balances have been eliminated upon consolidation.

(b) Use of Estimates

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. Specifically, amounts recorded for depletion, depreciation, amortization and accretion expense, asset retirement obligations, fair value of risk management contracts, employee future benefits and amounts used in the impairment tests for intangible assets, goodwill, inventory and property, plant and equipment are based on estimates. These estimates include petroleum and natural gas reserves, future petroleum and natural gas prices, future interest rates and future costs required to develop those reserves as well as other fair value assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future years could be material.

(c) Revenue Recognition

Revenues associated with the sale of crude petroleum, natural gas, natural gas liquids and refined products are recognized when title passes to customers and payment has either been received or collection is reasonably certain. Concurrent with the recognition of revenue from the sale of refined products and included in purchased products for resale and processing are associated transportation charges. Revenues for retail services are recorded when the services are provided.

The sales price of residential home heating fuels and automotive gasoline and diesel within the Province of Newfoundland and Labrador is subject to regulation under the Petroleum Products Act. The Petroleum Products Pricing Commissioner sets the maximum wholesale and retail prices that a wholesaler and a retailer may charge and sets the maximum mark-up between the wholesale price to the retailer and the retail price to the consumer. Prices are set biweekly using a price adjustment formula based on an allowable premium above Platt's with an interruption formula. The full effect of rate regulation is reflected in the product sales revenue as recorded by Harvest.

(d) Inventories

Inventories are carried at the lower of cost or net realizable value. The costs of in process inventory are determined using the weighted average cost method. The costs of purchased goods and petroleum products held for resale are determined under the first in, first out method. The costs of parts and supplies inventories are determined under the average cost method.

(e) Joint Venture and Partnership Accounting

The subsidiaries of Harvest conduct substantially all of their petroleum and natural gas production activities through joint ventures and through partnerships. The consolidated financial statements reflect only Harvest's proportionate interest in such activities.

(f) Property, Plant, and Equipment

Petroleum and Natural Gas

Harvest follows the full cost method of accounting for its petroleum and natural gas activities. All costs of acquiring petroleum and natural gas properties, whether productive or unproductive, related development costs, and overhead charges directly related to these activities, are capitalized and accumulated in one cost centre. Maintenance and repair costs that do not extend or enhance the recoverable reserves are charged against income.

Proceeds from the sale of petroleum and natural gas properties are applied against capital costs. Gains and losses are not recognized on the disposition of petroleum and natural gas properties unless that disposition would alter the rate of depletion and depreciation by 20% or more.

Provision for depletion and depreciation of petroleum and natural gas assets is calculated using the unit-of-production method, based on proved reserves net of royalties as evaluated by independent petroleum engineers. The cost basis used for the depletion and depreciation provision is the capitalized costs of petroleum and natural gas assets plus the estimated future development costs of proved undeveloped reserves. Reserves are converted to equivalent units on the basis of six thousand cubic feet of natural gas to one barrel of petroleum, reflecting the approximate relative energy content.

Harvest places a limit on the aggregate carrying amount of property, plant and equipment associated with petroleum and natural gas activities which may be amortized to depletion and depreciation in future periods. Impairment is recognized when the carrying amount of the petroleum and natural gas assets exceeds the sum of the undiscounted future cash flows expected from the proved reserves.

To recognize impairment, Harvest would then measure the amount of impairment by comparing the carrying amounts of the petroleum and natural gas assets to an amount equal to the estimated net present value of future cash flows from proved plus probable reserves using Harvest's risk-free discount rate. Any excess carrying amount above the net present value of Harvest's future cash flows would be a permanent impairment and reflected as a charge to net income for the period.

Cash flows are calculated based on future price estimates, adjusted for Harvest's contractual arrangements related to pricing and quality differentials.

The cost of unproved properties is excluded from the impairment test calculation described above and subject to a separate impairment test. An impairment of unproved properties is recognized when the cost base exceeds the fair value determined by a reference to market prices, historical experience or a third party independent evaluator. There were no impairment write downs for petroleum and natural gas assets for the years ended December 31, 2006 and 2005.

Refining and Marketing

Property, plant and equipment related to the refining assets are recorded at cost. Depreciation of recorded cost less salvage value is provided on a straight-line basis over the estimated useful life of the assets as set out below. Any gains or losses on disposal of individual assets are recognized in the year of disposal.

Asset	Period
Refining and production plant:	
Processing equipment	5 – 25 years
Structures	15 – 20 years
Catalysts	2 – 5 years
Tugs	25 years
Vehicles	2 – 5 years

Maintenance and repair costs including major maintenance activities, are expensed as incurred. Improvements that increase or prolong the service life or capacity of an asset are capitalized.

Property, plant and equipment related to refining assets are tested for recovery whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Property, plant and equipment related to refining assets are not recoverable if their carrying amounts exceed the sum of the undiscounted cash flows expected to result from their use and eventual disposition. If property, plant and equipment related to refining assets are not recoverable, an impairment loss is recognized in an amount by which their carrying amount exceed their fair value, with fair value determined based on discounted estimated net cash flows. There was no impairment write-down for refining assets for the year ended December 31, 2006.

(g) Goodwill and Other Intangible Assets

Goodwill is recognized when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of the acquired business. Goodwill is carried at cost less impairment and is not amortized. The carrying amount of goodwill is assessed for impairment annually at year-end, or more frequently if events occur that could result in an impairment. The goodwill impairment test is a two step test. In the first step, the carrying amount of the assets and liabilities, including goodwill, is compared to the fair value of the reporting unit. The fair value of a reporting unit is determined by calculating the present value of the expected future cash flows from the reporting unit. If the fair value is less than the carrying amount of the reporting unit, a potential impairment of goodwill may exist requiring the second test to be performed. Impairment is measured by allocating the fair value of the reporting unit, as determined in the first test, over the identifiable assets and liabilities. The excess of the fair value of the reporting unit over the fair value of the identifiable assets and liabilities represents the fair value of goodwill. The excess of the book value of goodwill over this implied fair value is then recognized as an impairment and charged to income in the period in which it occurs. There were no impairment write-downs for each of the years ended December 31, 2006 and 2005.

Intangible assets with determinable useful lives are amortized using the straight line method over the estimated lives of the assets, which range from 5–20 years. The amortization methods and estimated service lives are reviewed annually. The carrying amounts of intangible assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable. Intangibles are not recoverable if their carrying amounts exceed the sum of the undiscounted cash flows expected to result from their use and eventual disposition. If intangibles are not recoverable, an impairment loss is recognized in an amount by which their carrying amount exceeds their fair value, with fair value determined based on discounted estimated net cash flows. There was no impairment write-down for the year ended December 31, 2006.

(h) Asset Retirement Obligations

Harvest recognizes the fair value of any asset retirement obligations as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and normal use of the assets. Harvest uses a credit-adjusted risk free discount rate to estimate this fair value. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset and depleted and depreciated using the method described under "*Property, Plant and Equipment*". Subsequent to the initial measurement of the asset retirement obligation, the obligation is adjusted at the end of each subsequent period to reflect the passage of time and changes in the timing and amount of estimated future cash flows underlying the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

(i) Income Taxes

Under the Income Tax Act (Canada) the Trust and its trust subsidiary entities are taxable only on income that is not distributed or distributable to their Unitholders. As both the Trust and its Trust subsidiaries distribute all of their taxable income to their respective Unitholders pursuant to the requirements of their trust indentures, neither the Trust nor its trust subsidiaries make provisions for future income taxes.

Harvest follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements of the corporate subsidiaries and their respective tax bases, using enacted or substantively enacted income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs. A valuation allowance is recorded against any future income tax asset if it is more likely than not that the asset will not be realized.

(j) Unit-Based Compensation

Harvest determines compensation expense for the trust unit Rights Incentive Plan ("Trust Unit Incentive Plan") and the Unit Award Incentive Plan ("Unit Award Incentive Plan") by estimating the intrinsic value of the rights at each period end and recognizing the amount in income over the vesting period. After the rights have vested, further changes in the intrinsic value are recognized in income in the period of change.

The intrinsic value is the difference between the market value of the Units and the exercise price of the right in the case of the Trust Unit Incentive Plan, and in the case of the Unit Award Incentive Plan the market value of the Units represents the intrinsic value of the Award. Under the Trust Unit Incentive Plan, the intrinsic value method is used as participants in the plan have the option to either purchase the Units at the exercise price or to receive a cash payment or trust unit equivalent, equal to the excess of the market value of the Units over the exercise price. Under the Unit Award Incentive Plan participants have the option upon exercise to receive a cash payment or trust unit equivalent, equal to the value of awards outstanding, which is equivalent to the market value of the Units.

(k) Non-Controlling Interest

Non-controlling interest represents the exchangeable shares issued by Harvest Operations to third parties which are ultimately only exchangeable for Units of the Trust. These exchangeable shares were issued as partial consideration for a corporate acquisition during the year ended December 31, 2004. Non-controlling interest on the consolidated balance sheet is recognized based on the fair value of the exchangeable shares on issuance together with a portion of Harvest's accumulated earnings or loss attributable to the non-controlling interest subsequent to their issuance. Net income or loss is reduced for the portion of earnings or losses attributable to the non-controlling interest. As the exchangeable shares are converted to trust units, the non-controlling interest on the consolidated balance sheet is reduced on a pro-rata basis together with a corresponding increase in Unitholders' capital. During the year ended December 31, 2006, all of the exchangeable shares were converted to units of the Trust, therefore, as at December 31, 2006 all of the non-controlling interest has been eliminated.

(l) Deferred Charges

Deferred charges relate to costs incurred on the issuance of bank loans, $7^{7/8}$% senior notes and the convertible debentures and are amortized over the term of the related debt to interest expense.

(m) Financial Instruments

(i) Risk Management Contracts

Harvest is exposed to market risks resulting from fluctuations in commodity prices, power prices and currency exchange rates in the normal course of its business. Harvest may use a variety of instruments to manage these exposures. For transactions where hedge accounting is not applied, Harvest accounts for such instruments using the fair value method by initially recording an asset or liability, and recognizing changes in the fair value of the instruments in income as unrealized net gains or losses on risk management contracts. Where Harvest has a fixed price physical commodity sales contract, it is also recorded at fair value. Fair values of financial instruments are determined from third party quotes or valuations provided by independent third parties. Any realized gains or losses on risk management contracts are recognized in income as realized net gains or losses on risk management contracts in the period they occur.

Harvest may elect to use hedge accounting when there is a high degree of correlation between the price movements in the financial instruments and the items designated as being hedged and has documented the relationship between the instruments and the hedged item as well as its risk management objective and strategy for undertaking hedge transactions. At December 31, 2006 and 2005, Harvest had not designated any of its outstanding financial instruments as hedges.

(ii) Convertible Debentures

Harvest presents outstanding convertible debentures in their debt and equity component parts on the consolidated balance sheet.

The debt component represents the total discounted present value of the semi-annual interest obligations to be satisfied by cash and the principal payment due at maturity, using the rate of interest that would have been applicable to a non-convertible debt instrument of comparable term and risk at the date of issue. Typically, this results in an accounting value assigned to the debt component of the convertible debentures which is less than the principal amount due at maturity. The debt component presented on the balance sheet increases over the term of the relevant debenture to the full face value of the outstanding debentures at maturity. The difference is reflected as increased interest expense with the result that adjusted interest expense reflects the effective yield of the debt component of the convertible debentures.

The equity component of the convertible debentures is presented under "*Unitholders' Equity*" in the consolidated balance sheet. The equity component represents the value ascribed to the conversion right granted to the holder, which remains a fixed amount over the term of the related debentures. Upon conversion of the debentures into Units by the holders, a proportionate amount of both the debt and equity components are transferred to Unitholders' capital.

(n) Employee Future Benefits

North Atlantic maintains defined benefit and defined contribution plans and provides certain post-retirement health care benefits, which cover the majority of its employees and their surviving spouses.

(i) Defined Contribution Plan

Under the defined contribution plan, the annual contribution of each participating employee's pensionable earnings is as follows:

Employee category	2006
Permanent	**5.0%**
Part-time	**2.5%**

The contributions associated with the defined contribution plan is expensed as incurred.

(ii) Defined Benefit Plans

The cost of providing the defined benefits and other post-retirement benefits is actuarially determined based upon an independent actuarial valuation using management's best estimates of discount rates, rate of return on plan assets, rate of compensation increase, retirement ages of employees, and expected health care costs. The cost of pensions earned by employees is actuarially determined using the projected benefit method prorated on credited service. Funding of the defined benefit pension plans complies with Canadian federal and provincial regulations, and requires contributions to the plans be made based on independent actuarial valuation. Pension plan assets are measured at fair values with the difference between the fair value of the plan assets and the total employee benefit obligation recorded on the balance sheet. For the purpose of calculating the expected return on assets, the fair value of the plan assets is used.

The defined benefit plans provide benefits based on length of service and the best five years of the last ten years' average earnings. There is no recognition or amortization of actuarial gains or losses less than 10% of the greater of the accrued benefit obligations and the fair value of plan assets for the defined benefit pension plans. Actuarial gains and losses over 10% are amortized on a straight-line basis over the average remaining service period of the plan participants. Actuarial gains or losses related to the other post-retirements benefits are recognized in income immediately. Past service costs are amortized on a straight-line basis over the expected average remaining service life of plan participants.

(o) Currency Translation

Monetary assets and liabilities denominated in a currency other than Canadian dollars are translated at the rate of exchange in effect at the balance sheet date. Revenues and expenses denominated in a foreign currency are translated at the monthly average rate of exchange. Translation gains and losses are included in income in the period in which they arise.

Harvest's investment in a subsidiary with a functional currency denominated in a currency other than the Canadian dollars is translated using the current rate method as the subsidiary is considered a self-sustaining operation. Gains and losses resulting from this translation are recorded in the cumulative translation adjustment in unitholders' equity.

(p) Rate Regulation

The sales price of residential home heating fuels and automotive gasoline and diesel within the Province of Newfoundland and Labrador is subject to regulation under the Petroleum Products Act. The Petroleum Products Pricing Commissioner sets the maximum mark-up between the wholesale price to the retailer and the retail price to the consumer. The full effect of rate regulation is reflected in the product sales revenue as recorded.

3. BUSINESS ACQUISITIONS

(a) North Atlantic Refining Limited

On October 19, 2006, Harvest acquired all of the issued and outstanding shares of North Atlantic Refining Limited for $1.6 billion plus certain working capital and other adjustments. The principal asset of North Atlantic Refining Limited is a medium gravity, sour-crude hydrocracking refinery. North Atlantic Refining Limited also operates a marketing division which includes gas stations, a home heating business and other ancillary services. The results of operations of North Atlantic have been included in the consolidated financial statements since its acquisition on October 19, 2006.

The aggregate consideration for the acquisition of North Atlantic consists of the following:

Consideration for the acquisition:	Amount
Cash paid	$ 1,592,793
Acquisition costs	5,000
	$ 1,597,793

This transaction has been accounted for using the purchase method whereby the assets acquired and the liabilities assumed are recorded at their fair values with the excess of the aggregated consideration over the fair value of the identifiable net assets allocated to goodwill. These amounts are estimates made by management based on currently available information. The following summarizes the aggregate consideration for the North Atlantic acquisition:

	Amount
Net working capital (including cash of $22,464)	$ 581
Inventory	36,137
Property, plant and equipment	1,254,696
Intangible assets (Note 6)	111,977
Long-term receivables	2,729
Goodwill	203,876
Funding deficiency of pension and other benefit plans	(12,203)
	$ 1,597,793

Amendments may be made to the purchase equation as the cost estimates and balances are finalized.

(b) Birchill Energy Limited ("Birchill")

On July 26, 2006, Harvest signed a binding agreement to purchase all of the issued and outstanding shares of Birchill on August 15, 2006 for $446.8 million net of working capital adjustments and transaction costs. The results of operations of Birchill have been included in the consolidated financial statements since the time of effective control, July 26, 2006.

The aggregate consideration for the acquisition of Birchill consists of the following:

Consideration for the acquisition:	Amount
Cash paid, net of expected working capital recoveries	$ 445,538
Acquisition costs	1,309
	$ 446,847

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

Consideration for the acquisition:	Amount
Net working capital deficiency (including nil cash)	$ (14,755)
Property, plant and equipment	462,821
Asset retirement obligation	(1,219)
	$ 446,847

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

(c) Viking Energy Royalty Trust ("Viking")

On February 3, 2006, the unitholders of Harvest and Viking voted to approve a resolution to effect the Plan of Arrangement (the "Plan of Arrangement") by which unitholders of Viking received 0.25 Harvest trust units for every Viking trust unit held, and Harvest acquired all of the assets and assumed all of the liabilities of Viking for total consideration of approximately $1,638.1 million plus assumption of debt. This amount consisted of the issuance of 46,040,788 trust units [Note 13(b)] at an ascribed value of $35.58 per trust unit, based on the weighted average trading price of the Harvest trust units before and after the announcement date of November 28, 2005. Pursuant to the terms and conditions of Vikings' convertible debenture indenture, Harvest's acquisition of Viking's net assets resulted in Harvest assuming the obligations of Viking's convertible debentures, including the adjustment of the conversion ratio to reflect the 0.25 Harvest trust unit for each Viking trust unit exchange ratio.

The aggregate consideration for the acquisition of Viking consists of the following:

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

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

Allocation of purchase price:	Amount
Net working capital deficiency (including nil cash)	$ (31,297)
Property, plant and equipment	1,455,000
Fair value deficiency of risk management contracts	(1,224)
Fair value of office lease (Note 6)	931
Goodwill	612,416
Asset retirement obligation	(60,493)
	$ 1,975,333

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

(iv) Hay River

On August 2, 2005, Harvest acquired a partnership with certain petroleum and natural gas producing properties for total cash consideration of $237.8 million. The results have been included in the consolidated financial statements as of the closing date.

This transaction was accounted for using the purchase method. The following summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition.

Allocation of purchase price:	Amount
Working capital deficiency	$ (2,644)
Property, plant and equipment	244,995
Asset retirement obligation	(4,568)
Total cash consideration	$ 237,783

4. INVENTORIES

Inventories consist of the following:

	December 31, 2006
Petroleum products	$ 19,513
Parts and supplies	10,999
Total inventories, net	$ 30,512

For the year ended December 31, 2006, inventory included lower of cost or market write-downs of $0.3 million and nil, respectively. Such write-down amounts were included as costs in "purchased products for resale and processing" in the consolidated statements of income. There was no inventory for the year ended December 31, 2005.

5. PROPERTY, PLANT AND EQUIPMENT

	December 31, 2006			December 31, 2005
	Petroleum and natural gas	**Refining and marketing**	**Total**	Total [1]
Cost	**$ 3,801,054**	**$ 1,313,978**	**$ 5,115,032**	$ 1,438,661
Accumulated depletion and depreciation	**(706,540)**	**(14,660)**	**(721,200)**	(308,506)
Net book value	**$ 3,094,514**	**$ 1,299,318**	**$ 4,393,832**	$ 1,130,155

(1) In 2005, only petroleum and natural gas activities.

General and administrative costs of $12.1 million (2005 – $7.1 million) have been capitalized during the year ended December 31, 2006, of which $3.0 million (2005 - $3.7 million) relate to the Trust Unit Incentive Plan and the Unit award incentive plan.

All costs, except those associated with undeveloped properties and assets under construction, are subject to depletion and depreciation at December 31, 2006 including future development costs of $289.2 million (2005 – $183.5 million). Undeveloped properties of $12.0 million were excluded from the asset base subject to depletion at December 31, 2005 (no amounts excluded for December 31, 2006). Refining and marketing assets under construction of $5.5 million were excluded from the asset base subject to depreciation at December 31, 2006 (no amounts excluded for December 31, 2005).

The petroleum and natural gas future prices used in the impairment test for petroleum and natural gas assets were obtained from third party engineers and were adjusted for contractual arrangements relating to pricing and quality differentials specific to Harvest. Based on these assumptions, the undiscounted future net revenue from Harvest's proved reserves exceed the carrying amount of its petroleum and natural gas assets as at December 31, 2006 and 2005, and therefore no impairment was recorded in either of the periods ended on these dates.

Benchmark prices and U.S.$/Cdn.$ exchange rate assumptions reflected in the impairment test as at December 31, 2006 were as follows:

Year	WTI Oil[1] (US$/barrel)	Foreign Exchange Rate	Edmonton Light Crude Oil[1] (CDN$/barrel)	AECO Gas[1] (CDN$/Gigajoule)
2007	62.50	0.87	70.80	6.85
2008	61.20	0.87	69.30	7.05
2009	59.80	0.87	67.70	7.40
2010	58.40	0.87	66.10	7.50
2011	56.80	0.87	64.20	7.70
Thereafter (escalation)	2.0%	0%	2.0%	2.0%

(1) Actual prices used in the impairment test were adjusted for commodity price differentials specific to Harvest.

6. INTANGIBLE ASSETS [SEE NOTE 3(A)]

	December 31, 2006		
	Cost	Accumulated Amortization	Net book value
Engineering drawings	$ 103,721	$ 1,080	$ 102,641
Marketing contracts	7,214	105	7,109
Customer lists	4,368	92	4,276
Fair value of office lease	931	205	726
Total	$ 116,234	$ 1,482	$ 114,752

7. DEFERRED CHARGES AND OTHER NON-CURRENT ASSETS

	December 31, 2006	December 31, 2005
Financing costs, net of amortization	**$ 31,269**	$ 11,064
Discount on senior notes, net of amortization	**1,408**	1,704
Minimum lease payments receivable	**4,618**	-
Less: unearned finance income on lease receivable	**(235)**	-
	$ 37,060	$ 12,768
Less current portion of minimum lease payments receivable [1]	**(1,403)**	-
Total	**$ 35,657**	$ 12,768

(1) Included in accounts receivable and other.

8. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	December 31, 2006	December 31, 2005
Trade accounts payable	$ 111,837	$ 22,484
Accrued interest	14,367	4,959
Trust Unit Incentive Plan and Unit Award Incentive Plan [Note 14]	6,442	17,828
Premium on price risk management contracts	-	462
Other accrued liabilities	161,936	53,843
Total	$ 294,582	$ 99,576

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 $672 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% and inflation rate of approximately 2% (2005 - 1%) were used to calculate the fair value of the asset retirement obligations at the time they were initially set-up. Upward revisions and new obligations are discounted using a revised credit adjusted risk-free discount rate of 8%.

A reconciliation of the asset retirement obligations is provided below:

Year ended December 31	December 31, 2006	December 31, 2005
Balance, beginning of year	$ 110,693	$ 90,085
Incurred on acquisition of Hay River	-	4,568
Incurred on acquisition of Viking	60,493	-
Incurred on acquisition of Birchill	1,219	-
Liabilities incurred	2,763	2,760
Revision of estimates	20,544	8,656
Liabilities settled	(9,186)	(4,146)
Accretion expense	15,954	8,770
Balance, end of year	$ 202,480	$ 110,693

Harvest has gross asset retirement obligations of approximately $14.7 million relating to the refining and marketing assets that is expected to be settled after 2081. Due to the long time period prior to settlement, the discounted value today is immaterial and has not been recorded.

10. BANK LOAN

At December 31, 2006, Harvest had $1,306.0 million drawn under its three year revolving credit facilities, of which $763.0 million is payable in U.S. dollars, and $289.7 million drawn under its $350 million Senior Secured Bridge Facility. At December 31, 2005, Harvest had $13.9 million drawn under a $400 million credit facility.

On February 1, 2007, Harvest issued 6,146,750 trust units and 200,000 convertible debentures for total net proceeds of $328.6 million which was used to fully repay the remaining $289.7 million outstanding on the Senior Secured Bridge Facility with the remainder applied to the three year extendible revolving facility.

The $400 million credit facility consisted of a $375 million production facility plus a $25 million operating facility. This credit facility enabled funds to be borrowed, repaid and re-borrowed within the term that was extendible for an additional 364 day period on an annual basis with the consent of the lenders. If the term was not extended, the credit facilities would have converted to a 366 day non-revolving term loan with no repayments due until August 2, 2007. Amounts borrowed under the production and operating facilities bore interest at a floating rate based on the prime rate plus a range of 0 to 225 basis points depending on the type of borrowing and Harvest's debt to annualized cash flow ratio, as defined in the credit agreement. Availability under this facility was subject to a reserve based borrowing calculation performed by the lenders at least on a semi-annual basis. This facility was repaid on February 3, 2006 with proceeds from a new credit facility entered into concurrent with the closing of the acquisition of Viking.

On February 3, 2006, Harvest entered into a credit agreement which established a $750 million three year extendible revolving credit facility. With the consent of the lenders, this facility could be extended on an annual basis for an additional 364 days, and was capable of increasing to $900 million by way of a secondary syndication. On March 31, 2006, a secondary syndication was completed with an increase in the facility to $900 million and a maturity date of March 31, 2009. The credit facility was secured by a $1.5 billion first floating charge over all of the assets of Harvest's operating subsidiaries. Amounts borrowed under this facility bore interest at a floating rate based on bankers' acceptances plus a range of 65 to 115 basis points depending on Harvest's ratio of senior debt (excluding convertible debentures) to its earnings before interest, taxes, depletion, amortization and other non-cash amounts ("EBITDA"). Availability under this facility was subject to the following quarterly financial covenants:

Senior debt to EBITDA	3.0 to 1.0 or less
Total debt to EBITDA	3.5 to 1.0 or less
Senior debt to Capitalization	50% or less
Total debt to Capitalization	55% or less

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

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

On October 19, 2006, North Atlantic entered into an amended and restated credit agreement that provides for a $10 million demand operating line of credit to finance its receivables and inventory in the Province of Newfoundland and Labrador as well as support periodic cash management market transactions. This facility is secured by a guarantee from Harvest Operations Corp. with amounts borrowed bearing interest at the bank's prime lending rate.

On October 19, 2006, Harvest drew the full amount of the $450 million Senior Unsecured Credit Facility as well as the full amount of the $350 million Senior Secured Credit Facility plus $789.8 million from the Three Year Extendible Revolving Credit Facility to close the purchase of North Atlantic (see Note 3(a)).

On November 20, 2006, Harvest and its lenders amended the credit agreement to enable the first $100 million of the net proceeds from an offering of trust units and convertible debentures on November 22, 2006 to be retained by Harvest for general purposes. On November 22, 2006 Harvest issued 9,499,000 trust units and 379,500 convertible debentures for total net proceeds of $610.2 million, of which $450 million was used to fully repay the Senior Unsecured Bridge Facility,

$60.3 million was applied against the $350 million Senior Secured Bridge Facility and the remainder was applied against the three year extendible revolving facility.

For the year ended December 31, 2006 Harvest paid interest at an average rate of 4.86% (2005 – 4.75%) and 6.07% (2005 – 6.39%) for the Canadian and U.S amounts drawn, respectively.

11. CONVERTIBLE DEBENTURES

Harvest has six series of convertible unsecured subordinated debentures outstanding. Interest on the debentures is payable semi-annually in arrears in equal installments on dates prescribed by each series. The debentures are convertible into fully paid and non-assessable trust units, at the option of the holder, at any time prior to the close of business on the earlier of the maturity date and the business day immediately preceding the date specified by Harvest for redemption. The conversion price per trust unit is specified for each series and may be supplemented with a cash payment for accrued interest and in lieu of any fractional trust units resulting from the conversion.

The debentures may be redeemed by Harvest at its option in whole or in part prior to their respective maturity dates. The redemption price for the first redemption period is at a price equal to $1,050 per debenture and at $1,025 per debenture during the second redemption period. Any redemption will include accrued and unpaid interest at such time. Harvest may elect to settle the principal due at maturity or on redemption and periodic interest payments in the form of trust units at a price equal to 95% of the weighted average trading price for the preceding 20 consecutive trading days, 5 days prior to settlement date.

The following is a summary of the six 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%[(2)] Debenture Due 2008	$ 29.00	Jan. 31, 2008	Feb. 1/06-Jan. 31/07	Feb. 1/07-Jan. 30/08
6.40%[(1)(2)] Debenture Due 2012	$ 46.00	Oct. 31, 2012	Nov. 1/08-Oct. 31/09	Nov. 1/09-Oct. 31/10
7.25%[(3)] Debenture Due 2013	$ 32.20	Sept. 30, 2013	Oct. 1/09-Sept. 30/10	Oct. 1/10-Sept. 30/11

(1) This series of convertible debentures may also be redeemed by Harvest at a price of $1,000 per debenture on or after November 1, 2009 until maturity.

(2) The fair value, including the equity component, of the 10.5% convertible debentures and the 6.40% convertible debentures at acquisition on February 3, 2006 was $44.8 million and $181.5 million, respectively.

(3) This series of convertible debentures may also be redeemed by Harvest at a price of $1,000 per debenture on or after October 1, 2011 until maturity.

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

	December 31, 2006			December 31, 2005	
	Face Value	Carrying Amount[1]	Fair Value	Face Value	Carrying Amount[1]
9% Debentures Due 2009	$ 1,226	$ 1,226	$ 2,280	$ 1,777	$ 1,777
8% Debentures Due 2009	2,239	2,229	3,731	3,786	3,764
6.5% Debentures Due 2010	37,929	35,988	37,925	41,473	38,914
10.5% Debentures Due 2008	26,621	26,824	28,085	-	-
6.40% Debentures Due 2012	174,743	167,401	159,485	-	-
7.25% Debentures Due 2013	379,500	367,843	375,705	-	-
	$ 622,258	$ 601,511	$ 607,211	$ 47,036	$ 44,455

(1) Excluding the equity component.

12. $7^{7/8}$% SENIOR NOTES

On October 14, 2004, Harvest Operations Corp., a wholly owned subsidiary of Harvest, issued US$250 million of $7^{7/8}$% Senior Notes for cash proceeds of $311,951,000. The $7^{7/8}$% Senior Notes are unsecured, require interest payments semi-annually on April 15 and October 15 each year and mature on October 15, 2011. Prior to maturity, redemptions are permitted as follows:

- Before October 15, 2007 at 107.875% of the principal amount[1]
- Beginning on October 15, 2007 at 103.938% of the principal amount[2]
- After October 15, 2008 at 103.938% of the principal amount
- After October 15, 2009 at 101.969% of the principal amount
- After October 15, 2010 at 100% of the principal amount

(1) Limited to 35% of the notes issued and limited to repayment with proceeds from an equity offering.

(2) Only permitted if necessary to prevent the Trust from being disqualified as a trust for the purpose of the Income Tax Act. Limited to 35% of the notes issued or less; otherwise 100% of the notes issued.

The $7^{7/8}$% Senior Notes contain certain covenants restricting, among other things, the sale of assets and the incurrence of additional indebtedness if such issuance would result in an interest coverage ratio, as defined, of less than 2.5 to 1. The covenants of the $7^{7/8}$% Senior Notes also restrict Harvest's secured indebtedness to an amount less than 65% of the present value of the future net revenues from its proven petroleum and natural gas reserves discounted at an annual rate of 10%. In addition, the $7^{7/8}$% Senior Notes restrict Harvest's ability to pay distributions to an amount equal to 80% of the cumulative net proceeds from the issuance of trust units plus the cash flows from operations, before settlement of asset retirement obligations and changes in non-cash working capital, both calculated from the date of issuance of the $7^{7/8}$% Senior Notes. An excess carryforward balance of approximately Cdn$1 billion exists as at December 31, 2006.

The $7^{7/8}$% Senior Notes are unconditionally guaranteed by Harvest and all of its wholly-owned subsidiaries. The fair value of the $7^{7/8}$% Senior Notes at December 31, 2006 was US$236.3 million.

13. UNITHOLDERS' CAPITAL

(a) Authorized

The authorized capital consists of an unlimited number of trust units.

(b) Number of Units Issued

	Year ended December 31,	
	2006	2005
Outstanding, beginning of year	**52,982,567**	41,788,500
Issued in exchange for assets of Viking [Note 3 (c)]	**46,040,788**	-
Issued for cash		
August 17, 2006	**7,026,500**	-
November 22, 2006	**9,499,000**	-
Conversion of subscription receipts	**-**	6,505,600
Convertible debenture conversions		
9% Debentures Due 2009	**39,777**	643,133
8% Debentures Due 2009	**96,252**	703,976
6.5% Debentures Due 2010	**114,313**	1,081,497
10.5% Debentures Due 2008	**290,919**	-
6.40% Debentures Due 2012	**4,825**	-
Exchangeable share retraction [Note 15]	**184,809**	299,123
Distribution reinvestment plan issuance	**5,464,450**	1,632,394
Exercise of unit appreciation rights and other	**351,972**	328,344
Outstanding, end of year	**122,096,172**	52,982,567

On August 17, 2005, Harvest implemented a premium distribution reinvestment plan. The premium distribution program enables investors to receive a cash payment equal to 102% of the regular distribution amount. The impact to Harvest is the same as the regular distribution reinvestment plan whereby it settles distributions with units rather than cash, at a discount to the current market price of the Units.

(c) Per Trust Unit Information

The following tables summarize the net income and trust units used in calculating income per trust unit:

Net income adjustments	**December 31, 2006**	December 31, 2005
Net income, basic	**$ 136,046**	$ 104,946
Non-controlling interest	**(65)**	149
Interest on convertible debentures	**375**	1,128
Net income, diluted[1]	**$ 136,356**	$ 106,223
Weighted average trust units adjustments	**December 31, 2006**	December 31, 2005
Number of Units		
Weighted average trust units outstanding, basic	**101,590,850**	46,557,151
Effect of convertible debentures	**291,000**	880,208
Effect of exchangeable shares	**31,793**	274,768
Effect of Employee Unit Incentive Plans	**268,518**	795,754
Weighted average trust units outstanding, diluted[2]	**102,182,161**	48,507,881

(1) Net income, diluted excludes the impact of the conversions of certain of the convertible debentures of $19,855,000 for the year ended December 31, 2006 (2005 - $1,736,000), as the impact would be anti-dilutive.

(2) Weighted average trust units outstanding, diluted for the year ended December 31, 2006 does not include the unit impact of 6,980,000 for certain of the convertible debentures (2005 - 749,000), as the impact would be anti-dilutive.

14. EMPLOYEE UNIT INCENTIVE PLANS

Trust Unit Rights Incentive Plan

Harvest is authorized to grant non-transferable Unit appreciation rights to directors, officers, consultants, employees and other service providers to an aggregate of a rolling maximum of 7% of the outstanding trust units and the number of trust units issuable upon the exchange of any outstanding exchangeable shares. The initial exercise price of rights granted under the plan is equal to the market price of the trust units at the time of grant and the maximum term of each right is five years. The rights vest equally over four years commencing on the first anniversary of the grant date. The exercise price of the rights may be reduced by an amount up to the amount of cash distributions made on the trust units subsequent to the date of grant of the respective right, provided that Harvest's net operating cash flow (on an annualized basis) exceeds 10% of Harvest's recorded cost of property, plant and equipment less all debt, working capital deficiency (surplus) or debt equivalent instruments, accumulated depletion, depreciation and amortization charges, asset retirement obligations, and any future income tax liability associated with such property, plant and equipment. Any portion of a distribution that does not reduce the exercise price on exercised rights is paid to the holder in a lump sum cash payment after the rights have been exercised.

Upon the exercise of unit appreciation rights the holder has the sole discretion to elect to receive cash or units. As a result, Harvest recognizes a liability on its consolidated balance sheet associated with the rights reserved under the plan. This obligation represents the difference between the market value of the trust units and the exercise price of the vested Unit rights outstanding under the plan. As such, an obligation of $6.4 million (2005 - $17.8 million) has been recorded in accounts payable and accrued liabilities for the graded vested portion of the 3,788,125 (2005 – 1,305,143) trust units outstanding under the plan at December 31, 2006. For accounting purposes, vesting is deemed to occur on a pro rata basis throughout the year, rather than at a vesting date which only occurs on the anniversary date of the grant.

The following summarizes the trust units reserved for issuance under the Trust Unit Incentive Plan:

	Year ended December 31, 2006		Year ended December 31, 2005	
	Unit Appreciation Rights	**Weighted Average Exercise Price**	Unit Appreciation Rights	Weighted Average Exercise Price
Outstanding beginning of year	**1,305,143**	**$ 19.72**	1,117,725	$ 11.92
Granted	**3,924,300**	**31.92**	793,325	26.69
Exercised	**(1,039,018)**	**18.58**	(420,157)	9.49
Cancelled	**(402,300)**	**37.25**	(185,750)	25.70
Outstanding before exercise price reductions	**3,788,125**	**30.81**	1,305,143	19.72
Exercise price reductions	**-**	**(1.67)**	-	(2.99)
Outstanding, end of year	**3,788,125**	**$ 29.14**	1,305,143	$ 16.73
Exercisable before exercise price reductions	**266,125**	**$ 24.18**	109,068	$ 13.56
Exercise price reductions	**-**	**(5.37)**	-	(4.04)
Exercisable, end of year	**266,125**	**$ 18.81**	109,068	$ 9.52

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

		Outstanding			Exercisable	
Exercise Price before price reductions	Exercise Price net of price reductions	At December 31, 2006	Weighted Average Exercise Price net of price reductions[1]	Remaining Contractual Life [1]	At December 31, 2006	Weighted Average Exercise Price net of price reductions[1]
$12.19-$13.15	$ 4.74-$6.07	9,250	$ 5.57	1.9	9,250	$ 5.57
$13.35-$17.84	$ 6.46-$11.85	58,150	8.88	2.5	58,150	8.88
$18.90-$25.10	$ 12.99-$19.59	125,825	18.70	3.2	125,825	18.70
$26.17-$37.56	$ 22.85-$35.66	3,594,900	29.89	4.6	72,900	28.60
$12.19-$37.56	$ 4.74-$35.66	3,788,125	$ 29.14	4.5	266,125	$ 18.81

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

Unit Award Incentive Plan ("Unit Award Plan")

The Unit Award Plan authorizes Harvest to grant awards of trust units to directors, officers, employees and consultants of Harvest and its affiliates (to an aggregate of a rolling maximum of 0.5% of the outstanding trust units and the number of trust units issuable upon the exercise of any outstanding exchangeable shares). Subject to the Board of Directors' discretion, awards vest annually over a two to four year period and, upon vesting, entitle the holder to elect to receive the number of trust units subject to the award or the equivalent cash amount. The number of Units to be issued is adjusted at each distribution date for an amount approximately equal to the foregone distributions. The fair value associated with the trust units granted under the Unit Award Plan is expensed in the statement of income over the vesting period.

Number	**December 31, 2006**	December 31, 2005
Outstanding, beginning of year	**35,365**	10,662
Granted	**320,905**	23,466
Adjusted for distributions	**27,879**	1,237
Exercised	**(41,530)**	-
Forfeitures	**(35,920)**	-
Outstanding, end of year	**306,699**	35,365

Upon closing of the Viking Plan of Arrangement all awards and rights issued under Harvest's employee unit incentive plans vested and additional rights and awards were issued under both plans.

Harvest has recognized compensation expense of $9.9 million (2005 – $17.3 million), including non cash compensation recovery of $8.1 million (2005 expense - $16.3 million), for the year ended December 31, 2006, related to the Trust Unit Incentive Plan and the Unit Award Plan and this is reflected in general and administrative expense in the consolidated statements of income.

15. EXCHANGEABLE SHARES

(a) Authorized

Harvest Operations is authorized to issue an unlimited number of exchangeable shares without nominal or par value.

(b) Issued

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

On June 30, 2004, 600,587 exchangeable shares, series 1 were issued at $14.77 per share. After retractions of 145,040 shares in 2004, 272,578 shares in 2005 and 156,067 shares in 2006, Harvest elected on March 16, 2006 to exercise its de minimus redemption right to redeem all of the remaining exchangeable shares outstanding on June 20, 2006 for a cash payment totaling $1.0 million following which there were no exchangeable shares outstanding.

(c) Non-Controlling Interest

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

	December 31, 2006	December 31, 2005
Non-controlling interest, beginning of year	**$ 3,179**	$ 6,895
Exchanged for trust units	**(2,648)**	(3,865)
Redeemed for cash	**(1,022)**	-
Excess of redemption price over cost, charged to accumulated income	**556**	-
Current period income attributable to non-controlling interest	**(65)**	149
Non-controlling interest, end of year	**$ -**	$ 3,179

16. INCOME TAXES

The future income tax provision reflects the net tax effects of temporary differences between the carrying amounts of assets and liabilities of Harvest Operations and the Trust's other corporate subsidiaries and their corresponding income tax bases as at that date. Changes in the temporary differences are reflected in future income tax expense or recovery. The legislated reductions in the Federal and Provincial income tax rates were implemented as expected in 2004. Federal rates are expected to decline further until 2010, resulting in an effective tax rate of approximately 30% for the Trust, which is the rate applied to the temporary differences in the future income tax calculation based on when these differences are expected to reverse.

The provision for future income taxes varies from the amount that would be computed by applying the combined Canadian Federal and Provincial income tax rates to the reported income before taxes as follows:

	Year ended December 31,	
	2006	2005
Income before taxes	**$ 133,737**	$ 72,709
Combined Canadian Federal and Provincial statutory income tax rate	**35.3%**	37.6%
Computed income tax expense at statutory rates	**47,209**	27,339
Income earned by flow through entities	**(136,452)**	(64,763)
Loss in corporate entities	**(89,243)**	(37,424)
Increased expense (recovery) resulting from the following:		
Non-deductible crown charges	**6,935**	4,242
Resource allowance	**2,142**	(3,499)
Non-deductible portion of capital loss (gain)	**1,789**	(1,834)
Unit appreciation rights expense	**3,228**	4,455
Difference between current and expected tax rates	**10,465**	2,300
Benefit of future tax deductions not recognized	**62,384**	-
Other	**-**	(611)
Future income tax recovery	**$ (2,300)**	$ (32,371)

The components of the future income tax liability (asset) are as follows:

	December 31, 2006	December 31, 2005
Net book value of petroleum and natural gas assets in excess of tax pools	**$ 29,896**	$ 41,270
Asset retirement obligation	**(17,641)**	(12,826)
Net unrealized losses related to risk management contracts and foreign exchange positions – current	**(3,818)**	(17,483)
Net unrealized losses related to risk management contracts and foreign exchange positions – long-term	**(1,266)**	1,532
Non-capital loss carry forwards for tax purposes	**(40,412)**	(4,701)
Deferral of taxable income in Partnership	**1,483**	1,425
Working capital and other items	**(2,787)**	(6,917)
Valuation allowance	**34,545**	-
Future income tax liability (asset), net	**$ -**	$ 2,300

The amount of tax pools available to the Trust, in all of its subsidiaries, is approximately $2.3 billion. These tax pools are primarily made up of resource tax pools, undepreciated capital cost, non-capital losses, and unit issue costs. These tax pools are available for deduction in future years to enable the Trust to manage its exposure to income taxes.

Canada Revenue Agency (“CRA”) Assessment

In 2002, the CRA assessed, as a $30 million forgiveness of debt, a 1994 share issue in connection with the acquisition of North Atlantic in 1994 by a Vitol Refining S.A. affiliate. North Atlantic disagrees with the CRA’s position and believes that the value of the common shares issued in 1994 was equal to the value of the debt exchanged and has filed a Notice of Objection to the CRA’s Notice of Reassessment. There are no contingent amounts accrued related to this matter in these financial statements. Harvest is indemnified by the vendor of North Atlantic in respect of this contingent liability.

Proposed Income Tax Changes

On October 31, 2006, the Canadian government announced plans to introduce a 31.5% tax on distributions paid by publicly traded income trusts, which would include Harvest Energy Trust, as well as intentions that would limit the growth of such trusts. Harvest has not recorded provisions to reflect the impact of these announced changes as the legislation has not been substantially enacted.

17. EMPLOYEE FUTURE BENEFIT PLANS [SEE NOTE 3(A)]

Defined Contribution Pension Plan

Total expense for the defined contribution plan is equal to Harvest's required contributions and was $0.143 million, for the year ended December 31, 2006 (2005 – nil).

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:

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

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

	December 31, 2006
Bonds/fixed income securities	32%
Equity securities	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.

	December 31, 2006			
		Pension Plans		Other Benefit Plans
Employee benefit obligation, October 19, 2006 [note 3(a)]	$	**38,754**	$	5,315
Current service costs		**648**		88
Interest		**546**		74
Actuarial losses		**3,422**		601
Plan amendment		**-**		-
Benefits paid		**(269)**		(51)
Impact of foreign exchange on translation		**-**		-
Employee benefit obligation, end of year		**43,101**		6,027
Fair value of plan assets, October 19, 2006		**31,878**		-
Actual return on plan assets		**3,181**		-
Employer contributions		**1,306**		51
Employee contributions		**480**		-
Benefits paid		**(269)**		(51)
Impact of foreign exchange on translation		**-**		-
Fair value of plan assets, end of year		**36,576**		-
Funded status		**(6,525)**		(6,027)
Unamortized balances:				
Net actuarial losses		**325**		-
Past services		**-**		-
Carrying Amount	$	**(6,200)**	$	(6,027)

	December 31, 2006	
Summary:		
Pension plans	$	6,200
Other benefit plans		6,027
Carrying amount	$	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 21].

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

	Year ended December 31, 2006	
	Pension Plans	Other Benefit Plans
Current service cost	$ 648	$ 88
Interest costs	546	74
Expected return on assets	(563)	-
Amortization of net actuarial losses	-	588
Net benefit plan expense	$ 631	$ 750

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)

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT CONTRACTS

Harvest is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations.

(a) Fair Values

Financial instruments of Harvest consist mainly of accounts receivable, long-term receivables, accounts payable and accrued liabilities, cash distribution payable, bank loan, risk management contracts, convertible debentures and senior notes. Other than as disclosed in Note 11 for the convertible debentures and Note 12 for the senior notes, there were no significant differences between the carrying amounts of these financial instruments reported on the balance sheet and their estimated fair values due to their short term to maturity, the risk management contracts are presented at fair value on the balance sheet, and bank debt bears interest at a floating rate.

(b) 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.

(c) Credit Risk

Substantially all accounts receivable in our petroleum and natural gas operations are due from customers 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 partners and customers, including parties involved in marketing or other commodity arrangements. The Supply and Offtake Agreement entered into in conjunction with the purchase of the refinery increased Harvest's exposure to the credit risk of Vitol Refining S.A. as all feedstock purchases and substantially all products sales are made with Vitol Refining S.A. Harvest mitigates this risk by requiring that Vitol Refining S.A. maintain a minimum B+ credit rating. If the credit rating falls below this line additional security is required to be supplied to Harvest. The carrying amount of accounts receivable reflects management's assessment of the associated credit risks.

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. Harvest does not anticipate loss for non-performance other than as already recorded.

(d) Foreign Exchange Rate Risk

Harvest is exposed to the risk of changes in the Canadian/U.S. dollar exchange rate on purchases and sales of commodities that are denominated in U.S. dollars or directly influenced by U.S. dollar benchmark prices. In addition, Harvest's $7^{7/8}$% Senior Notes are denominated in U.S. dollars (U.S.$250 million). These notes act as an economic hedge to help offset the impact of exchange rate movements on commodity sales during the year. As at December 31, 2006 the full balance of the notes is still outstanding and is not repayable until October 15, 2011. Interest is payable semi-annually on the notes in U.S. dollars. Harvest also enters into foreign currency swaps to match the exchange rate on future U.S. dollar payments to the exchange rate received on U.S. dollar sales. Harvest is also exposed to the risk of changes in the Canadian/U.S. dollar exchange rate on its net investment in North Atlantic, as the functional currency of the refinery is U.S. dollars. However, a portion of the purchase price was financed with U.S. dollar borrowings, which acts as an economic hedge to help offset this exposure.

(e) Risk Management Contracts

Harvest uses fixed price petroleum sales contracts and financial instruments to manage its commodity price exposure. Under the terms of some of these instruments, Harvest is required to provide security to its counterparties from time to time based on the underlying market value of those contracts. As at December 31, 2006, no security was provided. Harvest is also exposed to counterparty risk for these risk management contracts. This risk is managed by diversifying Harvest's risk management portfolio among a number of counterparties and by dealing with large investment grade institutions.

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

Quantity	Type of Contract	Term	Reference	Fair value
5,000 bbl/d	Participating swap	January – December 2007	U.S.$60.00[a]	$ 1,718
5,000 bbl/d	Participating swap	January – December 2007	U.S.$65.00[b]	7,709
25,000 GJ/d	Natural gas price collar contract	January – March 2007	Cdn$5.00-$13.55	110
25,000 GJ/d	Natural gas price collar contract	January – March 2007	Cdn$7.00-$12.50	1,553
35 MWH	Electricity price swap contracts	January – December 2007	Cdn $56.69	6,765
$6,100,000/mnth	Foreign currency swap	January 2007	1.1553 Cdn/U.S.	59
Total current portion of fair value				**$ 17,914**
5,000 bbl/d	Participating swap	January – June 2008	U.S.$65.00[c]	$ 3,290
35 MWH	Electricity price swap contracts	January – December 2008	Cdn $56.69	6,553
Total long-term portion fair value				**$ 9,843**
1,000 bbl/d	Differential swap – Wainwright	January – April 2007	27.70%	$ (275)
5,000 bbl/d	Participating swap	January – June 2007	U.S.$49.03[d]	(3,607)
10,000 bbl/d	Participating swap	January – December 2007	U.S.$55.00[c]	(9,854)
5,000 bbl/d	Indexed put contract – bought put	January – December 2007	U.S.$50.00[e]	1,520
2,500 bbl/d	Indexed put contract – sold call	January – December 2007	U.S.$50.00[e]	(16,241)
2,500 bbl/d	Indexed put contract – bought call	January – December 2007	U.S.$60.00[e]	7,849
2,500 bbl/d	Indexed put contract – sold call	January – December 2007	U.S.$70.00[e]	(2,939)
2,500 bbl/d	Indexed put contract – bought call	January – December 2007	U.S.$83.00[e]	819
200 GJ/d	Fixed price – natural gas contract	January – December 2007	Cdn.$4.13[g]	(473)
76 GJ/d	Fixed price – natural gas contract	January – December 2007	Cdn.$2.16-2.22[g]	(125)
$416,700/mnth	Foreign currency swap	January – December 2007	1.14 Cdn/U.S.	(78)
$4,167,000/mnth	Foreign currency swap	January – December 2007	1.1189 Cdn/U.S.	(1,696)
$4,167,000/mnth	Foreign currency swap	January – December 2007	1.1249 Cdn/U.S.	(1,664)
Total current portion of fair value deficiency				**$ (26,764)**
5,000 bbl/d	Participating swap	January – June 2008	U.S.$55.00[f]	$ (276)
200 GJ/d	Fixed price – natural gas contract	January – December 2008	Cdn. $5.19[g]	(552)
76 GJ/d	Fixed price – natural gas contract	January – October 2008	Cdn. $2.22[g]	(127)
$8,333,000/mnth	Foreign currency swap	January – June 2008	1.1099 Cdn/U.S.	(1,930)
Total long-term portion of fair value deficiency				**$ (2,885)**

(a) This price is a floor. Harvest realizes this price plus 77% of the difference between spot price and this price.

(b) This price is a floor. Harvest realizes this price plus 79% of the difference between spot price and this price.

(c) This price is a floor. Harvest realizes this price plus 67% of the difference between spot price and this price.

(d) This price is a floor. Harvest realizes this price plus 75% of the difference between spot price and this price.

(e) 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.

(f) This price is a floor. Harvest realizes this price plus 80% of the difference between spot price and this price.

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

At December 31, 2006, the net unrealized loss position reflected on the balance sheet for all the risk management contracts outstanding at that date was approximately $1.9 million (2005 - $52.6 million).

For the year ended December 31, 2006, the total unrealized gain recognized in the consolidated statement of income, including amortization of deferred charges and gains, was $52.2 million (2005 - $45.1 million). The realized gains and losses on all risk management contracts are included in the period in which they are incurred.

19. SEGMENT INFORMATION

Harvest operates entirely in Canada and has two reportable operating segments in 2006, Petroleum and Natural Gas and Refining and Marketing. For 2005, 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 exploration, 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 to a large market and through a network of retail gas operations, home heating business and the supply of refined products to commercial and wholesale customers.

	December 31, 2006		
	Refining and Marketing[1]	Petroleum and Natural Gas [1]	**Total**
Revenue	$ 460,359[2]	$ 1,120,575	**$ 1,580,934[3]**
Royalties	-	(200,109)	**(200,109)**
Realized net losses	-	(62,619)	**(62,619)**
Unrealized net gains	-	52,179	**52,179**
Less: expenses			
Purchased products for resale and processing	386,014	-	**386,014**
Operating	34,063	242,474	**276,537**
Transportation and marketing	5,060	12,142	**17,202**
General and administrative	-	28,372	**28,372**
Transaction costs	-	12,072	**12,072**
Depletion, depreciation, amortization and accretion	15,482	413,988	**429,470**
	$ 19,740	$ 200,978	**$ 220,718**
Interest and other financing charges on short term debt, net			**(4,864)**
Interest and other financing charges on long term debt			**(78,893)**
Realized gains on risk management contracts			**17,811**
Foreign exchange gains/(losses)			**(21,100)**
Large corporate tax and other tax			**9**
Future income tax recovery			**2,300**
Non-controlling interest			**65**
Net income			**$ 136,046**
Total Assets[1]	$ 1,727,797	$ 4,017,761	**$ 5,745,558**
Capital Expenditures			
Development and other activity	$ 21,411	$ 376,881	**$ 398,292**
Business acquisitions	1,597,793	2,422,180	**4,019,973[4]**
Property acquisitions	-	65,773	**65,773**
Property dispositions	-	(20,856)	**(20,856)**
Increase in other non-current assets	165	-	**165**
Total expenditures	$ 1,619,369	$ 2,843,978	**$ 4,463,347**
Property, plant and equipment			
Cost	$ 1,313,978	$ 3,801,054	**$ 5,115,032**
Less: Accumulated depletion, depreciation, amortization and accretion	(14,660)	(706,540)	**(721,200)**
Net book value	$ 1,299,318	$ 3,094,514	**$ 4,393,832**
Goodwill, beginning of year	$ -	$ 43,832	**$ 43,832**
Additions to goodwill	209,930	612,416	**822,346**
Goodwill, end of year	$ 209,930	$ 656,248	**$ 866,178**

(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 year ended December 31, 2006, $427.1 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 year $1,150.5 million is attributable to sales in Canada, while $430.4 million is attributable to sales in the United States.

(4) Included in this amount is $1,975.3 million relating to the acquisition of Viking, which was acquired through the issuance of trust units and is therefore not reflected in the cash flow statement.

(5) There is no intersegment activity.

20. CHANGE IN NON-CASH WORKING CAPITAL

	Year ended December 31, 2006	2005
Changes in non-cash working capital items:		
Accounts receivable	**$ (55,505)**	$ (29,738)
Prepaid expenses and deposits	**(5,461)**	1,888
Current portion of risk management contracts assets	**3,317**	(12,370)
Inventory	**5,625**	-
Current portion of future income tax asset	**22,975**	(19,874)
Accounts payable and accrued liabilities	**17,932**	23,325
Cash distribution payable	**5,986**	10,186
Current portion of risk management contracts liability	**(40,069)**	38,041
	$ (45,200)	$11,458
Changes relating to operating activities	**$ (28,152)**	$ (22,519)
Changes relating to financing activities	**(12,604)**	(1,035)
Changes relating to investing activities	**10,886**	9,927
Add: Non-cash changes	**(15,330)**	25,085
	$ (45,200)	$ 11,458

21. 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 and contingencies at December 31, 2006:

(a) North Atlantic has a Supply and Offtake Agreement with Vitol Refining S.A. This agreement provides that the ownership of substantially all crude oil feedstock and refined product inventory at the refinery be retained by Vitol Refining S.A. and that for a minimum period of up to two years Vitol Refining S.A. will be granted the right and obligation to provide crude oil feedstock for delivery to the refinery, as well as the right and obligation to purchase substantially all refined products produced by the refinery. As such, at December 31, 2006, North Atlantic had commitments totaling approximately $550.2 million in respect of future crude oil feedstock purchases and related transportation from Vitol Refining S.A.

(b) North Atlantic has an agreement with Newsul Enterprises Inc. ("Newsul") whereby North Atlantic committed to provide Newsul with its inventory and production of sulphur to February 12, 2008. The agreement is subject to an automatic renewal for another ten years unless one of the parties elects not to renew.

Newsul has named North Atlantic in a claim in the amount of US$2.7 million and has requested the services of an arbitration board to make a determination on the claim. The claim is for additional costs and lost revenues related to alleged contaminated sulphur delivered by North Atlantic. The eventual outcome of the arbitration hearing is undeterminable.

(c) North Atlantic has an environmental agreement with the Province of Newfoundland and Labrador, Canada, committing to programs that reduce the environmental impact of the refinery over time. Initiatives include a schedule of activities to be undertaken with regard to improvements in areas such as emissions, waste water treatment, terrestrial effects, and other matters. In accordance with the agreement, certain projects have been completed and others have been scheduled.

(d) North Atlantic has been named a defendant in The State of New Hampshire versus Amerada Hess Corp. et al, one of many methyl tertiary butyl ether ("MTBE") U.S. product liability litigation cases that have been consolidated for pre-trial purposes in this matter. The plaintiffs seek relief for alleged contamination of ground water from the various defendants' use of the gasoline additive MTBE. Although the plaintiffs have not made a particular monetary demand, they are asserting collective and joint liability against all defendants. All consolidated lawsuits are at a preliminary stage and, accordingly, it is too early in the legal process to reach any conclusion regarding the ability of the State of New Hampshire to properly assert jurisdiction over North Atlantic in the lawsuit or to reach any conclusions regarding the substance of the plaintiffs' claims. Accordingly, the evaluation of the risk of liability to North Atlantic is not determinable at this time and no amounts are accrued in the consolidated financial statements in respect of this matter. Harvest is indemnified by Vitol Group B.V. in respect of this contingent liability.

(e) Petro-Canada, a former owner of the North Atlantic refinery, holds certain contractual rights in relation to production at the refinery, namely:

i. a right to share, subject to a maximum limit, in the profits of the sale of any refined product, refined at the refinery, sold in Canada, exclusive of the province of Newfoundland and Labrador;

ii. a right of first refusal to any refinery and/or terminaling capacity in excess of North Atlantic's requirements;

iii. a right to participate in any venture to produce petrochemicals at the refinery; and

iv. the rights in paragraphs (i) and (ii) above continue for a period of 25 years from December 1, 1986, while the rights in paragraph (iii) continue until amended by the parties.

The following is a summary of Harvest's contractual obligations and commitments as at December 31, 2006:

	Payments Due by Period						
	2007	2008	2009	2010	2011	Thereafter	**Total**
Debt repayments [1]	-	289,766	1,305,897	-	291,350	-	**1,887,013**
Capital commitments [2]	34,530	2,880	-	-	-	-	**37,410**
Operating leases [3]	6,476	5,879	4,966	2,153	258	258	**19,990**
Pension contributions [4]	780	1,510	1,835	2,219	2,586	19,147	**28,077**
Transportation agreements [5]	2,080	1,554	887	190	27	-	**4,738**
Feedstock commitments [6]	550,230	-	-	-	-	-	**550,230**
Contractual obligations	**594,096**	**301,589**	**1,313,585**	**4,562**	**294,221**	**19,405**	**2,527,458**

(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 17].

(5) Relating to oil and natural gas pipeline transportation agreements.

(6) Relating to crude oil feedstock purchases and related transportation costs [see Note 21(a) above].

22. RECONCILIATION OF THE CONSOLIDATED FINANCIAL STATEMENTS TO UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

These consolidated financial statements have been prepared in accordance with Canadian GAAP which, in most respects, conforms to U.S. GAAP. Any differences in accounting principles as they have been applied to the accompanying consolidated financial statements are not material except as described below. Items required for financial disclosure under U.S. GAAP may be different from disclosure standards under Canadian GAAP; any such differences are not reflected here.

The application of U.S. GAAP would have the following effects on net income as reported:

	Year Ended December 31,	
	2006	2005
Net income under Canadian GAAP	**$ 136,046**	$ 104,946
Adjustments		
Write-down of property, plant and equipment (a)	**(615,000)**	-
Unrealized loss on risk management contracts (f)	**(398)**	8,980
Future tax impact of deferred charges relating to risk management contracts (f) (g)	**-**	(3,019)
Depletion, depreciation, amortization and accretion (b)	**8,825**	1,592
Future tax impact on property, plant and equipment (b) (g)	**-**	(535)
Non-cash interest expense on debentures (d)	**454**	239
Amortization of deferred financing charges (d)	**65**	(38)
Foreign exchange gain on unit distribution (i)	**(1,038)**	-
Non-controlling interest (e)	**(65)**	149
Non-cash general and administrative expenses (c)	**(3,291)**	-
Future income tax recovery (g)	**670**	-
Net income (loss) under U.S. GAAP before cumulative effect of change in accounting policy	**(473,732)**	112,314
Cumulative effect of change in accounting policy (c)	**4,891**	-
Net income (loss) under U.S. GAAP after cumulative effect of change in accounting policy	**(468,841)**	112,314
Net change in cumulative translation adjustment (i)	**47,911**	-
Comprehensive income	**$ (420,930)**	$ 112,314
Net income (loss) under U.S. GAAP after cumulative effect of change in accounting policy	**(468,841)**	112,314
Increase in redemption value of trust units under U.S. GAAP (e)	**1,398,457**	(638,044)
Net income (loss) available to unitholders under U.S. GAAP (e)	**$ 929,616**	$ (525,730)

Basic		
Net (loss) income per trust unit under U.S. GAAP before cumulative effect of change in accounting policy	**$ (4.66)**	$ 2.41
Cumulative effect of change in accounting policy	**0.05**	-
Net income (loss) per trust unit under U.S. GAAP after cumulative effect of change in accounting policy (before changes in redemption value of trust units)	**$ (4.61)**	$ 2.41
Net income (loss) available to unitholders per trust unit under U.S. GAAP	**$ 9.15**	$ (11.29)
Diluted		
Net (loss) income per trust unit under U.S. GAAP before cumulative effect of change in accounting policy	**$ (4.66)**	$ 2.33
Cumulative effect of change in accounting policy	**0.05**	-
Net (loss) income per trust unit under U.S. GAAP after cumulative effect of change in accounting policy (before changes in redemption value of trust units)	**$ (4.61)**	$ 2.33
Net income (loss) available to unitholders per trust unit under U.S. GAAP	**$ 8.66**	$ (11.29)
Net income (loss) – U.S. GAAP	**$ 929,616**	$ (525,730)
Future income tax recovery – U.S. GAAP	**(2,970)**	(28,817)
Net income (loss) before taxes – U.S. GAAP	**$ 926,646**	$ (554,547)
Statement of Accumulated Income (loss)		
Balance, beginning of year – U.S. GAAP	**(895,736)**	(370,006)
Net income (loss) – U.S. GAAP	**(473,732)**	112,314
Cumulative effect of change in accounting policy	**4,891**	-
Change in redemption value of trust units	**1,398,457**	(638,044)
Balance, end of year – U.S. GAAP	**33,880**	(895,736)
Accumulated other comprehensive income (loss)		
Balance, beginning of year – U.S. GAAP	**-**	-
Net change in cumulative translation adjustment	**47,911**	-
Employee future benefits – Adoption of FAS 158 (j)	**(325)**	-
Balance, end of year – U.S. GAAP	**47,586**	-

The application of U.S. GAAP would have the following effect on the consolidated balance sheets as reported:

	December 31, 2006		December 31, 2005	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Assets				
Property, plant and equipment (a) (b)	$ 4,393,832	$ 3,788,606	$ 1,130,155	$ 1,131,747
Deferred charges (d) (f) (h)	$ 35,657	$ 34,199	$ 12,768	$ 10,951
Non current benefit plan assets (j)	$ -	$ 373	$ -	$ -
Future income tax (g)	$ -	$ -	$ 22,975	$ 22,975
Liabilities				
Accounts payable and accrued liabilities (c)	$ 294,582	$ 292,338	$ 99,576	$ 99,576
Current other benefit plan liability (j)	$ -	$ 162	$ -	$ -
Deferred credit (f)	$ 794	$ 794	$ 1,389	$ 991
7 7/8% Senior notes (h)	$ 291,350	$ 289,952	$ 290,750	$ 289,045
Convertible debentures – liability (d)	$ 601,511	$ 627,722	$ 44,455	$ 47,036
Non current benefit plan liability (j)	$ 12,227	$ 12,762	$ -	$ -
Future income tax (f) (g)	$ -	$ -	$ 25,275	$ 25,944
Non-controlling interest (e)	$ -	$ -	$ 3,179	$ -
Temporary equity (e)	$ -	$ 2,680,017	$ -	$ 1,783,159
Unitholders' Equity				
Unitholders' capital (e)	$ 3,046,876	$ -	$ 747,312	$ -
Equity component of convertible debentures (d)	$ 36,070	$ -	$ 2,639	$ -
Additional paid-in capital	$ -	$ 9,913	$ -	$ -
Accumulated income (i)	$ 271,155	$ 33,880	$ 135,665	$ (895,736)
Cumulative foreign currency translation adjustment (i)	$ 46,873	$ -	$ -	$ -
Accumulated other comprehensive income (j) (i)	$ -	$ 47,586	$ -	$ -

(a) Under Canadian GAAP, Harvest performs an impairment test that limits the capitalized costs of its petroleum and natural gas assets to the discounted estimated future net revenue from proved and probable petroleum and natural gas reserves plus the cost of unproved properties less impairment, estimated future prices and costs. The discount rate used is equal to Harvest's risk free interest rate. Under U.S. GAAP, entities using the full cost method of accounting for petroleum and natural gas activities perform an impairment test on each cost centre using discounted future net revenue from proved petroleum and natural gas reserves discounted at 10%. The prices used under the U.S. GAAP impairment test are those in effect at year end. As at December 31, 2005, the application of the ceiling test under U.S. GAAP resulted in a write down of $615.0 million of capitalized costs. There was no impairment under U.S. GAAP at December 31, 2005.

(b) Under Canadian GAAP, proved reserves are estimated using estimated future prices and costs. These proved reserves form the basis for the depletion calculation.

Under U.S. GAAP, proved reserves used for the depletion calculation are estimated using constant prices and costs as of the date the estimate of reserves is made. In both the current and comparative year there were significant differences in proved reserves under U.S. GAAP and Canadian GAAP and as a result the difference is realized in the depletion expense.

(c) Under Canadian GAAP, the Trust determines compensation expense and the resulting obligation related to its Trust Unit Incentive Plan and Unit Award Plan using the intrinsic value method described in Note 2 (j). Under U.S. GAAP, for the year ended December 31, 2006 Harvest adopted SFAS 123(R) "*Share Based Payment*" using the modified prospective approach. Under FAS 123(R), expenses and obligations for liability-based stock compensation plans are recorded using the fair-value method of accounting and are revalued at each period end. As a result, general and administrative expense is higher under U.S. GAAP by $3.3 million for the year ended December 31, 2006 and accounts payable and accrued liabilities is lower under U.S. GAAP by $2.2 million as at December 31, 2006.

To the extent compensation costs relates to employees directly involved in natural gas and crude oil exploration and development activities, such amounts are capitalized to property, plant and equipment. Amounts not capitalized are recognized as administrative expenses. As the Trust adopted SFAS 123(R) using the modified prospective approach, prior periods have not been restated, as required by the standard.

SFAS 123(R), under the modified prospective approach, requires the cumulative impact of a change in an accounting policy to be presented in the current year consolidated statement of income. The cumulative effect of initially adopting SFAS 123(R) January 1, 2006 was a gain of $4.9 million.

(d) Under Canadian GAAP, Harvest's convertible debentures are classified as debt with a portion, representing the value associated with the conversion feature, being allocated to equity under Canadian GAAP. Issue costs for the debentures are allocated between the equity portion and deferred charges for the debt portion. In addition, under Canadian GAAP a non-cash interest expense representing the effective yield of the debt component is recorded in the consolidated statements of income with a corresponding credit to the convertible debenture liability balance to accrete that balance to the full principal due on maturity.

Under U.S. GAAP, the convertible debentures in their entirety are classified as debt, and as a result all of the issue costs would be recorded as deferred charges. To the extent a portion of the issue costs were allocated to equity under Canadian GAAP there is a difference in amortization for the related deferred charges. The non-cash interest expense recorded under Canadian GAAP would not be recorded under U.S. GAAP.

In addition, convertible debentures that are assumed in a business combination are recorded at their fair value at the date of the acquisition as part of the cost of the acquired enterprise. Under U.S. GAAP, if the conversion feature is in-the-money at the acquisition date (beneficial conversion feature), the feature should be recognized and measured by allocating a portion of the proceeds equal to the intrinsic value of that feature to additional paid-in capital. Where the debenture has a stated redemption date, the corresponding value is recognized as a discount on the convertible debenture balance and accreted from the date of acquisition to the redemption date.

(e) Under Harvest's Indenture, trust units are redeemable at any time on demand by the Unitholder for cash. Under U.S. GAAP, the amount included on the consolidated balance sheet for Unitholders' Equity would be reduced by an amount equal to the redemption value of the trust units as at the balance sheet date. The same accounting treatment would be applicable to the exchangeable shares. The redemption value of the trust units and the exchangeable shares is determined with respect to the trading value of the trust units as at each balance sheet date, and the amount of the redemption value is classified as temporary equity. Changes, if any, in the redemption value during a period results in a charge to permanent equity and is reflected as either an increase or decrease in earnings available to Unitholders for the year. Under Canadian GAAP the exchangeable shares are recorded as non-controlling interest.

(f) Under U.S. GAAP, SFAS 133 "*Accounting for Derivative Instruments and Hedging Activities*" requires that all derivative instruments be recorded on the consolidated balance sheet as either an asset or liability measured at fair value, and requires that changes in fair value be recognized currently in income unless specific hedge accounting criteria are met. U.S. GAAP requires that a company formally document, designate, and assess the effectiveness of derivative instruments before hedge accounting may be applied. Harvest had not formally documented and designated any hedging relationships as at December 31, 2006 or December 31, 2005 and as such, the risk management contracts were not eligible for hedge accounting treatment under U.S. GAAP.

Harvest implemented fair value accounting effective January 1, 2004 under Canadian GAAP and had designated a portion of its risk management contracts as hedges. During the year ended December 31, 2004, the Trust discontinued hedge accounting for all risk management contracts under Canadian GAAP. Upon discontinuing hedge accounting, a deferred charge or gain is recorded representing the fair value of the contract at that time. This difference is amortized over the term of the contract. Under U.S. GAAP there were no contracts designated as hedges. To the extent deferred charges and credits were recorded and amortized when hedge accounting was discontinued, there is a difference between Canadian and U.S. GAAP. The deferred charges and gains continue to be amortized under Canadian GAAP for the years ended December 31, 2006 and 2005, and create a difference from U.S. GAAP.

(g) The Canadian GAAP liability method of accounting for income taxes is similar to the U.S. GAAP SFAS 109, "*Accounting for Income Taxes*", which requires the recognition of tax assets and liabilities for the expected future tax consequences of events that have been recognized in Harvest's consolidated financial statements. Pursuant to U.S. GAAP, enacted tax rates are used to calculate future income tax, whereas Canadian GAAP uses substantively enacted rates. There are no differences for the years ended December 31, 2006 and December 31, 2005 relating to tax rate differences.

Under Canadian GAAP as at December 31, 2006, Harvest's temporary differences are in a future income tax asset position. However, recognition of the asset in future periods is not more likely than not and therefore, the asset has not been recognized under Canadian GAAP. As adjustments under U.S. GAAP would result in a larger future income tax asset balance, the Trust has not recorded a future income tax asset under U.S. GAAP and has eliminated the remaining historical future income tax liability balance recognized under U.S. GAAP from previous periods. As such, an additional recovery of $0.7 million has been recognized under U.S. GAAP.

(h) Under Canadian GAAP, the discount on the senior notes has been recorded in deferred charges. Under U.S. GAAP, this amount is required to be applied against the senior notes balance.

(i) Under Canadian GAAP, the cumulative translation adjustment that is generated upon translating the financial statements of Harvest's self-sustaining foreign operations is included as a separate component of equity. Under U.S. GAAP this amount is recognized in comprehensive income and cumulative amounts are included in accumulated other comprehensive income. Harvest's comprehensive income for the year ended December 31, 2006 includes a net change in the cumulative translation adjustment of $46.9 million (2005 – nil). Additionally, exchange gains and losses from the translation of unit distributions from Harvest's self-sustaining foreign operations are included in other comprehensive income. Under Canadian GAAP these amounts are recorded as part of net income.

(j) At December 31, 2006 the Trust adopted U.S. GAAP SFAS 158, "*Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)*". Under SFAS 158, the over-funded or under-funded status of our defined benefit postretirement plan must be recognized on the balance sheet as an asset or liability and changes in the funded status are recognized through comprehensive income. As a result, employee future benefits are higher by $0.3 million (2005 – nil) and $0.3 million was included in accumulated other comprehensive income (2005 – nil). Canadian GAAP currently does not require the Trust to recognize the funded status of the plan on its balance sheet.

The following are standards and interpretations that have been issued by the Financial Accounting Standards Board ("FASB") which are not yet in effect for the periods presented but would comprise U.S. GAAP when implemented:

In July 2006, FASB issued FIN 48 "*Accounting for Uncertainty in Income Taxes*" with respect to SFAS 109 "*Accounting for Income Taxes*" regarding accounting for and disclosure of uncertain tax positions. This guidance seeks to reduce the diversity in practice associated with certain aspects of the recognition and measurement related to accounting for income taxes. This interpretation is effective for fiscal years beginning after December 15, 2006. We have not yet determined the impact this interpretation will have on our results from operations or financial position.

In September 2006, FASB issued Statement 157, "*Fair Value Measurements*". SFAS 157 defines fair value, establishes a framework for measuring fair value under U.S. GAAP and expands disclosures about fair value measurements. This statement is effective for fiscal years beginning after November 15, 2007. We do not expect the adoption of this statement will have a material impact on our results of operations or financial position.

In February 2006, FASB issued Statement No. 155 "*Accounting for Certain Hybrid Financial Instruments – an amendment of FASB Statements no. 133 and 140*" This statement amends FASB Statements No. 133 "*Accounting for Derivative Instruments and Hedging Activities*", and No. 140 "*Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*". This Statement resolves issues addressed in Statement 133 Implementation Issue No. D1 "*Application of Statement 133 to Beneficial Interests in Securitized Financial Assets*". The statement a) permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation, b) clarifies which interest-only strips and principal-only strips are not subject to the requirements of Statement 133, c) establishes a requirement to evaluate interests in securitized financial assets to identify interests that are freestanding derivatives or that are hybrid financial instruments that contain an embedded derivative requiring bifurcation, d) clarifies that concentrations of credit risk in the form of subordination are not embedded derivatives, and e) amends statement 140 to eliminate the prohibition on a qualifying special-purpose entity from holding a derivative financial instrument that pertains to a beneficial interest other than another derivative financial instrument. This statement is effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after September 15, 2006 with early adoption permitted.

In February 2007, the FASB issued SFAS No. 159, "*The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115*." This pronouncement permits entities to use the fair value method to measure certain financial assets and liabilities by electing an irrevocable option to use the fair value method at specified election dates. After election of the option, subsequent changes in fair value would result in the recognition of unrealized gains or losses as period costs during the period the change occurred. SFAS No. 159 becomes effective as of the beginning of the first fiscal year that begins after November 15, 2007, with early adoption permitted. However, entities may not retroactively apply the provisions of SFAS No. 159 to fiscal years preceding the date of adoption. We are currently evaluating the impact that SFAS No. 159 may have on our financial position, results of operations and cash flows.

Additional disclosures required under U.S. GAAP:

(thousands of Canadian dollars)	**December 31, 2006**	December 31, 2005
Components of accounts receivable		
Trade	**$ 135,578**	$ 16,555
Accruals	**118,573**	57,211
	$ 254,151	$ 73,766
Components of prepaid expenses and deposits		
Prepaid expenses	**$ 11,877**	$ 1,104
Funds on deposit	**836**	22
	$ 12,713	$ 1,126

23. SUBSEQUENT EVENTS

Subsequent to December 31, 2006, Harvest declared a distribution of $0.38 per unit for Unitholders of record on January 22, 2007, February 22, 2007 and March 22, 2007.

In January 2007, Vitol Refining S.A. entered into a six month term contract with Iraq's State Oil Marketing Organization ("SOMO") for 44,000 bbl/day of Basrah crude oil at market prices on behalf of Harvest per the Supply and Offtake Agreement.

Between January 1, 2007 and March 1, 2007, $584.8 million was committed to the purchase of feedstock inventory under the Supply and Offtake Agreement held with Vitol Refining S.A. Included in this total is approximately $267 million relating to the SOMO contract discussed above.

On February 1, 2007, Harvest issued $200 million principal amount of convertible debentures and 6,146,750 trust units (including the full exercise of the underwriters' option to purchase 801,750 additional trust units) at a price of $23.40 per trust unit. After the over-allotment option to purchase an additional 30,000 debentures was exercised on February 8, 2007, the total net proceeds of from the issue were $357.4 million.

24. COMPARATIVES

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

FORWARD-LOOKING INFORMATION

In the interest of providing our unitholders and potential investors with information regarding Harvest, including our assessment of our future plans and operations, this annual report 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 annual report 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, Cash Flow From Operations and regulatory changes. For this purpose, any statements that are contained herein that are not statements of historical fact may be deemed to be forward-looking statements. Forward-looking statements often contain terms such as "may", "will", "should", "anticipate", "expects", and similar expressions.

Readers are cautioned not to place undue reliance on forward-looking statements as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. Although 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 annual report are expressly qualified by this cautionary statement.

corporate INFORMATION

DIRECTORS

M. Bruce Chernoff, Chairman [3]
Kevin Bennett [2]
Dale Blue [1]
David Boone [2]
John Brussa [3]
William Friley [3]
Verne Johnson [1] [2]
Hector McFadyen [1]

[1] Member of the Audit Committee.
[2] Member of the Reserves, Safety and Environment Committee.
[3] Member of the Corporate Governance/Compensation Committee.

OFFICERS & SENIOR MANAGMENT

John Zahary, P.Eng.
President & Chief Executive Officer

Robert Fotheringham, C.A.
Chief Financial Officer

Rob Morgan, P.Eng.
Chief Operating Officer, Upstream

Jacob Roorda, P.Eng.
Vice President, Corporate

Gary Boukall, P. Geol
Vice President, Geosciences

Phil Reist, C.A.
Vice President, Controller

Jim Sheasby, P.Eng
Vice President, Engineering

Neil Sinclair
Vice President, Operations

Dean Beacon
Treasurer

David Rain, C.A.
Corporate Secretary

F. Steven Saunders, C.A.
Director of Taxation and Assistant Corporate Secretary

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AUDITOR

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LEGAL COUNSEL

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U.S: Paul, Weiss, Rifkind, Wharton & Garrison

RESERVES EVALUATORS

McDaniel & Associates Ltd.
GLJ Petroleum Consultants Ltd.
Sproule & Associates Ltd.

INVESTOR RELATIONS & GENERAL INQUIRIES

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Please contact us if you would like to receive an investor package or be added to Harvest's mailing lists.

Designed by Bryan Mills Iradesso