third quarter report

nine months ended September 30, 2007

enerPLUS

# the energy of enerplus

## financial & operating highlights

### Selected financial results

| For the nine months ended September 30, | 2007 | 2006 |
|---|---|---|
| **Financial (000's)** | | |
| Net Income | $ 240,990 | $ 434,623 |
| Cash Flow from Operating Activities | 663,464 | 656,589 |
| Cash Distributions to Unitholders[1] | 483,388 | 459,293 |
| Cash Withheld for Acquisitions and Capital Expenditures | 180,076 | 197,296 |
| Debt Outstanding (net of cash) | 649,829 | 589,420 |
| Development Capital Spending | 281,045 | 368,117 |
| Acquisitions | 269,149 | 46,553 |
| Divestments | 5,569 | 21,021 |
| **Financial per Unit[2]** | | |
| Net Income | $ 1.90 | $ 3.59 |
| Cash Flow from Operating Activities | 5.22 | 5.42 |
| Cash Distributions to Unitholders[1] | 3.81 | 3.79 |
| Cash Withheld for Acquisitions and Capital Expenditures | 1.42 | 1.63 |
| Payout Ratio[3] | 73% | 70% |
| **Selected Financial Results per BOE[4]** | | |
| Oil & Gas Sales[5] | $ 49.89 | $ 51.65 |
| Royalties | (9.38) | (9.89) |
| Commodity Derivative Instruments | 0.63 | (1.73) |
| Operating Costs | (9.32) | (7.85) |
| General and Administrative | (2.00) | (1.66) |
| Interest and Foreign Exchange | (1.34) | (0.91) |
| Taxes | (0.46) | (0.56) |
| Restoration and Abandonment | (0.47) | (0.31) |
| Cash Flow from Operating Activities before changes in non-cash working capital | $ 27.55 | $ 28.74 |
| Weighted Average Number of Trust Units Outstanding (thousands) | 127,031 | 121,120 |
| Debt/Trailing 12 Month Cash Flow Ratio | 0.7x | 0.6x |

### Selected operating results

| For the nine months ended September 30, | 2007 | 2006 |
|---|---|---|
| **Average Daily Production** | | |
| Natural gas (Mcf/day) | 263,884 | 268,700 |
| Crude oil (bbls/day) | 34,602 | 36,065 |
| NGLs (bbls/day) | 4,194 | 4,487 |
| Total (BOE/day) (6:1) | 82,777 | 85,335 |
| % Natural gas | 53% | 52% |
| **Average Selling Price[5]** | | |
| Natural gas (per Mcf) | $ 6.63 | $ 6.89 |
| Crude oil (per bbl) | $ 62.75 | $ 64.27 |
| NGLs (per bbl) | $ 49.26 | $ 52.49 |
| US$ exchange rate | 0.91 | 0.88 |
| Net Wells Drilled | 177 | 304 |
| Success Rate | 99% | 99% |

(1) Calculated based on distributions paid or payable. Cash distributions to unitholders per unit will not correspond to the actual cumulative monthly distributions of $3.78 as a result of using the weighted average trust units outstanding for the period.
(2) Based on weighted average trust units outstanding for the period.
(3) Calculated as Cash Distributions to Unitholders divided by Cash Flow from Operating Activities.
(4) Non-cash amounts have been excluded.
(5) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

The following discussion contains forward-looking information and statements. We refer you to the end of the MD&A for our disclaimer on forward-looking statements and information.

**Trust Unit Trading Summary**
for the nine months ended September 30, 2007

| | TSX – ERF.un (CDN$) | NYSE – ERF (US$) |
|---|---|---|
| High | $ 53.70 | $ 50.75 |
| Low | $ 41.00 | $ 38.11 |
| Close | $ 46.90 | $ 47.20 |

**2007 Cash Distributions Per Trust Unit**

| Production Month | Payment Month | CDN$ | US$ |
|---|---|---|---|
| **First Quarter Total** | | **$ 1.26** | **$ 1.12** |
| **Second Quarter Total** | | **$ 1.26** | **$ 1.19** |
| July | September | $ 0.42 | $ 0.41 |
| August | October | 0.42 | 0.43 |
| September | November | 0.42 | 0.44* |
| **Third Quarter Total** | | **$ 1.26** | **$ 1.28** |
| **Total Year-to-Date** | | **$ 3.78** | **$ 3.59** |

* Calculated using an exchange rate of 0.95

# president's message

I'm pleased to report that we continued to maintain our cash distribution at $0.42 per unit throughout the third quarter for a total of $1.26 per unit paid to Unitholders. Our payout ratio averaged 70% for the quarter and we maintained our balance sheet strength with a trailing twelve month debt to cash flow multiple of 0.7x. We have however faced some challenges in the quarter. Natural gas prices have continued to be depressed while the continued strength in crude oil prices combined with our production mix has somewhat mitigated the impact on our cash flows. In addition, we experienced shortfalls in our production in the quarter that will impact both our expected annual average production and our exit rate for 2007.

West Texas Intermediate (''WTI'') crude oil prices continued to rise during the third quarter and reached a peak of US$83.32/barrel on September 20, 2007. Unfortunately, the Canadian dollar has also continued to strengthen essentially offsetting this rise in U.S. dollar prices. Supply and demand fundamentals and geopolitical events continue to provide support for oil prices into the fourth quarter as we've seen WTI close above US$90.00/barrel subsequent to the quarter end. Natural gas prices however have not fared so well. A very warm August and September across the U.S. was not enough to counter the impact of LNG imports during the third quarter. When combined with steady U.S. drilling, the result has been continued weak natural gas prices. Inventory levels in the U.S. and Canada continued to build and are expected to approach capacity by the end of October. AECO natural gas prices reached a low of $4.43/Mcf during the quarter. While Canadian natural gas production is falling due to lower activity levels over the last six months and U.S. industry drilling is finally beginning to slow, winter weather remains the key element that will impact natural gas prices over the near term.

Operationally, a reduction in capital spending, lower than anticipated initial production rates on our third wells per section in the U.S. Bakken program and higher than anticipated downtime and unplanned turnarounds have resulted in production averaging 79,891 BOE/day during the quarter. Approximately $25 million has been eliminated from our full year capital development budget primarily in non-operated deep gas, shallow gas and coalbed methane activities due to lower gas prices and uncertainty around the province of Alberta's review of its royalty regime. This has impacted our third quarter volumes by approximately 1,300 BOE/day and our full-year average production by approximately 600 BOE/day. Although initial production rates on our U.S. Bakken third well per section program have been lower than anticipated, recoverable reserves remain in line with expectations and provide attractive returns. This has contributed to a shortfall in production volumes of approximately 1,000 BOE/day during the third quarter and will impact our full year and exit rate volumes by the same amount. Increased downtime and unplanned turn-around activities at our partner-operated facilities have also played a role in the lower production volumes realized during the quarter, accounting for roughly 1,500 BOE/day and will impact our annual average production by approximately 900 BOE/day. Due to these issues, we are reducing our annual average production guidance for 2007 by 3% to 82,500 BOE/day with a revised exit rate of 83,000 BOE/day. Our operating costs per BOE will also be impacted and are now expected to average $9.20/BOE for 2007. We are currently forecasting full year capital spending to be approximately $390 million versus our previous estimate of $415 million.

We continued with our low-risk development program during the quarter, investing $90.6 million into our asset base with our highest concentration of spending on oil properties in southeast Saskatchewan, Manitoba and Montana. In total we drilled 184 gross wells (101.2 net) during the quarter with a 99% success rate. With strong crude oil prices supporting robust drilling and development activity in Canada and the United States, pipeline capacity in growth areas is becoming constrained. In particular, producers in the Montana, North Dakota and southeast Saskatchewan producing regions are facing risks of curtailment until planned capacity expansions are brought on-line. There is potential that these curtailments could impact both our fourth quarter production and exit rates.

I am very pleased to report that September marks the fourteenth consecutive month where no Enerplus employee has suffered a lost time injury and the seventh consecutive month without an employee injury that required medical aid. Safety in the workplace is an important part of our culture and we continue to focus on our over-all safety performance through continual hazard awareness and identification, consistent safe work attitudes/behaviours, and promotion of communication on safety concerns.

## 2007 Development Activity

| | 3rd Quarter | | | Year to Date | | |
|---|---|---|---|---|---|---|
| | Capital Spending | Wells Drilled | | Capital Spending | Wells Drilled | |
| **Play Type** | **($ millions)** | **Gross** | **Net** | **($ millions)** | **Gross** | **Net** |
| Shallow Gas & CBM | $16.1 | 102.0 | 75.1 | $ 26.2 | 167.0 | 102.3 |
| Crude Oil Waterfloods | 12.8 | 14.0 | 5.5 | 39.8 | 32.0 | 20.8 |
| Bakken Oil | 21.6 | 14.0 | 7.2 | 92.5 | 36.0 | 20.9 |
| Oil Sands (SAGD/Mining) | 1.7 | – | – | 20.8 | – | – |
| Other Conventional Oil & Gas | 38.4 | 54.0 | 13.4 | 101.7 | 152.0 | 32.6 |
| Total | $90.6 | 184.0 | 101.2 | $281.0 | 387.0 | 176.6 |

Success Rate To Date: 99%

## Oil Sands Activities

Our oil sands business continues to take shape as our Kirby operated project and our Joslyn non-operated project advance.

At Joslyn, we have received the initial Norwest mining report on the Joslyn lease which indicates significantly increased contingent resource under a 15:1 total volume to bitumen in place ("TV:BIP") ratio. Previously a 12:1 TV:BIP ratio was the accepted standard for oil sands projects but recently a major oil sands producer has submitted an application with a 16:1 TV:BIP ratio for an expansion project and now other oil sand participants are considering this type of higher ratio. The original resource estimate of the Joslyn lease indicated 223 million barrels of contingent resources based upon a 12:1 TV:BIP ratio using the best estimates. If developed on a 15:1 TV:BIP ratio, essentially the entire Joslyn lease would be mineable resulting in increased recoveries and potentially increased production rates over the current plans with no expansion of the existing Phase II SAGD project. Our third party engineering firm will be using the Norwest report to update our resource estimates for our year-end engineering.

Although recent operational changes are having positive impacts on production rates, the Joslyn SAGD project continues to run behind expectations. A major turnaround of the facility is being completed subsequent to the quarter and performance of the existing well pairs is being monitored. There are currently no plans to drill any additional well pairs until at least 2009 nor does the operator expect to achieve commercial production prior to the 2009 timeframe. Future drilling will be dependent on the extent of the improved performance from the existing well pairs.

Full lease development plans are expected in late 2008 after completing updated engineering and economics around the mining options, assessing SAGD performance and completing an optimization analysis on various development options for the lease.

At Kirby, we expect to begin drilling approximately 80 new core holes on the Kirby lease this winter and will also be testing for water sources and disposal zones on the lease. We continue to add to our staff complement, and are advancing our preliminary engineering as we plan the filing of our regulatory application in 2008 for our 10,000 bbl/day project.

## Alberta Royalty Review

On October 25, 2007 the Alberta government announced a new oil and gas royalty framework for the province. This new royalty regime takes effect on January 1, 2009 and is expected to increase royalties paid by the oil and gas industry by 20% ($1.4 billion) by 2010, depending upon future prices and production levels in the province.

Enerplus currently has approximately 73% of our production derived from Alberta with roughly 45% of our total royalty expense paid to the Alberta government. Further details on the Alberta government's new framework are still to come however at this time, our best estimate of the impact of the new level of royalties on our conventional business will be approximately $15 – $20 million annually representing a reduction of approximately 2% to cash flow within the context of prices and production experienced in 2007. Refer to our MD&A for further discussion of this issue. With respect to oil sands, based upon the current commodity price environment, the estimated royalty impact on both the Kirby and Joslyn projects are essentially offset with the federal government's plans to reduce tax rates. Therefore we see no change to our development plans.

We expect to continue investing in the province of Alberta, but are reviewing the economics associated with our capital plans and our opportunities to reallocate additional investment outside of Alberta in light of the new royalty regime. A portion of our oil and natural gas interests in Alberta are operated by industry partners and we will be working with those partners to determine go forward plans on these properties. Given our diverse asset base, the results of our economic analysis and the response of our partners, we may shift some of our capital spending to other provinces or the U.S. in order to maximize our economic returns.

On October 30, 2007, a NAFTA claim with respect to the Canadian Government's plan to impose a tax on trusts was put forward by two income trust unitholders from the United States. The claim challenges the actions of the Canadian Government and seeks monetary compensation for losses related to those actions. It is our understanding that all U.S. and Mexican citizens who held units in a Canadian energy trust on October 31, 2006 may also be eligible to file a similar claim. Unitholders wishing further information about this claim and the NAFTA process can visit the following website, www.NAFTAtrustclaims.com.

Notwithstanding the challenges we are facing in our industry today, we fundamentally believe Enerplus is well positioned for the future. Our strong balance sheet, merger and acquisition capabilities, large inventory of development prospects and future oil sands opportunities set us apart from many other oil and gas producers. We will continue to seek out ways to improve and expand our business and are committed to providing our investors with a superior return on their investment.

Gordon J. Kerr
President & Chief Executive Officer

# management's discussion and analysis ("MD&A")

The following discussion and analysis of financial results is dated November 8, 2007 and is to be read in conjunction with:

- the MD&A and audited consolidated financial statements as at and for the years ended December 31, 2006 and 2005; and
- the unaudited interim consolidated financial statements as at September 30, 2007 and for the three and nine months ended September 30, 2007 and 2006.

All amounts are stated in Canadian dollars unless otherwise specified. All references to GAAP refer to Canadian generally accepted accounting principles. All note references relate to the notes included with the consolidated financial statements. In accordance with Canadian practice revenues are reported on a gross basis, before deduction of crown and other royalties, unless otherwise stated. In addition to disclosing reserves under the requirements of NI 51-101, we also disclose our reserves on a company interest basis which is not a term defined under NI 51-101. This information may not be comparable to similar measures presented by other issuers. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of BOE in isolation may be misleading. Certain prior year amounts have been restated to reflect current year presentation.

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

## Non-GAAP Measures

Throughout the MD&A we use the term "payout ratio" to analyze operating performance, leverage and liquidity. We calculate payout ratio by dividing cash distributions to unitholders ("cash distributions") by cash flow from operating activities ("cash flow"), both of which appear on our consolidated statements of cash flows. The term "payout ratio" does not have a standardized meaning or definition as prescribed by GAAP and therefore may not be comparable with the calculation of similar measures by other entities.

Refer to the Liquidity and Capital Resources section of the MD&A for further information on cash flow, cash distributions and payout ratio.

## Alberta Royalty Review

On October 25, 2007 the Alberta government announced changes to the provincial royalty program effective January 1, 2009. The government has introduced dual sliding scale royalties for conventional crude oil and natural gas production that are based on commodity price levels and monthly well production rates. Although royalty rates were reduced for certain low productivity wells in low price environments, most royalties are expected to increase, especially with higher well productivity and commodity prices. The Alberta government expects to increase its royalty revenues by 20% or $1.4 billion by 2010 as a result of this change in the royalty regime.

New royalty rates for natural gas wells will range from 5% to 50% of a market-based reference price, an increase from the current program that ranges from 5% to 35%. In addition, the government has announced a program whereby deep gas wells are less affected by the new royalty regime based on a formula that is sensitive to total drilling distances (both vertical and horizontal) that exceed 2,000 meters. We also expect a more favorable royalty framework is forthcoming (lower royalties and a wider price range than other conventional gas) for coal bed methane, tight gas and shale gas but no specific information with respect to these royalty programs are available from the government.

Furthermore on natural gas, the government announced it will implement "shallow rights reversion" whereby mineral rights to undeveloped shallow gas above zones that are being developed will revert back to the government and made available for resale. Enerplus is assessing the potential impact of this policy on our reserves and development plans pending further details from the government.

Royalty rates for crude oil wells will increase from the current maximum of 35% to a new maximum of 50% for higher ranging prices and production levels. Most other specialty royalty programs will be eliminated.

For oil sands, the current base or start-up royalty rate is 1%. Under the new system the pre-payout rate will start at 1% and increase for oil priced above $55/bbl to a maximum of 9% when oil is priced at $120/bbl or higher. The current post-payout royalty rate is 25% for oil sands. Under the new regime, the post-payout royalty will start at 25% and increase for oil priced above $55/bbl to a maximum of 40% when oil is priced at $120/bbl or higher. We don't expect these increases will have a significant impact on our oil sands projects.

Details of the new royalty program can be found on the Alberta government's website at www.gov.ab.ca.

Approximately $96.0 million (45%) of Enerplus' total royalties during the nine months ended September 30, 2007 were Alberta crown royalties. We have attempted to estimate the impact of the royalty changes on Enerplus however this is difficult as details have yet to be finalized.

Based on royalties paid during 2007 and in the context of production and pricing during that period, we would expect Alberta royalties to increase by approximately $15 to $20 million annually or 2% of operating cash flow and total royalties to increase by approximately 5% to 7%. Our total consolidated royalty rate would increase from 19% to approximately 20% of total revenues. The moderate increase is a reflection of the new royalty regime's sensitivity to the low natural gas prices experienced this year and Enerplus' portfolio of lower productivity wells. It is important to note that these estimates have assumed the applicability of deeper well relief to our current wells and that the current "corporate effective" royalty rates used to calculate the Crown's share of capital for gas processing facilities will be similar to the new "facility effective" rates proposed by the government. Also, these estimates are based on production and pricing that may not be indicative of the environment in 2009 when these royalty changes come into effect.

We have not finalized our 2008 capital budget; however, we expect some capital spending may be redirected to the U.S., Manitoba, Saskatchewan and B.C. in pursuit of more attractive economic returns.

## Canadian Government's Tax on Income Trusts

On June 22, 2007 Bill C-52, which contains legislative provisions to implement the proposals to tax publicly traded income trusts in Canada became law. As a result, our year to date future income tax provision includes a future income tax expense of $78.1 million related to this legislation. This non-cash expense relates to temporary differences between the accounting and tax basis of the Fund's assets and liabilities and has no immediate impact on cash flow.

We are currently evaluating alternatives to determine the optimal structure for our unitholders. However, we see value in the remaining three-year tax exemption period through 2010 and will look to maintain our current structure during this period unless there are compelling reasons to change.

## Overview

During the third quarter we had a modest decrease in cash flow to $232.8 million from $237.5 million in the second quarter. Our year-to-date cash flow is consistent with the previous period, however third quarter cash flow decreased 13% compared to the same period in 2006. Strong crude oil prices helped to reduce the impact of weak natural gas prices, lower production and the strengthening Canadian dollar. Overall our production decreased by 3% from the second quarter to 79,891 BOE/day and development capital spending totaled $90.6 million for the quarter. Based on our year-to-date results we are revising our annual development capital spending guidance down by $25 million to $390 million. We are also decreasing our average annual production guidance to 82,500 BOE/day and our 2007 exit rate to 83,000 BOE/day. In conjunction with the revised production estimates, we are increasing our annual operating cost guidance to $9.20/BOE however our general and administrative expense guidance remains unchanged.

Despite these challenges, we maintained our monthly distributions at $0.42 per unit during the third quarter with a payout ratio of 70% and our debt-to-cash flow remains at a conservative 0.7x (based on trailing twelve month cash flow).

## Results of Operations

### Production

Production averaged 79,891 BOE/day during the third quarter of 2007, a decrease of 3% from 82,478 BOE/day during the second quarter of 2007.

For the three and nine months ended September 30, 2007 production decreased by 5% and 3% respectively, compared to the same periods in 2006. The decrease was due to lower than anticipated initial production rates in the U.S. and increased downtime and unplanned turn-around activities at partner operated facilities, partially offset by production from our development capital program and our acquisition of gross-overriding royalty interests in the Jonah natural gas field in Wyoming ("Jonah") that closed on January 31, 2007.

Based on our year-to-date results we are decreasing our annual production guidance by approximately 3% to 82,500 BOE/day from 85,000 BOE/day and our 2007 exit rate by approximately 3% to 83,000 BOE/day from 86,000 BOE/day. A $25 million reduction in our annual development capital spending program to $390 million has decreased our annual production estimate by approximately 600 BOE/day and exit rate estimate by approximately 1,100 BOE/day. Our U.S. Bakken oil program continues to deliver attractive economics and reserves, however lower initial production rates have decreased both our annual production and exit rate estimates by approximately 1,000 BOE/day. Unplanned turn-around activities primarily at partner-operated facilities along with increased downtime in the U.S. and other minor factors have negatively impacted our annual average and exit rate production by approximately 900 BOE/day. Although the partner-operated facilities are expected to be back on line at year-end, the U.S. downtime and other minor factors will continue to impact our exit rate. Further, there is the potential that pipeline constraints in Montana, North Dakota and southeast Saskatchewan, resulting from strong crude oil prices and robust drilling and development activities, could impact both our fourth quarter production and exit rate.

Our average production during the third quarter was weighted 52% natural gas and 48% crude oil and natural gas liquids on a BOE basis. Average production volumes for the three and nine months ended September 30, 2007 and 2006 are outlined below:

| | Three months ended September 30, | | | Nine months ended September 30, | | |
|---|---|---|---|---|---|---|
| Daily Production Volumes | 2007 | 2006 | % Change | 2007 | 2006 | % Change |
| Natural gas (Mcf/day) | 251,264 | 266,292 | (6)% | 263,884 | 268,700 | (2)% |
| Crude oil (bbls/day) | 34,077 | 35,952 | (5)% | 34,602 | 36,065 | (4)% |
| Natural gas liquids (bbls/day) | 3,937 | 4,199 | (6)% | 4,194 | 4,487 | (6)% |
| Total daily sales (BOE/day) | 79,891 | 84,533 | (5)% | 82,777 | 85,335 | (3)% |

### Pricing

The prices received for our natural gas and crude oil production directly impact our earnings, cash flow and financial condition. The following tables compare our average selling prices and benchmark price indices for the three and nine months ended September 30, 2007 and 2006.

| | Three months ended September 30, | | | Nine months ended September 30, | | |
|---|---|---|---|---|---|---|
| Average Selling Price(1) | 2007 | 2006 | % Change | 2007 | 2006 | % Change |
| Natural gas (per Mcf) | $ 5.59 | $ 6.13 | (9)% | $ 6.63 | $ 6.89 | (4)% |
| Crude oil (per bbl) | $69.16 | $68.57 | 1% | $62.75 | $64.27 | (2)% |
| Natural gas liquids (per bbl) | $50.79 | $54.63 | (7)% | $49.26 | $52.49 | (6)% |
| Per BOE | $49.64 | $51.18 | (3)% | $49.89 | $51.65 | (3)% |

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

| | Three months ended September 30, | | | Nine months ended September 30, | | |
|---|---|---|---|---|---|---|
| Average Benchmark Pricing | 2007 | 2006 | % Change | 2007 | 2006 | % Change |
| AECO natural gas – monthly index (CDN$/Mcf) | $ 5.61 | $ 6.03 | (7)% | $ 6.81 | $ 7.19 | (5)% |
| AECO natural gas – daily index (CDN$/Mcf) | $ 5.18 | $ 5.64 | (8)% | $ 6.55 | $ 6.40 | 2% |
| NYMEX natural gas – monthly NX3 index (US$/Mcf) | $ 6.13 | $ 6.53 | (6)% | $ 6.88 | $ 7.47 | (8)% |
| NYMEX natural gas – monthly NX3 index CDN$ equivalent (CDN$/Mcf) | $ 6.39 | $ 7.34 | (13)% | $ 7.56 | $ 8.49 | (11)% |
| WTI crude oil (US$/bbl) | $75.38 | $70.48 | 7% | $66.23 | $68.22 | (3)% |
| WTI crude oil CDN$ equivalent (CDN$/bbl) | $78.52 | $79.19 | (1)% | $72.78 | $77.52 | (6)% |
| US$/CDN$ exchange rate | 0.96 | 0.89 | 8% | 0.91 | 0.88 | 3% |

We realized an average price on our natural gas of $5.59/Mcf (net of transportation) during the three months ended September 30, 2007 a decrease of 9% from $6.13/Mcf for the same period in 2006. For the nine months ended September 30, 2007 our average price of $6.63/Mcf was 4% lower as compared to the same period in 2006. We sell approximately one third of our natural gas to aggregators, with the remainder sold under month and day AECO index contracts and NYMEX monthly index contracts. Although our realized average natural gas price fluctuates from month to month, it remains comparable to the movement of the benchmark indices as the volume of natural gas sold on each index can vary each month. Overall our 9% and 4% decreases for the three and nine months ended September 30, 2007 compared to the same periods in 2006 are fairly consistent with the fluctuations experienced by the AECO and NYMEX indices.

The average price we received for our crude oil during the three months ended September 30, 2007 increased 1% to $69.16/bbl (net of transportation) from $68.57/bbl during the same period in 2006. The West Texas Intermediate ("WTI") crude oil benchmark price, after adjusting for the change in the US$ exchange rate, decreased 1% from the corresponding period in 2006. For the nine months ended September 30, 2007 our crude oil price fell 2% relative to the same period in 2006, while the CDN$ equivalent WTI crude oil benchmark price fell 6%. This difference was largely due to improved pricing differentials for our sour and heavy crude oil.

The Canadian dollar strengthened significantly against the U.S. dollar during the quarter and the average exchange rates for both the three and nine month periods in 2007 were also higher than the comparable periods in 2006. At September 30, 2007 the Canadian dollar was at a thirty year high and at par with the U.S. dollar. As most of our crude oil and a portion of our natural gas is priced in reference to U.S. dollar denominated benchmarks this movement in the exchange rate reduced the Canadian dollar prices that we would have otherwise realized. For the three months ended September 30, 2007 compared to September 30, 2006 the WTI price in U.S. dollars increased approximately $5.00/bbl or 7% but after conversion to Canadian dollars the WTI price actually decreased by 1%. We expect every $0.01 change in the Canadian/U.S. dollar exchange rate to impact our annualized cash flow by $0.10 per trust unit.

**Price Risk Management**

Spot natural gas prices in Alberta were generally in a downtrend during the quarter influenced by strong production in the U.S., high LNG imports to the U.S. early in the quarter and continued strength in the Canadian dollar. Prices peaked in August at CDN$5.94/Mcf due to a heat wave in the U.S. and tropical storm threats, but subsided again going into September as it became clear that natural gas storage inventories would be close to capacity by the end of the storage season.

Global crude oil pricing continued to rise in the third quarter driven by continued concerns about the supply/demand balance, hurricane season risks, geopolitical instability and weakness in the U.S. dollar. There was significant volatility in the quarter with prices moving between US$69.26/bbl and US$83.32/bbl compared to an opening price of US$71.09/bbl.

We have developed a price risk management framework to respond to the volatile price environment in a prudent manner. Consideration is given to our overall financial position together with the economics of our development capital program and acquisitions. Consideration is also given to the upfront costs of our risk management program as we seek to limit our exposure to price downturns while maintaining participation should commodity prices increase.

Given our price risk management framework, we entered into additional commodity contracts during the third quarter of 2007. We have protected a portion of our natural gas and crude oil sales for the period October 2007 through December 2009 and have also protected a portion of our exposure to rising electricity costs in the Alberta power market for the period October 2007 through September 2008. See Note 11 for a detailed list of our current price risk management positions.

The following is a summary of the physical and financial contracts in place at October 29, 2007 as a percentage of our forecasted net production volumes:

| | Natural Gas (CDN$/Mcf) | | | | Crude Oil (US$/bbl) | | | |
|---|---|---|---|---|---|---|---|---|
| | October 1, 2007– October 31, 2007 | November 1, 2007– March 31, 2008 | April 1, 2008– October 31, 2008 | November 1, 2008– March 31, 2009 | October 1, 2007– December 31, 2007 | January 1, 2008– June 30, 2008 | July 1, 2008– December 31, 2008 | January 1, 2009– December 31, 2009 |
| Floor Prices (puts) | $7.32 | $ 8.12 | $7.05 | $ 7.91 | $69.89 | $70.40 | $69.66 | $70.00 |
| % (net of royalties) | 31% | 18% | 11% | 3% | 39% | 31% | 26% | 4% |
| Fixed Price (swaps) | $7.58 | $ 8.81 | $8.18 | $ – | $68.13 | $73.52 | $73.52 | $ – |
| % (net of royalties) | 6% | 3% | 2% | –% | 11% | 11% | 11% | –% |
| Capped Price (calls) | $9.07 | $10.42 | $8.43 | $10.71 | $84.10 | $85.09 | $85.09 | $85.00 |
| % (net of royalties) | 28% | 18% | 11% | 3% | 5% | 21% | 21% | 4% |

Based on weighted average price (before premiums), average annual production of 82,500 BOE/day and assuming a 19% royalty rate.

*Accounting for Price Risk Management*

During the third quarter of 2007, our commodity price risk management program generated cash gains of $7.4 million and non-cash losses of $3.8 million compared to cash losses of $1.1 million and non-cash gains of $19.1 million during the second quarter of 2007. The increase in cash gains is due to the impact of lower natural gas prices which more than offset the impact of higher crude oil prices during the third quarter. The change in non-cash costs is attributable to the impact of higher forward crude oil prices on our crude oil positions at the end of the third quarter, partially offset by the impact of lower forward natural gas prices.

Our natural gas cash gains for the three months ended September 30, 2007 increased to $14.1 million from $0.5 million for the same period in 2006. For the nine months ended September 30, 2007 we had a natural gas cash gain of $12.8 million as compared to

$10.1 million in cash losses for the same period in 2006. These increases in cash gains were due to contracts in place during 2007 that provided floor protection as the price of natural gas declined.

Compared to the third quarter of 2006 our crude oil cash losses increased to $6.7 million from $1.3 million. The increase in cash losses is due to crude oil prices rising above our swap positions. For the nine months ended September 30, 2007 we had a slight crude oil cash gain of $1.4 million as compared to cash losses of $30.2 million for the same period in 2006. The cash losses in 2006 were caused by contracts that had ceiling prices between US$35.35/bbl and US$45.80/bbl that expired June 30, 2006.

At September 30, 2007 the fair value of our crude oil derivative instruments, net of premiums, represents a loss of $14.9 million and is recorded on our balance sheet as a deferred financial credit. The fair value of our natural gas derivative instruments, net of premiums, represents a gain of $20.3 million and is recorded on our balance sheet as a deferred financial asset. In comparison at December 31, 2006 the fair value of our crude oil derivative instruments represented a gain of $10.9 million and the fair value of our natural gas derivative instruments represented a gain of $12.7 million, both of which were recorded on our balance sheet as a deferred financial asset. As the forward markets for natural gas and crude oil fluctuate, and new contracts are executed and existing contracts are realized, changes in fair value are reflected as a non-cash charge or increase to earnings. These changes amounted to a $3.8 million loss during the third quarter of 2007 and an $18.2 million loss during the nine months ended September 30, 2007. See Note 3 for details.

The following table summarizes the effects of our commodity derivative instruments on income.

| Risk Management Costs<br>($ millions, except per unit amounts) | Three months ended September 30,<br>2007 | | Three months ended September 30,<br>2006 | |
|---|---|---|---|---|
| Cash (gains)/losses: | | | | |
| Crude oil | $ 6.7 | $ 2.14/bbl | $ 1.3 | $ 0.39/bbl |
| Natural gas | (14.1) | $ (0.61)/Mcf | (0.5) | $ (0.02)/Mcf |
| Total Cash (gains)/losses | $ (7.4) | $(1.00)/BOE | $ 0.8 | $ 0.10/BOE |
| Non-cash losses/(gains) on financial contracts: | | | | |
| Change in fair value – crude oil | $ 6.6 | $ 2.12/bbl | $(23.0) | $ (6.96)/bbl |
| Change in fair value – natural gas | (2.8) | $ (0.12)/Mcf | (4.0) | $ (0.16)/Mcf |
| Amortization of deferred financial assets | – | $ – /BOE | 10.3 | $ 1.32/BOE |
| Total Non-cash losses/(gains) | $ 3.8 | $ 0.51/BOE | $(16.7) | $(2.15)/BOE |
| Total gains | $ (3.6) | $(0.49)/BOE | $(15.9) | $(2.05)/BOE |

| Risk Management Costs<br>($ millions, except per unit amounts) | Nine months ended September 30,<br>2007 | | Nine months ended September 30,<br>2006 | |
|---|---|---|---|---|
| Cash (gains)/losses: | | | | |
| Crude oil | $ (1.4) | $ (0.15)/bbl | $ 30.2 | $ 3.07/bbl |
| Natural gas | (12.8) | $ (0.18)/Mcf | 10.1 | $ 0.14/Mcf |
| Total Cash (gains)/losses | $(14.2) | $(0.63)/BOE | $ 40.3 | $ 1.73/BOE |
| Non-cash losses/(gains) on financial contracts: | | | | |
| Change in fair value – crude oil | $ 25.8 | $ 2.74/bbl | $(42.5) | $ (4.32)/bbl |
| Change in fair value – natural gas | (7.6) | $ (0.11)/Mcf | (47.0) | $ (0.64)/Mcf |
| Amortization of deferred financial assets | – | $ – /BOE | 47.0 | $ 2.02/BOE |
| Total Non-cash losses/(gains) | $ 18.2 | $ 0.81/BOE | $(42.5) | $(1.82)/BOE |
| Total losses/(gains) | $ 4.0 | $ 0.18/BOE | $ (2.2) | $(0.09)/BOE |

### Revenues

Crude oil and natural gas revenues during the third quarter of 2007 were lower than the second quarter of 2007 as improved crude oil prices were more than offset by the impact of lower production and natural gas prices.

Crude oil and natural gas revenues for the three months ended September 30, 2007 were $364.8 million ($370.2 million, net of $5.4 million transportation) compared to $398.0 million ($403.7 million, net of $5.7 million transportation) for the same period in 2006. For the nine months ended September 30, 2007 revenues were $1,127.3 million ($1,144.0 million, net of $16.7 million transportation) compared to $1,203.2 million ($1,220.7 million, net of $17.5 million transportation) during the same period in 2006.

The decrease in revenues of $33.2 million or 8% for the three months ended September 30, 2007 and $75.9 million or 6% for the nine months ended September 30, 2007 compared to the same periods in 2006 was due to decreased production and lower realized commodity prices.

The following table summarizes the changes in sales revenue:

Analysis of Sales Revenue[1]

| ($ millions) | Crude Oil | NGLs | Natural Gas | Total |
|---|---|---|---|---|
| Quarter ended September 30, 2006 | $226.8 | $21.1 | $150.1 | $398.0 |
| Price variance[1] | 1.8 | (1.4) | (12.0) | (11.6) |
| Volume variance | (11.8) | (1.3) | (8.5) | (21.6) |
| **Quarter ended September 30, 2007** | **$216.8** | **$18.4** | **$129.6** | **$364.8** |

| ($ millions) | Crude Oil | NGLs | Natural Gas | Total |
|---|---|---|---|---|
| Year-to-date ended September 30, 2006 | $632.7 | $64.3 | $506.2 | $1,203.2 |
| Price variance[1] | (14.4) | (3.7) | (18.9) | (37.0) |
| Volume variance | (25.6) | (4.2) | (9.1) | (38.9) |
| **Year-to-date ended September 30, 2007** | **$592.7** | **$56.4** | **$478.2** | **$1,127.3** |

[1] Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

### Other Income

Other income for the three and nine months ended September 30, 2007 was $0.1 million and $14.6 million, respectively, compared to $1.1 million and $2.4 million for the same periods in 2006. During the first quarter of 2007 we sold certain marketable securities which resulted in a gain of $14.1 million. These marketable securities were historically recorded in other current assets at a cost of $2.4 million.

### Royalties

Royalties are paid to various government entities and other land and mineral rights owners. For the three and nine months ended September 30, 2007 royalties were $68.2 million and $211.9 million, respectively, both approximately 19% of oil and gas sales, net of transportation. For the three and nine months ended September 30, 2006 royalties were $70.9 million and $230.3 million, approximately 18% and 19% of oil and gas sales, net of transportation, respectively. The decrease in royalties for the three and nine months ended September 30, 2007 compared to the same periods in 2006 is a result of lower natural gas prices.

For 2007 we expect royalties to be approximately 19% of oil and gas sales, net of transportation costs.

As mentioned at the beginning of this MD&A, the Alberta government announced changes to the province's oil and gas royalty regime. Alberta Crown royalties represented approximately 45% of total royalties incurred during the nine months ended September 30, 2007.

### Operating Expenses

Operating expenses during the third quarter of 2007 were $9.73/BOE which was consistent with the second quarter costs of $9.69/BOE.

Operating expenses for the three months ended September 30, 2007 were $71.6 million or $9.73/BOE compared to $59.7 million or $7.68/BOE for the third quarter of 2006. For the nine months ended September 30, 2007 operating costs were $210.3 million or $9.31/BOE compared to $183.0 million or $7.85/BOE for the same period in 2006. We have experienced higher costs for well servicing, labour, supplies, and repairs and maintenance associated with unplanned turnaround activities during the quarter. Furthermore, we continue to implement our field training initiative focused on improving operating results over the long-term. Lower production volumes compared to 2006 have also contributed to the cost increase on a dollar per BOE basis.

As a result of our lower annual production forecast, we are revising our operating cost guidance to approximately $9.20/BOE for 2007.

### General and Administrative Expenses

General and administrative (''G&A'') expenses for the third quarter of 2007 were 6% higher than the second quarter of 2007.

G&A expenses for the three months ended September 30, 2007 were $17.7 million or $2.41/BOE compared to $15.0 million or $1.93/BOE for the third quarter of 2006. G&A expenses totaled $51.5 million or $2.28/BOE for the nine months ended September 30, 2007 compared to $42.9 million or $1.84/BOE for the same period in 2006. The year-over-year increase is primarily due to compensation costs and is in line with our expectations for 2007.

For the three and nine months ended September 30, 2007 our G&A expenses included non-cash charges of $2.2 million or $0.30/BOE and $6.4 million or $0.28/BOE respectively, compared to $1.8 million or $0.23/BOE and $4.3 million or $0.18/BOE for the same periods in 2006. These amounts relate solely to our trust unit rights incentive plan and are determined using a binomial lattice option-pricing model. The volatility of our trust unit price combined with the increased number of rights outstanding associated with additional employees have increased the non-cash cost of the plan.

The following table summarizes the cash and non-cash expenses recorded in G&A:

| General and Administrative Costs | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| ($ millions) | 2007 | 2006 | 2007 | 2006 |
| Cash | $15.5 | $13.2 | $45.1 | $38.6 |
| Non-cash trust unit rights incentive plan | 2.2 | 1.8 | 6.4 | 4.3 |
| Total G&A | $17.7 | $15.0 | $51.5 | $42.9 |
| (Per BOE) | 2007 | 2006 | 2007 | 2006 |
| Cash | $2.11 | $1.70 | $2.00 | $1.66 |
| Non-cash trust unit rights incentive plan | 0.30 | 0.23 | 0.28 | 0.18 |
| Total G&A | $2.41 | $1.93 | $2.28 | $1.84 |

We are maintaining our guidance for G&A expenses at $2.40/BOE, including non-cash G&A costs of approximately $0.30/BOE.

### Interest Expense

Interest expense includes interest on long-term debt, the amortization of the premium on our US$175 million senior unsecured notes, and unrealized gains and losses resulting from the change in fair value of our interest rate swaps as well as the interest component on our cross currency interest rate swap (''CCIRS''). See Note 9 for more details.

Interest expense in the third quarter of 2007 was $6.4 million or 46% lower than the second quarter of 2007 due to changes in the fair value of our interest rate swaps and CCIRS. The third quarter of 2007 included an unrealized gain of $4.0 million whereas the second quarter of 2007 included an unrealized loss of $2.1 million. After adjusting for these unrealized amounts, interest on long-term debt for the third quarter of 2007 was comparable to the second quarter of 2007.

Interest on long-term debt for the three and nine months ended September 30, 2007 was $10.4 million and $29.8 million compared to $8.6 million and $23.6 million for the same periods in 2006. These increases are due to higher average indebtedness and interest rates during 2007.

Unrealized gains during the three and nine months ended September 30, 2007 were $4.0 million and $3.4 million. The unrealized gain for the quarter results mainly from the change in fair value of the interest component on our CCIRS while the unrealized gain for the nine months results from the change in fair value of the interest component on our CCIRS and our interest rate swaps.

The following table summarizes the cash and non-cash interest expense recorded.

| Interest Expense | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| ($ millions) | 2007 | 2006 | 2007 | 2006 |
| Interest on long-term debt | $10.4 | $8.6 | $29.8 | $23.6 |
| Unrealized gain | (4.0) | – | (3.4) | – |
| Total Interest Expense | $ 6.4 | $8.6 | $26.4 | $23.6 |

At September 30, 2007 20% of our debt was based on fixed interest rates while 80% had floating interest rates.

### Capital Expenditures

We spent $90.6 million and $281.0 million on development drilling and facilities for the three and nine months ended September 30, 2007 respectively, compared to $131.7 million and $368.1 million during the same periods in 2006. We achieved a 99% success rate with our third quarter drilling program as 101.2 net wells were drilled. Year-to-date, 176.6 net wells were drilled compared to 304.3 in 2006. Development in 2007 continues to focus primarily on Sleeping Giant Bakken oil and crude oil waterfloods. The reduction in the total number of wells drilled in 2007 compared to 2006 reflects more high cost oil wells being drilled in 2007 compared to low cost shallow gas wells in 2006 and the deferral of several natural gas projects into 2008.

Property acquisitions were $1.8 million and $269.1 million for the three and nine months ended September 30, 2007, compared to $4.3 million and $46.5 million for the same periods in 2006. During the second quarter of 2007 we acquired the Kirby Oil Sands Partnership (''Kirby'') for total consideration of $203.1 million. During the first quarter of 2007 we acquired Jonah for total consideration of approximately $61 million.

Property dispositions were $0.1 million and $5.5 million for the three and nine months ended September 30, 2007 compared to $0.2 million and $21.0 million for the same periods in 2006. The majority of the $21.0 million divestment in 2006 related to the sale of a 1% interest in the Joslyn project.

Total net capital expenditures for 2007 and 2006 are outlined below.

| Capital Expenditures ($ millions) | Three months ended September 30, 2007 | Three months ended September 30, 2006 | Nine months ended September 30, 2007 | Nine months ended September 30, 2006 |
|---|---|---|---|---|
| Development expenditures | $72.1 | $ 96.0 | $232.3 | $284.0 |
| Plant and facilities | 18.5 | 35.7 | 48.7 | 84.1 |
| Development Capital | 90.6 | 131.7 | 281.0 | 368.1 |
| Office | 1.7 | 1.0 | 4.6 | 2.3 |
| Sub-total | 92.3 | 132.7 | 285.6 | 370.4 |
| Acquisitions of oil and gas properties[1] | 1.8 | 4.3 | 269.1 | 46.5 |
| Dispositions of oil and gas properties[1] | (0.1) | (0.2) | (5.5) | (21.0) |
| Total Net Capital Expenditures | $94.0 | $136.8 | $549.2 | $395.9 |
| Total Capital Expenditures financed with cash flow | $69.7 | $114.2 | $180.1 | $197.3 |
| Total Capital Expenditures financed with debt and equity | 24.3 | 22.6 | 369.1 | 218.1 |
| Total non-cash consideration for 1% sale of Joslyn project | – | – | – | (19.5) |
| Total Net Capital Expenditures | $94.0 | $136.8 | $549.2 | $395.9 |

[1] Net of post-closing adjustments.

Due to the delays in our capital program to date and the deferral of several natural gas projects into 2008 in areas such as Elmworth, Ferrier, Shackleton and Joffre, we are revising our 2007 annual development capital spending guidance down by $25 million to $390 million.

### Depletion, Depreciation, Amortization and Accretion (''DDA&A'')

DDA&A of property, plant and equipment is recognized using the unit-of-production method based on proved reserves.

For the three and nine months ended September 30, 2007, DDA&A was $15.78/BOE and $15.58/BOE compared to $16.64/BOE and $15.54/BOE during the corresponding period in 2006. Although the depletion rate for the third quarter of 2006 was higher than trend, the full year annual rate for 2006 was $15.38/BOE, which is comparable to our depletion rates during 2007.

No impairment of the Fund's assets existed at September 30, 2007 using year-end reserves updated for acquisitions, divestitures, production and management's estimates of future prices.

### Asset Retirement Obligations

The following chart compares the amortization of the asset retirement costs, accretion of the asset retirement obligation, and actual site restoration costs incurred.

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| ($ millions) | **2007** | 2006 | **2007** | 2006 |
| Amortization of the asset retirement cost | **$3.4** | $3.3 | **$ 6.9** | $ 9.4 |
| Accretion of the asset retirement obligation | **1.7** | 1.6 | **5.0** | 4.6 |
| Total Amortization and Accretion | **$5.1** | $4.9 | **$11.9** | $14.0 |
| Asset Retirement Obligations Settled | **$3.5** | $1.6 | **$10.7** | $ 7.2 |

The timing of actual asset retirement costs will differ from the timing of amortization and accretion charges. Actual asset retirement costs will be incurred over the next 66 years with the majority between 2036 and 2045. For accounting purposes, the asset retirement cost is amortized using a unit-of-production method based on proved reserves before royalties while the asset retirement obligation accretes until the time the obligation is settled.

### Taxes

*Future Income Taxes*

Future income taxes arise from differences between the accounting and tax bases of assets and liabilities. A portion of the future income tax liability that is recorded on the balance sheet will be recovered through earnings before 2011. The balance will be realized when future income tax assets and liabilities are realized or settled.

With the enactment of the tax on distributions from publicly traded income trusts and limited partnerships (''SIFT tax'') during the second quarter of 2007, all entities within our organization are now subject to future income taxes whereas prior to the SIFT tax enactment only incorporated entities in our organization were subject to future income taxes. As a result our future income tax recovery was $8.8 million for the three months ended September 30, 2007 compared to a recovery of $32.3 million for the same period in 2006. For the nine months ended September 30, 2007 a future income tax expense of $38.4 million was recorded in income compared to a future income tax recovery of $78.9 million during the same period in 2006. The changes in future income taxes for the nine months ended September 30, 2007 compared to the same period in 2006 are primarily a result of the following:

- The 31.5% SIFT tax will be applicable to the Fund effective January 1, 2011 provided that we remain a trust and comply with the ''normal growth'' guidelines regarding equity capital as outlined by the government. This change resulted in a future income tax expense of $78.1 million in the second quarter of 2007.
- During the second quarter of 2007, the Federal Government also enacted a decrease in the corporate rate of tax from 19.0% to 18.5% effective January 1, 2011. The effect of this rate change is a future income tax recovery of $1.2 million recorded in the second quarter of 2007.
- A future income tax recovery of $32.2 million was included in the second quarter of 2006 due to a reduction in the federal and provincial corporate tax rates enacted in that quarter.

After consideration of the above items, the future income tax provisions were comparable between the periods.

On October 30, 2007 the Federal Government announced its fall economic statement (''mini-budget''). The mini-budget proposes to cut the general corporate tax rate by 1% in 2008 from 20.5% to 19.5%. There are additional rate reductions scheduled until the target federal tax rate of 15% is reached as of January 1, 2012. These rate reductions will also apply to the SIFT tax on distributions from income trusts. If the tax rate reductions are enacted as presented, the SIFT tax rate will fall by 3.5% from 31.5% to 28%.

If the mini-budget proposals become substantially enacted, we would record a future income tax recovery, however at this time we are unable to determine when or if the mini-budget proposals will become substantively enacted.

*Current Income Taxes*

In our current structure, payments are made between the operating entities and the Fund which ultimately transfers both income and future income tax liability to our unitholders. As a result, no cash income taxes have been paid by our Canadian operating entities. However, effective January 1, 2011 we will be subject to the SIFT tax at a rate of 31.5% should we remain a trust.

For the three and nine months ended September 30, 2007 our U.S. operations incurred current taxes in the amounts of $5.1 million and $10.4 million respectively, compared to $3.1 million and $13.1 million during the same periods in 2006. The increase in current taxes in the three months ended September 30, 2007 is due to a decrease in drilling and completion expenditures incurred in the period. However there is a decrease in current taxes for the nine months ended September 30, 2007 due to an increase in drilling and completion expenditures year-to-date.

The amount of current taxes recorded throughout the year is dependent upon the timing of both capital expenditures and repatriation of the funds to Canada. We now expect current income and withholding taxes to be approximately 10% of cash flow from U.S. operations in 2007 assuming all funds available after U.S. development capital spending are repatriated to Canada compared to our previous estimate of 15%.

**Net Income**

Net income for the third quarter of 2007 was $93.0 million or $0.72 per trust unit compared to $161.3 million or $1.31 per trust unit for the third quarter of 2006. Net income for the nine months ended September 30, 2007 was $241.0 million or $1.90 per trust unit compared to $434.6 million or $3.59 per trust unit for the same period in 2006. The decrease during the three and nine months ended September 30, 2007 is due to increased future income tax expense (or reduced recovery) resulting from the SIFT tax enactment, lower oil and gas sales and increased operating and G&A costs, partially offset by lower royalties and depletion expense.

**Cash Flow from Operating Activities**

Cash flow for the three and nine months ended September 30, 2007 was $232.8 million and $663.5 million respectively, compared to $268.9 million and $656.6 million for the three and nine months ended September 30, 2006. For the quarter, this decrease was primarily a result of lower oil and gas sales and higher operating costs. For the nine months ended September 30, 2007 cash flow was consistent with the same period in 2006.

**Selected Financial Results**

| | Three months ended September 30, 2007 | | | Three months ended September 30, 2006 | | |
|---|---|---|---|---|---|---|
| Per BOE of production (6:1) | Operating Cash Flow[(1)] | Non-Cash & Other Items | Total | Operating Cash Flow[(1)] | Non-Cash & Other Items | Total |
| Production per day | | | 79,891 | | | 84,533 |
| Weighted average sales price[(2)] | $49.64 | $ – | $ 49.64 | $51.18 | $ – | $ 51.18 |
| Royalties | (9.28) | – | (9.28) | (9.12) | – | (9.12) |
| Commodity derivative instruments | 1.00 | (0.51) | 0.49 | (0.10) | 2.15 | 2.05 |
| Operating costs | (9.61) | (0.12) | (9.73) | (7.68) | – | (7.68) |
| General and administrative | (2.11) | (0.30) | (2.41) | (1.70) | (0.23) | (1.93) |
| Interest expense, net of interest income | (1.40) | 0.54 | (0.86) | (0.96) | – | (0.96) |
| Foreign exchange gain/(loss) | 0.06 | 0.03 | 0.09 | 0.08 | – | 0.08 |
| Current income tax | (0.70) | – | (0.70) | (0.40) | – | (0.40) |
| Restoration and abandonment cash costs | (0.48) | 0.48 | – | (0.21) | 0.21 | – |
| Depletion, depreciation, amortization and accretion | – | (15.78) | (15.78) | – | (16.64) | (16.64) |
| Future income tax (expense)/recovery | – | 1.20 | 1.20 | – | 4.16 | 4.16 |
| Total per BOE | $27.12 | $(14.46) | $ 12.66 | $31.09 | $(10.35) | $ 20.74 |

(1) Cash Flow from Operating Activities before changes in non-cash working capital.
(2) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

| Per BOE of production (6:1) | Nine months ended September 30, 2007 Operating Cash Flow[(1)] | Non-Cash & Other Items | Total | Nine months ended September 30, 2006 Operating Cash Flow[(1)] | Non-Cash & Other Items | Total |
|---|---|---|---|---|---|---|
| Production per day | | | 82,777 | | | 85,335 |
| Weighted average sales price[(2)] | $49.89 | $ – | $ 49.89 | $51.65 | $ – | $ 51.65 |
| Royalties | (9.38) | – | (9.38) | (9.89) | – | (9.89) |
| Commodity derivative instruments | 0.63 | (0.81) | (0.18) | (1.73) | 1.82 | 0.09 |
| Operating costs | (9.32) | 0.01 | (9.31) | (7.85) | – | (7.85) |
| General and administrative | (2.00) | (0.28) | (2.28) | (1.66) | (0.18) | (1.84) |
| Interest expense, net of interest income | (1.29) | 0.15 | (1.14) | (0.91) | – | (0.91) |
| Foreign exchange gain/(loss) | (0.05) | 0.23 | 0.18 | – | 0.12 | 0.12 |
| Current income tax | (0.46) | – | (0.46) | (0.56) | – | (0.56) |
| Restoration and abandonment cash costs | (0.47) | 0.47 | – | (0.31) | 0.31 | – |
| Depletion, depreciation, amortization and accretion | – | (15.58) | (15.58) | – | (15.54) | (15.54) |
| Future income tax (expense)/recovery | – | (1.70) | (1.70) | – | 3.39 | 3.39 |
| Gain on sale of marketable securities[(3)] | – | 0.62 | 0.62 | – | – | – |
| Total per BOE | $27.55 | $(16.89) | $ 10.66 | $28.74 | $(10.08) | $ 18.66 |

(1) Cash Flow from Operating Activities before changes in non-cash working capital.
(2) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(3) Gain on sale of marketable securities was a cash item however it is included in cash flow from investing activities not cash flow from operating activities.

### Selected Canadian and U.S. Financial Results

The following tables provide a geographical analysis of key operating and financial results for the three and nine months ended September 30, 2007 and 2006.

| (CDN$ millions, except per unit amounts) | Three months ended September 30, 2007 Canada | U.S. | Total | Three months ended September 30, 2006 Canada | U.S. | Total |
|---|---|---|---|---|---|---|
| **Daily Production Volumes** | | | | | | |
| Natural gas (Mcf/day) | 241,196 | 10,068 | 251,264 | 260,381 | 5,911 | 266,292 |
| Crude oil (bbls/day) | 24,236 | 9,841 | 34,077 | 25,288 | 10,664 | 35,952 |
| Natural gas liquids (bbls/day) | 3,937 | – | 3,937 | 4,199 | – | 4,199 |
| Total daily sales (BOE/day) | 68,372 | 11,519 | 79,891 | 72,884 | 11,649 | 84,533 |
| **Pricing[(1)]** | | | | | | |
| Natural gas (per Mcf) | $ 5.58 | $ 5.67 | $ 5.59 | $ 6.09 | $ 7.69 | $ 6.13 |
| Crude oil (per bbl) | $65.78 | $77.49 | $69.16 | $66.28 | $74.00 | $68.57 |
| Natural gas liquids (per bbl) | $50.79 | $ – | $50.79 | $54.63 | $ – | $54.63 |
| **Capital Expenditures** | | | | | | |
| Development capital and office | $ 70.5 | $ 21.8 | $ 92.3 | $ 99.0 | $ 33.7 | $132.7 |
| Acquisitions of oil and gas properties | $ 1.8 | $ – | $ 1.8 | $ 3.6 | $ 0.7 | $ 4.3 |
| Dispositions of oil and gas properties | $ (0.1) | $ – | $ (0.1) | $ (0.2) | $ – | $ (0.2) |
| **Revenues** | | | | | | |
| Oil and gas sales[(1)] | $289.4 | $ 75.4 | $364.8 | $321.2 | $ 76.8 | $398.0 |
| Royalties | $ (52.6) | $ (15.6)[(2)] | $ (68.2) | $ (56.2) | $ (14.7)[(2)] | $ (70.9) |
| Commodity derivative instruments | $ 3.6 | $ – | $ 3.6 | $ 15.9 | $ – | $ 15.9 |
| **Expenses** | | | | | | |
| Operating | $ 68.9 | $ 2.7 | $ 71.6 | $ 57.6 | $ 2.1 | $ 59.7 |
| General and administrative | $ 16.3 | $ 1.4 | $ 17.7 | $ 12.1 | $ 2.9 | $ 15.0 |
| Depletion, depreciation, amortization and accretion | $ 88.9 | $ 27.1 | $116.0 | $ 98.3 | $ 31.1 | $129.4 |
| Current income taxes | $ – | $ 5.1 | $ 5.1 | $ – | $ 3.1 | $ 3.1 |

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) Royalties include U.S. state production tax.

| (CDN$ millions, except per unit amounts) | **Nine months ended September 30, 2007** Canada | U.S. | Total | Nine months ended September 30, 2006 Canada | U.S. | Total |
|---|---|---|---|---|---|---|
| Daily Production Volumes | | | | | | |
| Natural gas (Mcf/day) | 253,698 | 10,186 | 263,884 | 262,983 | 5,717 | 268,700 |
| Crude oil (bbls/day) | 24,705 | 9,897 | 34,602 | 25,843 | 10,222 | 36,065 |
| Natural gas liquids (bbls/day) | 4,194 | – | 4,194 | 4,487 | – | 4,487 |
| Total daily sales (BOE/day) | 71,182 | 11,595 | 82,777 | 74,160 | 11,175 | 85,335 |
| Pricing[1] | | | | | | |
| Natural gas (per Mcf) | $ 6.63 | $ 6.78 | $ 6.63 | $ 6.86 | $ 8.16 | $ 6.89 |
| Crude oil (per bbl) | $ 60.06 | $69.45 | $ 62.75 | $ 61.72 | $70.71 | $ 64.27 |
| Natural gas liquids (per bbl) | $ 49.26 | $ – | $ 49.26 | $ 52.49 | $ – | $ 52.49 |
| Capital Expenditures | | | | | | |
| Development capital and office | $ 193.1 | $ 92.5 | $ 285.6 | $ 281.8 | $ 88.6 | $ 370.4 |
| Acquisitions of oil and gas properties | $ 208.3 | $ 60.8 | $ 269.1 | $ 31.2 | $ 15.3 | $ 46.5 |
| Dispositions of oil and gas properties | $ (5.6) | $ – | $ (5.6) | $ (21.0) | $ – | $ (21.0) |
| Revenues | | | | | | |
| Oil and gas sales[1] | $ 920.8 | $206.5 | $1,127.3 | $ 993.1 | $210.1 | $1,203.2 |
| Royalties | $(170.2) | $ (41.7)[2] | $ (211.9) | $(190.3) | $ (40.0)[2] | $ (230.3) |
| Commodity derivative instruments | $ (4.1) | $ – | $ (4.1) | $ 2.2 | $ – | $ 2.2 |
| Expenses | | | | | | |
| Operating | $ 203.3 | $ 7.0 | $ 210.3 | $ 177.5 | $ 5.5 | $ 183.0 |
| General and administrative | $ 46.1 | $ 5.4 | $ 51.5 | $ 37.8 | $ 5.1 | $ 42.9 |
| Depletion, depreciation, amortization and accretion | $ 269.9 | $ 82.1 | $ 352.0 | $ 276.3 | $ 85.8 | $ 362.1 |
| Current income taxes | $ – | $ 10.4 | $ 10.4 | $ – | $ 13.1 | $ 13.1 |

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) Royalties include U.S. state production tax.

**Quarterly Financial Information – 2005 to 2007**

Oil and gas sales for the third quarter of 2007 were lower than the first and second quarters of 2007 mainly due to lower production and lower natural gas prices. Overall oil and gas sales increased during 2005 due to increased crude oil production and higher commodity prices, but decreased throughout 2006 as a result of softening natural gas prices.

Net income for the third quarter of 2007 was consistent with net income for the first quarter of 2007 and higher than net income in the second quarter mainly due to the increased future income tax expense resulting from the enactment of the SIFT tax during the second quarter of 2007. Net income has been affected by fluctuating commodity prices and risk management costs, the fluctuating Canadian dollar, higher operating and G&A costs, changes in future income tax provisions as well as changes to accounting policies adopted during 2005 and 2007. Furthermore, changes in the fair value of our commodity derivative instruments along with changes in fair value of other financial instruments cause net income to fluctuate between quarters.

Quarterly information is summarized in the following table:

| Quarterly Financial Information ($ millions, except per trust unit amounts) | Oil and Gas Sales[1] | Net Income | Net Income per trust unit Basic | Net Income per trust unit Diluted |
|---|---|---|---|---|
| 2007 | | | | |
| Third Quarter | $ 364.8 | $ 93.0 | $0.72 | $0.72 |
| Second Quarter | 382.5 | 40.1 | 0.31 | 0.31 |
| First Quarter | 380.0 | 107.9 | 0.88 | 0.87 |
| 2006 | | | | |
| Fourth Quarter | $ 369.5 | $110.2 | $0.90 | $0.89 |
| Third Quarter | 398.0 | 161.3 | 1.31 | 1.31 |
| Second Quarter | 403.5 | 146.0 | 1.19 | 1.19 |
| First Quarter | 401.7 | 127.3 | 1.08 | 1.07 |
| Total | $1,572.7 | $544.8 | $4.48 | $4.47 |
| 2005 | | | | |
| Fourth Quarter | $ 503.2 | $150.9 | $1.29 | $1.28 |
| Third Quarter | 398.7 | 107.1 | 0.97 | 0.97 |
| Second Quarter | 320.0 | 108.8 | 1.04 | 1.04 |
| First Quarter | 301.8 | 65.2 | 0.63 | 0.62 |
| Total | $1,523.7 | $432.0 | $3.96 | $3.95 |

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

**Liquidity and Capital Resources**

*Sustainability of our Distributions and Asset Base*

As an oil and gas producer we have a declining asset base and therefore rely on ongoing development activities and acquisitions to replace production and add additional reserves. Our future oil and natural gas production and reserves are highly dependent on our success in exploiting our asset base and acquiring additional reserves. To the extent we are unsuccessful in these activities our cash distributions could be reduced.

Development activities and acquisitions may be funded internally by withholding a portion of cash flow or through external sources of capital such as debt or the issuance of equity. To the extent that we withhold cash flow to finance these activities, the amount of cash distributions may be reduced. Should external sources of capital become limited or unavailable, our ability to make the necessary development expenditures and acquisitions to maintain or expand our asset base may be impaired and ultimately reduce the amount of cash distributions.

*Distribution Policy*

The amount of cash distributions is proposed by management and approved by the Board of Directors. We continually assess distribution levels with respect to forecasted cash flows, debt levels and capital spending plans. The level of cash withheld has historically varied between 10% and 40% of annual cash flow from operating activities and is dependent upon numerous factors, the most significant of which are the prevailing commodity price environment, our current levels of production, debt obligations, our access to equity markets and funding requirements for our development capital program.

At December 31, 2006 we changed our methodology for calculating payout ratio to cash distributions to unitholders divided by cash flow from operating activities (after changes in non-cash working capital) as presented on our Consolidated Statements of Cash Flows. As a result, fluctuations in non-cash changes in operating working capital will continue to impact our payout ratio from quarter to quarter.

Although we intend to continue to make cash distributions to our unitholders, these distributions are not guaranteed. To the extent there is taxable income at the trust level determined in accordance with the Canadian Income Tax Act, the distribution of that taxable income is non-discretionary.

*Cash Flow from Operating Activities, Cash Distributions and Payout Ratio*

Cash flow from operating activities and cash distributions are reported on the Consolidated Statements of Cash Flows. During the third quarter of 2007 cash distributions of $163.1 million were funded entirely through cash flow of $232.8 million. The payout ratio was 70% for the three months ended September 30, 2007 compared to 58% for the same period in 2006. For the nine months ended September 30, 2007 our cash distributions were $483.4 million and were funded entirely through cash flow of $663.5 million.

The payout ratio for the nine months ended September 30, 2007 was 73% compared to 70% for the nine months ended September 30, 2006.

After consideration of cash distributions, the balance of our third quarter cash flow of $69.7 million was used to fund 77% of our $90.6 million in development capital spending. The balance of our development capital expenditures and our property acquisitions were financed through a combination of debt and our distribution reinvestment program.

In aggregate, our 2007 third quarter cash distributions of $163.1 million and our development capital spending of $90.6 million totaled $253.7 million, or approximately 109% of our cash flow of $232.8 million. For the nine months ended September 30, 2007 our cash distributions of $483.4 million and our development capital spending of $281.0 million totaled $764.4 million, or approximately 115% of our cash flow of $663.5 million. We rely on access to capital markets to the extent cash distributions and net capital expenditures exceed cash flow. Over the long term we would expect to support our distributions and capital expenditures with our cash flow however, we would continue to fund acquisitions and growth through additional debt and equity. There will be years, when we are investing capital in opportunities that do not immediately generate cash flow (such as our Joslyn and Kirby oil sands projects) that this relationship will vary. It is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities in the oil and gas sector due to the nature of reserve reporting, natural reservoir declines and the risks involved with capital investment. Therefore we do not disclose maintenance capital separate from development capital spending.

For the three months ended September 30, 2007 our cash distributions exceeded our net income by $70.1 million (2006 – cash distributions $6.6 million lower than net income) however net income includes $109.9 million of non-cash items (2006 – $82.1 million) that do not impact our cash flow. For the nine months ended September 30, 2007 our cash distributions exceeded our net income by $242.4 million (2006 – $24.7 million) which includes $406.4 million of non-cash items (2006 – $242.3 million) that do not impact our cash flow. Future income taxes can fluctuate from period to period as a result of changes in tax rates (such as the enactment of the SIFT tax during the second quarter of 2007), or changes in the royalty, interest and dividends from our operating subsidiaries paid to the Fund. In addition, other non-cash charges such as DDA&A are not a good proxy for the cost of maintaining our productive capacity as they are based on the historical costs of our PP&E and not the fair market value of replacing those assets within the context of the current commodity price environment. The level of investment in a given period may not be sufficient to replace productive capacity given the natural declines associated with oil and natural gas assets. In these instances a portion of the cash distributions paid to unitholders may represent a return of the unitholders' capital.

The following table compares cash distributions to cash flow and net income.

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| ($ millions, except per unit amounts) | **2007** | 2006 | **2007** | 2006 |
| Cash flow from operating activities: | $232.8 | $268.9 | $ 663.5 | $656.6 |
| Use of cash flow: | | | | |
| Cash distributions | $163.1 | $154.7 | $ 483.4 | $459.3 |
| Capital expenditures | 69.7 | 114.2 | 180.1 | 197.3 |
| | $232.8 | $268.9 | $ 663.5 | $656.6 |
| Excess of cash flow over cash distributions | $ 69.7 | $114.2 | $ 180.1 | $197.3 |
| Net income | $ 93.0 | $161.3 | $ 241.0 | $434.6 |
| (Shortfall)/excess of net income over cash distributions | $ (70.1) | $ 6.6 | $(242.4) | $ (24.7) |
| Cash distributions per weighted average trust unit | $ 1.26 | $ 1.26 | $ 3.81 | $ 3.79 |
| Payout ratio(1) | 70% | 58% | 73% | 70% |

(1) Based on cash distributions divided by cash flow from operating activities.

*Long-Term Debt*

Long-term debt at September 30, 2007 which was comprised of $421.0 million of bank indebtedness and $231.4 million of senior unsecured notes, decreased to $652.4 million from $679.8 million at December 31, 2006. With the adoption of the financial instrument accounting standards (see Note 2) on January 1, 2007 we adjusted the carrying value of our US$175 million senior unsecured notes to fair value of $208.2 million from their previous carrying value of $268.3 million, a decrease of $60.1 million. Subsequent to this adoption entry, our total long term debt has increased by approximately $32.7 million from December 31, 2006. Increases in long-term debt resulting from the Jonah and Kirby acquisitions more than offset decreases resulting from the April 2007 equity issue and the foreign exchange impact of the strengthening Canadian dollar against the U.S. dollar on our U.S. dollar denominated senior notes.

Subsequent to September 30, 2007 we extended our bank credit facility by one year to November 2010. In addition, the facility size was increased to $1.0 billion and there were no changes to the floating interest rates under the facility.

We continue to maintain a conservative balance sheet with a long-term debt to trailing cash flow ratio of 0.7x times as demonstrated below:

| Financial Leverage and Coverage | **September 30, 2007** | December 31, 2006 |
|---|---|---|
| Long-term debt to trailing cash flow | **0.7 x** | 0.8 x |
| Cash flow to interest expense | **24.9 x** | 26.8 x |
| Long-term debt to long-term debt plus equity | **19%** | 20% |

Long-term debt is measured net of cash.
Cash flow and interest expense are 12-months trailing.

Payments with respect to the bank facilities, senior unsecured notes and other third party debt have priority over claims of and future distributions to the unitholders. Unitholders have no direct liability should cash flow be insufficient to repay this indebtedness. The agreements governing these bank facilities and senior unsecured notes stipulate that if we default or fail to comply with certain covenants, the ability of the Fund's operating subsidiaries to make payments to the Fund and consequently the Fund's ability to make distributions to the unitholders may be restricted. At September 30, 2007 we are in compliance with our debt covenants, the most restrictive of which limits our long term debt to 3 times trailing cash flow reflecting acquisitions on a pro forma basis. Refer to ''Debt of Enerplus'' in our 2006 Annual Information Form for a detailed description of these covenants.

Principal payments on Enerplus' senior unsecured notes are required commencing in 2010 and 2011 and are more fully discussed in Note 7.

We anticipate that we will continue to have adequate liquidity to fund planned development capital spending for the remainder of 2007 through a combination of cash flow retained by the business and debt.

*Foreign Exchange Swaps*

Our US$54 million debentures, which were entered into on October 1, 2003 at a CAD/US$ exchange rate of 1.35, require principal repayments in five equal installments beginning on October 1, 2011 and ending October 2015. As a result of the strengthening Canadian dollar against the U.S. dollar, we entered into foreign exchange swaps during the quarter which effectively fix the principal repayments at a CAD/US$ exchange rate of 1.02 and secures an economic gain of $17.9 million. For accounting purposes these swaps have been designated as held for trading and are recorded on the balance sheet at fair value with the non-cash changes in fair value recorded in earnings. We will continue to record the US$54 million debentures on our balance sheet at the period end foreign exchange rate with the non-cash change recorded in earnings. As the principal repayments occur and the foreign exchange swaps mature the realized cash gain or loss at each payment date will be recorded through earnings and the corresponding non-cash gain or loss will reverse through earnings.

### Commitments

Subsequent to September 30, 2007, Enerplus extended its bank credit facility by one year to November 2010 and increased the facility size to $1.0 billion. Enerplus also extended the Canadian office lease from December 2009 to November 2014. Annual costs of this lease extension, including operating fees, are approximately $10.7 million annually for a total additional commitment of approximately $53.6 million.

### Trust Unit Information

We had 129,552,000 trust units outstanding at September 30, 2007 compared to 122,854,000 trust units at September 30, 2006 and 123,151,000 at December 31, 2006. The weighted average basic number of trust units outstanding for the nine months ended September 30, 2007 was 127,031,000 (2006 – 121,120,000). At November 7, 2007 we had 129,634,000 trust units outstanding.

For the three months ended September 30, 2007, 347,000 trust units (2006 – 272,000) were issued pursuant to the Trust Unit Monthly Distribution Reinvestment and Unit Purchase Plan (''DRIP'') and the trust unit rights plan. This resulted in $15.1 million (2006 – $13.7 million) of additional equity for the Fund. During the nine months ended September 30, 2007, 1,046,000 trust units ($46.8 million additional equity) were issued pursuant to DRIP and the trust unit options and rights plans compared to 945,000 trust units ($41.7 million) during the same period in 2006. For further details see Note 10.

On April 10, 2007 in conjunction with the acquisition of Kirby we issued 1,105,000 trust units as part of the purchase price consideration representing $54.8 million and also closed a public offering of 4,250,000 trust units for net proceeds of $199.6 million.

**Canadian and U.S. Taxpayers**

Enerplus estimates that approximately 95% of cash distributions paid to Canadian unitholders and 90% of cash distributions paid to U.S. unitholders will be taxable in 2007 and the remaining 5% and 10% respectively will be treated as a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions which are dependent upon production, commodity prices and cash flow experienced throughout the year.

For U.S. taxpayers the taxable portion of cash distributions are considered to be a dividend for U.S. tax purposes. For most U.S. taxpayers this should be a "Qualified Dividend" eligible for the reduced tax rate. This preferential rate of tax for "Qualified Dividends" is set to expire at the end of 2010. On March 24, 2007, Bill 1672 was introduced into the U.S. House of Representatives which, if enacted as presented, would make dividends from Canadian income funds such as Enerplus ineligible for treatment as a "Qualified Dividend". The dividends would then become a "non-qualified dividend from a foreign corporation" subject to the normal rates of tax commencing with dividends received after the date of enactment. The proposed bill still requires the approval of the House of Representatives, the Senate and the President prior to it being enacted. Therefore, we are unable to determine when or even if the bill will become enacted as presented.

In October 2007, Enerplus estimated its non-resident ownership to be approximately 70%.

## Recent Canadian Accounting Pronouncements

*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.

This standard is effective for January 1, 2008 and will result in additional disclosures for our financial instruments.

*CICA Section 3863 – Financial Instruments – Presentation*

This standard establishes presentation guidelines for 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.

This standard is effective for January 1, 2008 and should have a minimal impact on our reporting.

*CICA Section 1535 – Capital Disclosures*

This section details disclosures that must be made regarding an entity's capital and how it is managed. The standard requires qualitative information about an entity's objectives, policies and processes for managing capital and quantitative data about what the entity regards as capital. It requires disclosure of compliance with any capital requirements and consequences of any non-compliance.

This standard is effective for January 1, 2008 and will result in additional disclosures around managing capital.

## Internal Controls and Procedures

There were no changes in our internal control over financial reporting during the quarter ended September 30, 2007 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

## Additional Information

Additional information relating to Enerplus Resources Fund, including the Fund's Annual Information Form, is available under the Fund's profile on the SEDAR website at www.sedar.com and at www.enerplus.com.

## Forward-Looking Statements and Information

This management's discussion and analysis (''MD&A'') contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words ''expect'', ''anticipate'', ''continue'', ''estimate'', ''objective'', ''ongoing'', ''may'', ''will'', ''project'', ''should'', ''believe'', ''plans'', ''intends'' and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this MD&A contains forward-looking information and statements pertaining to the following: the amount, timing and tax treatment of cash distributions to unitholders; future payout ratio; future tax treatment of income trusts such as the Fund; future structure of the Fund and its subsidiaries; the Fund's tax pools; the volumes and estimated value of the Fund's oil and gas reserves and resources; the volume and product mix of the Fund's oil and gas production; future oil and natural gas prices and the Fund's commodity risk management programs; the amount of future asset retirement obligations; future liquidity and financial capacity; future results from operations, cost estimates and royalty rates; future development, exploration, and acquisition and development activities and related expenditures, including with respect to both our conventional and oil sands activities.

The forward-looking information and statements contained in this MD&A reflect several material factors and expectations and assumptions of the Fund including, without limitation: that the Fund will continue to conduct its operations in a manner consistent with past operations; the general continuance of current industry conditions; the continuance of existing and in certain circumstances, proposed tax and royalty regimes; the accuracy of the estimates of the Fund's reserve volumes; and certain commodity price and other cost assumptions. The Fund believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information and statements included in this MD&A are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; unanticipated operating results or production declines; changes in tax or environmental laws or royalty rates; increased debt levels or debt service requirements; inaccurate estimation of the Fund's oil and gas reserves volumes; limited, unfavourable or no access to capital markets; increased costs; the impact of competitors; and certain other risks detailed from time to time in the Fund's public disclosure documents including, without limitation, those risks identified in this MD&A, our MD&A for the year ended December 31, 2006, and in the Fund's annual information form.

The forward-looking information and statements contained in this MD&A speak only as of the date of this MD&A, and none of the Fund or its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable laws.

## consolidated balance sheets

| (CDN$ thousands) (Unaudited) | September 30, 2007 | December 31, 2006 |
|---|---|---|
| Assets | | |
| Current assets | | |
| Cash | $ 2,570 | $ 124 |
| Accounts receivable | 135,918 | 175,454 |
| Deferred financial assets (Note 3) | 21,834 | 23,612 |
| Other current | 3,908 | 6,715 |
| | 164,230 | 205,905 |
| Property, plant and equipment (Note 4) | 3,834,212 | 3,726,097 |
| Goodwill | 196,336 | 221,578 |
| Other assets (Note 11) | 58,402 | 50,224 |
| | $ 4,253,180 | $4,203,804 |
| Liabilities | | |
| Current liabilities | | |
| Accounts payable | $ 270,194 | $ 284,286 |
| Distributions payable to unitholders | 54,413 | 51,723 |
| Deferred financial credits (Note 3) | 112,244 | – |
| | 436,851 | 336,009 |
| Long-term debt (Note 7) | 652,399 | 679,774 |
| Future income taxes | 342,750 | 331,340 |
| Asset retirement obligations (Note 6) | 124,511 | 123,619 |
| | 1,119,660 | 1,134,733 |
| Equity | | |
| Unitholders' capital (Note 10) | 4,020,597 | 3,713,126 |
| Accumulated deficit | (1,219,207) | (971,085) |
| Accumulated other comprehensive loss (Note 2) | (104,721) | (8,979) |
| | 2,696,669 | 2,733,062 |
| | $ 4,253,180 | $4,203,804 |

## consolidated statements of accumulated deficit

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| (CDN$ thousands) (Unaudited) | 2007 | 2006 | 2007 | 2006 |
| Accumulated income, beginning of period | $ 2,095,193 | $ 1,681,484 | $ 1,952,960 | $ 1,408,178 |
| Adjustment for adoption of financial instruments standards (Note 2) | – | – | (5,724) | – |
| Revised Accumulated income, beginning of period | 2,095,193 | 1,681,484 | 1,947,236 | 1,408,178 |
| Net income | 93,033 | 161,317 | 240,990 | 434,623 |
| Accumulated income, end of period | $ 2,188,226 | $ 1,842,801 | $ 2,188,226 | $ 1,842,801 |
| Accumulated cash distributions, beginning of period | $(3,244,323) | $(2,614,298) | $(2,924,045) | $(2,309,705) |
| Cash distributions | (163,110) | (154,700) | (483,388) | (459,293) |
| Accumulated cash distributions, end of period | $(3,407,433) | $(2,768,998) | $(3,407,433) | $(2,768,998) |
| Accumulated deficit, end of period | $(1,219,207) | $ (926,197) | $(1,219,207) | $ (926,197) |

## consolidated statements of accumulated other comprehensive income

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| (CDN$ thousands) (Unaudited) | 2007 | 2006 | 2007 | 2006 |
| Balance, beginning of period | $ (65,378) | $(39,217) | $ (8,979) | $(15,568) |
| Transition adjustments (Note 2): | | | | |
| Cash flow hedges | – | – | 660 | – |
| Available for sale marketable securities | – | – | 14,252 | – |
| Other comprehensive (loss)/income | (39,343) | 978 | (110,654) | (22,671) |
| Balance, end of period | $(104,721) | $(38,239) | $(104,721) | $(38,239) |

# consolidated statements of income

| (CDN$ thousands except per trust unit amounts) (Unaudited) | Three months ended September 30, 2007 | 2006 | Nine months ended September 30, 2007 | 2006 |
|---|---|---|---|---|
| Revenues | | | | |
| Oil and gas sales | $ 370,163 | $ 403,761 | $1,143,960 | $1,220,677 |
| Royalties | (68,165) | (70,931) | (211,927) | (230,320) |
| Commodity derivative instruments (Notes 3 and 11) | 3,585 | 15,911 | (4,067) | 2,179 |
| Other income (Note 11) | 143 | 1,085 | 14,575 | 2,375 |
| | 305,726 | 349,826 | 942,541 | 994,911 |
| Expenses | | | | |
| Operating | 71,551 | 59,689 | 210,337 | 182,960 |
| General and administrative (Note 10) | 17,718 | 14,997 | 51,488 | 42,862 |
| Transportation | 5,334 | 5,728 | 16,651 | 17,455 |
| Interest (Note 9) | 6,438 | 8,586 | 26,400 | 23,592 |
| Foreign exchange (Note 8) | (643) | (639) | (4,117) | (2,893) |
| Depletion, depreciation, amortization and accretion | 116,001 | 129,400 | 352,001 | 362,134 |
| | 216,399 | 217,761 | 652,760 | 626,110 |
| Income before taxes | 89,327 | 132,065 | 289,781 | 368,801 |
| Current taxes | 5,081 | 3,092 | 10,372 | 13,101 |
| Future income tax (recovery)/expense | (8,787) | (32,344) | 38,419 | (78,923) |
| Net Income | $ 93,033 | $ 161,317 | $ 240,990 | $ 434,623 |
| Net income per trust unit | | | | |
| Basic | $ 0.72 | $ 1.31 | $ 1.90 | $ 3.59 |
| Diluted | $ 0.72 | $ 1.31 | $ 1.90 | $ 3.58 |
| Weighted average number of trust units outstanding (thousands) | | | | |
| Basic | 129,373 | 122,712 | 127,031 | 121,120 |
| Diluted | 129,402 | 123,126 | 127,089 | 121,511 |

# consolidated statements of comprehensive income

| (CDN$ thousands) (Unaudited) | Three months ended September 30, 2007 | 2006 | Nine months ended September 30, 2007 | 2006 |
|---|---|---|---|---|
| Net income | $ 93,033 | $161,317 | $ 240,990 | $434,623 |
| Other comprehensive (loss)/income, net of tax (Note 11): | | | | |
| Unrealized gains/(losses) on marketable securities | 545 | – | (109) | – |
| Realized gains on marketable securities included in net income | – | – | (11,654) | – |
| Gains and losses on derivatives designated as hedges in prior periods included in net income | (177) | – | (557) | – |
| Change in cumulative translation adjustment | (39,711) | 978 | (98,334) | (22,671) |
| Other comprehensive (loss)/income | (39,343) | 978 | (110,654) | (22,671) |
| Comprehensive income (Note 2) | $ 53,690 | $162,295 | $ 130,336 | $411,952 |

# consolidated statements of cash flows

| (CDN$ thousands) (Unaudited) | Three months ended September 30, 2007 | 2006 | Nine months ended September 30, 2007 | 2006 |
|---|---|---|---|---|
| **Operating Activities** | | | | |
| Net income | $ 93,033 | $ 161,317 | $ 240,990 | $ 434,623 |
| Non-cash items add/(deduct): | | | | |
| Depletion, depreciation, amortization and accretion | 116,001 | 129,400 | 352,001 | 362,134 |
| Change in fair value of derivative instruments (Note 3) | 16,388 | (16,754) | 49,841 | (42,513) |
| Unit based compensation (Note 10) | 2,192 | 1,765 | 6,410 | 4,291 |
| Foreign exchange on translation of senior notes (Note 8) | (15,586) | 16 | (39,276) | (2,732) |
| Future income tax | (8,787) | (32,344) | 38,419 | (78,923) |
| Amortization of senior notes premium | (155) | – | (483) | – |
| Reclassification adjustments from AOCI to net income | (177) | – | (557) | – |
| Gain on sale of marketable securities | – | – | (14,055) | – |
| Asset retirement obligations settled (Note 6) | (3,547) | (1,636) | (10,664) | (7,220) |
| | 199,362 | 241,764 | 622,626 | 669,660 |
| Decrease/(Increase) in non-cash working capital | 33,439 | 27,140 | 40,838 | (13,071) |
| Cash flow from operating activities | 232,801 | 268,904 | 663,464 | 656,589 |
| **Financing Activities** | | | | |
| Issue of trust units, net of issue costs (Note 10) | 15,087 | 13,713 | 246,311 | 281,957 |
| Cash distributions to unitholders | (163,110) | (154,700) | (483,388) | (459,293) |
| (Decrease)/Increase in bank credit facilities | 8,145 | (14,692) | 72,495 | (67,291) |
| Decrease in non-cash financing working capital | 141 | 101 | 2,690 | 2,232 |
| Cash flow from financing activities | (139,737) | (155,578) | (161,892) | (242,395) |
| **Investing Activities** | | | | |
| Capital expenditures | (92,324) | (132,673) | (285,678) | (370,366) |
| Property acquisitions | (1,755) | (4,296) | (214,399) | (46,553) |
| Property dispositions | 96 | 215 | (1,056) | 1,493 |
| Proceeds on sale of marketable securities | – | – | 16,467 | – |
| Decrease/(Increase) in non-cash investing working capital | 3,419 | 24,798 | (11,078) | (5,711) |
| Cash flow from investing activities | (90,564) | (111,956) | (495,744) | (421,137) |
| Effect of exchange rate changes on cash | (1,980) | (1,547) | (3,382) | (2,675) |
| Change in cash | 520 | (177) | 2,446 | (9,618) |
| Cash, beginning of period | 2,050 | 652 | 124 | 10,093 |
| Cash, end of period | $ 2,570 | $ 475 | $ 2,570 | $ 475 |
| **Supplementary Cash Flow Information** | | | | |
| Cash income taxes paid | $ 3,340 | $ – | $ 10,586 | $ 3,770 |
| Cash interest paid | $ 6,052 | $ 4,563 | $ 26,782 | $ 19,324 |

# notes to consolidated financial statements

(Tabular amounts in thousands of Canadian dollars and thousands of units except per unit amounts) (Unaudited)

## 1. Summary of Significant Accounting Policies

The interim consolidated financial statements of Enerplus Resources Fund ("Enerplus" or the "Fund") have been prepared by management following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2006, except as identified in Note 2. The note disclosure requirements for annual statements provide additional disclosure to that required for these interim statements. Accordingly, these interim statements should be read in conjunction with the Fund's consolidated financial statements for the year ended December 31, 2006. The disclosures provided below are incremental to those included in the 2006 annual consolidated financial statements of the Fund.

## 2. Changes in Accounting Policies

**Financial Instruments**

Effective January 1, 2007, the Fund adopted five new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA"): Handbook Section 1530, Comprehensive Income, Handbook Section 3251, Equity, Handbook Section 3855, Financial Instruments – Recognition and Measurement, Handbook Section 3861, Financial Instruments – Disclosure and Presentation and Handbook Section 3865, Hedges. These standards were adopted prospectively pursuant to their respective adoption provisions, and therefore there is no effect on prior periods.

*Comprehensive Income*

CICA Handbook Section 1530 introduces comprehensive income, which consists of net income and other comprehensive income ("OCI"). OCI represents changes in equity during a period arising from transactions and other events with non-owner sources and includes unrealized gains and losses on marketable securities classified as available-for-sale along with unrealized foreign currency translation gains or losses arising from self-sustaining foreign operations, among other things. The Consolidated Statements of Comprehensive Income include a calculation of comprehensive income, while the cumulative changes in OCI are included in the Statements of Accumulated Other Comprehensive Income (AOCI). CICA Handbook Section 3251 establishes standards for the presentation of equity and changes in equity during the period.

*Financial Instruments – Recognition and Measurement*

CICA Handbook Section 3855 establishes the criteria for recognizing and measuring financial assets, financial liabilities and non-financial derivatives. Under this standard, all financial instruments are required to be measured at fair value on recognition except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as held-for-trading, available-for-sale, held-to-maturity, loans and receivables, or other financial liabilities.

Financial assets and financial liabilities classified as held-for-trading are measured at fair value with changes in fair value recognized in net income. Financial assets classified as loans and receivables along with financial liabilities classified as other liabilities are measured at amortized cost using the effective interest rate method. Financial assets classified as available-for-sale are measured at fair value with changes in fair value recognized in OCI. Investments in equity instruments classified as available-for-sale that do not have a quoted price in an active market are measured at cost. Transaction costs or fees attributable to the acquisition, issue, or disposal of a financial asset or liability are expensed immediately to net income.

Derivative instruments are recorded on the consolidated balance sheets at fair value, including those derivatives that are embedded in financial or non-financial contracts that are not closely related to the host contracts. Changes in the fair values of derivative instruments are recognized in net income with the exception of derivatives that are designated as effective cash flow hedges. Refer to the *Hedges* section for further detail.

CICA Handbook Section 3861 establishes standards for the presentation and disclosure of financial instruments and non-financial derivatives.

*Hedges*

CICA Handbook Section 3865 specifies the criteria and method of accounting for each of the designated hedging strategies.

When hedge accounting is discontinued for a cash flow hedge, the amounts previously recognized in AOCI are reclassified to net income over the remaining term of the hedged item.

When hedge accounting is discontinued for a fair value hedge, the carrying value of the hedged item is no longer adjusted. Any difference between the carrying value and the face value or principal amount of the hedged item is amortized to net income over the remaining term of the original hedging relationship using the effective interest method.

**Impact upon Adoption of Sections 1530, 3251, 3855, 3861 and 3865**

As a result of the adoption of these standards on January 1, 2007 the Fund elected to stop designating its interest rate and electricity swaps as cash flow hedges and recorded these items on the consolidated balance sheet at their fair values with the offset recorded to opening accumulated other comprehensive income. In addition, the Fund elected to stop designating its cross currency and interest rate swap (''CCIRS'') as a fair value hedge and recorded the CCIRS on the consolidated balance sheet at fair value with the offset recorded to opening accumulated deficit. In conjunction, the underlying US$175,000,000 senior unsecured notes were recorded at fair value with the offset recorded to opening accumulated deficit.

The Fund's investments in marketable securities have been classified as available-for-sale and were therefore recorded on the consolidated balance sheet at fair value with the offset recorded to opening AOCI.

Deferred charges of $1,523,000 associated with issuance of the senior unsecured notes were recorded to the opening accumulated deficit.

Amounts previously recorded in the cumulative translation adjustment were reclassified into opening AOCI. Our prior year comparative statements have been restated to reflect this change.

The Fund has recorded the following transition adjustments as of January 1, 2007 in the Consolidated Financial Statements: (a) an increase of $1,494,000 to deferred financial assets to record the electricity swaps at fair value; (b) an increase to other current assets of $14,493,000 to record publicly traded marketable securities at fair value; (c) an increase of $1,708,000 to other assets, consisting of $3,231,000 to record publicly traded marketable securities at fair value less $1,523,000 to write-off the deferred charges associated with the issuance of the senior unsecured notes; (d) an increase of $65,675,000 to deferred financial credits to record the CCIRS and interest rates swaps at fair value; (e) a decrease to long-term debt of $60,111,000 to record the US$175,000,000 senior unsecured note at fair value; (f) an increase to future income taxes of $ 2,943,000 to reflect the tax impact of the adoption entries; (g) an increase of $5,724,000, net of taxes, to the opening accumulated deficit; (h) recognition in AOCI of $14,912,000, net of taxes, related to the net gains on marketable securities classified as available-for-sale along with the fair value of the interest rate and power swaps formerly designated as cash flow hedges. In addition, the Fund reclassified to AOCI $8,979,000 of net unrealized foreign currency losses that were previously presented as a separate item in equity. These transition adjustments are summarized below.

Impact of transition adjustment on selected consolidated balance sheets line items:

| (CDN$ thousands) | **Transition adjustment as at January 1, 2007** |
|---|---|
| Deferred financial assets | $ 1,494 |
| Other current assets | 14,493 |
| Other assets | 1,708 |
| Deferred credits | 65,675 |
| Long-term debt | (60,111) |
| Future income taxes | 2,943 |
| Accumulated deficit | (5,724) |
| Cumulative translation adjustment | 8,979 |
| Accumulated other comprehensive income | 5,933 |

As a result of these changes, net income increased by $678,000 ($958,000 before future income taxes of $280,000) and $589,000 ($832,000 before future income taxes of $243,000) for the three and nine months ended September 30, 2007 respectively. Both the basic and diluted net income per trust unit calculations for the three months ended September 30, 2007 increased by $0.01 and were unchanged for the nine months ended September 30, 2007.

**Recent Canadian Accounting Pronouncements**

*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.

This standard is effective for January 1, 2008 and will result in additional disclosures for our financial instruments.

*CICA Section 3863 – Financial Instruments – Presentation*

This standard establishes presentation guidelines for 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.

This standard is effective for January 1, 2008 and should have a minimal impact on our reporting.

*CICA Section 1535 – Capital Disclosures*

This section details disclosures that must be made regarding an entity's capital and how it is managed. The standard requires qualitative information about an entity's objectives, policies and processes for managing capital and quantitative data about what the entity regards as capital. It requires disclosure of compliance with any capital requirements and consequences of any non-compliance.

This standard is effective for January 1, 2008 and will result in additional disclosures around managing capital.

## 3. Deferred Financial Assets and Credits

The deferred financial assets and credits result from recording our derivative financial instruments at fair value. The deferred financial credit relating to crude oil instruments of $14,918,000 at September 30, 2007 consists of the fair value of the financial instruments, a loss position of $5,809,000, less the related deferred premiums of $9,109,000. The deferred financial asset relating to natural gas instruments of $20,301,000 at September 30, 2007 consists of the fair value of the financial instruments of $21,543,000 less the related deferred premiums of $1,242,000.

| | | | | | Commodity Derivative Instruments | | |
|---|---|---|---|---|---|---|---|
| ($ thousands) | Interest Rate Swaps | Cross Currency Interest Rate Swaps | Foreign Exchange Swaps | Electricity Swaps | Oil | Gas | Total |
| Deferred financial assets/(credits) as at December 31, 2006 | $ – | $ – | $ – | $ – | $ 10,922 | $12,690 | $ 23,612 |
| Adoption of financial instruments standards(1) | (673) | (65,002) | – | 1,494 | – | – | (64,181) |
| Change in fair value asset/(credits) | 1,228(2) | (31,071)(3) | (1,253)(4) | (516)(5) | (25,840)(6) | 7,611(6) | (49,841) |
| Deferred financial assets/(credits) as at September 30, 2007 | $ 555 | $(96,073) | $(1,253) | $ 978 | $(14,918) | $20,301 | $(90,410)(7) |

(1) The adoption of the financial instruments standards on January 1, 2007 resulted in a decrease to the deferred financial assets balance. See Note 2 for further details.
(2) Recorded in interest expense.
(3) Recorded in foreign exchange expense (loss of $32,879) and interest expense (gain of $1,808).
(4) Recorded in foreign exchange expense.
(5) Recorded in operating expense.
(6) Recorded in commodity derivative instruments (see below).
(7) For financial statement presentation at September 30, 2007 this amount has been presented as a deferred financial asset of $21,834 and a deferred financial credit of $112,244.

The following table summarizes the income statement effects of commodity derivative instruments:

| Commodity Derivative Instruments ($ thousands) | Three months ended September 30, 2007 | 2006 | Nine months ended September 30, 2007 | 2006 |
|---|---|---|---|---|
| Change in fair value, loss/(gain) | $ 3,799 | $(26,992) | $ 18,229 | $(89,491) |
| Amortization of deferred financial assets | – | 10,238 | – | 46,978 |
| Realized cash costs/(gains), net | (7,384) | 843 | (14,162) | 40,334 |
| Commodity derivative instruments | $(3,585) | $(15,911) | $ 4,067 | $ (2,179) |

## 4. Property, Plant and Equipment

| ($ thousands) | September 30, 2007 | December 31, 2006 |
|---|---|---|
| Property, plant and equipment | $ 6,282,141 | $ 5,855,511 |
| Accumulated depletion, depreciation and accretion | (2,447,929) | (2,129,414) |
| Net property, plant and equipment | $ 3,834,212 | $ 3,726,097 |

Capitalized development G&A of $12,497,000 (2006 – $10,157,000) is included in property, plant and equipment (''PP&E'') for the nine months ended September 30, 2007. Excluded from PP&E for the purpose of the depletion and depreciation calculation is $303,678,000 (2006 – $60,499,000) related to the Joslyn and Kirby development projects, both of which have not yet commenced commercial production.

## 5. Property Acquisition

On April 10, 2007 the Fund acquired a 90% interest in the Kirby Oil Sands Partnership (''Kirby'') for total consideration of $182,800,000, consisting of $128,050,000 in cash and the issuance of 1,104,945 trust units at a price of $49.55 per unit ($54,750,000 of equity). On June 22, 2007, the Fund acquired the remaining 10% interest in Kirby for cash consideration of $20,276,000. The acquisition of Kirby has been accounted for as an asset acquisition pursuant to the guidance in the Emerging Issues Committee Abstract 124.

## 6. Asset Retirement Obligations

The following table reconciles the Fund's asset retirement obligations:

| ($ thousands) | Nine months ended September 30, 2007 | Year ended December 31, 2006 |
|---|---|---|
| Asset retirement obligations, beginning of period | $123,619 | $110,606 |
| Changes in estimates | 5,362 | 12,757 |
| Acquisition and development activity | 1,939 | 5,574 |
| Dispositions | (759) | (45) |
| Asset retirement obligations settled | (10,664) | (11,514) |
| Accretion expense | 5,014 | 6,241 |
| Asset retirement obligations, end of period | $124,511 | $123,619 |

## 7. Long-Term Debt

| ($ thousands) | September 30, 2007 | December 31, 2006 |
|---|---|---|
| Bank credit facilities (a) | $421,015 | $348,520 |
| Senior notes (b) | | |
| US$175 million (issued June 19, 2002) | 177,584 | 268,328 |
| US$54 million (issued October 1, 2003) | 53,800 | 62,926 |
| Total long-term debt | $652,399 | $679,774 |

### (a) Unsecured Bank Credit Facility

Enerplus currently has a $1.0 billion unsecured covenant based three year term facility ($850,000,000 at September 30, 2007). The facility is extendible each year with a bullet payment required at the end of the three year term. Subsequent to September 30, 2007 the bank credit facility was extended by one year to November 2010. In addition, the facility size was increased and there were no changes to the floating interest rates under the facility. Various borrowing options are available under the facility including prime rate based advances and bankers' acceptance loans. This facility carries floating interest rates that are expected to range between 55.0 and 110.0 basis points over bankers' acceptance rates, depending on Enerplus' ratio of senior debt to earnings before interest, taxes and non-cash items. The effective interest rate on the facility for the nine months ended September 30, 2007 was 5.0% (2006 – 4.7%).

### (b) Senior Unsecured Notes

On October 1, 2003 when the Cdn/US exchange rate was 1.35 Enerplus issued US$54,000,000 senior unsecured notes that mature October 1, 2015. The notes have a coupon rate of 5.46% priced at par with interest paid semi-annually on April 1 and October 1 of each year. Principal payments are required in five equal installments beginning October 1, 2011 and ending October 1, 2015. The notes are translated into Canadian dollars using the period end foreign exchange rate.

During September 2007 Enerplus entered into foreign exchange swaps that effectively fix the five principal payments on the US$54,000,000 senior unsecured notes at a CAD/US exchange rate of 1.02.

On June 19, 2002 Enerplus issued US$175,000,000 senior unsecured notes that mature June 19, 2014. The notes have a coupon rate of 6.62% priced at par, with interest paid semi-annually on June 19 and December 19 of each year. Principal payments are required in five equal installments beginning June 19, 2010 and ending June 19, 2014. Concurrent with the issuance of the notes on June 19, 2002, the Fund entered into a cross currency interest rate swap ("CCIRS") with a syndicate of financial institutions. Under the terms of the swap, the amount of the notes was fixed for purposes of interest and principal repayments at a notional amount of CDN$268,328,000. Interest payments are made on a floating rate basis, set at the rate for three-month Canadian bankers' acceptances, plus 1.18%.

On January 1, 2007 in conjunction with the adoption of CICA Sections 3855 and 3865, the Fund elected to stop designating the CCIRS as a fair value hedge on the US$175,000,000 senior notes. As a result, the Fund recorded the senior notes at their fair value of US$178,681,000 (CDN $208,217,000) with the offset to opening accumulated deficit. In addition, the Fund recorded a liability of $65,002,000 with the offset to opening accumulated deficit, which represented the fair value of the CCIRS. The premium amount of US$3,681,000, representing the difference between the January 1, 2007 fair value and the face amount of the senior notes, will be amortized to net income over the remaining term of the notes using the effective interest method. The effective interest rate over the remaining term of the senior notes is 6.16%. The senior notes are carried at amortized cost and are translated into Canadian dollars using the period end foreign exchange rate. At September 30, 2007 the amortized cost of the US$175,000,000 senior notes was US$178,243,000.

## 8. Foreign Exchange

| ($ thousands) | Three months ended September 30, 2007 | 2006 | Nine months ended September 30, 2007 | 2006 |
|---|---|---|---|---|
| Unrealized foreign exchange (gain)/loss on translation of U.S. dollar denominated senior notes | $(15,586) | $ 16 | $(39,276) | $(2,732) |
| Unrealized foreign exchange loss on cross currency interest rate swap | 14,105 | – | 32,879 | – |
| Unrealized foreign exchange loss on foreign exchange swaps | 1,253 | – | 1,253 | – |
| Realized foreign exchange (gain)/loss | (415) | (655) | 1,027 | (161) |
| Foreign exchange gain | $ (643) | $(639) | $ (4,117) | $(2,893) |

The US$54,000,000 and US$175,000,000 senior unsecured notes are exposed to foreign currency fluctuations and are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Foreign exchange gains and losses are included in the determination of net income for the period.

## 9. Interest Expense

| ($ thousands) | Three months ended September 30, 2007 | 2006 | Nine months ended September 30, 2007 | 2006 |
|---|---|---|---|---|
| Interest on long-term debt | $10,405 | $8,586 | $29,842 | $23,592 |
| Unrealized gain on cross currency interest rate swap | (4,718) | – | (1,808) | – |
| Unrealized loss/(gain) on interest rate swaps | 871 | – | (1,228) | – |
| Amortization of the premium on senior unsecured notes | (120) | – | (406) | – |
| Interest expense | $ 6,438 | $8,586 | $26,400 | $23,592 |

## 10. Fund Capital

### (a) Unitholders' Capital

Trust Units

Authorized: Unlimited number of trust units

| Issued: (thousands) | Nine months ended September 30, 2007 Units | Amount | Year ended December 31, 2006 Units | Amount |
|---|---|---|---|---|
| Balance before Contributed Surplus, beginning of period | 123,151 | $3,706,821 | 117,539 | $3,407,567 |
| Issued for cash: | | | | |
| Pursuant to public offerings | 4,250 | 199,558 | 4,370 | 240,287 |
| Pursuant to rights plans | 157 | 5,379 | 640 | 22,974 |
| Trust unit rights incentive plan (non-cash) – exercised | – | 1,816 | – | 3,065 |
| DRIP*, net of redemptions | 889 | 41,374 | 602 | 32,928 |
| Issued for acquisition of property interests (non-cash) | 1,105 | 54,750 | – | – |
| | 129,552 | 4,009,698 | 123,151 | 3,706,821 |
| Contributed Surplus (Trust Unit Rights Plan) | – | 10,899 | – | 6,305 |
| Balance, end of period | 129,552 | $4,020,597 | 123,151 | $3,713,126 |

* Distribution Reinvestment and Unit Purchase Plan

| Contributed Surplus ($ thousands) | Nine months ended September 30, 2007 | Year ended December 31, 2006 |
|---|---|---|
| Balance, beginning of period | $ 6,305 | $ 3,047 |
| Trust unit rights incentive plan (non-cash) – exercised | (1,816) | (3,065) |
| Trust unit rights incentive plan (non-cash) – expensed | 6,410 | 6,323 |
| Balance, end of period | $10,899 | $ 6,305 |

On April 10, 2007 the Fund closed an equity offering of 4,250,000 trust units at a price of $49.55 per unit for gross proceeds of $210,588,000 ($199,558,000 net of issuance costs). These trust units were eligible for the April 20, 2007 cash distribution paid to unitholders of record at the close of business on April 10, 2007.

In conjunction with the acquisition of Kirby on April 10, 2007, the Fund issued 1,105,000 trust units at a price of $49.55 per unit for gross proceeds of $54,750,000.

### (b) Trust Unit Rights Incentive Plan

As at September 30, 2007, a total of 3,494,000 rights issued pursuant to the Trust Unit Rights Incentive Plan (''Rights Plan'') with an average exercise price of $47.89 were outstanding. This represents 2.7% of the total trust units outstanding of which 1,151,000 rights with an average exercise price of $43.69 were exercisable. Under the Rights Plan, distributions per trust unit to Enerplus unitholders in a calendar quarter which represent a return of more than 2.5% of the net PP&E of Enerplus at the end of such calendar quarter may result in a reduction in the exercise price of the rights. Results for the first, second and third quarters of 2007 reduced the exercise price of the outstanding rights by $0.51 per trust unit (effective July 2007) and $0.51 per trust unit (effective October 2007) and $0.52 per trust unit (effective January 2008), respectively.

Activity for the rights issued pursuant to the Rights Plan is as follows:

| | Nine months ended September 30, 2007 | | Year ended December 31, 2006 | |
|---|---|---|---|---|
| | Number of Rights (000's) | Weighted Average Exercise Price[1] | Number of Rights (000's) | Weighted Average Exercise Price[1] |
| Trust unit rights outstanding | | | | |
| Beginning of period | 3,079 | $48.53 | 2,621 | $42.80 |
| Granted | 802 | 48.89 | 1,473 | 54.49 |
| Exercised | (157) | 34.35 | (640) | 35.94 |
| Cancelled | (230) | 50.90 | (375) | 46.35 |
| End of period | 3,494 | $47.89 | 3,079 | $48.53 |
| Rights exercisable at the end of the period | 1,151 | $43.69 | 809 | $39.81 |

(1) Exercise price reflects grant prices less reduction in strike price discussed above.

The Fund uses a binomial option-pricing model to calculate the estimated fair value of rights under the plan. Non-cash compensation costs for the three and nine months ended September 30, 2007 were $2,192,000 ($0.02 per unit) and $6,410,000 ($0.05 per unit) respectively. The non-cash compensation costs for the three and nine months ended September 30, 2006 were $1,765,000 ($0.01 per unit) and $4,291,000 ($0.04 per unit) respectively.

### (c) Basic and Diluted per Trust Unit Calculations

Net income per trust unit has been determined based on the following:

| | Nine months ended September 30, | |
|---|---|---|
| (thousands) | 2007 | 2006 |
| Weighted average units | 127,031 | 121,120 |
| Dilutive impact of rights | 58 | 391 |
| Diluted trust units | 127,089 | 121,511 |

### (d) Cash Distributions to Unitholders

Cash distributions to unitholders for the three months ended September 30, 2007 were $163,110,000 (2006 – $154,700,000). Cash distributions to unitholders for the nine months ended September 30, 2007 were $483,388,000 (2006 – $459,293,000). Cash distributions are determined by the Board of Directors in accordance with the Trust indenture and are paid monthly.

## 11. Financial Instruments

### (a) Fair Value of Financial Instruments

As a result of the adoption of the new financial instrument and hedging accounting standards described in Note 2, certain financial instruments are now measured and reported on the balance sheet at fair value which were previously reported at amortized cost.

The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's-length transaction between knowledgeable, willing parties who are under no compulsion to act. Fair values are determined by reference to quoted bid or ask prices, as appropriate, in the most advantageous active market for that instrument to which we have immediate access. Where bid and ask prices are unavailable, we would use the closing price of the most recent transaction for that instrument. In the absence of an active market, we determine fair values based on prevailing market rates for instruments with similar characteristics. Fair values may also be determined based on internal and external valuation models, such as option pricing models and discounted cash flow analysis, that use observable market based inputs and assumptions.

### (b) Carrying Value and Fair Value of Financial Instruments

I. CASH

Cash is classified as held-for-trading and is reported at fair value.

II. ACCOUNTS RECEIVABLE

Accounts receivable are classified as loans and receivables which are reported at cost. At September 30, 2007 the carrying value of accounts receivable approximated their fair value.

III. MARKETABLE SECURITIES

Marketable securities with a quoted market price in an active market are classified as available-for-sale and are reported at fair value, with changes in fair value recorded in other comprehensive income. As at September 30, 2007 the Fund reported investments in marketable securities of publicly traded marketable securities at a fair value of $13,077,000. For the three months ended September 30, 2007, the change in fair value of these investments represented a gain of $769,000 ($544,000 net of tax). For the nine months ended September 30, 2007 the change in fair value of these investments represented a loss of $154,000 ($109,000 net of tax).

Marketable securities without a quoted market price in an active market are reported at cost. As at September 30, 2007 the Fund reported investments in marketable securities of private companies at cost of $45,325,000.

During the first quarter of 2007 the Fund disposed of certain marketable securities which resulted in a gain of $14,493,000 ($11,654,000 net of tax) being reclassified from accumulated other comprehensive income to net income.

At September 30, 2007 total marketable securities of $58,402,000 are presented as other assets on the Consolidated Balance Sheet. Any realized gains and losses on marketable securities are included in other income.

IV. ACCOUNTS PAYABLE & DISTRIBUTIONS PAYABLE TO UNITHOLDERS

Accounts payable as well as Distributions payable to unitholders are classified as other liabilities and are reported at cost. At September 30, 2007 the carrying value of these accounts approximated their fair value.

V. LONG-TERM DEBT

*Bank Credit Facilities*

The bank credit facilities are classified as other liabilities and are reported at cost. At September 30, 2007 the carrying value of the bank credit facilities approximated their fair value.

*US$54 million senior notes*

The US$54,000,000 million senior notes, which are classified as other liabilities, are reported at their amortized cost of US$54,000,000 and are translated into Canadian dollars at the period end exchange rate. At September 30, 2007 the Canadian dollar amortized cost of the senior notes was approximately $53,800,000.

*US$175 million senior notes*

The US$175,000,000 million senior notes, which are classified as other liabilities, are reported at their amortized cost of US$178,243,000 and are translated to Canadian dollars at the period end exchange rate. At September 30, 2007 the Canadian dollar amortized cost of the senior notes was approximately $177,584,000.

VI. DERIVATIVE FINANCIAL INSTRUMENTS

*Interest Rate Swaps*

The Fund has entered into interest rate swaps on $75,000,000 of notional debt at rates varying from 4.10% to 4.61% before banking fees that are expected to range between 0.55% and 1.10%. These interest rate swaps mature between June 2011 and January 2012. The interest rate swaps are classified as held-for-trading and are reported at fair value. At September 30, 2007 the fair value of the interest rate swaps represented an asset of $555,000. For the nine months ended September 30, 2007, the change in fair value of these contracts represented an unrealized gain of $1,228,000.

*Cross Currency Interest Rate Swap (CCIRS)*

Concurrent with the issuance of the notes on June 19, 2002, the Fund entered into a CCIRS with a syndicate of financial institutions. Under the terms of the swap, the amount of the notes was fixed for purposes of interest and principal payments at a notional amount of CDN$268,328,000. Interest payments are made on a floating rate basis, set at the rate for three-month Canadian bankers' acceptances, plus 1.18%. The CCIRS is classified as held-for-trading and is reported at fair value. At September 30, 2007 the fair value of the CCIRS represented a liability of $96,073,000. For the nine months ended September 30, 2007, the change in fair value of the CCIRS represented an unrealized loss of $31,071,000.

*Foreign Exchange Swaps*

In September 2007 the Fund entered into foreign exchange swaps on US$54,000,000 of notional debt at an average CAD/US foreign exchange rate of 1.02. These foreign exchange swaps mature between October 2011 and October 2015 in conjunction with the principal repayments on the US$54,000,000 senior notes. The foreign exchange swaps are classified as held-for-trading and are reported at fair value. At September 30, 2007 the fair value of the interest rate swaps represented a liability of $1,253,000. For the nine months ended September 30, 2007, the change in fair value of these contracts represented an unrealized loss of $1,253,000.

*Electricity Instruments*

The Fund has entered into electricity swaps that fix the price of electricity. These contracts are classified as held-for-trading and are reported at fair value. At September 30, 2007 the fair value of these contracts represented an asset of $978,000. For the nine months ended September 30, 2007, the change in fair value of these contracts represented an unrealized loss of $516,000.

Unrealized gains or losses resulting from changes in fair value along with realized gains or losses on settlement of the electricity contracts are recognized as operating costs.

The following table summarizes the Fund's electricity management positions at October 29, 2007.

| Term | Volumes MWh | Price CDN$/MWh |
|---|---|---|
| October 1, 2007 – December 31, 2007 | 5.0 | $61.50 |
| October 1, 2007 – December 31, 2007 | 4.0 | $62.90 |
| January 1, 2008 – September 30, 2008 | 4.0 | $63.00 |

The Fund did not enter into any new electricity contracts in the third quarter of 2007.

*Crude Oil Instruments*

Enerplus has entered into the following financial option contracts to reduce the impact of a downward movement in crude oil prices. These contracts are classified as held-for-trading and are reported at fair value. At September 30, 2007 the fair value of these contracts represented a liability of $14,918,000. For the nine months ended September 30, 2007, the change in fair value of these contracts represented an unrealized loss of $25,840,000.

The net premium cost of the crude oil instruments entered into as of September 30, 2007 is $9,109,000.

The following table summarizes the Fund's crude oil risk management positions at October 29, 2007:

| | Daily Volumes bbls/day | WTI US$/bbl Sold Call | Purchased Put | Sold Put | Fixed Price and Swaps |
|---|---|---|---|---|---|
| Term | | | | | |
| October 1, 2007 – December 31, 2007 | | | | | |
| Put | 5,000 | – | $71.00 | – | – |
| Put | 2,500 | – | $68.00 | – | – |
| Put | 2,500 | – | $65.70 | – | – |
| Swap | 2,500 | – | – | – | $66.24 |
| Swap(1) | 600 | – | – | – | $76.00 |
| November 1, 2007 – December 31, 2007 | | | | | |
| Costless Collar(1) | 1,500 | $84.10 | $76.00 | – | – |
| January 1, 2008 – June 30, 2008 | | | | | |
| Put(1) | 1,500 | – | $74.00 | – | – |
| January 1, 2008 – December 31, 2008 | | | | | |
| Collar | 750 | $77.00 | $67.00 | – | – |
| 3-Way option | 1,000 | $84.00 | $66.00 | $50.00 | – |
| 3-Way option | 1,000 | $84.00 | $66.00 | $52.00 | – |
| 3-Way option | 1,000 | $86.00 | $68.00 | $52.00 | – |
| 3-Way option(1) | 1,000 | $87.50 | $70.00 | $52.00 | – |
| 3-Way option(1) | 1,500 | $90.00 | $70.00 | $60.00 | – |
| Put Spread(2) | 1,500 | – | $76.50 | $58.00 | – |
| Swap(1) | 750 | – | – | – | $72.94 |
| Swap(1) | 750 | – | – | – | $74.00 |
| Swap(1) | 750 | – | – | – | $73.80 |
| Swap(1) | 750 | – | – | – | $73.35 |
| January 1, 2009 – December 31, 2009 | | | | | |
| 3-Way option(2) | 1,000 | $85.00 | $70.00 | $57.50 | – |

(1) Financial contracts entered into during the third quarter of 2007.
(2) Financial contracts entered into subsequent to September 30, 2007.

*Natural Gas Instruments*

Enerplus has certain physical and financial contracts outstanding as at October 29, 2007 on its natural gas production that are detailed below. In addition, the Fund has outstanding physical natural gas contracts that provide the Fund a premium of $0.38/Mcf on 21.2MMcf/day for the month of October 2007.

These contracts are classified as held-for-trading and are reported at fair value. At September 30, 2007 the fair value of these contracts represented an asset of $20,301,000. For the nine months ended September 30, 2007, the change in fair value of these contracts represented an unrealized gain of $7,611,000.

The net premium cost of the financial natural gas instruments entered into as of September 30, 2007 is $1,242,000.

The following table summarizes the Fund's natural gas risk management positions at October 29, 2007:

| | Daily Volumes MMcf/day | AECO CDN$/Mcf | | | |
|---|---|---|---|---|---|
| | | Sold Call | Purchased Put | Sold Put | Fixed Price and Swaps |
| Term | | | | | |
| October 1, 2007 – October 31, 2007 | | | | | |
| Collar | 6.6 | $10.02 | $7.50 | – | – |
| Collar | 6.6 | $ 9.00 | $7.50 | – | – |
| Collar | 9.5 | $ 9.11 | $7.10 | – | – |
| Collar | 9.5 | $ 9.15 | $7.14 | – | – |
| Collar | 9.5 | $ 9.50 | $7.20 | – | – |
| Costless Collar | 4.7 | $ 8.02 | $7.17 | – | – |
| Costless Collar | 4.7 | $ 8.23 | $7.28 | – | – |
| Costless Collar | 4.7 | $ 8.20 | $7.50 | – | – |
| 3-Way option | 4.7 | $ 9.50 | $7.75 | $5.49 | – |
| Put | 4.7 | – | $7.28 | – | – |
| Swap | 6.6 | – | – | – | $7.60 |
| Swap | 4.7 | – | – | – | $7.33 |
| Swap | 2.4 | – | – | – | $7.84 |
| Swap | 2.4 | – | – | – | $7.96 |
| Swap | 7.1 | – | – | – | $7.17 |
| Swap | 2.4 | – | – | – | $7.70 |
| Swap | 2.4 | – | – | – | $7.53 |
| Swap | 2.4 | – | – | – | $8.35 |
| November 1, 2007 – March 31, 2008 | | | | | |
| Collar | 2.4 | $ 9.95 | $8.00 | – | – |
| Collar | 2.4 | $10.15 | $8.00 | – | – |
| 3-Way option | 4.7 | $10.50 | $8.20 | $5.70 | – |
| 3-Way option | 9.5 | $11.61 | $8.97 | $6.33 | – |
| 3-Way option | 4.7 | $11.08 | $8.55 | $6.01 | – |
| 3-Way option(1) | 4.7 | $ 9.50 | $7.49 | $5.70 | – |
| 3-Way option(1) | 9.5 | $ 9.50 | $7.39 | $5.70 | – |
| Swap | 4.7 | – | – | – | $8.70 |
| Swap | 2.4 | – | – | – | $9.01 |
| April 1, 2008 – October 31, 2008 | | | | | |
| 3-Way option(2) | 11.8 | $ 7.91 | $6.75 | $5.49 | – |
| 3-Way option | 5.7 | $ 9.50 | $7.54 | $5.28 | – |
| Collar(1) | 6.6 | $ 8.44 | $7.17 | – | – |
| Swap | 4.7 | – | – | – | $8.18 |
| November 1, 2008 – March 31, 2009 | | | | | |
| 3-Way option(1) | 5.7 | $10.71 | $7.91 | $5.80 | – |
| 2007 - 2010 | | | | | |
| Physical (escalated pricing) | 2.0 | – | – | – | $2.52 |

(1) Financial contracts entered into during the third quarter of 2007.
(2) Financial contracts entered into subsequent to September 30, 2007.

Enerplus has captured the gain on former fixed price swaps by purchasing 19 MMcf/day at a fixed price of $4.91/Mcf from October 1, 2007 to October 31, 2007.

## BOARD OF DIRECTORS

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Okotoks, Alberta

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Managing Director
EnCap Investments L.P.
Houston, Texas

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(2) *Ex-Officio* member of all Committees of the Board
(3) Member of the Corporate Governance & Nominating Committee
(4) Chairman of the Corporate Governance & Nominating Committee
(5) Member of the Audit & Risk Management Committee
(6) Chairman of the Audit & Risk Management Committee
(7) Member of the Reserves Committee
(8) Chairman of the Reserves Committee
(9) Member of the Compensation & Human Resources Committee
(10) Chairman of the Compensation & Human Resources Committee
(11) Member of the Environment, Health & Safety Committee
(12) Chairman of the Environment, Health & Safety Committee

## OFFICERS

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Vice President, Development Services

**Wayne G. Ford**
Controller, Operations

**Jodine J. Jenson Labrie**
Controller, Finance

## OPERATING COMPANIES OWNED BY ENERPLUS RESOURCES FUND

EnerMark Inc.
Enerplus Resources Corporation
Enerplus Oil & Gas Ltd.
Enerplus Commercial Trust
Enerplus Resources (USA) Corporation

## LEGAL COUNSEL

Blake, Cassels & Graydon LLP
Calgary, Alberta

## AUDITORS

Deloitte & Touche LLP
Calgary, Alberta

## TRANSFER AGENT

CIBC Mellon Trust Company
Calgary, Alberta
Toll free: 1.800.387.0825
Email: inquiries@cibcmellon.com

## CO-TRANSFER AGENT

Mellon Investor Services L.L.C.
Ridgefield, New Jersey

## INDEPENDENT RESERVE ENGINEERS

Sproule Associates Limited
Calgary, Alberta

GLJ Petroleum Consultants
Calgary, Alberta

DeGolyer and MacNaughton
Dallas, Texas

## STOCK EXCHANGE LISTINGS AND TRADING SYMBOLS

Toronto Stock Exchange: ERF.un
New York Stock Exchange: ERF

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## ABBREVIATIONS

| | |
|---|---|
| AECO | Alberta Energy Company interconnect with the Nova Gas System, the Canadian benchmark for natural gas pricing purposes |
| bbl(s)/day | barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S. gallons |
| BOE(s)/day | barrel of oil equivalent per day (6 Mcf of gas:1 BOE) |
| CBM | coalbed methane, otherwise known as natural gas from coal – NGC |
| GAAP | Generally accepted accounting principles |
| Mbbls | thousand barrels |
| MBOE | thousand barrels of oil equivalent |
| Mcf/day | thousand cubic feet per day |
| MMbbl(s) | million barrels |
| MMBOE | million barrels of oil equivalent |
| MMBtu | million British Thermal Units |
| MMcf/day | million cubic feet per day |
| MWh | Megawatt hour(s) of electricity |
| NGLs | natural gas liquids |
| NYSE | New York Stock Exchange |
| SAGD | steam assisted gravity drainage |
| SEDAR | System for Electronic Document Analysis and Retrieval |
| TSX | Toronto Stock Exchange |
| WI | percentage working interest ownership |
| WTI | West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing purposes |


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