enerPLUS

SECOND QUARTER REPORT

SIX MONTHS ENDED JUNE 30, 2012

SELECTED FINANCIAL RESULTS	Three months ended June 30, 2012	2011	Six months ended June 30, 2012	2011
Financial (000's)				
Funds Flow	$ 146,547	$ 132,441	$ 309,253	$ 293,665
Cash and Stock Dividends	88,599	97,077	194,594	193,763
Net Income	100,264	267,982	66,443	297,531
Debt Outstanding – net of cash	1,152,746	460,087	1,152,746	460,087
Capital Spending	208,587	145,165	525,653	319,609
Property and Land Acquisitions	23,649	94,415	56,669	142,633
Divestments	(87)	571,096	52,524	630,788
Debt to Trailing 12 Month Funds Flow	2.0x	0.7x	2.0x	0.7x
Financial per Weighted Average Shares Outstanding				
Funds Flow	$ 0.74	$ 0.74	$ 1.60	$ 1.64
Net Income	0.51	1.50	0.34	1.66
Weighted Average Number of Shares Outstanding	196,768	179,583	193,306	179,209
Selected Financial Results per BOE(1)				
Oil & Gas Sales(2)	$ 42.07	$ 51.62	$ 44.51	$ 49.28
Royalties	(8.36)	(9.07)	(8.80)	(8.85)
Commodity Derivative Instruments	0.68	(3.03)	(0.38)	(1.30)
Operating Costs	(10.80)	(9.86)	(10.32)	(9.37)
G&A and Equity Based Compensation	(2.57)	(3.16)	(2.83)	(3.21)
Interest and Other Expenses	(0.90)	(0.89)	(0.81)	(1.82)
Taxes	(0.51)	(6.30)	(0.31)	(3.22)
Funds Flow	$ 19.61	$ 19.31	$ 21.06	$ 21.51

SELECTED OPERATING RESULTS	Three months ended June 30, 2012	2011	Six months ended June 30, 2012	2011
Average Daily Production				
Crude oil (bbls/day)	36,527	29,330	35,300	29,831
NGLs (bbls/day)	3,393	3,442	3,698	3,337
Natural gas (Mcf/day)	253,126	255,665	249,905	253,584
Total (BOE/day)	82,108	75,383	80,649	75,433
% Crude Oil & Natural Gas Liquids	49%	43%	48%	44%
Average Selling Price(2)				
Crude oil (per bbl)	$ 74.36	$ 90.92	$ 79.93	$ 84.23
NGLs (per bbl)	60.11	66.20	58.30	63.35
Natural gas (per Mcf)	2.06	3.86	2.17	3.88
USD/CDN exchange rate	1.01	0.97	1.01	0.98
Net Wells drilled	19	14	53	40

(1) Non-cash amounts have been excluded.
(2) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

SHARE TRADING SUMMARY
For the three months ended June 30, 2012

	CDN* – ERF (CDN$)	U.S.** – ERF (US$)
High	$ 22.57	$ 22.78
Low	$ 11.67	$ 11.35
Close	$ 13.08	$ 12.87

* TSX and other Canadian trading data combined.
** NYSE and other U.S. trading data combined.

2012 DIVIDENDS PER SHARE(2)

Payment Month	CDN$	US$(1)
First Quarter Total	$ 0.54	$ 0.54
April	$ 0.18	$ 0.18
May	0.18	0.17
June	0.18	0.18
Second Quarter Total	$ 0.54	$ 0.53
Total Year-to-Date	$ 1.08	$ 1.07

(1) US$ dividends represent CDN$ dividends converted at the relevant foreign exchange rate on the payment date.
(2) The dividend has been reduced to $0.09 per share effective for the July 20, 2012 payment.

PRESIDENT'S MESSAGE

Throughout the first half of 2012, we have been focused on executing our strategy to deliver organic production growth and preserving our financial flexibility. I am pleased to report that our operations have delivered another quarter of growth with production averaging 82,108 BOE/day during the second quarter, up approximately 4% over our average volumes for the first quarter of 2012 and up almost 9% over the same period last year.

Through our capital spending program, our plan has been to increase the weighting of crude oil within our portfolio. Our total crude oil volumes increased by 7% in the second quarter over the first quarter, with light oil production from Fort Berthold increasing by almost 35%. Our light and medium crude oil now represents 76% of our total oil production, an improvement from 72% last year at this time. Total crude oil and natural gas liquids now represent 49% of our production volumes, a 6% increase over the second quarter of 2011.

We also continued to protect our balance sheet throughout the quarter in response to the further decline in natural gas prices as well as the sharp decline in crude oil prices. In May we closed a $405 million private placement of long-term, senior unsecured notes, the proceeds of which were used to reduce borrowings under our existing bank credit facility. These notes have terms ranging from seven to twelve years with attractive interest rates of approximately 4.4%. We also implemented a Stock Dividend Program ("SDP") in June which allows all of our shareholders the option to elect to receive shares instead of a cash dividend. We believe this program will provide an additional source of funding for our capital investment strategies. As a result of lower cash flow expectations due to the drop in commodity prices, we elected to reduce our monthly dividend from $0.18/share to $0.09/share commencing with our July dividend. We believe this reduction was necessary in order to strike a better balance between yield and growth for our investors and also preserve greater financial flexibility going forward.

Our growing production as well as our crude oil hedges helped offset the impact of lower commodity prices and wider crude oil differentials during the quarter. Our oil hedging program added $1.50/bbl of cash gains to our realized crude oil pricing during the quarter. We have 18,500 bbls/day of oil production hedged at US$96.17/bbl for the remainder of 2012 and 14,500 bbls/day of oil production hedged at US$101.36/bbl for 2013. In response to the recent increase in natural gas prices, we've started to add hedge positions on our natural gas production for 2013, purchasing put protection which allows us to retain the upside price on approximately 23 MMcf/day of natural gas production hedged at $3.17/Mcf.

We generated funds flow of $147 million during the quarter ($0.74/share), down 10% from the first quarter of 2012. Our trailing twelve month debt to funds flow ratio was 2.0x at June 30, 2012 and we had $680 million available on our $1 billion bank credit facility. We continue to progress on our plans for the partial sale and/or monetization of a portion of our early stage asset portfolio which includes the Duvernay, Montney and operated Marcellus. We have retained a financial advisor and are actively marketing these assets. In addition, our plans also include selling a portion of our equity portfolio and other non-core producing assets to help maintain our financial flexibility.

OPERATIONAL HIGHLIGHTS

We invested a total of $209 million in exploration and development capital during the second quarter. Approximately 80% of this spending was focused on our crude oil resource plays, specifically at Fort Berthold in the U.S. and on our waterflood assets in Canada. The bulk of our natural gas spending was focused in the Marcellus with our non-operated partners as we continued to focus on lease retention in the region. Our Canadian natural gas production declined quarter over quarter as expected due primarily to the limited capital investment in our conventional and shallow gas assets. However, our gas production volumes in the Deep Basin region were higher as a result of our drilling success in the Ansell area earlier this year. We drilled a total of 18.7 net wells during the quarter, approximately 75% of which were oil wells, and brought on stream a total of 18.4 net wells, 67% of which were oil.

	Three months ended June 30, 2012		Six months ended June 30, 2012	
Play Type	**Average Production Volumes**	**Capital Spending** ($ millions)	**Average Production Volumes**	**Capital Spending** ($ millions)
Tight Oil (BOE/day)	18,329	$ 139	16,986	$ 301
Crude Oil Waterflood (BOE/day)	16,953	27	16,539	70
Conventional Oil (BOE/day)	4,883	2	4,840	14
Total Crude Oil (BOE/day)	40,165	$ 168	38,365	$ 385
Marcellus Shale Gas (Mcfe/day)	36,868	29	32,493	90
Other Natural Gas (Mcfe/day)	214,790	12	221,209	51
Total Gas (Mcfe/day)	251,658	$ 41	253,702	$ 141
Company Total	82,108	$ 209	80,649	$ 526

Net Drilling Activity – for the three months ended June 30, 2012

Play Type	Horizontal Wells Drilled	Vertical Wells Drilled	Total Wells Drilled	Wells Pending Completion/ Tie-in*	Wells On-stream**	Dry & Abandoned Wells
Tight Oil	7.2	–	7.2	7.2	8.0	–
Crude Oil Waterflood	5.8	1.0	6.8	6.8	4.4	–
Conventional Oil	–	–	–	–	–	–
Total Crude Oil	**13.0**	**1.0**	**14.0**	**14.0**	**12.4**	**–**
Marcellus Shale Gas	3.5	–	3.5	3.5	3.0	–
Other Natural Gas	1.2	–	1.2	0.2	3.0	–
Total Gas	**4.7**	**–**	**4.7**	**3.7**	**6.0**	**–**
Company Total	**17.7**	**1.0**	**18.7**	**17.7**	**18.4**	**–**

* Wells drilled during the quarter that are pending potential completion/tie-in or abandonment.

** Total wells brought on-stream during the quarter regardless of when they were drilled.

Tight Oil – Fort Berthold, ND

Production from the Fort Berthold region continued to increase through the second quarter as planned. We spent $138 million on development capital, drilling 7.0 net wells and bringing 8.0 net wells on-stream. Production averaged 11,700 BOE/day, up almost 35% from 8,700 BOE/day during the first quarter of this year and slightly ahead of expectations.

We continued to pursue measures to control our costs in the Fort Berthold region. Operated spending continues to be ahead of budget as we have not been able to see a meaningful reduction in well costs year-to-date. As part of our effort to manage costs, we have eliminated our two least efficient operated drilling rigs and are now running two rigs which we expect will effectively execute the remainder of our operated 2012 capital program. Non-operated activity has also increased significantly as our partners are drilling more than we originally anticipated. In conjunction with our drilling activities, infrastructure build-out (compression, metering and pipelines) in the region has continued at a brisk pace as we tie-in more wells and capture the associated natural gas volumes, thereby reducing our emissions. We originally expected to fund this tie-in activity through a mid-stream third party however we have been funding these capital costs directly year-to-date. We continue to evaluate fee-based arrangements for the tie-in capital linked to the gathering agreements now in place. We now have approximately 66% of our wells pipeline connected.

We expect spending to moderate in the second half of 2012. Year-to-date, we've drilled 16.5 net horizontal wells at Fort Berthold, 82% of which have been long horizontals.

Crude Oil Waterfloods

Production from our waterflood properties grew by 5% quarter over quarter as a result of our development activities. Despite wet conditions through spring break-up at our Medicine Hat waterflood property, we were able to complete our plans on our polymer project and began injecting polymer into five injector wells in the latter part of May. We also drilled 2.9 net producer wells and 1.4 net injector wells at Medicine Hat as part of our on-going waterflood optimization program. Production from this field was up 20% over the first quarter and is currently producing at the highest volume achieved since 1997. We also restarted our drilling program in southeast Saskatchewan targeting the Ratcliffe with two horizontal wells brought on stream during the quarter.

Shale Gas – Marcellus

We continued to invest with our non-operated partners in the Marcellus during the second quarter spending $29 million and participating in drilling 3.5 net wells with 3.0 net wells brought on-stream. Our capital program has been designed to maximize lease retention in this region throughout 2012. Some of our partners have slowed completion and tie-in activities including reducing the number of frac stages per well in an effort to preserve capital. As a result of these activities, we believe production may be lower than originally expected in the latter half of the year exiting 2012 at approximately 60 MMcf/day compared to our original estimate of 70 MMcf/day. Our Marcellus production increased to 37 MMcf/day in the second quarter.

UPDATE ON 2012 GUIDANCE

We continue to manage spending levels throughout our operations in order to offset higher spending in the Fort Berthold region. While we expect capital spending to be lower in the second half of 2012, the increased capital expenditures at Fort Berthold has increased our overall capital spending program for 2012. We now expect full year capital expenditures to be approximately $850 million, up from our original estimate of $800 million.

We are increasing our annual average production guidance from 83,000 BOE/day to 83,500 BOE/day however, we are maintaining our exit production guidance of 88,000 BOE/day. The additional spending at Fort Berthold is expected to add oil production to our exit volumes, however we expect this will be offset by lower production associated with slower completion and tie-in activity in the Marcellus region. We continue to expect our oil and liquids production weighting to be approximately 50% as we exit 2012. We are maintaining our guidance for full year operating costs at $10.40/BOE however, general and administrative costs are now expected to average $3.30/BOE down from our previous forecast of $3.55/BOE due to reduced costs associated with our long-term incentive programs.

OUTLOOK

I am very pleased with the progress we continue to make on the operational front. We are increasing production quarter over quarter and have successfully shifted our production mix to be close to 50% crude oil and natural gas liquids. Although weaker commodity prices and widening differentials have presented challenges for ourselves and the industry in general, we've taken a number of steps to help manage our balance sheet and continue to pursue additional funding sources to help improve our liquidity beyond 2012. Based upon our success and the outlook for commodity prices, we will adjust our growth targets and capital spending levels as needed in order to ensure we have sufficient liquidity and deliver a competitive return to our investors.

Gordon J. Kerr
President & Chief Executive Officer
Enerplus Corporation

Management's Discussion and Analysis ("MD&A")

The following discussion and analysis of financial results is dated August 9, 2012 and is to be read in conjunction with:

- the audited consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the years ended December 31, 2011 and 2010; and
- the unaudited interim consolidated financial statements of Enerplus as at and for the three and six months ended June 30, 2012 and 2011, the "Interim Financial Statements".

All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included with the Interim Financial Statements. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and oil and natural gas liquids have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcfe. The BOE and Mcfe rates are based on an energy equivalent conversion method primarily applicable at the burner tip and do not represent a value equivalent at the wellhead. Given that the value ratio based on the current price of natural gas as compared to crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value. Use of BOE and Mcfe in isolation may be misleading. All production volumes are presented on a company interest basis, being the Company's working interest share before deduction of any royalties paid to others, plus the Company's royalty interests. Company interest is not a term defined in Canadian National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities and may not be comparable to information produced by other entities.

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A under "Forward-Looking Information and Statements" for further information.

NON-GAAP MEASURES

The Company utilizes the following terms for measurement within the MD&A that do not have a standardized meaning or definition as prescribed by IFRS and therefore may not be comparable with the calculation of similar measures by other entities:

"Payout ratio" is used to analyze operating performance, leverage and liquidity. We calculate payout ratio by dividing cash dividends to shareholders by funds flow.

"Adjusted payout ratio" is used to analyze operating performance, leverage and liquidity. We calculate our adjusted payout ratio as cash dividends to shareholders plus capital spending (including office capital) divided by funds flow.

"Netback" is used to evaluate operating performance of our crude oil and natural gas assets. The term netback is calculated as oil and gas sales revenue (net of transportation), less royalties and operating costs.

OVERVIEW

During the second quarter of 2012 we continued to see growth in our production resulting from our capital program focused primarily on our tight oil assets in Fort Berthold. Production was on-track averaging 82,108 BOE/day for the quarter, representing a 4% increase over the first quarter of 2012 and a 9% increase compared to the second quarter of 2011. Our crude oil and liquids weighting increased to 49% which provided a positive impact to our cash flow.

Capital spending totaled $208.6 million for the second quarter, slightly higher than our expectations mainly due to increased costs and activity on our Fort Berthold assets. We have worked to reallocate our capital budget to compensate for these costs however we now expect aggregate capital spending of $850 million, up $50 million from our previous guidance. In conjunction with these changes, we are also increasing our annual average production guidance to 83,500 BOE/day from 83,000 BOE/day. Our exit production guidance remains unchanged at 88,000 BOE/day as we anticipate our non-operated partners in Marcellus may delay tie in activities and potentially reduce the number of fracturing stages as they focus solely on lease retention without the accompanying production build.

Funds flow for the quarter totaled $146.5 million, down 10% from $162.7 million during the first quarter of 2012, as lower commodity prices offset higher crude oil production levels. Our second quarter net income benefited from non-cash mark-to-market gains of $137.7 million on our crude oil contracts as oil prices declined during the quarter.

Operating costs were on target at $10.78/BOE for the quarter while G&A and equity based compensation expenses were lower than expected at $2.81/BOE due to reduced costs related to our long-term incentive plans. We are maintaining our annual operating cost guidance at $10.40/BOE and reducing our G&A and equity based compensation expense guidance to $3.30/BOE from $3.55/BOE.

During the second quarter we took additional steps to manage our balance sheet. In May we closed a private placement of senior unsecured notes, raising a total of $405 million at interest rates ranging from 4.34% to 4.40%. We also introduced a new Stock Dividend Program ("SDP") that went into effect for our June 20th dividend payment. Furthermore we reduced our monthly dividend from $0.18 per share to $0.09 per share, effective for our July 20th dividend payment.

RESULTS OF OPERATIONS

Production

Production in the second quarter of 2012 was in line with our expectations averaging 82,108 BOE/day, an increase of approximately 4% from our first quarter production of 79,190 BOE/day. Compared to the second quarter of 2011, production increased 9% or 6,725 BOE/day. We increased our crude oil production by 25% compared to the second quarter of 2011 primarily due to our investment in Fort Berthold. Natural gas volumes were relatively flat year over year as increased volumes from our U.S. Marcellus assets offset production declines on our shallow and conventional natural gas assets in Canada.

Our weighting of crude oil and liquids production increased to 49% in the second quarter, up from 48% in the first quarter of 2012 and from 43% in the second quarter of 2011. We continue to expect our crude oil and liquids weighting to increase throughout the year and exit 2012 at approximately 50%.

Average daily production volumes for the three and six months ended June 30, 2012 and 2011 are outlined below:

	Three months ended June 30,			Six months ended June 30,		
Average Daily Production Volumes	**2012**	**2011**	**% Change**	**2012**	**2011**	**% Change**
Crude oil (bbls/day)	36,527	29,330	25%	35,300	29,831	18%
Natural gas liquids (bbls/day)	3,393	3,442	(1)%	3,698	3,337	11%
Natural gas (Mcf/day)	253,126	255,665	(1)%	249,905	253,584	(1)%
Total daily sales (BOE/day)	82,108	75,383	9%	80,649	75,433	7%

Based on the heightened pace of non-operated activity in Fort Berthold we are increasing our annual average production guidance to 83,500 BOE/day from 83,000 BOE/day. We are leaving our exit production guidance unchanged at 88,000 BOE/day as we expect that our non-operated partners in the Marcellus may look to further conserve capital and delay completion activities, or reduce the number of fracturing stages per well. These changes would have a negative impact on our forecasted exit production and a modest impact on annual average production and cash flow. This guidance does not contemplate any acquisitions or dispositions of producing assets.

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, funds flow and financial condition. The following table compares our average selling prices for the three and six months ended June 30, 2012 and 2011. It also compares the benchmark price indices for the same periods.

	Three months ended June 30,			Six months ended June 30,		
Average Selling Price(1)	**2012**	**2011**	**% Change**	**2012**	**2011**	**% Change**
Crude oil (per bbl)	$ 74.36	$ 90.92	(18)%	$ 79.93	$ 84.23	(5)%
Natural gas liquids (per bbl)	60.11	66.20	(9)%	58.30	63.35	(8)%
Natural gas (per Mcf)	2.06	3.86	(47)%	2.17	3.88	(44)%
Per BOE	42.07	51.62	(19)%	44.51	49.28	(10)%

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

	Three months ended June 30,			Six months ended June 30,		
Average Benchmark Pricing	**2012**	**2011**	**% Change**	**2012**	**2011**	**% Change**
WTI crude oil (US$/bbl)	$ 93.49	$ 102.56	(9)%	$ 98.21	$ 98.33	–%
WTI crude oil CDN$ equivalent (CDN$/bbl)	94.43	99.57	(5)%	99.19	96.40	3%
AECO natural gas – monthly index (CDN$/Mcf)	1.83	3.74	(51)%	2.18	3.76	(42)%
AECO natural gas – daily index (CDN$/Mcf)	1.90	3.88	(51)%	2.02	3.82	(47)%
NYMEX natural gas – monthly NX3 index (US$/Mcf)	2.26	4.36	(48)%	2.52	4.25	(41)%
NYMEX natural gas – monthly NX3 index CDN$ equivalent (CDN$/Mcf)	2.28	4.23	(46)%	2.55	4.17	(39)%
USD/CDN exchange rate	1.01	0.97	4%	1.01	0.98	3%

CRUDE OIL

Crude oil prices weakened during the second quarter of 2012 due to macroeconomic concerns and slower anticipated growth in the U.S., Europe and China. The pricing of West Texas Intermediate ("WTI") continues to be discounted relative to Brent. Despite the Seaway pipeline reversal which started in late May to move 150,000 bbls/day of crude away from Cushing to the U.S. Gulf Coast, inventories at Cushing continued to rise, ending the quarter at record levels of 48 million barrels. Given this ample supply, Canadian and U.S. Bakken light sweet differentials widened significantly in 2012.

The average price received for our crude oil (net of transportation) in the second quarter of 2012 decreased by 18% to $74.36/bbl from $90.92/bbl in the second quarter of 2011. For the six months ended June 30, 2012 our realized crude oil sales price (net of transportation costs) decreased 5% to $79.93/bbl from $84.23/bbl during the same period in 2011. Light sweet differentials for U.S. Bakken averaged a discount of US$14.40/bbl in the first six months of 2012 compared to a discount of US$9.13/bbl during the same period of 2011. Canadian light sweet crudes were similarly affected and as a result the change in our realized price for both the three and six month periods was less favorable than the change in WTI benchmark prices.

NATURAL GAS

Natural gas prices continued to decline in the second quarter of 2012 with the market suffering from high storage levels due to the lack of cold weather this past winter. However, increased natural gas usage for power generation along with warmer than normal summer temperatures have started to reduce the storage surplus post quarter-end. If temperatures remain above normal across North America for the remainder of the summer we may avoid storage congestion at the end of the injection season.

For the three months ended June 30, 2012 we sold our natural gas for an average price of $2.06/Mcf (net of transportation costs) which represented a 47% decline from the prices received during the same period of 2011. This decrease was less than the decrease in the monthly and daily AECO indices mainly due to our marketing arrangements which tied a portion of our Canadian gas production to the NYMEX price. Additionally we are seeing our sales price shift to track more closely to NYMEX given that our Marcellus gas production now represents a larger portion of our portfolio.

For the six months ended June 30, 2012 our average realized natural gas sale price was $2.17/Mcf (net of transportation costs), a 44% decrease from $3.88/Mcf during the same period in 2011. This decrease was in line with the changes in the AECO and Nymex indices for the same period.

Price Risk Management

We have a price risk management program that considers our overall financial position, the economics of our capital program and potential acquisitions. Consideration is also given to the cost of our risk management program as we seek to limit our exposure to price downturns. See Note 14 for further information regarding our current price risk management positions.

We have continued to add crude oil hedge positions for 2013. As of July 26, 2012 we have swapped 14,500 bbls/day at US$101.36/bbl, which represents approximately 50% of our forecasted net oil production after royalties for 2013. Subsequent to the second quarter we also added natural gas positions to provide some downside protection. As of July 26, 2012 we have floor protection on 22,700 Mcf/day at $3.17/Mcf before premiums, representing approximately 11% of our forecasted natural gas production after royalties for 2013.

The following is a summary of the financial contracts in place at July 26, 2012 expressed as a percentage of our anticipated net production volumes:

	Crude Oil (US$/bbl)[1][2]		Natural Gas[1] (CDN$/Mcf)
	July 1, 2012 – December 31, 2012	January 1, 2013 – December 31, 2013	January 1, 2013 – December 31, 2013
Purchased Puts (floor prices)	$ 103.00	$ –	$ 3.17
%	3%	–	11%
Sold Puts (limiting downside protection)	$ 65.00	$ 63.33	$ –
%	7%	15%	–
Swaps (fixed price)	$ 95.83	$ 101.36	$ –
%	60%	50%	–
Sold Calls (capped price)	$ 133.00	$ 130.00	$ –
%	3%	7%	–
Purchased Calls (repurchasing upside)	$ 103.00	$ 104.09	$ –
%	3%	12%	–
Brent – WTI Spread	$ 13.52	$ –	$ –
%	10%	–	–

(1) Based on weighted average price (before premiums), estimated average annual production of 83,500 BOE/day for 2012 and 2013, less royalties of 21%.
(2) The majority of our crude oil positions are priced in relation to WTI.

We have also entered into physical fixed price natural gas contracts for 79,400 Mcf/day, or approximately 38% of our forecasted net natural gas production after royalties, at an average price of $2.20/Mcf for the period July through October 2012. In addition, for the last six months of 2012 we have costless collars for 19,900 Mcf/day of physical gas sales with a weighted average floor price of $2.16/Mcf and a weighted average ceiling price of $2.90/Mcf.

ACCOUNTING FOR PRICE RISK MANAGEMENT

During the second quarter of 2012 we recorded $5.0 million of cash gains on our crude oil contracts. In comparison, during the second quarter of 2011 we realized cash losses of $20.8 million on crude oil contracts. The cash gains in 2012 were due to contracts which provided floor protection above market prices. The cash losses in 2011 were a result of crude oil prices rising above our fixed price swap positions.

As the forward markets for crude oil and natural gas fluctuate and new contracts are executed and existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. During the second quarter of 2012 we experienced a significant decrease in the forecast for crude oil prices which resulted in the fair value of our oil contracts increasing to $101.0 million at June 30, 2012. The change in the fair value of our oil contracts for the three and six months ended June 30, 2012 represented unrealized gains of $137.7 million and $120.6 million respectively. See Note 14 for details.

The following table summarizes the effects of our risk management gains and losses:

Risk Management Gains/(Losses) ($ millions, except per unit amounts)	**Three months ended June 30, 2012**				**Three months ended June 30, 2011**			
Cash gains/(losses):								
Crude Oil	$	5.0	$	1.50/bbl	$	(20.8)	$	(7.79)/bbl
Natural Gas		–	$	–/Mcf		–	$	–/Mcf
Total cash gains/(losses)	$	5.0	$	0.68/BOE	$	(20.8)	$	(3.03)/BOE
Non-cash gains/(losses) on financial contracts:								
Change in fair value – crude oil	$	137.7	$	41.43/bbl	$	72.6	$	27.20/bbl
Change in fair value – natural gas		–	$	–/Mcf		–	$	–/Mcf
Total non-cash gains/(losses)	$	137.7	$	18.42/BOE	$	72.6	$	10.58/BOE
Total gains/(losses)	$	142.7	$	19.10/BOE	$	51.8	$	7.55/BOE

Risk Management Gains/(Losses) ($ millions, except per unit amounts)	**Six months ended June 30, 2012**				**Six months ended June 30, 2011**			
Cash gains/(losses):								
Crude Oil	$	(5.6)	$	(0.87)/bbl	$	(31.0)	$	(5.74)/bbl
Natural Gas		–	$	–/Mcf		13.3	$	0.29/Mcf
Total cash gains/(losses)	$	(5.6)	$	(0.38)/BOE	$	(17.7)	$	(1.30)/BOE
Non-cash gains/(losses) on financial contracts:								
Change in fair value – crude oil	$	120.6	$	18.77/bbl	$	6.0	$	1.11/bbl
Change in fair value – natural gas		–	$	–/Mcf		(12.6)	$	(0.27)/Mcf
Total non-cash gains/(losses)	$	120.6	$	8.22/BOE	$	(6.6)	$	(0.48)/BOE
Total gains/(losses)	$	115.0	$	7.84/BOE	$	(24.3)	$	(1.78)/BOE

Revenues

Crude oil and natural gas revenues for the second quarter of 2012 were $314.4 million ($321.2 million, net of $6.8 million of transportation costs), a decrease of $39.8 million compared to $354.2 million ($359.4 million, net of $5.2 million of transportation costs) for the second quarter of 2011. Crude oil and natural gas revenues for the six months ended June 30, 2012 were $653.3 million ($666.3 million, net of $13.0 million of transportation costs), a decrease of $19.5 million compared to $672.8 million ($683.4 million, net of $10.6 million of transportation costs) for the same period in 2011. Lower realized commodity prices have reduced our revenues during 2012, however increased crude oil production has helped to mitigate the impact.

Analysis of Sales Revenue[1] ($ millions)		**Crude oil**		**NGLs**		**Natural Gas**		**Total**
Three months ended June 30, 2011	$	242.7	$	20.7	$	90.8	$	354.2
Price variance		(55.0)		(1.8)		(41.3)		(98.1)
Volume variance		59.5		(0.3)		(0.9)		58.3
Three months ended June 30, 2012	$	247.2	$	18.6	$	48.6	$	314.4

($ millions)		**Crude oil**		**NGLs**		**Natural Gas**		**Total**
Six months ended June 30, 2011	$	455.0	$	38.2	$	179.6	$	672.8
Price variance		(27.6)		(3.4)		(77.5)		(108.5)
Volume variance		86.2		4.4		(1.6)		89.0
Six months ended June 30, 2012	$	513.6	$	39.2	$	100.5	$	653.3

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

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. For the three and six months ended June 30, 2012 royalties were $62.5 million and $129.2 million respectively, compared to $62.2 million and $120.8 million for the same periods of 2011. As a percentage of oil and gas sales, net of transportation costs, royalties were 20% for the three and six months ended June 30, 2012 compared to 18% in the same periods in 2011. The royalty rate increase is primarily due to an increased proportion of U.S. production where royalty rates are generally higher than those on our Canadian production. We continue to expect an average royalty rate of approximately 21% in 2012.

Operating Expenses

Our operating expenses were on track at $80.5 million or $10.78/BOE for the second quarter of 2012 and $152.6 million or $10.40/BOE for the six months ended June 30, 2012. In comparison, we had operating costs of $67.5 million ($9.84/BOE) and $124.6 million ($9.13/BOE) for the same periods during 2011.

During the first six months of 2012 we had higher well servicing and repairs and maintenance costs compared to the first half of 2011 when wet weather delayed our ability to access our leases. Our U.S. tight oil play had lower fluid handling costs in 2012, however facility charges there have increased as we began sending our associated natural gas and natural gas liquids through a third party processing facility. In addition, during the first half of 2012 our operating costs included a non-cash power hedging loss of $1.2 million, compared to a gain of $3.3 million for the same period during 2011, which also contributed to the year over year increase.

We continue to maintain our annual guidance of $10.40/BOE for operating costs during 2012.

Netbacks

The following tables outline our crude oil and natural gas netbacks for the three and six months ended June 30, 2012 and 2011. The crude oil and natural gas classifications below contain properties according to their dominant production category. These properties may include associated crude oil, natural gas or natural gas liquids volumes which have been converted to the equivalent BOE/day or Mcfe/day.

	Three months ended June 30, 2012		
	Crude Oil	**Natural Gas**	**Total**
Average daily production	40,165 BOE/day	251,658 Mcfe/day	82,108 BOE/day
Netback[1]	(per BOE)	(per Mcfe)	(per BOE)
Revenue[2]	$ 68.05	$ 2.87	$ 42.07
Royalties	(14.93)	(0.34)	(8.36)
Cash operating costs	(11.93)	(1.62)	(10.80)
Netback before hedging	$ 41.19	$ 0.91	$ 22.91
Cash hedging gains/(losses)	1.38	–	0.68
Netback after hedging	$ 42.57	$ 0.91	$ 23.59
Netback before hedging ($ millions)	$ 150.6	$ 20.6	$ 171.2
Netback after hedging ($ millions)	$ 155.6	$ 20.6	$ 176.2

	Three months ended June 30, 2011		
	Crude Oil	**Natural Gas**	**Total**
Average daily production	32,114 BOE/day	259,613 Mcfe/day	75,383 BOE/day
Netback[1]	(per BOE)	(per Mcfe)	(per BOE)
Revenue[2]	$ 84.38	$ 4.55	$ 51.62
Royalties	(15.71)	(0.69)	(9.07)
Cash operating costs	(11.80)	(1.39)	(9.80)
Netback before hedging	$ 56.87	$ 2.47	$ 32.75
Cash hedging gains/(losses)	(7.10)	–	(3.03)
Netback after hedging	$ 49.77	$ 2.47	$ 29.72
Netback before hedging ($ millions)	$ 166.1	$ 58.5	$ 224.6
Netback after hedging ($ millions)	$ 145.3	$ 58.5	$ 203.8

(1) See "Non-GAAP Measures" in this MD&A.
(2) Net of oil and gas transportation costs.

	Six months ended June 30, 2012		
	Crude Oil	**Natural Gas**	**Total**
Average daily production	38,365 BOE/day	253,702 Mcfe/day	80,649 BOE/day
Netback[1]	(per BOE)	(per Mcfe)	(per BOE)
Revenue[2]	$ 73.42	$ 3.05	$ 44.51
Royalties	(15.91)	(0.39)	(8.80)
Cash operating costs	(11.70)	(1.51)	(10.32)
Netback before hedging	$ 45.81	$ 1.15	$ 25.39
Cash hedging gains/(losses)	(0.80)	–	(0.38)
Netback after hedging	$ 45.01	$ 1.15	$ 25.01
Netback before hedging ($ millions)	$ 319.9	$ 52.9	$ 372.8
Netback after hedging ($ millions)	$ 314.3	$ 52.9	$ 367.2

	Six months ended June 30, 2011		
	Crude Oil	**Natural Gas**	**Total**
Average daily production	32,845 BOE/day	255,530 Mcfe/day	75,433 BOE/day
Netback[1]	(per BOE)	(per Mcfe)	(per BOE)
Revenue[2]	$ 77.99	$ 4.52	$ 49.28
Royalties	(15.75)	(0.59)	(8.85)
Cash operating costs	(10.70)	(1.38)	(9.34)
Netback before hedging	$ 51.54	$ 2.55	$ 31.09
Cash hedging gains/(losses)	(5.22)	0.29	(1.30)
Netback after hedging	$ 46.32	$ 2.84	$ 29.79
Netback before hedging ($ millions)	$ 306.3	$ 118.3	$ 424.6
Netback after hedging ($ millions)	$ 275.3	$ 131.6	$ 406.9

(1) See "Non-GAAP Measures" in this MD&A.
(2) Net of oil and gas transportation costs.

Our crude oil properties accounted for 86% of our corporate netback before hedging for the first six months of 2012 compared to 72% for the same period in 2011. Crude oil netbacks per BOE have decreased for the three and six months ended June 30, 2012 primarily due to lower realized crude oil prices. Natural gas netbacks per Mcfe have also decreased for the same periods due to lower realized natural gas prices and lower hedging gains.

General and Administrative ("G&A") and Equity Based Compensation Expenses

G&A expenses during the second quarter of 2012 were $20.7 million or $2.76/BOE compared to $17.4 million or $2.53/BOE in the second quarter of 2011. G&A expenses for the six months ended June 30, 2012 were $41.4 million or $2.82/BOE compared to $34.4 million or $2.51/BOE for the same period during 2011. G&A expenses were higher during 2012 due to increased compensation costs associated with expanding our U.S. operations throughout 2011 along with additional legal and professional fees.

Equity based compensation expense includes charges related to our long-term incentive plans ("LTI plans") and our stock option plan (see Note 13 for further details). The cost of our LTI plans is dependent on our share price and given the decrease in the price during the quarter we had a significant reduction in the estimated value of these plans. As a result we recorded a recovery of $1.5 million for the second quarter of 2012 compared to an expense of $4.3 million for the same period in 2011. For the six months ended June 30, 2012 we recorded an expense of $0.1 million compared to $9.5 million for the six months ended June 30, 2011.

During the second quarter of 2012 we also entered into an equity swap with respect to our LTI plans. Under the swap we have effectively fixed the future settlement cost at $12.64 per share on 800,000 shares, representing 67% of the notional shares currently outstanding under these plans. At June 30, 2012 the fair value of the swap was approximately $0.3 million which resulted in an unrealized gain of the same amount for the quarter.

The following table summarizes our G&A and equity based compensation expenses:

G&A and Equity Based Compensation Expenses ($ millions)	**Three months ended June 30, 2012**	**Three months ended June 30, 2011**	**Six months ended June 30, 2012**	**Six months ended June 30, 2011**
G&A	$ 20.7	$ 17.4	$ 41.4	$ 34.4
Equity based compensation:				
LTI plans expense/(recovery) – cash	(1.5)	4.3	0.1	9.5
LTI plans equity swap loss/(gain) – non-cash	(0.3)	–	(0.3)	–
Stock option plan – non-cash	2.1	3.3	5.1	6.8
	0.3	7.6	4.9	16.3
Total G&A and Equity Based Compensation Expenses	$ 21.0	$ 25.0	$ 46.3	$ 50.7

(Per BOE)	**Three months ended June 30, 2012**	**Three months ended June 30, 2011**	**Six months ended June 30, 2012**	**Six months ended June 30, 2011**
G&A	$ 2.76	$ 2.53	$ 2.82	$ 2.51
Equity based compensation:				
LTI plans expense/(recovery) – cash	(0.19)	0.63	0.01	0.70
LTI plans equity swap loss/(gain) – non-cash	(0.04)	–	(0.02)	–
Stock option plan – non-cash	0.28	0.48	0.34	0.50
	0.05	1.11	0.33	1.20
Total G&A and Equity Based Compensation Expenses	$ 2.81	$ 3.64	$ 3.15	$ 3.71

We are lowering our annual guidance for G&A and equity based compensation expenses to $3.30/BOE from $3.55/BOE primarily due to the reduced charges on our LTI plans.

Finance Expense

Interest on our senior notes and bank credit facility for the three and six months ended June 30, 2012 totaled $13.4 million and $24.3 million respectively, compared to $12.7 million and $24.6 million for the same periods in 2011. Although we had higher average debt levels in 2012 compared to 2011 the impact of lower credit charges on our bank credit facility resulted in relatively flat interest costs year over year.

Non-cash amounts recorded in finance expense include accretion of decommissioning liabilities, amortization of financing fees and premiums, and unrealized gains and losses resulting from the change in fair value of our interest rate swaps and the interest component on our cross currency interest rate swap ("CCIRS"). See Note 10 for further details.

The following table summarizes the cash and non-cash finance expense:

	Three months ended June 30,		Six months ended June 30,	
Finance Expense ($ millions)	**2012**	**2011**	**2012**	**2011**
Interest on senior notes and bank credit facility	$ 13.4	$ 12.7	$ 24.3	$ 24.6
Non-cash finance expense	4.0	5.1	8.9	7.2
Total Finance Expense	$ 17.4	$ 17.8	$ 33.2	$ 31.8

At June 30, 2012, after including our underlying derivatives, approximately 68% of our debt was based on fixed interest rates while 32% had floating interest rates. In comparison, at June 30, 2011 approximately 80% of our debt was based on fixed interest rates and 20% was floating.

Foreign Exchange

During the second quarter of 2012 realized foreign exchange losses of $11.2 million were completely offset by unrealized foreign exchange gains of $11.2 million. On June 19, 2012 we made the third US$35.0 million principal repayment on our US$175.0 million senior notes. In conjunction with the repayment we also made a settlement on the underlying CCIRS which resulted in both a realized foreign exchange loss and an unrealized foreign exchange gain of approximately $18.0 million. During the quarter we also recorded an unrealized loss of $11.9 million related to the translation of our U.S. dollar debt to the period end exchange rate. See Note 11 for further information.

	Three months ended June 30,		Six months ended June 30,	
Foreign Exchange ($ millions)	**2012**	**2011**	**2012**	**2011**
Realized loss/(gain)	$ 11.2	$ 13.0	$ 5.9	$ 20.3
Unrealized loss/(gain)	(11.2)	(17.5)	(11.2)	(23.2)
Total Foreign Exchange loss/(gain)	$ –	$ (4.5)	$ (5.3)	$ (2.9)

Capital Investment

Capital spending for the second quarter of 2012 totaled $208.6 million compared to $145.2 million for the same period in 2011. During the quarter we continued to focus on our key growth plays spending $137.6 million on the development of our tight oil assets at Fort Berthold and $26.8 million on our crude oil waterflood properties in Canada. We also spent $28.5 million on our Marcellus assets primarily on drilling to retain leases.

In Fort Berthold we are seeing higher than anticipated costs and activity with our non-operated partners which has contributed positively to our production but put upward pressure on our capital spending. On our operated properties in Fort Berthold we have also had higher than expected spending due in part to cost inflation along with additional costs for metering, compression and gathering facilities that we originally expected to be outsourced to a midstream company. We have worked to reallocate our capital budget to compensate for these cost pressures however we are now expecting aggregate capital spending of $850 million for the year, up from our previous guidance of $800 million. In conjunction with these changes we have increased our annual average production guidance by 500 BOE/day to 83,500 BOE/day.

Property and land acquisitions for the three and six months ended June 30, 2012 totaled $23.6 million and $56.6 million respectively compared to $94.4 million and $142.6 million for the same periods in 2011. During the second quarter we spent $2.4 million on undeveloped land acquisitions in Canada ($13.8 million year-to-date) as well as $5.8 million on additional lands in the Marcellus and Ft. Berthold areas

($11.3 million year-to-date). We also spent US$15.3 million during the quarter on our Marcellus carry obligation (US$31.4 million year-to-date) resulting in a remaining carry obligation of US$4.6 million at June 30, 2012. Property and land acquisitions in the first half of 2011 included $59.5 million on undeveloped land acquisitions in Canada and $21.8 million on undeveloped land in the Marcellus area, as well as US$63.2 million on our Marcellus carry obligation.

Dispositions during the second quarter of 2011 related to the sale of approximately 91,000 net acres of our Marcellus interests for proceeds of $567.9 million (US$580 million).

Our total capital investment activity for the three and six months ended June 30, 2012 and 2011 are outlined below:

	Three months ended June 30,		Six months ended June 30,	
Capital Investment ($ millions)	**2012**	**2011**	**2012**	**2011**
Capital Spending	$ 208.6	$ 145.2	$ 525.7	$ 319.6
Office Capital	3.6	3.4	6.1	5.0
Sub-total	212.2	148.6	531.8	324.6
Property and Land Acquisitions	23.6	94.4	56.6	142.6
Property Dispositions	0.1	(571.1)	(52.5)	(630.8)
Sub-total	23.7	(476.7)	4.1	(488.2)
Total Net Capital Investment	$ 235.9	$ (328.1)	$ 535.9	$ (163.5)

Depletion, Depreciation and Amortization ("DD&A")

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved plus probable reserves. For the three months ended June 30, 2012 DD&A increased to $128.2 million or $17.16/BOE compared to $103.7 million or $15.11/BOE during the same period in 2011. For the six months ended June 30, 2012 DD&A increased to $246.7 million or $16.81/BOE from $203.6 million or $14.91/BOE during the same period in 2011. The rise in DD&A for the three and six months ended June 30, 2012 is primarily due to higher well costs with respect to our U.S. operations resulting in higher depletion per BOE.

Impairments

When indicators of impairment are present, tests are carried out on our Cash Generating Units ("CGUs") to determine if D&P asset carrying values, including goodwill, are impaired. Our impairment test compares the CGU recoverable amount, which is estimated using proved plus probable reserves discounted at 10%, to the CGU carrying value. Calculated impairments are initially allocated to any goodwill carried by the CGU with the remainder recorded against its carrying value.

In the second quarter of 2012 we did not record any additional impairments beyond those in the first quarter of 2012. D&P asset impairments of $86.9 million were recorded in the first quarter of 2012 in our Canadian natural gas CGUs due to lower forecast natural gas prices.

Other Assets

Other assets consist of our portfolio of equity investments in other oil and gas companies. These investments are carried at their estimated fair value with changes in fair value recorded in other comprehensive income. Consistent with the downturn in the equity markets and commodity prices, the fair value of these investments also decreased for the three and six months ended June 30, 2012 resulting in unrealized losses of $53.9 million ($46.9 million net of tax) and $58.7 million ($51.1 million net of tax), respectively. For the same periods last year the change in fair value of these investments represented unrealized gains of $54.6 million ($50.2 million net of tax) and $58.1 million ($53.2 million net of tax), respectively. During the second quarter of 2012 we disposed of a small portion of our portfolio for proceeds of $4.4 million.

Decommissioning Liabilities

In connection with our operations we incur abandonment and reclamation costs related to assets such as surface leases, wells, facilities and pipelines. Total decommissioning liabilities included on our balance sheet are estimated by management based on our net ownership interest, estimated costs to abandon and reclaim and the estimated timing of the costs to be incurred in future periods.

We have estimated the net present value of our decommissioning liability to be $582.0 million at June 30, 2012 compared to $563.8 million at December 31, 2011. The majority of this increase relates to the risk-free rate used to calculate the present value of the future cash outflows, which fell to 2.33% at June 30, 2012 from 2.49% at December 31, 2011. See Note 9 for further information.

Taxes

Current Income Taxes

We recorded current taxes of $3.8 million for the three months ended June 30, 2012 compared to $43.2 million for the same period in 2011. The majority of our tax expense in 2011 related to the gain we recognized on our Marcellus property disposition and the resulting income taxes. Our current tax is comprised mainly of Alternative Minimum Tax ("AMT") payable with respect to our U.S. subsidiary. We expect to recover AMT in future years as an offset to regular U.S. income taxes otherwise payable.

We continue to expect to pay U.S. AMT up to a maximum of 5% of our U.S. cash flow in 2012 and 2013. We do not expect to pay material cash taxes in Canada until after 2015 as we have sufficient tax pools to offset our anticipated taxable income prior to that time. These estimates may vary depending on numerous factors, including but not limited to fluctuating commodity prices, production levels, capital spending and acquisition or disposition activity.

Deferred Income Taxes

Our deferred income tax expense was $43.1 million for the three months ended June 30, 2012 compared to $95.2 million for the same period in 2011. The decrease in deferred income tax expense also relates to the gain we recognized on our 2011 Marcellus property disposition.

Net Income

Net income for the second quarter of 2012 totaled $100.3 million or $0.51 per share compared to $268.0 million or $1.50 per share for the second quarter of 2011. Net income for the six months ended June 30, 2012 was $66.4 million compared to $297.5 for the same period in 2011.

Net income was lower in 2012 primarily due to a $271.9 million gain recorded in 2011 on our Marcellus property disposition. As well, lower oil and gas sales in 2012 were offset by higher non-cash mark-to-market gains on our commodity derivative instruments.

Selected Canadian and U.S. Results

The following table provides a geographical analysis of key operating and financial results for the three and six months ended June 30, 2012 and 2011.

(CDN$ millions, except per unit amounts)	Three months ended June 30, 2012			Three months ended June 30, 2011		
	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	21,028	15,499	36,527	18,934	10,396	29,330
Natural gas liquids (bbls/day)	2,947	446	3,393	3,344	98	3,442
Natural gas (Mcf/day)	203,030	50,096	253,126	225,158	30,507	255,665
Total average daily production (BOE/day)	57,813	24,295	82,108	59,805	15,578	75,383
Pricing(1)						
Crude oil (per bbl)	$ 69.50	$ 80.96	$ 74.36	$ 88.79	$ 94.79	$ 90.92
Natural gas liquids (per bbl)	63.79	35.80	60.11	66.37	60.41	66.20
Natural gas (per Mcf)	1.91	2.70	2.06	3.69	5.12	3.86
Capital Expenditures						
Capital spending	$ 45.6	$ 163.0	$ 208.6	$ 42.2	$ 106.4	$ 148.6
Acquisitions	2.4	21.2	23.6	47.3	47.1	94.4
Dispositions	–	0.1	0.1	(3.2)	(567.9)	(571.1)
Revenues						
Oil and gas sales(1)	$ 185.0	$ 129.4	$ 314.4	$ 249.8	$ 104.4	$ 354.2
Royalties(2)	(28.7)	(33.8)	(62.5)	(37.5)	(24.7)	(62.2)
Commodity derivative instruments gain/(loss)	142.7	–	142.7	51.8	–	51.8
Expenses						
Operating	$ 68.3	$ 12.2	$ 80.5	$ 58.9	$ 8.6	$ 67.5
G&A and equity based compensation	17.5	3.5	21.0	23.0	2.0	25.0
Depletion, depreciation and amortization	79.8	48.4	128.2	83.1	20.6	103.7
Impairment	–	–	–	–	–	–
Current income taxes expense/(recovery)	0.5	3.3	3.8	–	43.2	43.2

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

(CDN$ millions, except per unit amounts)	Six months ended June 30, 2012 Canada	U.S.	Total	Six months ended June 30, 2011 Canada	U.S.	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	20,814	14,486	35,300	19,064	10,767	29,831
Natural gas liquids (bbls/day)	3,372	326	3,698	3,221	116	3,337
Natural gas (Mcf/day)	205,571	44,334	249,905	221,287	32,297	253,584
Total average daily production (BOE/day)	58,449	22,200	80,649	59,167	16,266	75,433
Pricing(1)						
Crude oil (per bbl)	$ 77.20	$ 83.86	$ 79.93	$ 82.01	$ 88.15	$ 84.23
Natural gas liquids (per bbl)	60.05	40.25	58.30	63.94	47.08	63.35
Natural gas (per Mcf)	2.01	2.89	2.17	3.69	5.20	3.88
Capital Expenditures						
Capital spending	$ 156.8	$ 368.9	$ 525.7	$ 134.4	$ 190.2	$ 324.6
Acquisitions	13.9	42.8	56.7	59.5	83.1	142.6
Dispositions	(30.7)	(21.8)	(52.5)	(62.9)	(567.9)	(630.8)
Revenues						
Oil and gas sales(1)	$ 405.0	$ 248.4	$ 653.4	$ 469.7	$ 203.2	$ 672.9
Royalties(2)	(64.4)	(64.8)	(129.2)	(71.2)	(49.6)	(120.8)
Commodity derivative instruments gain/(loss)	115.0	–	115.0	(24.3)	–	(24.3)
Expenses						
Operating	$ 128.4	$ 24.2	$ 152.6	$ 109.5	$ 15.1	$ 124.6
G&A and equity based compensation	39.2	7.1	46.3	45.3	5.4	50.7
Depletion, depreciation and amortization	160.5	86.2	246.7	161.9	41.7	203.6
Impairment	86.9	–	86.9	32.4		32.4
Current income taxes expense/(recovery)	(0.1)	4.6	4.5	–	44.0	44.0

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

Quarterly Financial Information

During the first half of 2012 oil and gas sales were relatively flat as higher production volumes offset the impact of lower commodity prices. During 2011 and 2010 the impact of higher crude oil prices were also offset by the decline in natural gas prices as well as a reduction in production levels due to our disposition activity, resulting in flat oil and gas sales year-over-year.

Net income was also affected by fluctuating risk management costs, impairments related to the decrease in natural gas prices, gains on asset dispositions along with changes in tax provisions.

Quarterly Financial Information ($ millions, except per share amounts)	**Oil and Gas Sales**[1]	**Net Income/(Loss)**	**Net Income/(Loss) Per Share** Basic	Diluted
2012				
Second Quarter	$ 314.4	$ 100.3	$ 0.51	$ 0.51
First quarter	339.0	(33.8)	(0.18)	(0.18)
Total	$ 653.4	$ 66.5	$ 0.34	$ 0.34
2011				
Fourth Quarter	$ 357.3	$ (299.4)	$ (1.66)	$ (1.65)
Third Quarter	312.9	111.3	0.62	0.62
Second Quarter	354.2	268.0	1.50	1.49
First Quarter	318.7	29.5	0.17	0.16
Total	$ 1,343.1	$ 109.4	$ 0.61	$ 0.61
2010				
Fourth Quarter	$ 313.2	$ 64.5	$ 0.37	$ 0.36
Third Quarter	305.5	(136.3)	(0.77)	(0.77)
Second Quarter	318.2	76.5	0.44	0.38
First Quarter	363.3	(184.0)	(1.05)	(1.08)
Total	$ 1,300.2	$ (179.3)	$ (1.02)	$ (1.02)

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

LIQUIDITY AND CAPITAL RESOURCES

We continue to manage our liquidity in the context of the current natural gas price environment and our 2012 capital spending plans. During the first quarter we closed an equity offering of 14,708,500 common shares for net proceeds of $331 million. On May 15, 2012 we closed a private placement of senior unsecured notes for proceeds of approximately $405 million which were used to repay bank indebtedness. The notes were issued in three separate tranches with terms ranging from seven to twelve years and interest rates from 4.34% to 4.40%.

We also implemented a number of other alternatives to manage our balance sheet. First, we replaced our Dividend Reinvestment Program ("DRIP"), which was only available to Canadian shareholders, with a Stock Dividend Program ("SDP") that is available to all shareholders effective for our June 20th dividend payment. We also announced a reduction in our monthly dividend from CDN$0.18 per share to CDN$0.09 per share, effective for our July 20, 2012 payment. We believe this reduction will allow for continued investment in our asset base in a more sustainable manner, given the lower commodity price environment.

Despite the reduction in our dividend we continue to pursue other measures to support our capital spending activities including the sale of our equity portfolio and the sale or joint venture of our undeveloped land in the Duvernay, Montney and operated Marcellus. We have retained advisors and are actively marketing these assets. We will also consider the sale of non-core producing properties and monetization of infrastructure which are not expected to have a material impact on our 2012 production, reserves or cash flow.

Total debt at June 30, 2012, including the current portion, was $1,159.9 million compared to $907.1 million at December 31, 2011. Total debt at June 30, 2012 was comprised of $321.9 million of bank indebtedness and $838.0 million of senior notes. The proceeds from our equity issue and cash flow from operations were exceeded by our capital spending, acquisitions and cash dividends, resulting in an increase in our debt balance for the six months ended June 30, 2012.

Our working capital deficiency at June 30, 2012, excluding cash and current deferred financial assets and credits, decreased by $115.1 million compared to December 31, 2011. The change in our working capital resulted from decreased accounts payable balances due to lower capital spending compared to the fourth quarter of 2011 as well as lower dividends payable following the reduction of our monthly dividend. We expect to finance our working capital deficit through funds flow and our bank credit facility.

Our payout ratio, which is calculated as cash dividends divided by funds flow, was 57% for the second quarter of 2012 compared to 73% for the second quarter of 2011. Our adjusted payout ratio, which is calculated as cash dividends plus capital spending and office capital divided by funds flow, was 202% for the second quarter of 2012 compared to 185% for the second quarter of 2011. We expect that our payout and adjusted payout ratios will moderate over the remainder of the year given the reduction in our monthly dividend, our new SDP, along with forecasted growth in production and funds flow.

Our key leverage ratios are detailed below:

Financial Leverage and Coverage	June 30, 2012	December 31, 2011
Long-term debt to funds flow (12 month trailing)(1)	2.0 x	1.6 x
Funds flow to interest expense (12 month trailing)(2)	12.6 x	12.2 x
Long-term debt to long-term debt plus equity(1)	25%	22%

(1) Long-term debt is measured net of cash and includes the current portion of the senior notes.
(2) Interest expense is calculated as finance expense excluding non-cash items.

Our unsecured, covenant-based, $1.0 billion bank credit facility will mature on October 13, 2014. Drawn fees under the facility range between 160 and 325 basis points over bankers' acceptance rates. We are currently paying 160 basis points over bankers' acceptance rates, which are trading around 1.2%, for a combined rate of 2.8%.

At June 30, 2012 we were in compliance with our debt covenants. Our bank credit facility and senior note purchase agreements have been filed as material documents on the Company's SEDAR profile at www.sedar.com.

Dividends

During the three and six months ended June 30, 2012 we reported a total of $88.6 million ($0.45/share) and $194.6 million ($0.99/share) in dividends to our shareholders, of which $5.4 million is non-cash and related to our June SDP. On June 12, 2012, we announced a reduction in our monthly dividend from CDN$0.18 per share to CDN$0.09 per share, effective for our July 20, 2012 dividend payment. We continue to assess our dividend levels with respect to anticipated funds flow, debt levels, capital spending plans and capital market conditions.

On May 11, 2012 we replaced our previous DRIP that was available only to Canadian shareholders with a SDP that is available to all shareholders. The SDP allows shareholders to receive dividends in the form of shares of Enerplus at a 5% discount to the current weighted average price in lieu of a cash dividend. For Canadian and non-Canadian investors holding their shares in taxable accounts, the SDP has attractive tax attributes in comparison to a DRIP.

Participation in the SDP is optional allowing our shareholders to continue to receive cash dividends unless they elect to receive stock dividends. We are pleased by the level of response to the SDP, which currently has a participation rate of approximately 17% or $3.0 million per month at the reduced rate of $0.09 per share. In comparison, the DRIP participation for the first 5 months of the year averaged approximately 11%. As with the DRIP, the SDP will serve as a source of capital by allowing us to retain cash that would otherwise be paid out as dividends.

Shareholders' Capital

During the second quarter of 2012, a total of 869,000 shares (2011 – 709,000) were issued pursuant to the SDP, DRIP and the stock option plan, resulting in $12.5 million (2011 – $18.3 million) of additional equity for the company. For the six months ended June 30, 2012, a total of 1,464,000 shares (2011 – 1,339,000) and $25.8 million of additional equity (2011 – $34.3 million) was issued pursuant to the SDP, DRIP and the stock option plan. On February 8, 2012 we completed a bought deal equity financing of 14,708,500 common shares at a price of $23.45 per share for gross proceeds of $344.9 million ($330.6 million net of issuance costs). For further details see Note 13.

We had 197,332,000 shares outstanding at June 30, 2012 compared to 179,988,000 shares outstanding at June 30, 2011. We had 181,159,000 shares outstanding at December 31, 2011. The weighted average basic number of shares outstanding for the six months ended June 30, 2012 was 193,306,000 (2011 – 179,209,000). At August 1, 2012 we had 197,560,000 shares outstanding.

2012 GUIDANCE

A summary of our updated 2012 guidance is below. This guidance does not include any potential acquisitions or divestments.

Summary of 2012 Expectations	Target	Comments
Average annual production	83,500 BOE/day	Increased from 83,000 BOE/day
Exit rate production	88,000 BOE/day	No change
Capital spending	$850 million	Increased from $800 million
Marcellus carry commitment spending	$37 million (US$4.6 million remaining at the end of Q2 2012)	
Exit production mix (volumes)	50% natural gas, 50% crude oil and liquids	No change
Average royalty rate (% of gross sales, net of transportation)	21%	No change
Operating costs	$10.40/BOE	No change
G&A and equity based compensation expenses	$3.30/BOE	Decreased from $3.55/BOE
Average interest and financing costs	6%	No change

INTERNAL CONTROLS AND PROCEDURES

There were no changes in our internal control over financial reporting during the period beginning on April 1, 2012 and ending on June 30, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

Additional information relating to Enerplus, including our current Annual Information Form, is available under our profile on the SEDAR website at www.sedar.com, on the EDGAR website at www.sec.gov and at www.enerplus.com.

FORWARD-LOOKING INFORMATION AND STATEMENTS

*This MD&A contains certain forward-looking information and forward-looking statements within the meaning of applicable securities laws (**"forward-looking information"**). The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this MD&A contains forward-looking information pertaining to the following: expected 2012 average and exit production volumes and the anticipated production mix; the results from our Fort Berthold drilling program and the timing of related production; future oil and natural gas prices and our commodity risk management programs; future royalty rates on our production; anticipated cash and non-cash G&A and financing expenses; operating costs; capital spending levels in 2012 and its impact on our production levels; the amount of our future abandonment and reclamation costs and decommissioning liabilities; our 2012 U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes; future debt and working capital levels and debt-to-funds-flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; the amount and timing of future cash dividends that we may pay to our shareholders; the amount and timing of future debt and equity issuances and expected use of proceeds therefrom; and the amount and timing of future asset dispositions.*

The forward-looking information contained in this MD&A reflects several material factors, expectations and assumptions including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, *royalty and regulatory regimes; the accuracy of the estimates of our reserve and resource volumes; commodity price and cost assumptions; the continued availability of adequate debt and/or equity financing and funds flow to fund our capital and operating requirements and dividend payments as needed; the availability of third party services; and the extent of our liabilities. We believe the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.*

The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves 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 including, without limitation: changes in commodity prices; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties, increased debt levels or debt service requirements; inaccurate estimation of our oil and gas reserve and resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; a failure to complete planned asset dispositions on the terms anticipated or at all; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks and contingencies described under "Risk Factors and Risk Management" in our MD&A for the year ended December 31, 2011 and under "Risk Factors" in our Annual Information Form for the year ended December 31, 2011 dated March 9, 2012, which are available on our website at www.enerplus.com and on our SEDAR profile at www.sedar.com and which form part of our Form 40-F filed with the SEC on March 9, 2012 available on EDGAR at www.sec.gov.

The forward-looking information contained in this MD&A speaks only as of the date of this MD&A, and we do not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws.

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	June 30, 2012	December 31, 2011
Assets			
Current assets			
Cash		$ 7,175	$ 5,629
Accounts receivable		116,187	124,806
Deferred financial assets	14	102,281	2,312
Other current		32,850	14,655
		258,493	147,402
Exploration and evaluation assets	4	900,209	874,799
Property, plant and equipment	5	4,563,778	4,332,011
Goodwill		155,002	154,691
Deferred financial assets	14	10,248	6,585
Other assets	7	174,743	207,824
Total Assets		$ 6,062,473	$ 5,723,312
Liabilities			
Current liabilities			
Accounts payable		$ 331,854	$ 422,666
Dividends payable		17,760	32,609
Current portion of long-term debt	8	46,906	46,808
Deferred financial credits	14	16,171	35,711
		412,691	537,794
Long-term debt	8	1,113,015	860,286
Deferred financial credits	14	15,606	31,820
Deferred tax liability		478,150	452,670
Decommissioning liability	9	582,013	563,763
		2,188,784	1,908,539
Total Liabilities		2,601,475	2,446,333
Equity			
Shareholders' capital	13	3,799,874	3,442,364
Contributed surplus	13	30,900	26,910
Accumulated deficit		(407,618)	(279,467)
Accumulated other comprehensive income		37,842	87,172
		3,460,998	3,276,979
Total Liabilities & Equity		$ 6,062,473	$ 5,723,312

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Income and Comprehensive Income

		Three months ended June 30,		Six months ended June 30,	
(CDN$ thousands) unaudited	Note	2012	2011	2012	2011
Revenues					
Oil and gas sales		$ 321,163	$ 359,427	$ 666,314	$ 683,429
Royalties		(62,453)	(62,224)	(129,179)	(120,777)
Commodity derivative instruments gain/(loss)	14	142,710	51,817	115,056	(24,310)
		401,420	349,020	652,191	538,342
Expenses					
Operating		80,520	67,516	152,583	124,591
General and administrative		20,653	17,342	41,373	34,409
Equity based compensation		322	7,639	4,897	16,303
Transportation		6,808	5,288	12,960	10,562
Depletion, depreciation and amortization	5	128,217	103,695	246,735	203,596
Impairments	6	–	–	86,906	32,394
Foreign exchange	11	44	(4,542)	(5,276)	(2,880)
Finance expense	10	17,408	17,834	33,206	31,841
Asset disposition loss/(gain)		–	(271,910)	(24,100)	(298,145)
Other expense/(income)		228	(189)	(114)	(596)
		254,200	(57,327)	549,170	152,075
Income before taxes		147,220	406,347	103,021	386,267
Current tax expense	12	3,845	43,214	4,548	43,996
Deferred tax expense	12	43,111	95,151	32,030	44,740
Net Income		$ 100,264	$ 267,982	$ 66,443	$ 297,531
Other Comprehensive Income					
Change in fair value of available for sale financial instruments, net of tax	7	(46,901)	50,270	(51,077)	53,218
Change in cumulative translation adjustment		30,731	(14,953)	1,747	(46,118)
Other Comprehensive Income, net of tax		(16,170)	35,317	(49,330)	7,100
Total Comprehensive Income		$ 84,094	$ 303,299	$ 17,113	$ 304,631
Net income per share					
Basic		$ 0.51	$ 1.50	$ 0.34	$ 1.66
Diluted		$ 0.51	$ 1.49	$ 0.34	$ 1.66
Weighted average number of shares outstanding (thousands)	13				
Basic		196,768	179,583	193,306	179,209
Diluted		196,768	180,085	193,393	179,711

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Changes in Shareholders' Equity

Six months ended June 30 (CDN$ thousands) unaudited	2012	2011
Shareholders' Capital		
Balance, beginning of year	$ 3,442,364	$ 5,639,380
Reclassification of EELP units	–	44,387
Reclassification of accumulated deficit	–	(2,314,775)
Public offering	330,618	–
Stock Option Plan – cash	1,180	9,714
Stock Option Plan – non cash	1,119	7,346
Dividend Reinvestment Plan	19,150	–
Stock Dividend Plan	5,443	24,553
Balance, end of period	$ 3,799,874	$ 3,410,605
Contributed Surplus		
Balance, beginning of year	$ 26,910	$ 3,795
Reclassification of trust unit rights liability	–	20,156
Stock Option Plan – exercised	(1,119)	(7,346)
Stock Option Plan – expensed	5,109	6,778
Balance, end of period	$ 30,900	$ 23,383
Accumulated Deficit		
Balance, beginning of year	$ (279,467)	$ (2,314,775)
Reclassification to Shareholders' Capital	–	2,314,775
Net income	66,443	297,531
Cash dividends	(189,151)	(193,763)
Stock dividends	(5,443)	–
Balance, end of period	$ (407,618)	$ 103,768
Accumulated other comprehensive income		
Balance, beginning of year	$ 87,172	$ (22)
Change in fair value of available for sale financial instruments, net of tax	(51,077)	53,218
Change in cumulative translation adjustment	1,747	(46,118)
Balance, end of period	$ 37,842	$ 7,078
Total Equity	$ 3,460,998	$ 3,544,834

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Cash Flows

(CDN$ thousands) unaudited	Three months ended June 30, 2012	Three months ended June 30, 2011	Six months ended June 30, 2012	Six months ended June 30, 2011
Operating Activities				
Net income	$ 100,264	$ 267,982	$ 66,443	$ 297,531
Non-cash items add/(deduct):				
Depletion, depreciation and amortization	128,217	103,695	246,735	203,596
Impairments	–		86,906	32,394
Change in fair value of derivative instruments	(161,210)	(87,664)	(139,386)	(6,887)
Deferred tax expense	43,111	95,151	32,030	44,740
Foreign exchange loss/(gain) on U.S. dollar debt	11,920	(1,189)	9,555	(13,123)
Accretion expense	3,515	3,379	6,968	6,794
Equity based compensation – stock option plan	2,117	3,295	5,109	6,778
Amortization of debt transaction costs	414	284	794	569
Loss on equity investment sale	156	–	156	–
Cross currency interest rate swap principal settlement	18,043	19,418	18,043	19,418
Asset disposition loss/(gain)	–	(271,910)	(24,100)	(298,145)
Funds Flow	146,547	132,441	309,253	293,665
Decommissioning expenditures	(3,712)	(3,961)	(11,010)	(8,171)
Changes in non-cash operating working capital	14,421	34,843	(72,006)	10,232
Cash flow from operating activities	157,256	163,323	226,237	295,726
Financing Activities				
Issuance of shares	7,050	18,266	350,948	34,266
Cash dividends to shareholders	(83,156)	(97,077)	(189,151)	(193,763)
Change in bank debt	(126,742)	(353,261)	(126,971)	(220,290)
Repayment on senior notes	(35,623)	(34,248)	(35,623)	(34,248)
Proceeds from senior note issue	406,088	–	406,088	–
Cross currency interest rate swap principal settlement	(18,043)	(19,418)	(18,043)	(19,418)
Changes in non-cash financing working capital	(17,604)	124	(14,849)	247
Cash flow from financing activities	131,970	(485,614)	372,399	(433,206)
Investing Activities				
Capital expenditures	(212,173)	(148,573)	(531,743)	(324,628)
Property and land acquisitions	(23,649)	(94,415)	(56,669)	(142,633)
Property dispositions	(87)	571,095	22,524	630,788
Sale of equity investment	4,410	–	4,410	–
Changes in non-cash investing working capital	(48,972)	(5,150)	(34,260)	(30,415)
Cash flow from investing activities	(280,471)	322,957	(595,738)	133,112
Effect of exchange rate changes on cash	(3,033)	94	(1,352)	370
Change in cash	5,722	760	1,546	(3,998)
Cash, beginning of period	1,453	3,616	5,629	8,374
Cash, end of period	$ 7,175	$ 4,376	$ 7,175	$ 4,376
Supplementary Cash Flow Information				
Cash income taxes paid	$ 3,213	$ 45	$ 17,651	$ 168
Cash interest paid	$ 17,058	$ 20,661	$ 21,525	$ 25,128

See accompanying notes to the Condensed Consolidated Financial Statements

Notes to Consolidated Financial Statements

1. REPORTING ENTITY

These interim condensed consolidated financial statements and notes ("interim Consolidated Financial Statements") present the results of Enerplus Corporation ("Enerplus") including its Canadian and U.S. subsidiaries.

Enerplus is a North American crude oil and natural gas exploration and development company, and is publicly traded on the Toronto and New York stock exchanges under the ticker symbol ERF. Enerplus' head office is located in Calgary, Alberta, Canada.

The interim Consolidated Financial Statements were authorized for issue by the Board of Directors on August 9, 2012.

2. BASIS OF PREPARATION

Enerplus' interim Consolidated Financial Statements present its results of operations and financial position under International Financial Reporting Standards ("IFRS") as at and for the three and six months ended June 30, 2012, including the 2011 comparative periods. They have been prepared in accordance with IAS 34, "Interim Financial Reporting" as issued by the International Accounting Standards Board ("IASB"). These interim Consolidated Financial Statements do not include all the necessary annual disclosures as prescribed by IFRS and should be read in conjunction with Enerplus' audited Consolidated Financial Statements as of December 31, 2011. There have been no changes to the use of estimates or judgments since December 31, 2011.

3. SIGNIFICANT ACCOUNTING POLICIES

Enerplus' accounting policies are unchanged from December 31, 2011. There have been no new accounting pronouncements during the period. These interim Consolidated Financial Statements should be read in conjunction with Enerplus' audited Consolidated Financial Statements as of December 31, 2011.

4. EXPLORATION AND EVALUATION ("E&E") ASSETS

Carrying value ($ thousands)	**E&E assets**
At December 31, 2011	$ 874,799
Capital spending and acquisitions	157,463
Dispositions	(23,387)
Transfers to Property, Plant and Equipment	(108,728)
Foreign currency translation adjustment	62
As at June 30, 2012	$ 900,209

As at June 30, 2012 the E&E asset balance of $900,209,000 (December 31, 2011 – $874,799,000) consists of undeveloped lands and assets that management has not fully evaluated for technical feasibility and commercial viability.

5. PROPERTY, PLANT AND EQUIPMENT ("PP&E")

Carrying value before accumulated depletion and depreciation ($ thousands)	**D&P assets**	**Office and other**	**Total**
As at December 31, 2011	$ 5,904,859	$ 71,016	$ 5,975,875
Capital spending and acquisitions	424,859	6,090	430,949
Transfers from Exploration and Evaluation	108,728	–	108,728
Change in decommissioning costs (Note 9)	22,309	–	22,309
Dispositions	(5,036)	–	(5,036)
Foreign currency translation adjustment	9,870	28	9,898
As at June 30, 2012	$ 6,465,589	$ 77,134	$ 6,542,723

Accumulated Depletion and Depreciation	D&P assets	Office and other	Total
As at December 31, 2011	$ 1,591,199	$ 52,665	$ 1,643,864
Depletion, Depreciation and Amortization	243,560	3,175	246,735
Impairment expense (Note 6)	86,906	–	86,906
Foreign currency translation adjustment	1,435	5	1,440
As at June 30, 2012	$ 1,923,100	$ 55,845	$ 1,978,945

Net carrying value	D&P assets	Office and other	Total
As at December 31, 2011	$ 4,313,660	$ 18,351	$ 4,332,011
As at June 30, 2012	$ 4,542,489	$ 21,289	$ 4,563,778

As at June 30, 2012 the Marcellus carry commitment balance remaining was US$4,586,000.

6. IMPAIRMENT

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2012	2011	2012	2011
D&P assets	$ –	$ –	$ 86,906	$ 32,394
Impairment expense	$ –	$ –	$ 86,906	$ 32,394

There were no impairments for the three months ended June 30, 2012 and 2011. D&P asset impairments recorded for the six months ended June 30, 2012 and 2011 relate to natural gas focused cash generating units ("CGUs") and reflect lower forecast natural gas prices at March 31, 2012 and 2011. The estimated recoverable amounts used for impairment testing were based on the respective assets value in use, calculated using proved plus probable reserves discounted at 10%.

7. OTHER ASSETS

Other assets of $174,743,000 (December 31, 2011 – $207,824,000) represent Enerplus' marketable securities portfolio. For the three and six months ended June 30, 2012 the change in fair value of these investments represented unrealized losses of $53,917,000 ($46,901,000 net of tax) and $58,709,000 ($51,077,000 net of tax), respectively. For the same periods in 2011 the change in fair value of these investments represented unrealized gains of $54,636,000 ($50,270,000 net of tax) and $58,069,000 ($53,218,000 net of tax), respectively. During the three months ended June 30, 2012 Enerplus sold certain marketable securities for proceeds of $4,410,000, recognizing a loss of $156,000.

8. DEBT

($ thousands)	June 30, 2012	December 31, 2011
Current:		
Current portion of long-term debt	$ 46,906	$ 46,808
	46,906	46,808
Long-term:		
Bank credit facility	$ 321,871	$ 446,182
Senior notes		
CDN$30 million (Matures May 15, 2019)	30,000	–
US$20 million (Matures May 15, 2022)	20,382	–
US$355 million (Matures May 15, 2024)	361,781	–
CDN$40 million (Matures June 18, 2015)	40,000	40,000
US$40 million (Matures June 18, 2015)	40,764	40,680
US$225 million (Matures June 18, 2021)	229,298	228,825
US$54 million (Matures October 1, 2015)(2)	33,019	32,951
US$175 million (Matures June 19, 2014)(1)	35,900	71,648
	1,113,015	860,286
Total debt	$ 1,159,921	$ 907,094

(1) The outstanding U.S. principal as at June 30, 2012 was US$70,000,000, a portion of which is classified as current.
(2) The outstanding U.S. principal as at June 30, 2012 was US$43,200,000, a portion of which is classified as current.

On May 15, 2012 Enerplus closed a private offering of senior unsecured notes raising gross proceeds of approximately $405,000,000. The notes rank equally with the bank credit facility and other outstanding senior notes. The terms and rates of the Company's outstanding senior notes are detailed below:

Issue Date	Original Principal ($ millions)	Remaining Principal ($ millions)	Coupon Rate	Interest Payment Dates	Repayment
May 15, 2012	CDN$ 30,000	CDN$ 30,000	4.34%	May 15 and Nov 15	Bullet payment on May 15, 2019
May 15, 2012	US$ 20,000	US$ 20,000	4.40%	May 15 and Nov 15	Bullet payment on May 15, 2022
May 15, 2012	US$ 355,000	US$ 355,000	4.40%	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020
June 18, 2009	CDN$ 40,000	CDN$ 40,000	6.37%	June 18 and Dec 18	Bullet payment on June 18, 2015
June 18, 2009	US$ 40,000	US$ 40,000	6.82%	June 18 and Dec 18	Bullet payment on June 18, 2015
June 18, 2009	US$ 225,000	US$ 225,000	7.97%	June 18 and Dec 18	5 equal annual installments beginning June 18, 2017
Oct 1, 2003	US$ 54,000	US$ 43,200	5.46%	April 1 and Oct 1	5 equal annual installments beginning Oct 1, 2011
June 19, 2002	US$ 175,000	US$ 70,000	6.62%	June 19 and Dec 19	5 equal annual installments beginning June 19, 2010

9. DECOMMISSIONING LIABILITY

Enerplus has estimated the net present value of its decommissioning liability to be $582,013,000 as at June 30, 2012 compared to $563,763,000 at December 31, 2011, based on a total undiscounted liability of $638,065,000 and $644,922,000 respectively. The decommissioning liability was calculated using a risk free rate of 2.33% at June 30, 2012 (December 31, 2011 – 2.49%). The majority of the change in estimates relates to changes in the risk free rate used to calculate the present value of the liability.

($ thousands)	Six months ended June 30, 2012	Year ended December 31, 2011
Decommissioning liability, beginning of year	$ 563,763	$ 392,709
Change in estimates	18,888	174,807
Property acquisition and development activity	3,702	4,828
Dispositions	(281)	(692)
Capitalized decommissioning costs	22,309	178,943
Decommissioning expenditures	(11,010)	(21,656)
Accretion	6,968	13,803
Foreign currency translation adjustment	(17)	(36)
Decommissioning liability, end of period	$ 582,013	$ 563,763

10. FINANCE EXPENSE

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2012	2011	2012	2011
Realized:				
Interest on bank debt and senior notes	$ 13,427	$ 12,690	$ 24,275	$ 24,590
Unrealized:				
Cross currency interest rate swap loss /(gain)	284	1,927	1,733	1,095
Interest rate swap loss/(gain)	(232)	(446)	(564)	(1,207)
Premium and transaction cost amortization	414	284	794	569
Accretion of decommissioning liability	3,515	3,379	6,968	6,794
Finance expense	$ 17,408	$ 17,834	$ 33,206	$ 31,841

11. FOREIGN EXCHANGE

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2012	2011	2012	2011
Realized:				
Foreign exchange loss/(gain)	$ 11,188	$ 13,049	$ 5,908	$ 20,308
Unrealized:				
Translation of U.S. dollar debt loss/(gain)	11,920	(1,189)	9,555	(13,123)
Cross currency interest rate swap loss/(gain)	(19,373)	(17,293)	(17,312)	(13,366)
Foreign exchange swaps loss/(gain)	(3,691)	891	(3,427)	3,301
Foreign exchange loss/(gain)	$ 44	$ (4,542)	$ (5,276)	$ (2,880)

12. INCOME TAXES

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2012	2011	2012	2011
Current tax expense/(recovery)				
Canada	510	$ –	$ (123)	$ –
U.S.	3,335	43,214	4,671	43,996
Total current tax expense/(recovery)	3,845	43,214	$ 4,548	$ 43,996
Deferred tax expense/(recovery)	43,111	95,151	32,030	44,740
Total income tax expense/(recovery)	$ 46,956	$ 138,365	$ 36,578	$ 88,736

13. SHAREHOLDERS' CAPITAL

(a) Share Capital

Authorized unlimited number of common shares	Six months ended June 30, 2012		Year ended December 31, 2011	
Issued: (thousands)	**Shares**	**Amount**	**Shares**	**Amount**
Balance, beginning of year	181,159	$ 3,442,364	176,946	$ 5,639,380
Corporate Conversion:				
Reclassification of EELP units (non-cash)	–	–	1,703	44,387
Reclassification of Accumulated Deficit (non-cash)	–	–	–	(2,314,775)
Issued for cash:				
Public offerings	14,709	330,618	–	–
Dividend reinvestment plan	955	19,150	1,928	52,375
Stock Option Plan	68	1,180	582	11,626
Non-cash:				
Stock Dividend Plan	441	5,443	–	–
Stock Option Plan	–	1,119	–	9,371
Balance, end of period	197,332	$ 3,799,874	181,159	$ 3,442,364

(b) Dividends

During the second quarter Enerplus announced a reduction in its monthly dividend to $0.09 per share from $0.18 per share, effective for the July dividend payment. Additionally, Enerplus replaced its Dividend Reinvestment Plan ("DRIP") with a Stock Dividend Plan ("SDP") effective for the June dividend payment. The SDP allows all shareholders to receive dividends in the form of Enerplus shares at a 5% discount to the current weighted average price. For the three months ended June 30, 2012, Enerplus paid cash dividends of $83,156,000 (June 30, 2011 – $97,077,000) and issued stock dividends of $5,443,000. For the six months ended June 30, 2012 Enerplus paid cash dividends of $189,151,000 (June 30, 2011 – $193,763,000) and issued stock dividends of $5,443,000.

(c) Equity Based Compensation

The following table summarizes Enerplus' equity based compensation expense:

($ thousands)	Three months ended June 30, 2012	Three months ended June 30, 2011	Six months ended June 30, 2012	Six months ended June 30, 2011
Cash:				
Long term incentive plans expense/(recovery)	$ (1,452)	$ 4,344	$ 131	$ 9,525
Non-Cash:				
Stock option plan expense	2,117	3,295	5,109	6,778
Equity total return swap loss /(gain)	(343)	–	(343)	–
Equity based compensation expense	$ 322	$ 7,639	$ 4,897	$ 16,303

(i) Stock Option Plan

The following assumptions were used to arrive at the estimates of fair value during each of the respective reporting periods:

Weighted average for the period	June 30, 2012	December 31, 2011
Dividend yield(1)	7.7%	7.14%
Volatility(1)	30.2%	35.0%
Risk-free interest rate	1.18%	2.34%
Forfeiture rate	10%	9.4%
Expected life	4.5 years	4.5 years

(1) Reflects the expected dividend yield and volatility of Enerplus shares over the life of the option.

The weighted average grant date fair value of options granted in 2012 was $2.52 (June 30, 2011 – $4.80). At June 30, 2012, 3,207,000 options were exercisable at a weighted average reduced exercise price of $30.11 with a weighted average remaining contractual term of 3.6 years, giving an aggregate intrinsic value of nil (June 30, 2011 – $8,980,000).

For the six months ended June 30, 2012, a total of 68,000 options were exercised at a weighted average reduced exercise price of $17.35. The weighted average share price throughout the period was $19.39.

For the three and six months ended June 30, 2012, Enerplus expensed a total of $2,117,000 and $5,109,000 respectively related to its stock option plan. The remaining unamortized grant date fair value of outstanding options of $10,232,000 will be recognized in net income over the remaining vesting period. Activity for the periods is as follows:

	Six months ended June 30, 2012		Year ended December 31, 2011	
	Number of Options (000's)	Weighted Average Exercise Price(1)	Number of Options (000's)	Weighted Average Exercise Price(1)
Options outstanding				
Beginning of year	5,098	$ 29.41	5,457	$ 32.11
Granted	4,469	22.65	2,154	30.27
Exercised	(68)	17.35	(582)	19.97
Forfeited	(616)	26.19	(845)	33.22
Expired	–	–	(1,086)	47.05
End of period	8,883	$ 26.32	5,098	$ 29.41
Options exercisable at the end of period	3,207	$ 30.11	1,932	$ 33.86

(1) Exercise price reflects grant prices less any reduction in strike price for outstanding rights under the rights incentive plan.

The following table summarizes the Contributed Surplus balance as at:

($ thousands)	June 30, 2012	December 31, 2011
Cancelled shares	$ 3,795	$ 3,795
Stock option plan	27,105	23,115
Balance, end of period	$ 30,900	$ 26,910

(ii) Long-term Incentive Plans

The following table summarizes the Performance Share Units ("PSU"), Restricted Share Units ("RSU") and Director Share Units ("DSU") activity for the six months ended June 30, 2012:

(thousands of units)	PSUs	RSUs	DSUs
Number of units, beginning of year	170	895	14
Granted	281	401	29
Settled	–	(480)	–
Forfeited	(38)	(83)	–
Number of units, end of period	413	733	43

During the quarter Enerplus entered into an equity total return swap derivative ("equity swap") with respect to its cash settled long term incentive plans. Under the equity swap Enerplus effectively fixed the settlement cost on 800,000 units outstanding under the plans at price of approximately $12.64 per unit. At June 30, 2012 the long term incentive plans had a liability balance of $8,036,000 (December 31, 2011 – $21,254,000).

(d) Basic and Diluted Earnings per Share

Net income per share has been determined based on the following:

	Three months ended June 30,		Six months ended June 30,	
(thousands of shares)	2012	2011	2012	2011
Weighted average shares	196,768	179,583	193,306	179,209
Dilutive impact of options	–	502	87	502
Diluted shares	196,768	180,085	193,393	179,711

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

(a) Carrying Value and Fair Value of Non-Derivative Financial Instruments

Enerplus' non-derivative financial instruments include accounts receivable, accounts payable, marketable securities, dividends payable, bank indebtedness and long-term debt.

(i) Accounts Receivable, Accounts Payable, Dividends Payable, Bank Credit Facilities and Senior Notes

The carrying value of accounts receivable, accounts payable, dividends payable and bank credit facilities approximated their fair value at June 30, 2012 and December 31, 2011 due to their short term nature. At June 30, 2012 the combined fair values of Enerplus' senior notes was $953,382,000 and the carrying amount was $838,050,000 (December 31, 2011 – fair value of $540,426,000 and carrying value of $460,912,000). The fair value of the senior notes was estimated by discounting future interest and principal payments using available market information at the balance sheet date.

(b) Fair Value of Derivative Financial Instruments

Derivative instruments are recorded at their estimated fair value using observable market inputs, other than quoted prices, at the balance sheet date. The deferred financial assets and credits on the Consolidated Balance Sheets result from recording derivative financial instruments at fair value. At June 30, 2012 a current deferred financial asset of $102,281,000, a current deferred financial credit of $16,171,000, a non-current deferred financial asset of $10,248,000 and a non-current deferred financial credit of $15,606,000 are recorded on the Consolidated Balance Sheet.

The following table summarizes the change in fair value for the three months ended June 30, 2012:

($ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swap	Foreign Exchange Swaps	Electricity Swaps	Oil Commodity Derivative Instruments	Equity Swap	Total
Deferred financial assets/(liabilities), beginning of period	$ (1,271)	$ (49,827)	$ 6,378	$ 899	$ (36,637)	$ –	$ (80,458)
Change in fair value gain/(loss)	232(1)	19,089(2)	3,691(3)	187(4)	137,668(5)	343(6)	161,210
Deferred financial assets/(liabilities), end of period	**$ (1,039)**	**$ (30,738)**	**$ 10,069**	**$ 1,086**	**$ 101,031**	**$ 343**	**$ 80,752**

(1) Recorded in finance expense.
(2) Recorded in foreign exchange expense (gain of $19,373) and finance expense (loss of $284).
(3) Recorded in foreign exchange expense.
(4) Recorded in operating expense.
(5) Recorded in commodity derivative instruments (see below).
(6) Recorded in equity based compensation expense.

The following table summarizes the change in fair value for the six months ended June 30, 2012:

($ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swap	Foreign Exchange Swaps	Electricity Swaps	Oil Commodity Derivative Instruments	Equity Swap	Total
Deferred financial assets/(liabilities), beginning of period	$ (1,603)	$ (46,317)	$ 6,642	$ 2,255	$ (19,611)	$ –	$ (58,634)
Change in fair value gain/(loss)	564(1)	15,579(2)	3,427(3)	(1,169)(4)	120,642(5)	343(6)	139,386
Deferred financial assets/(liabilities), end of period	**$ (1,039)**	**$ (30,738)**	**$ 10,069**	**$ 1,086**	**$ 101,031**	**$ 343**	**$ 80,752**

(1) Recorded in finance expense.
(2) Recorded in foreign exchange expense (gain of $17,312) and finance expense (loss of $1,733).
(3) Recorded in foreign exchange expense.
(4) Recorded in operating expense.
(5) Recorded in commodity derivative instruments (see below).
(6) Recorded in equity based compensation expense.

The following table summarizes the ending balances as at June 30, 2012:

($ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swap	Foreign Exchange Swaps	Electricity Swap	Oil Commodity Derivative Instruments	Equity Swap	Total
Balance Sheet classification:							
Current assets/(liabilities)	$ (998)	$ (15,173)	$ 33	$ 1,086	$ 101,031	$ 131	$ 86,110
Non-current assets/(liabilities)	$ (41)	$ (15,565)	$ 10,036	$ –	$ –	$ 212	$ (5,358)
Total	**$ (1,039)**	**$ (30,738)**	**$ 10,069**	**$ 1,086**	**$ 101,031**	**$ 343**	**$ 80,752**

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

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2012	2011	2012	2011
Change in fair value of commodity derivative instruments gain/(loss)	$ 137,668	$ 72,578	$ 120,642	$ (6,580)
Net realized cash gain/(loss)	5,042	(20,761)	(5,586)	(17,730)
Commodity derivative instruments gain/(loss)	$ 142,710	$ 51,817	$ 115,056	$ (24,310)

(c) Risk Management

Commodity Price Risk

Enerplus manages a portion of commodity price risk through a combination of financial derivative and physical delivery sales contracts. Enerplus' policy is to enter into commodity contracts considered appropriate to a maximum of 80% of forecasted production volumes net of royalties.

Crude Oil Instruments:

At June 30, 2012 the fair value of Enerplus' crude oil derivative contracts represented an asset of $101,031,000 and the change in fair value of these contracts for the three and six months ended June 30, 2012 represented an unrealized gain of $137,668,000 and $120,642,000 respectively.

The following table summarizes Enerplus' crude oil risk management positions at July 26, 2012:

Instrument Type	bbls/day	US$/bbl(1)
Jul 1, 2012 – Dec 31, 2012		
WTI Swap	17,500	95.83
WTI Purchased Put	1,000	103.00
WTI Purchased Call	1,000	103.00
WTI Sold Put	2,000	65.00
WTI Sold Call	1,000	133.00
Brent-WTI Spread	2,900	13.52
Jan 1, 2013 – Dec 31, 2013		
WTI Swap	14,500	101.36
WTI Purchased Call	3,500	104.09
WTI Sold Put	4,500	63.33
WTI Sold Call	2,000	130.00

(1) Swap transactions and the Brent-WTI spread with a common term have been aggregated and presented as the weighted average price/bbl.

Natural Gas Instruments:

At June 30, 2012 Enerplus did not have any natural gas derivative contracts in place, however subsequent to the quarter Enerplus entered into certain natural gas contracts.

The following table summarizes Enerplus' natural gas financial contracts at July 26, 2012:

Instrument Type	MMcf/day	CDN$/Mcf
Jan 1, 2013 – Dec 31, 2013		
AECO Purchased Put	22.7	3.17

For the period July 2012 through October 2012 Enerplus has entered into physical fixed price natural gas contracts for 79,400 Mcf/day at an average price of $2.20/Mcf. In addition, for the last six months of 2012 Enerplus has costless collars for 19,900 Mcf/day of physical gas sales with a weighted average floor price of $2.16/Mcf and a weighted average ceiling price of $2.90/Mcf.

Electricity:

Enerplus is subject to electricity price fluctuations and it manages this risk by entering into forward fixed rate electricity derivative contracts on a portion of its electricity requirements. At June 30, 2012 the fair value of Enerplus' electricity contracts represented an asset of $1,086,000 and the change in fair value of these contracts for the three and six months ended June 30, 2012 represented an unrealized gain of $187,000 and an unrealized loss of $1,169,000 respectively.

The following table summarizes Enerplus' electricity derivative contracts at July 26, 2012:

Instrument Type	MWh	CDN$/Mwh
Apr 1, 2012 – Dec 31, 2012		
AESO Power Swap(1)	13.0	54.04
Jan 1, 2013 – Dec 31, 2013		
AESO Power Swap(1)	6.0	70.63

(1) Alberta Electrical System Operator ("AESO") fixed pricing.

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Corporate Director
Calgary, Alberta

(1) Chairman of the Board
(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
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Kenneth W. Young
Vice President, Land

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ENERPLUS RESOURCES (USA) CORPORATION

Edward L. McLaughlin
President

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Enerplus Partnership
Enerplus Resources (USA) Corporation

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ABBREVIATIONS

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AECO a reference to the physical storage and trading hub on the TransCanada Alberta Transmission System (NOVA) which is the delivery point for the various benchmark Alberta Index prices

AOCI accumulated other comprehensive income

API American Petroleum Institute

bbl(s)/day barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S. gallons

Bcf billion cubic feet

Bcfe billion cubic feet equivalent

BOE barrels of oil equivalent

Brent Crude oil sourced from the North Sea, the benchmark for global oil trading quoted in $US dollars.

CTA cumulative translation adjustment

D&P developed and producing

E&E exploration and evaluation

F&D Costs finding and development costs

FD&A Costs finding, development and acquisition costs

FDC future development capital

HH "Henry Hub" a reference to the physical storage and trading hub in Louisiana which is the delivery point for the NYMEX Natural Gas contract

IFRS International Financial Reporting Standards

Mbbls thousand barrels

MBOE thousand barrels of oil equivalent purposes

Mcf thousand cubic feet

Mcfe thousand cubic feet equivalent

Mcf/day thousand cubic feet per day

Mcfe/day thousand cubic feet equivalent per day

MMbbl(s) million barrels

MMBOE million barrels of oil equivalent

MMBtu million British Thermal Units

MMBtu/day million British Thermal Units per day

MMcf million cubic feet

MMcf/day million cubic feet per day

MWh megawatt hour(s) of electricity

NGLs natural gas liquids

NI 51-101 National Instrument 51-101 Oil and Gas Activities adopted by the Canadian Securities regulatory Authorities (pertaining to reserve reporting in Canada)

OCI other comprehensive income

PDP Reserves proved developed producing reserves

P+P Reserves proved plus probable reserves

RLI reserve life index

WCS Western Canadian Select at Hardisty, Alberta, the benchmark for Western Canadian heavy oil pricing purposes

WI percentage working interest ownership

WTI West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing enerPLUS

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