second quarter report 2

Canadian Oil Sands Trust second quarter funds from operations increase 14 per cent with higher crude oil prices and production

All financial figures are unaudited and in Canadian dollars unless otherwise noted. All figures provided per Unit reflect the 5:1 Unit split effective on the close of business May 3, 2006.

Calgary, Alberta (July 25, 2006) – Canadian Oil Sands Trust ("Canadian Oil Sands" or the "Trust" or "we") (TSX - COS.UN) today announced funds from operations rose 14 per cent to $324 million, or $0.70 per Unit, in the second quarter of 2006 compared to $284 million, or $0.62 per Unit, for the same 2005 quarter. In the first six months of 2006, funds from operations rose to $465 million, or $1.00 per Unit, from $377 million, or $0.82 per Unit, in 2005. The increase in funds from operations for both the three and six month periods ended June 30, 2006 reflect higher realized Syncrude TM Sweet Blend ("SSB") selling prices and sales volumes, partially offset by an increase in operating expenses and Crown royalties. The Trust is declaring a quarterly distribution of $0.30 per Unit for Unitholders of record on August 4, 2006 payable on August 31, 2006.

"While we are pleased with the quarter's strong financial results, the suspension of our Stage 3 expansion has been disappointing," said Marcel Coutu, President and Chief Executive Officer. "We are in the process of resuming Stage 3 operations and expect incremental production to come on-stream in early August. Aside from the odour issues, Stage 3 operations were performing as expected, leaving us optimistic about the potential contribution this expansion could have on our results for the remainder of the year."

Second Quarter 2006 overview

- Net income was $337 million, or $0.72 per Unit, in the second quarter of 2006, up from $219 million, or $0.48 per Unit, in the same 2005 period. Net income before unrealized foreign exchange and future income tax, which management believes is a better measure of operational performance than net income, was $259 million, or $0.56 per Unit, in the second quarter of 2006 compared to $233 million, or $0.51 per Unit, in the same period of 2005. For the first six months of 2006 and 2005, respectively, net income before unrealized foreign exchange and future income tax rose to $346 million, or $0.75 per Unit, from $293, or $0.64 per Unit.

- The increase in net income before unrealized foreign exchange and future income tax for the second quarter of 2006 reflects higher realized SSB selling prices and sales volumes, partially offset by an increase in operating, depreciation and depletion expenses, and Crown royalties. The same factors also impacted net income for the first half of the year, although higher non-production costs in 2006 compared to the same 2005 period further reduced 2006 year-to-date net income.
- Canadian Oil Sands' 2006 sales volumes averaged 86,000 barrels per day in the second quarter and 81,000 barrels per day for the first half of the year compared to 80,000 barrels per day and 70,000 barrels per day for the respective 2005 periods.
- Operating costs in the second quarter of 2006 increased to $28.48 per barrel from $21.35 per barrel in 2005. The 33 per cent rise in per barrel operating costs primarily reflects the shift to an expanded operating facility to support the Stage 3 project without an offsetting increase in production. The new Stage 3 units coming into operation also contributed to an 18 per cent rise in per barrel purchased energy costs. In addition, the increase in operating costs reflects higher costs associated with Syncrude's long term incentive compensation and employee retention programs. On a year-to-date basis, operating costs rose to $33.92 per barrel in 2006 compared to $28.51 per barrel in 2005.
- Capital expenditures declined to $59 million in the second quarter of 2006 from $205 million in 2005 with approximately 28 per cent of second quarter 2006 expenditures related to Stage 3 compared to about 75 per cent in the same 2005 period. The Stage 3 project is now essentially complete, although expenditures related to final site clean-up and improvements remain to be incurred, which are estimated at $115 million, gross to Syncrude.
- Net debt to book capitalization was 30 per cent at the end of the second quarter of 2006, down from 33 per cent at December 31, 2005.

CANADIAN OIL SANDS TRUST Highlights								
(millions of Canadian dollars, except Trust unit and volume amounts)								
	Three Months Ended June 30				Six Months Ended June 30			
	2006		2005		2006		2005	
Net Income	$	337	$	219	$	428	$	278
Per Trust unit- Basic	$	0.72	$	0.48	$	0.92	$	0.61
Per Trust unit- Diluted	$	0.72	$	0.48	$	0.92	$	0.61
Funds From Operations	$	324	$	284	$	465	$	377
Per Trust unit	$	0.70	$	0.62	$	1.00	$	0.82
Unitholder Distributions	$	139	$	46	$	232	$	92
Per Trust unit	$	0.30	$	0.10	$	0.50	$	0.20
Syncrude Sweet Blend Sales Volumes *								
Total (MMbbls)		7.9		7.2		14.6		12.6
Daily average (bbls)		86,394		79,506		80,693		69,755
Per Trust unit (bbls/Trust unit)		-		0.1		-		0.1
Operating Costs per barrel	$	28.48	$	21.35	$	33.92	$	28.51
Net Realized Selling Price per barrel								
Sales revenue	$	79.76	$	68.99	$	75.46	$	66.95
Transportation and marketing expense		(1.43)		(1.64)		(1.37)		(1.60)
Realized selling price before hedging	$	78.33	$	67.35	$	74.09	$	65.35
Currency hedging gains (losses)		1.02		0.68		1.04		0.82
Net realized selling price	$	79.35	$	68.03	$	75.13	$	66.17
West Texas Intermediate ($US per barrel)	$	70.72	$	53.22	$	67.13	$	51.66

* The Trust's sales volumes may differ from its production volumes due to changes in inventory, which are primarily in-transit pipeline volumes.

Second quarter production impacted by planned coker turnaround

Figures provided below are the gross Syncrude numbers and are not the Trust's net share.

SSB production during the second quarter of 2006 totalled 21.9 million barrels, or approximately 241,000 barrels per day, compared to 21.3 million barrels, or approximately 234,000 barrels per day in the second quarter of last year. For the six months ended June 30, 2006 production was up 14 per cent to 40.4 million barrels, or 223,000 barrels per day, compared to 35.4 million barrels, or 196,000 barrels per day, in the same 2005 period.

The startup of Coker 8-3 temporarily contributed incremental production volumes during the second quarter of 2006 while the extension of the Coker 8-1 turnaround into April was the primary factor in reducing production. In the same quarter of 2005, production was impacted by repairs to a hydrogen plant, feed restrictions in our vacuum distillation unit, and sulphur pump difficulties. For the first half of both 2006 and 2005, production was impacted by extended coker turnarounds, although 2005 production was further reduced by the hydrogen plant repairs, feed restrictions in the vacuum distillation unit, and sulphur pump repairs.

Syncrude employees and contractors recorded a lost time injury rate of 0.15 per 200,000 workforce hours during the first half of 2006, not as strong as last year's rate but still among the best in the industry.

Syncrude announced a major donation of $2.5 million in May 2006 to help meet the growing need for greater recreational facilities in Fort McMurray. This donation constitutes the largest single community investment ever made in Syncrude's history, and commemorates the completion of the Stage 3 expansion.

Stage 3 operations resume

Syncrude has resumed start-up activities for its Flue Gas Desulphurization ("FGD") Unit and other associated operating units. Once the units reach stable operation, Syncrude plans to introduce bitumen feed into Coker 8-3 with incremental production from Stage 3 coming on-stream shortly thereafter. Syncrude currently anticipates that bitumen feed will be introduced into Coker 8-3 in early August, the exact timing of which is dependent upon successful start-up of the remaining Stage 3 units.

Syncrude obtained regulatory approval from Alberta Environment to resume operations of the facilities after investigating the source of odorous emissions, and undertaking facilities modifications and other steps to help prevent a similar occurrence. Odours were reported by the local communities following the start-up of Syncrude's Stage 3 expansion on May 8, and led to the temporary shut-down of the expansion on May 18. The new FGD Unit is an important part of Syncrude's commitment to improving environmental performance by reducing its sulphur dioxide emissions.

Syncrude has expended the total estimated Stage 3 project costs of $8.4 billion with the completion of the project in the second quarter. Ancillary costs, such as final site clean-up and recently identified improvements, totalling approximately $115 million, gross to Syncrude, remain to be incurred.

Canadian Oil Sands to acquire Canada Southern Petroleum Ltd.

The Trust's wholly-owned subsidiaries, Canadian Oil Sands Limited and 1212707 Alberta Ltd., have offered to purchase all of the outstanding common shares of Canada Southern Petroleum Ltd. ("Canada Southern") for cash consideration of US$13.10 per common share (or approximately Cdn$224 million in aggregate).

Canada Southern owns mostly carried interests in seven significant discovery licenses in the Arctic islands that, based on available information and Canada Southern's internal estimates, represent a net recoverable resource of approximately 927 billion cubic feet equivalent of natural gas. This resource provides Canadian Oil Sands with a unique opportunity to reduce the risk of significant future natural gas price increases on its Syncrude oil sands production, and to participate in the future development of a long-life energy resource. The acquisition will not change the Trust's business model or strategy as Canadian Oil Sands plans to dispose of Canada Southern's conventional natural gas assets, and with mostly carried interests in the Arctic assets, there is no requirement to fund any field development costs. The Trust plans to finance the acquisition entirely with bank debt and funds from operations. Following the sale of the conventional assets, the transaction cost should represent less than two months of funds from operations, modestly deferring our overall debt reduction target timing accordingly.

Our offer to purchase all of the issued and outstanding shares of Canada Southern expires on August 1, 2006. If 90 per cent or more of the Canada Southern shares are tendered into our offer, we intend to use the compulsory acquisition rules to acquire the remainder of the shares. If we obtain 66 2/3 per cent but less that 90 per cent, we will take up the Canada Southern shares tendered and extend the offer for another ten days to about August 11, 2006. Following the acquisition of Canada Southern, we intend to sell the conventional oil and natural gas assets through an auction process. It is anticipated that the purchase and the subsequent sale will not be finalized until year end. Canadian Oil Sands has received approval in the form of an advance ruling certificate from the Canada Competition Bureau to proceed with the acquisition.

Distribution reinvestment plan (DRIP)

Eligible Unitholders who wish to participate in the Trust's current DRIP must file their election form, in the case of registered Unitholders, with Computershare Trust Company of Canada at the number or address noted on the enrolment forms **before the August 4, 2006 record date**. Unitholders who hold their Units in the name of a broker should contact their broker to ensure that the proper election forms are completed and sent in before August 4, 2006. Information on the plan and enrolment forms are available on the Trust's web site or by calling Investor Relations. The Trust has previously announced it plans to modify the DRIP once it approaches its debt target to allow only reinvestment of distributions at a volume-weighted average market price with no discount, which should be implemented around the end of this year.

Foreign ownership update

Based on information from the statutory declarations by Unitholders, we estimate that, as of May 8, 2006 approximately 36 per cent of our Unitholders are non-Canadian residents with the remaining 64 per cent being Canadian residents. Canadian Oil Sands' Trust Indenture provides that not more than 49 per cent of its Units can be held by non-Canadian residents.

The Trust continues to monitor its foreign ownership levels on a regular basis through declarations from Unitholders. The next declarations to be requested will be as of August 4, 2006. The Trust plans to post the results of the declarations on its web site at www.cos-trust.com under investor information, frequently asked questions. This section of the web site and page 45 of the Management's Discussion and Analysis section of the Trust's 2005 annual report describe the Trust's steps for managing its non-Canadian resident ownership levels.

2006 Outlook

The following provides Canadian Oil Sands' outlook for 2006 as of July 25, 2006 and is subject to change without notice. Certain information regarding the Trust and Syncrude set forth below, including management's assessment of the expected timing of Stage 3 operations being fully resumed, the closing of the proposed acquisition of Canada Southern and its impact on reaching the Trust's debt target, the expectation that Canada Southern's natural gas resource will provide a low cost financial hedge against the impact of significant rising natural gas prices on our business and the future production of natural gas from the Arctic licenses and that the Arctic licenses will be developed at some time in the future; resources are not the same as reserves and may not be recognized under applicable Canadian or US securities rules and regulations; the Trust's future production revenues and costs for 2006, the maintenance schedule for the remainder of 2006, crude oil prices for the year, and the start-up and production from Stage 3 in 2006, may constitute forward-looking statements under applicable securities law. Forward-looking statements often contain terms such as "may", "will", "should", "anticipate", "expects" and similar expressions. These statements represent management's current expectations and beliefs based on information known today. However, by their nature, forward-looking statements necessarily involve risks and uncertainties, known and unknown, which may cause actual performance and financial results in future periods to materially differ from the estimations or results expressed or implied by such forward-looking statements. For more detail on the factors and risks that could potentially impact the outlook, please refer to the Management's Discussion and Analysis section of the second quarter 2006 report and the July 25, 2006 guidance document, as well as the risk factors contained in the Trust's annual information form, all of which are available on the Trust's web site at www.cos-trust.com under investor information. The information in these sections is all forward-looking, and as such, is qualified by this advisory. Unless required by law, the Trust assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change.

Canadian Oil Sands has revised its outlook for 2006 as follows. More information on the Trust's outlook is available in its Guidance Document dated July 25, 2006, which is posted on the Trust's website at http://www.cos-trust.com/investor/guidance.aspx.

- Syncrude production in 2006 has been revised to range from 85 to 95 million barrels, or 30 to 34 million barrels net to the Trust based on our 35.49 per cent interest. The single point estimate has been reduced from 95 to 90 million barrels, or 32 million barrels net to the Trust, primarily due to the delay in restarting Stage 3 operations as well as additional contingency for further unplanned outages. The high end of the revised production range assumes a stable re-start of Stage 3 operations without any significant future operational shutdowns while the low end assumes current production levels for the remainder of the year. The next coker turnaround is assumed to occur in 2007, as currently scheduled.
- Production in the third quarter of 2006 is estimated at 24 million barrels, or 8.5 million barrels net to the Trust, which reflects the currently scheduled early August start-up of Coker 8-3.

- Funds from operations in 2006 are anticipated to total $1.0 billion, or $2.22 per Unit, based on an average WTI crude oil price of US$67.50 per barrel and a foreign exchange rate of $0.90 US/Cdn for the year.
- Operating costs are estimated to total $902 million, or $28.25 per barrel, which includes $7.43 per barrel of purchased energy at an estimated $7.00 per gigajoule ("GJ") natural gas price. The higher per barrel operating cost reflects the incremental fixed costs of supporting Syncrude's Stage 3 productive capacity without an offsetting increase in production as the units start-up. In addition, while the forecast for 2006 natural gas prices has been reduced, purchased energy consumption is expected to average approximately 1.1 GJs per barrel as a result of fluctuating production levels while the Stage 3 expansion is brought into operation. Beyond 2006, per barrel energy consumption is expected to be approximately 0.85 GJs per barrel.
- Our estimate for 2006 capital expenditures decreased to $328 million from $367 million due to a reduction in maintenance of business projects and deferral of a portion of the Stage 3 and Syncrude Emissions Reduction Project costs into subsequent years.
- Of the approximately $224 million total acquisition cost for Canada Southern, Canadian Oil Sands expects to incur a net cost of $150 million, after disposition of the producing assets and liquidation of working capital.
- Under the Trust's 2006 outlook, we anticipate reaching our net debt target of approximately $1.2 billion in the first quarter of 2007. Once we have achieved our net debt target, unless capital investment growth opportunities exist that we believe would offer Unitholders better value, we intend to approach full payout of our free cash flow (funds from operations less capital expenditures and reclamation trust contributions).
- We estimate that approximately 95 per cent of the distributions pertaining to 2006 will be taxable as other income with the remainder classified as a tax-deferred return of capital. The actual taxability of the distributions will be determined and reported to Unitholders prior to the end of the first quarter of 2007.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") was prepared as of July 25, 2006 and should be read in conjunction with the unaudited interim consolidated financial statements of Canadian Oil Sands Trust ("Canadian Oil Sands" or the "Trust") for the six month periods ended June 30, 2005 and June 30, 2006 as well as the audited consolidated financial statements and MD&A of the Trust for the year ended December 31, 2005.

ADVISORY- in the interest of providing the Trust's Unitholders and potential investors with information regarding the Trust, including management's assessment of the Trust's future production and cost estimates, plans and operations, certain statements throughout this MD&A contain "forward-looking statements" under applicable securities law. Forward-looking statements in this M&DA include, but are not limited to, statements with respect to: the anticipated date for feed into and the restart of production from Coker 8-3, the expected timing of reaching the debt target and the anticipated impact that the acquisition of Canada Southern Petroleum Ltd. would have on such timing, production estimates for each quarter and the remainder of 2006, the view that future financing risks are not significant, the expected realized selling price for Canadian Oil Sands' product as expressed as the differential to WTI, the level of natural gas consumption post Stage 3 and the expected impact that supplying more bitumen from Aurora North will have on that consumption, the anticipated capital expenditures for 2006 including the amount attributable to the Stage 3 expansion, the costs to bring Stage 3 into operations and the expected ancillary costs for Stage 3 post start-up, the expected increase in demand and the expected higher price for SSP compared to SSB, the plans to revise the DRIP, the view that Stage 3 will increase production and sales, thereby increasing free cash flow, the return achieved from sales of Syncrude™ Sweet Blend and Syncrude Sweet Premium, the expected price for crude oil and natural gas in 2006, the expected revenues and operating costs for 2006; the expected costs relating to the anticipated higher Crown royalty payments, the expected funds from operations for 2006, the expected acquisition and timing of the acquisition of Canada Southern Petroleum Ltd., the anticipated impact that certain factors such as natural gas and oil prices, foreign exchange and operating costs have on the Trust's funds from operations and net income. You are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur. Although the Trust believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks and other factors which could cause results to differ materially from those expressed in the forward-looking statements contained in this MD&A include, but are not limited to: the impact of technology on operations and processes and how new complex technology may not perform as expected, labour shortages and the productivity achieved from labour in the Fort McMurray area, the supply and demand metrics for oil and natural gas, the impact that pipeline capacity and refinery demand have on prices for our products, the variances of stock market activities generally, normal risks associated with litigation, general economic, business and market conditions, regulatory changes, and such other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by the Trust. You are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this MD&A are made as of the date of this MD&A, and unless required by law, the Trust does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

REVIEW OF SYNCRUDE OPERATIONS

During the second quarter of 2006, Syncrude oil production totalled 21.9 million barrels, or 7.8 million barrels net to the Trust based on its 35.49 per cent working interest, compared to 21.3 million barrels, or 7.5 million barrels net to the Trust, in the second quarter of 2005. Second quarter 2006 production was slightly less than the revised 22.0 million barrel estimate provided in the Canadian Oil Sands Trust press release dated May 26, 2006.

Syncrude's second quarter 2006 production of approximately 241,000 barrels per day, or 86,000 barrels per day net to the Trust, slightly exceeded that of the same period of 2005, which averaged 234,000 barrels per day, or 83,000 barrels per day net to the Trust. The startup of Coker 8-3 temporarily contributed incremental volumes during the second quarter of 2006 while the extension of the Coker 8-1 turnaround into April was the primary factor in reducing production. In the same quarter of 2005, production was impacted by repairs to a hydrogen plant, feed restrictions in our vacuum distillation unit, and sulphur pump difficulties. Operating costs in the second quarter of 2006 rose to $28.48 per barrel compared to $21.35 per barrel in the second quarter of 2005 primarily due to increased fixed costs to support the Stage 3 productive capacity, Syncrude long-term incentive compensation and employee retention plans and purchased energy.

For the six months ended June 30, 2006 Syncrude production was 40.4 million barrels, or 14.3 million barrels net to the Trust, relative to 35.4 million barrels, or 12.6 million barrels net to the Trust in the first half of 2005. Daily production levels in the first half of 2006 were approximately 223,000 barrels per day, or 79,000 barrels per day net to the Trust, versus 196,000 barrels per day, or 69,000 barrels per day net to the Trust, in the same period of 2005. Production in both years was impacted by extended coker turnarounds, although 2005 production was further reduced by repairs to Hydrogen Plant 9-3 following a tube rupture, feed restrictions in the vacuum distillation unit and sulphur pump repairs. Operating costs of $33.92 per barrel and $28.51 per barrel for the first half of 2006 and 2005, respectively, reflect the extensive maintenance activity; however, increased production costs, long-term incentive and retention compensation and purchased energy costs contributed to higher per barrel operating costs in the first half of 2006 compared to the same period in 2005.

Stage 3 construction was completed in the second quarter of 2006 and first bitumen feed was introduced into Coker 8-3 in early May, consistent with expectations in the 2006 first quarter report. Despite a satisfactory ramp up, Coker 8-3 was shut-down about 10 days later following an Environmental Protection Order issued by Alberta Environment in response to odorous emissions. Stage 3 therefore did not materially increase production in the quarter. The emissions are believed to be associated with the start-up of the Flue Gas Desulphurization ("FGD") unit, which is designed to essentially eliminate the sulphur dioxide emissions from Coker 8-3. Syncrude is implementing several changes to address the odorous emissions and has received approval from Alberta Environment to resume Stage 3 operations. As a result, Syncrude has begun start-up activities on the FGD and plans to introduce bitumen feed into Coker 8-3 in early August with incremental production coming on-stream shortly thereafter. If this schedule is achieved, the Stage 3 restart will have taken approximately two and a half months instead of the one to two month estimate provided in our press release dated May 26, 2006, and upon which our May 30 production outlook had been based.

The Trust's production volumes may differ from its sales volumes due to changes in inventory, which are primarily in-transit pipeline volumes. The impact of Syncrude's operations on Canadian Oil Sands' financial results is more fully discussed later in this MD&A.

SUMMARY OF QUARTERLY RESULTS

($ millions, except per Trust unit and volume amounts)	2006		2005				2004	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Revenues, after transportation and marketing expense	$ 624	$ 473	$ 519	$ 612	$ 492	$ 344	$ 333	$ 359
Net income	$ 337	$ 91	$ 174	$ 380	$ 219	$ 59	$ 122	$ 186
Per Trust unit, Basic	$ 0.72	$ 0.20	$ 0.38	$ 0.83	$ 0.48	$ 0.13	$ 0.27	$ 0.41
Per Trust unit, Diluted	$ 0.72	$ 0.20	$ 0.37	$ 0.83	$ 0.48	$ 0.13	$ 0.27	$ 0.41
Funds from operations	$ 324	$ 141	$ 264	$ 364	$ 284	$ 94	$ 122	$ 157
Per Trust unit	$ 0.70	$ 0.30	$ 0.57	$ 0.79	$ 0.62	$ 0.20	$ 0.27	$ 0.35
Daily average sales volumes (bbls)	86,394	74,929	78,318	85,942	79,506	59,897	78,294	86,635
Net realized selling price, after hedging ($/bbl)	$ 79.35	$ 70.24	$ 72.07	$ 77.43	$ 68.03	$ 63.66	$ 46.29	$ 45.07
Operating costs ($/bbl)	$ 28.48	$ 40.26	$ 25.54	$ 23.61	$ 21.35	$ 38.13	$ 21.27	$ 20.60
Purchased natural gas price ($/GJ)	$ 5.72	$ 7.42	$ 10.73	$ 8.31	$ 6.94	$ 6.45	$ 6.40	$ 6.18

Quarterly variances in revenues, net income, and funds from operations are caused mainly by fluctuations in crude oil prices, production, unit operating costs and natural gas prices. A large proportion of operating costs are fixed, and as such, unit operating costs are highly variable to production. While the supply/demand balance for crude oil affects selling prices, the impact of this equation is difficult to predict and quantify and has not displayed significant seasonality. Maintenance and turnaround activities are typically scheduled to occur in the first or second quarter. However, the exact timing of unit shutdowns cannot be precisely scheduled, and unplanned outages will occur. As a result, production levels also may not display reliable seasonality patterns or trends. Maintenance and turnaround costs are expensed in the period incurred and can lead to significant increases in operating costs and reductions in production in those periods, as demonstrated by the high per barrel operating costs in the first quarters of 2006 and 2005. Natural gas prices are typically higher in winter months as heating demand rises, but this seasonality is significantly influenced by weather conditions and North American natural gas inventory levels.

REVIEW OF FINANCIAL RESULTS

In order to provide meaningful information to our Unitholders, the focus of our MD&A is to provide explanations of material variances in our quarterly financial results and significant events that have occurred since year-end. We believe material information relates to the business of the Trust and would reasonably be expected to have a significant influence on an investor's investment decision. We endeavor to explain the factors, when material, that ultimately impact the Trust's Unitholder distributions, such as revenues, operating and non-production costs, financing expenses, and capital expenditures. As well, we provide an overview of the Trust's financing and risk management activity in the period.

In each of 2006 and 2005, the financial results of Canadian Oil Sands reflect a 35.49 per cent working interest in the Syncrude Joint Venture. All information provided per Trust Unit ("Unit") also has been adjusted to reflect the 5:1 Unit split effective May 3, 2006.

Canadian Oil Sands' funds from operations rose 14 per cent to $324 million, or $0.70 per Trust Unit, in the second quarter of 2006, compared to $284 million, or $0.62 per Unit for the same quarter of 2005. Net income was $337 million, or $0.72 per Unit, in the second quarter of 2006, up from $219 million, or $0.48 per Unit, in the second quarter of 2005.

The second quarter 2006 performance reflects a continuing robust realized selling price for our Syncrude™ Sweet Blend ("SSB") product, which averaged $78.33 per barrel before hedging, a 16 per cent increase from the $67.35 per barrel before hedging realized in the comparable 2005 quarter. The Trust benefited from full exposure to the market price in both years as there were no oil price hedges in place. The Trust's sales volumes also increased 10 per cent in the second quarter of 2006 to 7.9 million barrels from 7.2 million barrels in the second quarter of 2005. The higher realized price and production in the second quarter of 2006 translated directly into higher revenues, which rose to $616 million before hedging in the second quarter of 2006, a 26 per cent increase from the comparable 2005 quarter.

Higher revenues were, however, partially offset by the 45 per cent increase in second quarter 2006 operating expenses to $224 million from $154 million in the second quarter of 2005, as discussed in more detail in the operating costs section of this MD&A. In addition, crown royalties increased by $24 million in the second quarter of 2006 compared to the same quarter in 2005, reflecting the shift from the one per cent minimum royalty rate to the 25 per cent rate of net revenue royalty during the 2006 comparable quarter. Second quarter 2006 net income also includes a $46 million foreign exchange gain, which mainly reflects unrealized gains on U.S. denominated debt, compared to a $15 million foreign exchange loss in the second quarter of 2005. Net income was also higher in the second quarter of 2006 than the comparable quarter in 2005 as a result of a $28 million increase in future income tax recoveries, which reflected substantively enacted reductions to both federal and Alberta corporate tax rates.

Funds from operations rose to $465 million, or $1.00 per Unit from $377 million, or $0.82 per Unit in the first six months of 2006 and 2005, respectively. The realized selling price increased to $74.09 per barrel before hedging in the first half of 2006 from $65.35 per barrel in the same period of 2005. Sales volumes also increased 16 per cent to 14.6 million barrels for the first half of 2006 over the same 2005 period. The higher realized price and sales volumes resulted in a 31 per cent rise in revenues before hedging to $1,082 million from $826 million in the first half of 2006 and 2005, respectively.

Higher revenues were partially offset by increased operating costs, which rose to $495 million, or $33.92 per barrel, from $360 million, or $28.51 per barrel, in the first six months of 2006 and 2005, respectively. Non-production costs rose by $12 million to $45 million in the six months ended June 30, 2006 compared to the same 2005 period. Crown royalties also increased $26 million to $34 million in the first half of 2006, reflecting the shift to a higher royalty rate from the minimum one per cent rate that applied in 2005. Depreciation and depletion expense rose $32 million to $110 million in the six months ended June 30, 2006, reflecting both higher production volumes and a higher per barrel depreciation and depletion rate. Foreign exchange gains of $44 million and losses of $20 million were recorded in the first half of 2006 and 2005, respectively, reflecting the impact on U.S. dollar denominated debt of a strengthening Canadian dollar in the 2006 period compared to a weakening Canadian dollar in the same period of 2005. Future income tax recoveries increased to $34 million in 2006, compared to $6 million in 2005, as a result of reductions to the federal and Alberta corporate tax rates announced during the year.

Net income before unrealized foreign exchange and future income tax, which management believes is a better measure of operational performance than net income, was $259 million, or $0.56 per Unit in the second quarter of 2006, compared to $233 million, or $0.51 per Unit, in the same period of 2005. For the first six months of 2006 and 2005, respectively, net income before unrealized foreign exchange and future income tax rose to $346 million, or $0.75 per Unit, from $293, or $0.64 per Unit. The table below reconciles this measure to net income.

($ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2006	**2005**	**2006**	**2005**
Net income per GAAP	$ 337	$ 219	$ 428	$ 278
Add (Deduct):				
Foreign exchange loss (gain) on long-term debt	(49)	15	(48)	21
Future income tax expense (recovery)	(29)	(1)	(34)	(6)
Net income before foreign exchange and future income taxes	$ 259	$ 233	$ 346	$ 293

The net income before unrealized foreign exchange and future income tax reflected in the previous table is a measurement that is not defined by Canadian generally accepted accounting principles (“GAAP”). The Trust also reports funds from operations, free cash flow, and Unitholder distributions on both a total and per Unit basis, which are measures that do not have any standardized meaning under Canadian GAAP. Funds from operations is calculated on the Trust’s consolidated statement of cash flows as cash from operating activities before changes in working capital. Free cash flow is calculated as funds from operations less capital expenditures and reclamation trust contributions in the period. In management’s opinion, funds from operations is a key performance indicator of the Trust’s ability to generate cash to fund capital expenditures, while free cash flow is a key indicator of the Trust’s ability to repay debt and pay distributions. Net income before unrealized foreign exchange and future income tax, funds from operations, and free cash flow may not be directly comparable to similar measures presented by other companies or trusts.

Revenues after Transportation and Marketing Expense

($ millions)	Three Months Ended June 30			Six Months Ended June 30		
	2006	2005	Variance	2006	2005	Variance
Sales revenue [1]	$ 627	$ 499	$ 128	$ 1,102	$ 846	$ 256
Transportation and marketing expense	(11)	(12)	1	(20)	(20)	0
	616	487	129	1,082	826	256
Currency hedging gains [1]	8	5	3	15	10	5
	$ 624	$ 492	$ 132	$ 1,097	$ 836	$ 261
Sales volumes (MMbbls)	7.9	7.2	0.7	14.6	12.6	2.0

[1] *The sum of sales revenue and currency hedging gains (losses) equals Syncrude Sweet Blend revenues on the Trust's consolidated statement of income.*

($ per barrel)	2006	2005	Variance	2006	2005	Variance
Sales revenue	$ 79.76	$ 68.99	$ 10.77	$ 75.46	$ 66.95	$ 8.51
Transportation and marketing expense	(1.43)	(1.64)	0.21	(1.37)	(1.60)	0.23
Realized selling price before hedging	78.33	67.35	10.98	74.09	65.35	8.74
Currency hedging gains	1.02	0.68	0.34	1.04	0.82	0.22
Net realized selling price	$ 79.35	$ 68.03	$ 11.32	$ 75.13	$ 66.17	$ 8.96

Revenues after transportation and marketing expense and before hedging increased by $129 million to $616 million in the second quarter of 2006 compared to the same quarter in 2005 due to increased sales volumes and a higher realized selling price. Sales volumes rose 0.7 million barrels to 7.9 million barrels in the second quarter of 2006 from 7.2 million barrels in the second quarter of 2005. The second quarter 2006 realized selling price before hedging was $78.33 per barrel, a 16 per cent increase over the $67.35 per barrel price in the comparable 2005 quarter. No crude oil hedges were in place in either period, but currency hedging gains of $8 million and $5 million were realized in the second quarter of 2006 and 2005, respectively.

For the first six months of 2006 revenues after transportation and marketing expense and before hedging increased by $256 million to $1,082 million from $826 million in the same period of 2005, reflecting higher sales volumes and a higher realized selling price for our SSB product. Sales volumes rose 2.0 million barrels to 14.6 million barrels from 12.6 million barrels in the first half of 2006 and 2005, respectively. The realized selling price before hedging in the six months ended June 30, 2006 rose to $74.09 per barrel from $65.35 per barrel in the comparable 2005 period.

The high realized SSB selling price reflects a continuing robust benchmark West Texas Intermediate ("WTI") price, which our SSB product closely follows. WTI averaged US$70.72 per barrel in the second quarter of 2006, a 33 per cent increase over the US$53.22 per barrel average WTI price in the same period of 2005. However, the benefit of a strong WTI price was partially eroded by the weaker differential our product received relative to the WTI price and a stronger Canadian dollar in the first half of 2006 compared to the same period in 2005.

Our SSB crude oil realized a weighted-average discount of $0.94 per barrel relative to average Canadian dollar WTI in the second quarter of 2006 compared to a $1.20 per barrel premium in the second quarter of 2005. SSB differentials to Canadian dollar WTI averaged a discount of $2.53 per barrel versus a premium of $1.33 per barrel in the first half of 2006 and 2005, respectively. The shift to discounts from premiums in the 2006 periods relative to 2005 primarily reflects additional synthetic crude oil supply in the market. During the first quarter of 2006, in particular, a high number of planned and unplanned third party refinery outages reduced product demand and, concurrently, a pipeline reconfiguration resulted in increased light crude oil volumes available to the market. The typical markets for our product were not willing to absorb the excess volumes without pricing incentives and pipeline dynamics prevented moving the product to more distant markets for better prices. In comparison, the first half of 2005 was characterized by reduced production from a number of synthetic producers, translating into strong demand from customers. Differentials to WTI did improve in the second quarter of 2006 compared to the first quarter of 2006 as other synthetic producers performed scheduled maintenance; however, with additional volumes from the Syncrude project anticipated in the last half of 2006, we continue to expect an average 2006 SSB/SSP discount to WTI of $3.00 per barrel in our 2006 outlook discussed later in this MD&A.

The Canadian dollar averaged $0.89 US/Cdn in the second quarter of 2006 relative to the same period in 2005 when the foreign exchange rate averaged $0.80 US/Cdn. For the first six months of the year the Canadian dollar averaged $0.88 US/Cdn and $0.81 US/Cdn in 2006 and 2005, respectively.

Currency hedging gains added $8 million and $15 million to revenues in the second quarter and first half of 2006 compared to gains of $5 million and $10 million in the second quarter and first half of 2005.

Operating costs

	Three Months Ended June 30				Six Months Ended June 30			
	2006		2005		2006		2005	
	$/bbl Bitumen	$/bbl SSB	$/bbl Bitumen	$/bbl SSB	$/bbl Bitumen	$/bbl SSB	$/bbl Bitumen	$/bbl SSB
Bitumen Costs [1]								
Overburden removal	2.33		1.46		2.74		2.11	
Bitumen production	8.15		6.89		8.78		8.16	
Purchased energy [3]	2.83		2.47		3.28		2.83	
	13.31	15.49	10.82	12.85	14.80	17.18	13.10	15.97
Upgrading Costs [2]								
Bitumen processing and upgrading		5.02		3.41		5.12		4.47
Turnaround and catalysts		2.19		1.08		4.61		4.21
Purchased energy [3]		3.17		2.56		3.59		2.68
		10.38		7.05		13.32		11.36
Other and research		1.53		1.17		2.44		1.63
Change in treated and untreated inventory		0.52		(0.21)		0.70		(0.67)
Total Syncrude operating costs		27.92		20.86		33.64		28.29
Canadian Oil Sands adjustments [4]		0.56		0.49		0.28		0.22
Total operating costs		28.48		21.35		33.92		28.51
	Bitumen	SSB	Bitumen	SSB	Bitumen	SSB	Bitumen	SSB
Syncrude production volumes (thousands of barrels per day)	280	241	277	234	259	223	239	196

1 Bitumen costs relate to the removal of overburden, oil sands mining, bitumen extraction and tailings dyke construction and disposal costs. The costs are expressed on a per barrel of bitumen production basis and converted to a per barrel of SSB based on the yield of SSB from the processing and upgrading of bitumen.

2 Upgrading costs include the production and ongoing maintenance costs associated with processing and upgrading of bitumen to SSB. It also includes the costs of major refining equipment turnarounds and catalyst replacement.

3 Natural gas costs averaged $5.72/GJ and $6.94/GJ in the second quarter of 2006 and 2005, respectively. For the first six months of the year natural gas costs averaged $6.51/GJ and $6.71/GJ in 2006 and 2005, respectively.

4 Canadian Oil Sands' adjustments mainly pertain to Syncrude-related pension costs, property insurance costs, site restoration costs, as well as the inventory impact of moving from production to sales as Syncrude reports per barrel costs based on production volumes and we report based on sales volumes.

	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	2006	2005
	$/bbl SSB	$/bbl SSB	$/bbl SSB	$/bbl SSB
Production costs	22.02	15.86	26.52	22.38
Purchased energy	6.46	5.49	7.40	6.13
Total operating costs	28.48	21.35	33.92	28.51
	GJs/bbl SSB	GJs/bbl SSB	GJs/bbl SSB	GJs/bbl SSB
Purchased energy consumption	1.13	0.79	1.14	0.91

Equipment and staff to support Syncrude's expected increase in productive capacity from Stage 3 were in place during the second quarter of 2006 as Syncrude worked to start up Coker 8-3. This new infrastructure level carries higher fixed costs which should eventually be spread over the incremental Stage 3 production. During planned and unplanned shutdowns Syncrude directs resources towards other activities, but the operation is less efficient with lower production and higher per barrel operating costs.

Operating costs in the second quarter of 2006 increased to $224 million, or $28.48 per barrel, from $154 million, or $21.35 per barrel, in the same quarter of 2005. In the first half of 2006 and 2005, respectively, operating costs increased to $495 million, or $33.92 per barrel, from $360 million, or $28.51 per barrel.

Overburden removal costs increased in the second quarter and first half of 2006 compared to the same 2005 periods as the Stage 3 shutdown reduced bitumen requirements and additional resources were directed to overburden removal. In addition, bitumen production, processing, and upgrading in 2006 reflects costs to support the increased infrastructure levels over 2005 without the incremental Stage 3 efficiencies or volumes. Turnaround and catalysts costs increased to $2.19 per barrel from $1.08 per barrel in the second quarter of 2006 and 2005, respectively, reflecting the extension of the Coker 8-1 turnaround into April and several smaller unplanned outages during the 2006 quarter versus the same 2005 period.

Purchased energy costs per barrel rose 18 per cent to $6.46 per barrel from $5.49 per barrel in the second quarter of 2006 and 2005, respectively. The increased purchased energy, which consists mainly of natural gas, reflects a 43 per cent rise in purchased energy consumption to 1.13 gigajoules (“GJ”) per barrel in the second quarter of 2006 from 0.79 GJs per barrel in the second quarter of 2005. Natural gas prices averaged $5.72 per GJ in the second quarter of 2006 compared to $6.94 per GJ in the same 2005 quarter. Energy efficiency is reduced during maintenance and start-up periods as the Syncrude operation is highly integrated. Some units may be run to provide steam or fuel to other facilities resulting in increased energy needs without an offsetting production increase, while other unit outages may necessitate energy purchases to temporarily power a connected facility. The increased second quarter 2006 energy consumption reflects these start-up activities.

Purchased energy costs per barrel in the first half of 2006 rose 21 per cent to $7.40 per barrel compared to $6.13 per barrel in the first six months of 2005. Purchased energy consumption rose to 1.14 GJs per barrel from 0.91 GJs per barrel in 2006 and 2005, respectively, mainly as a result of reduced energy efficiency experienced during Stage 3 start-up activities. In addition, repairs on a hot water line during the first quarter of 2006 resulted in additional bitumen requirements from the Aurora mine, which relies mainly on purchased natural gas for its energy needs.

Purchased energy consumption per barrel is expected to decline from levels recorded in the first half of 2006 but remain higher than historical norms of about 0.7 GJs per barrel following the completion of Stage 3. We expect that long-term consumption going forward will be about 0.85 GJs per barrel as additional hydrogen, which is derived from natural gas, will be used to increase product quality from SSB to SSP and bitumen will increasingly be sourced from the Aurora mine. The Aurora mine relies mainly on purchased natural gas for its energy needs as process heat from the upgrader is unavailable due to the mine's location.

A portion of Syncrude's long term incentive compensation is based on the market return performance of several Syncrude owners' shares/units. The resulting incentive plan valuation changes are recorded as operating cost increases or decreases at each period end. Strong return performance of the Syncrude owners' securities during the second quarter and first half of 2006 was the main factor contributing to the per barrel increases in the "Other and research" line of the operating costs table. In 2006 Syncrude also introduced an employee retention program similar to other operators in the area to reduce staff turnover, which has resulted in increased operating costs in the first six months of 2006 compared to the same period in 2005.

Non-production costs

Non-production costs in the first six months of 2006 were $45 million, or $3.08 per barrel, compared to $33 million, or $2.62 per barrel, in the same period of 2005. The increase reflects additional costs related to the commissioning and start up of Stage 3. Non-production costs consist primarily of development expenditures relating to capital programs, which are expensed, such as commissioning costs, pre-feasibility engineering, technical and support services, research and development, and regulatory and stakeholder consultation expenditures.

Crown Royalties

Crown royalties increased to $29 million, or $3.67 per barrel, in the second quarter of 2006 from $5 million, or $0.69 per barrel, in the comparable 2005 quarter. For the six months ended June 30, Crown royalties were $34 million, or $2.33 per barrel, and $8 million, or $0.63 per barrel, in 2006 and 2005, respectively. The increase in 2006 Crown royalties reflects the shift in royalty rate to 25 per cent of net revenues from the minimum one per cent of gross revenue, which occurred in the second quarter of the year.

Under Alberta's generic Oil Sand Royalty, the Crown royalty is calculated as the greater of one per cent of gross plant gate revenue before hedging or 25 per cent of gross plant gate revenue before hedging, less Syncrude operating, non-production and capital costs.

Depreciation, depletion and accretion expense

($ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	2006	2005
Depreciation and depletion expense	$ 58	$ 46	$ 106	$ 77
Accretion expense	2	1	4	1
	$ 60	$ 47	$ 110	$ 78

Excluding accretion expense, depreciation and depletion ("D&D") expense for the three months ended June 30, 2006 rose by $12 million compared to the same period in 2005 as a result of a three per cent increase in Syncrude production volumes and a higher per barrel D&D rate. In the first six months D&D expense rose to $106 million from $77 million in 2006 and 2005, respectively, reflecting a 14 per cent increase in Syncrude production and a higher 2006 per barrel D&D rate.

The Trust revises its estimate of per barrel D&D expense in the first quarter of each year based on updated reserve and future development costs estimates. The effective property, plant, and equipment D&D rate in the first half of 2006 rose to $7.34 per barrel of production compared to $6.11 per barrel in the same period of 2005. The higher 2006 D&D rate reflects increased estimates of the Trust's future development costs as provided for in the Trust's December 31, 2005 independent reserves report, which is outlined in the Trust's Annual Information Form and can be found at www.sedar.com, or on our web site at www.cos-trust.com under investor information.

The increased accretion expense in the second quarter and first half of 2006 compared to the same periods of 2005 reflects the higher asset retirement obligation outstanding at December 31, 2005 compared to December 31, 2004.

Foreign exchange

Foreign exchange gains/losses in the first six months of 2006 and 2005 are mainly the result of revaluations of our U.S. denominated long-term debt caused by fluctuations in U.S. and Canadian exchange rates. Canadian Oil Sands recorded a $46 million foreign exchange gain in the second quarter of 2006 compared to a $15 million loss in the same period of 2005. These figures reflect $49 million of unrealized gains and $15 million of unrealized losses as a result of long term debt revaluations in the second quarter of 2006 and 2005, respectively. In the first half of 2006 $44 million of gains were recorded versus $20 million of losses in the first half of 2005. Revaluations of U.S. denominated debt contributed $48 million of unrealized gains in the first half of 2006 and $21 million of unrealized losses in the first six months of 2005.

The Canadian dollar strengthened to $0.90 US/Cdn at June 30, 2006 from $0.86 US/Cdn at March 31, 2006 and December 31, 2005. By comparison, the dollar weakened to $0.82 US/Cdn at June 30, 2005 from $0.83 US/Cdn at March 31, 2005 and December 31, 2004, respectively. The remaining foreign exchange gains and losses relate to the conversion of U.S. denominated cash, receivable, and payable balances.

Large corporations tax and other

In the second quarter of 2006, the federal government enacted legislation that eliminates federal capital tax, retroactive to January 1, 2006. The resulting second quarter 2006 reversal of large corporations tax recorded in the first quarter of the year reduced this expense category to nil for the six months ended June 30, 2006.

Future Income Tax

Future income tax recoveries increased to $29 million in the second quarter of 2006 from $1 million in the second quarter of 2005. For the six months ended June 30, 2006 future income tax recoveries were $34 million compared to $6 million in the first half of 2005.

On April 10, 2006 the Alberta government substantively enacted a decrease of 1.5 per cent to the provincial corporate tax rate. In addition, on June 6, 2006 the Federal government substantively enacted a two per cent decrease to the federal corporate tax rate from January 1, 2008 to January 1, 2010 and an elimination of the 1.12 per cent federal surtax at January 1, 2008. These rate reductions were recorded as future tax recoveries in the second quarter of 2006, accounting for the majority of the 2006 tax recovery increase relative to 2005.

Capital expenditures

Capital spending in the second quarter of 2006 decreased to $59 million from $205 million in the same period of 2005. Only 28 per cent of second quarter 2006 expenditures pertained to Syncrude's Stage 3 project, as the project is essentially complete, and as a result, the Trust spent $137 million less on Stage 3 in the second quarter of 2006 compared to the same 2005 period. In addition, 2005 second quarter capital expenditures included $38 million related to the South West Quadrant Replacement ("SWQR") project, which was largely complete at the end of 2005. For the six months ended June 30, capital spending decreased to $196 million in 2006 from $393 million in 2005, again reflecting the completion of the Stage 3 and SWQR projects.

As at June 30, 2006 the Syncrude Joint Venture had expended approximately $8.4 billion to bring the Stage 3 project into operation, including $0.7 billion for the Aurora 2 Mining Train completed in late 2003. Ancillary costs, such as final site clean-up and recently identified improvements, totalling approximately

$115 million gross to Syncrude remain to be incurred. The total cost for Stage 3 net to Canadian Oil Sands is equivalent to approximately $3.0 billion.

Our forecast annual capital expenditures for 2006 are $328 million, which is approximately $472 million lower than the annual capital expenditures incurred in 2005. The decrease reflects the lower capital expenditures for the Stage 3 project and completion of the SWQR. Our capital expenditure forecast is discussed more fully in the Outlook section of this MD&A.

CHANGE IN ACCOUNTING POLICIES

As of June 30, 2006 there were no significant changes to the Trust's accounting policies from December 31, 2005.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	June 30 2006	December 31 2005
Current portion of long-term debt	$ 273	$ -
Long-term debt	1,354	1,737
Cash and short-term investments	(59)	(88)
Net debt	$ 1,568	$ 1,649
Unitholders' equity	$ 3,690	$ 3,383
Total capitalization [1]	$ 5,258	$ 5,032

[1] Net debt plus unitholders' equity

Canadian Oil Sands' capital structure improved at June 30, 2006 compared to December 31, 2005. The $428 million of net income generated in the first half of 2006 was more than sufficient to cover the $121 million of distributions, net of the DRIP, paid in the first six months, leading to an increase in Unitholder's equity.

Net debt decreased to $1,568 million at June 30, 2006 as a result of credit facility repayments and foreign exchange gains on our U.S. dollar denominated long-term debt. As a result, net debt to total capitalization at June 30, 2006 decreased to 30 per cent from 33 per cent at December 31, 2005. The Trust's Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan ("DRIP") generated $111 million in new equity in the first half of 2006.

Funds from operations in the second quarter of 2006 rose to $324 million, or $0.70 per Unit, an increase of $40 million over the same period in 2005. Second quarter funds from operations were sufficient to cover the $71 million of distributions paid on May 31, 2006, net of the DRIP, the $60 million of capital expenditures and reclamation trust contributions, and $172 million of credit facility repayments and working capital requirements during the quarter.

In the first half of 2006, funds from operations totalled $465 million, or $1.00 per Unit, an $88 million increase over the $377 million, or $0.82 per Unit, recorded in the same period of 2005. First half 2006 funds from operations were used to pay $121 million of distributions, net of the DRIP, $198 million of capital expenditures and reclamation trust contributions, and $62 million of credit facility repayments, with the remainder used to finance increased working capital requirements.

The Trust's financing strategy remains unchanged with a clear focus on debt reduction towards a net debt target of about $1.2 billion. With our lower 2006 production outlook and the recent Canada Southern Petroleum Ltd. ("Canada Southern") tender offer, projected to be financed through credit facility draws, we expect that this target will be achieved approximately two months later than anticipated in our first quarter 2006 report, assuming resale of the conventional gas assets. Based on our second quarter 2006 outlook, disclosed in detail later in this MD&A, we anticipate that the net debt target will be reached in the first quarter of 2007. The Stage 3 project is essentially complete, and with the additional sales revenues from the production increase expected in the second half of 2006, Stage 3 should provide significant free cash flow to support our debt repayment plan. While a reduction in crude oil prices or production would extend the time required to reach our net debt target, significant reductions from current oil price levels would be required to materially impact the debt repayment timeline.

With crude oil prices remaining robust for the first half of 2006, we have raised our full year 2006 outlook WTI price to average US$67.50 per barrel. The Trust's 2006 funds from operations is now estimated at approximately $1,034 million, a $83 million increase compared to the outlook provided at May 30, 2006.

In March 2006, Canadian Oil Sands extended its $840 million operating credit facilities. An overview of the key facilities terms can be found in Note 4 of the Notes to the Unaudited Consolidated Financial Statements.

UNITHOLDERS' CAPITAL AND UNIT TRADING ACTIVITY

Canadian Oil Sands Trust Units trade on the Toronto Stock Exchange under the symbol COS.UN. The Trust had a market capitalization of approximately $17 billion with 466 million Units outstanding and a closing price of $36.00 per Unit on June 30, 2006.

Canadian Oil Sands Trust - Trading Activity	Second Quarter 2006	June 2006	May 2006	April 2006
Unit price				
High	$ 38.59	$ 36.10	$ 38.59	$ 35.85
Low	$ 28.35	$ 28.35	$ 30.38	$ 32.90
Close	$ 36.00	$ 36.00	$ 35.50	$ 35.00
Volume traded (millions)	88.1	29.9	36.8	21.4
Weighted average Trust units outstanding (millions)	464.9	466.3	464.2	464.2

The Trust has declared a distribution of $0.30 per Unit in respect of the quarter ended September 30, 2006 for total distributions of approximately $140 million. The distribution will be paid on August 31, 2006 to Unitholders of record on August 4, 2006. A Unitholder distribution schedule pertaining to the quarter and year-to-date periods ending June 30 is included in Note 7 of the Notes to the Unaudited Consolidated Financial Statements. During the Stage 3 expansion at Syncrude, we utilized debt and equity financing to partially fund capital expenditures to the extent funds from operations were insufficient to fund the Trust's distributions, capital expenditures, mining reclamation trust contributions, and working capital changes. As the Stage 3 project is essentially complete, this debt financing is now being repaid. Such repayments are disclosed as "non-acquisition financing, net" on the Unitholder distributions schedule.

Canadian Oil Sands issues Unit options ("options") as part of its long-term incentive plan for employees. There were 192,205 options granted in the first half of 2006 with an average exercise price of $29.59 per option and a fair value of approximately $1 million, which will be amortized into income over a three-year vesting period. Each option represents the right of the optionholder to purchase a Unit at the exercise price determined at the date of grant. The exercise price is reduced by distributions over a threshold amount. The options vest by one-third following the date of grant for the first three years and expire seven years from the date of grant.

In addition, 34,345 performance unit rights ("PUPs") were issued in the first half of 2006 with a fair value of approximately $1 million. These PUPs are earned based on total unitholder return at the end of three years compared to a peer group, with the actual unit equivalents earned ranging from zero to double the target award. More detail on the options and PUPs is contained in the Management Proxy Circular dated March 10, 2006.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

As of June 30, 2006 there have been no significant changes to the Trust's contractual obligations or commitments from our 2005 year-end disclosure, other than reductions to the capital expenditure and various payment obligation commitments as a result of expenditures incurred in the first half of the year and an estimated increase of approximately $77 million related to a new Syncrude employee retention program to be earned and paid over a three-year period.

FINANCIAL RISK MANAGEMENT

Crude Oil Price Risk

As Canadian Oil Sands did not have any 2006 or 2005 crude oil price hedges, revenues were not impacted by crude oil hedging gains or losses and benefited fully from strong WTI prices. The Trust's financing risk has declined with the Stage 3 expansion essentially complete, and the Trust's balance sheet has been improving with the continuing strength in crude oil prices. Therefore, as at June 30, 2006 and based on current expectations, the Trust remains unhedged on its crude oil price exposure.

Foreign Currency Hedging

As at June 30, 2006 we had the following currency hedges outstanding:

Canadian Oil Sands Trust Exchange Hedging Activities	**2006**	**2007**
U.S. dollars hedged *($ millions)*	$ 10	$ 20
Average U.S. dollar exchange rate	$ 0.692	$ 0.692

Canadian Oil Sands' revenues in the second quarter of 2006 include foreign currency hedging gains of $8 million, or $1.02 per barrel, compared to gains of $5 million, or $0.68 per barrel, in the comparable quarter in 2005. For the six months ended June 30, currency hedging gains of $15 million and $10 million were recorded in 2006 and 2005, respectively. The gains in each period reflect the stronger Canadian dollar relative to the strike rate in each of the hedge contracts. The Canadian dollar averaged $0.88 US/Cdn and $0.81 US/Cdn in the first half of 2006 and 2005, respectively.

Interest Rate Risk

Canadian Oil Sands' net income and funds from operations are impacted by interest rate changes based on the amount of floating rate debt outstanding. At June 30, 2006 we had $225 million of floating rate debt with maturities less than one year, comprised of $30 million drawn on our credit facilities, $20 million of floating rate medium term notes outstanding and $175 million of fixed rate debt, which was swapped into floating rate debt in January 2004. Any gains or losses related to the swaps are recognized in the period the swaps are settled as they are considered hedges for accounting purposes.

Unrecognized gains and losses

At June 30, 2006 the unrecognized gain relating to our foreign currency hedges was $10 million, and the unrecognized loss on the interest rate swaps on the $175 million of 3.95% medium term notes was $1 million. These unrecognized amounts and the fair values of the hedges are disclosed in Note 8 of the Notes to the Unaudited Consolidated Financial Statements.

FOREIGN OWNERSHIP

Based on information from the statutory declarations by Unitholders, we estimate that, as of May 8, 2006, approximately 36 per cent of our Unitholders are non-Canadian residents with the remaining 64 per cent being Canadian residents. The statutory declarations are only as of a specific record date, and therefore may still not reflect the current ownership level of the Trust's Units; however, given the limitations in the securities registration system and the lack of any process for real-time residency information to flow to the trustee and transfer agent, the Trust is of the view that statutory declarations are currently the most appropriate method of determining the residency status of its Unitholders.

Canadian Oil Sands' Trust Indenture provides that not more than 49 per cent of its Units can be held by non-Canadian residents. The Trust intends to require its Unitholders to complete statutory declarations as to their residency status each quarter to enable the Trust to monitor its level of non-Canadian resident ownership. The Trust Indenture requires all Unitholders to provide such statutory declarations when requested to do so by the trustee and transfer agent. The Trust plans to post the results of the declarations on its web site at www.cos-trust.com under investor information, frequently asked questions. This section of the web site also describes the Trust's steps for managing its non-Canadian resident ownership levels.

2006 OUTLOOK

Our outlook for 2006 Syncrude production has been revised from the guidance provided on May 30, 2006. As incremental Stage 3 production is not expected until August 2006, we are reducing our estimate for the annual Syncrude production provided in our 2006 guidance document to range between 85 and 95 million barrels, or 30 to 34 million barrels net to the Trust based on our 35.49 per cent interest. The high end of the range reflects a stable Stage 3 restart without significant future operational shutdowns, while the low end of this range assumes that Syncrude continues to run at restricted production levels for the remainder of the year. Turnaround of Coker 8-2 is also assumed not to take place until 2007, as currently scheduled.

We have lowered our single point 2006 estimate from 95 to 90 million barrels of Syncrude production, or 32 million barrels net to the Trust. The revised estimate reflects a three million barrel reduction due to a longer than anticipated implementation of the FGD modifications and an additional contingency of two million barrels for future unforeseen outages. Production in the third quarter of 2006 is estimated at 24 million barrels, or 8.5 million barrels net to the Trust, which reflects the impact of Coker 8-3's August start-up.

We continue to anticipate that a period of lining out and optimization of the different operating units will be required to ramp up to full productive capacity of 128 million barrels, or 45 million barrels net to the Trust.

In addition to increased production, Stage 3 also is expected to improve product quality from SSB to SSP in 2006. We believe that SSP's higher quality should differentiate it from the growing volumes of other synthetic crude in the market produced by competing projects and provide a higher market price per barrel relative to SSB in the same market environment. While the supply/demand equation for synthetic oil is difficult to predict and quantify, we believe that the differential to WTI will tend to deteriorate as the increase in synthetic supply needs to be absorbed by the market. We are therefore estimating an average 2006 discount to WTI of $3.00 per barrel in our 2006 outlook.

A strong mining sector is currently resulting in a worldwide shortage of off-road tires. While the tire shortage has been identified as a production and cost risk for 2006 and 2007, Syncrude has implemented various measures aimed at reducing tire wear and damage in order to more conservatively manage their supply, and based on recent good experience we do not expect the shortage to impact our current 2006 production outlook.

Funds from operations in 2006 are anticipated to total $1.0 billion, or $2.22 per Unit, based on an average WTI crude oil price of US$67.50 per barrel and a foreign exchange rate of $0.90 US/Cdn for the year. Revenues are estimated at approximately $2.3 billion in 2006, with operating costs of $902 million, or $28.25 per barrel, which includes $7.43 per barrel of purchased energy at an estimated $7.00/GJ natural gas price. In addition, funds from operations reflect the increase to the full 25 per cent Crown royalty rate that occurred in the second quarter of 2006. Crown royalties are estimated at $190 million, or $5.95 per barrel in 2006. Under Alberta's generic Oil Sand Royalty, the Crown royalty is calculated as the greater of one per cent of gross plant gate revenue before hedging or 25 per cent of gross plant gate revenue before hedging, less Syncrude operating, non-production and capital costs.

The higher per barrel operating costs reflect the incremental fixed costs of supporting Syncrude's Stage 3 productive capacity without the benefit of full production as the units start up. In addition, while the forecast for 2006 natural gas prices has been reduced, purchased energy consumption is expected to average approximately 1.1 GJs per barrel as a result of fluctuating production levels while the Stage 3 expansion is brought into operation. Beyond 2006 per barrel energy consumption is expected to be approximately 0.85 GJs per barrel as additional hydrogen derived from natural gas will be used to increase product quality from SSB to SSP and bitumen will be increasingly sourced from the Aurora mine. Due to Aurora's location, process heat from the upgrader is unavailable and the mine relies mainly on purchased natural gas for its energy needs.

The Trust's 2006 crude oil production is unhedged, and under the current financing plan we do not intend to undertake any crude oil hedging transactions. The Trust may hedge its crude oil production in the future depending on the business environment and our growth opportunities. In addition, the Trust will continue to monitor hedging opportunities to reduce operating cost exposure to rising natural gas prices, particularly during winter months when natural gas prices tend to rise relative to crude oil prices.

Our estimate for 2006 capital expenditures decreased $39 million from our guidance provided on May 30, 2006 to total $328 million due to a reduction in maintenance of business projects and deferral of a portion of the Stage 3 and Syncrude Emissions Reduction Project costs into subsequent years. We anticipate being successful in our offer to acquire all of the outstanding shares of Canada Southern at a price of US$13.10 per share, or a total cost of approximately $224 million. We intend to divest the conventional natural gas properties acquired as part of the transaction with the resulting cost of the Arctic natural gas properties estimated at approximately $150 million, net of disposal proceeds and liquidation of working capital.

Under the Trust's 2006 outlook, we anticipate reaching our net debt target of approximately $1.2 billion in the first quarter of 2007. Once we have achieved our net debt target, unless capital investment growth opportunities exist that we believe would offer Unitholders better value, we intend to approach full payout of our free cash flow (funds from operations less capital expenditures and reclamation trust contributions).

With the expectation of achieving our net debt target in the first quarter of 2007, Canadian Oil Sands anticipates revising its DRIP terms around the end of 2006. The premium distribution component of the DRIP and the ability to purchase units at 95 per cent of the volume weighted average price ("VWAP") will be suspended and/or amended. Subject to the receipt of all applicable regulatory approvals, the Trust plans to continue to provide Unitholders with the ability to reinvest quarterly distributions at the VWAP. The DRIP has been an important component of the Trust's financing plan for the Stage 3 expansion.

We estimate that approximately 95 per cent of the distributions pertaining to 2006 will be taxable as other income with the remainder classified as a tax-deferred return of capital. The actual taxability of the distributions will be determined and reported to Unitholders prior to the end of the first quarter of 2007.

Changes in certain factors and market conditions could potentially impact Canadian Oil Sands' outlook. The following table provides a sensitivity analysis of the key factors affecting the Trust's performance. In addition to the factors described in the table, the supply/demand equation for synthetic crude oil in the North American markets could impact the price differential for SSB/SSP relative to crude benchmarks; however, this factor is difficult to predict and quantify.

2006 Outlook Sensitivity Analysis			
	Annual [2]	Funds from Operations Increase	
Variable [1]	Sensitivity	$ millions	$/Trust unit
Syncrude operating costs decrease	C$1.00/bbl	26	0.06
Syncrude operating costs decrease	C$50 million	13	0.03
WTI crude oil price increase	US$1.00/bbl	29	0.06
Syncrude production increase	2 million bbls	33	0.07
Canadian dollar weakening	US$0.01/C$	19	0.04
AECO natural gas price decrease	C$0.50/GJ	12	0.03

[1] An opposite change in each of these variables will result in the opposite funds from operations and net income impacts.

[2] Sensitivities assume a larger change in unrealized quarters to result in the annual impact. Variable changes apply only to unhedged positions.

More information on the Trust's outlook is provided in the July 25, 2006 guidance document, which is available on the Trust's web site at www.cos-trust.com under investor information.

CANADIAN OIL SANDS TRUST

CONSOLIDATED STATEMENTS OF INCOME AND UNITHOLDERS' EQUITY

(unaudited)

($ millions, except per unit amounts)

	Three Months Ended June 30		Six Months Ended June 30	
	2006	**2005**	**2006**	**2005**
Syncrude Sweet Blend revenues	$ 635	$ 504	$ 1,117	$ 856
Transportation and marketing expense	(11)	(12)	(20)	(20)
	624	492	1,097	836
Expenses:				
Operating	224	154	495	360
Non-production	20	21	45	33
Crown royalties	29	5	34	8
Administration	4	3	9	6
Insurance	2	2	4	4
Interest, net (Note 5)	25	26	50	52
Depreciation, depletion and accretion	60	47	110	78
Foreign exchange loss (gain)	(46)	15	(44)	20
Large Corporations Tax and other	(2)	1	-	3
Future income tax expense (recovery)	(29)	(1)	(34)	(6)
	287	273	669	558
Net income for the period	$ 337	$ 219	$ 428	$ 278
Unitholders' equity, beginning of period	$ 3,424	$ 2,667	$ 3,383	$ 2,636
Net income for the period	337	219	428	278
Issue of Trust units (Note 2)	68	19	111	37
Unitholder distributions (Note 7)	(139)	(46)	(232)	(92)
Contributed surplus	-	1	-	1
Unitholders' equity, end of period	$ 3,690	$ 2,860	$ 3,690	$ 2,860
Weighted average Trust units (millions)	465	459	464	458
Trust units, end of period (millions)	466	460	466	460
Net income per Trust unit				
Basic	$ 0.72	$ 0.48	$ 0.92	$ 0.61
Diluted	$ 0.72	$ 0.48	$ 0.92	$ 0.61

CANADIAN OIL SANDS TRUST
CONSOLIDATED BALANCE SHEETS
(unaudited)
($ millions)

	June 30 2006	December 31 2005
ASSETS		
Current assets:		
Cash and short-term investments	$ 59	$ 88
Accounts receivable	296	197
Inventories	73	87
Prepaid expenses	2	3
	430	375
Capital assets, net	5,592	5,502
Other assets		
Reclamation trust	27	25
Deferred financing charges, net and other	20	23
	47	48
	$ 6,069	$ 5,925
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 254	$ 281
Current portion of long-term debt	273	-
Current portion of employee future benefits	10	10
	537	291
Employee future benefits and other liabilities	96	93
Long-term debt	1,354	1,737
Asset retirement obligation (Note 6)	150	148
Deferred currency hedging gains	37	34
Future income taxes	205	239
	2,379	2,542
Unitholders' equity	3,690	3,383
	$ 6,069	$ 5,925

CANADIAN OIL SANDS TRUST
CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited)
($ millions)

	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	2006	2005
Cash provided by (used in):				
Operating activities				
Net income	$ 337	$ 219	$ 428	$ 278
Items not requiring outlay of cash:				
Depreciation, depletion and accretion	60	47	110	78
Amortization	-	1	1	2
Foreign exchange on long-term debt	(49)	15	(48)	21
Future income tax expense (recovery)	(29)	(1)	(34)	(6)
Other	1	-	2	-
Net change in deferred items	4	3	6	4
Funds from operations	324	284	465	377
Change in non-cash working capital	(115)	(85)	(69)	(73)
	209	199	396	304
Financing activities				
Net drawdown (repayment) of bank credit facilities	(40)	47	(62)	173
Unitholder distributions (Note 7)	(139)	(46)	(232)	(92)
Issuance of Trust units (Note 2)	68	19	111	37
	(111)	20	(183)	118
Investing activities				
Capital expenditures	(59)	(205)	(196)	(393)
Reclamation trust	(1)	(1)	(2)	(2)
Change in non-cash working capital	(17)	1	(44)	1
	(77)	(205)	(242)	(394)
Increase (decrease) in cash	21	14	(29)	28
Cash at beginning of period	38	32	88	18
Cash at end of period	$ 59	$ 46	$ 59	$ 46
Supplemental Information				
Large Corporations Tax and income tax paid	$ 2	$ 2	$ 5	$ 5
Interest charges paid	$ 14	$ 19	$ 47	$ 53

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

FOR THE SIX MONTHS ENDED JUNE 30, 2006
(Tabular amounts expressed in millions of Canadian dollars, except where otherwise noted.)

1) ACCOUNTING POLICIES

The interim consolidated financial statements include the accounts of Canadian Oil Sands Trust and its subsidiaries (collectively, the "Trust" or "Canadian Oil Sands"), and are presented in accordance with Canadian generally accepted accounting principles. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the year ended December 31, 2005. The disclosures provided below are incremental to those included with the annual consolidated financial statements. The interim consolidated financial statements should be read in conjunction with the consolidated financial statements and the notes thereto in the Trust's annual report for the year ended December 31, 2005.

2) UNITHOLDERS' EQUITY

In the three months ended June 30, 2006 approximately 2.1 million Units were issued for proceeds of $68 million related to the exercise of options and the Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan ("DRIP") with respect to the distributions paid on May 31, 2006.

The following table summarizes Units that have been issued:

Date	Net Proceeds per Unit	Number of Units	Net Proceeds
Balance, January 1, 2006		462.6	$ 2,010
Option exercises	$ 7.14	0.1	$ 1
February 28, 2006 (DRIP)	$ 28.14	1.5	$ 42
May 31, 2006 (DRIP)	$ 32.38	2.1	$ 68
Balance, June 30, 2006		466.3	$ 2,121

3) EMPLOYEE FUTURE BENEFITS

Syncrude Canada Ltd. ("Syncrude Canada"), the operator of the Syncrude Joint Venture, has a defined benefit and two defined contribution plans providing pension benefits and other retirement and post-employment benefits plans covering most of its employees. Post-employment benefits include certain health care and life insurance benefits for retirees, their beneficiaries and covered dependents.

Canadian Oil Sands accrues its obligations as a joint venture owner in respect of Syncrude Canada's employee benefit plans and the related costs, net of plan assets. The cost of employee pension and other retirement benefits is actuarially determined using the projected benefit method based on length of service and reflects Canadian Oil Sands' best estimate of the expected performance of the plan investment, salary escalation factors, retirement ages of employees and future health care costs. The expected return on plan assets is based on the fair value of those assets. Past service costs from plan amendments are amortized on a straight-line basis over the estimated average remaining service life of active employees ("EARSL") at the date of amendment. The excess of any net actuarial gain or loss exceeding 10 per cent of the greater of the benefit obligation and fair value of the plan assets is amortized over the EARSL.

Canadian Oil Sands' share of Syncrude Canada's net defined benefit and contribution plans expense for the three and six months ended June 30, 2006 and 2005, which is recorded in operating expense, is as follows:

($ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	2006	2005
Defined benefit plans				
Pension benefits	$ 7	$ 6	$ 15	$ 12
Other benefit plans	1	1	2	2
	$ 8	$ 7	$ 17	$ 14
Defined contribution plan	-	1	1	1
Total Benefit cost	$ 8	$ 8	$ 18	$ 15

4) BANK CREDIT FACILITIES

($ millions)	Credit facility
Extendible revolving term facility (a)	$ 40
Line of credit (b)	35
Operating credit facility (c)	800
	$ 875

a) The $40 million extendible revolving term facility is a 364-day facility with a one year term out, expiring April 25, 2007. This facility may be extended on an annual basis with the agreement of the bank. Amounts borrowed through this facility bear interest at a floating rate based on bankers' acceptances plus a credit spread, while any unused amounts are subject to standby fees.

b) The $35 million line of credit is a one year revolving letter of credit facility. Letters of credit drawn on the facility mature April 30th each year and are automatically renewed, unless notification to cancel is provided by Canadian Oil Sands or the financial institution providing the facility at least 60 days prior to expiry. Letters of credit on this facility bear interest at a credit spread.

Letters of credit of approximately $49 million have been written against the extendible revolving term facility and line of credit.

c) The $800 million operating facility is a five year facility, expiring April 27, 2011. Amounts borrowed through this facility bear interest at a floating rate based on bankers' acceptances plus a credit spread, while any unused amounts are subject to standby fees.

d) Each of the Trust's credit facilities is unsecured. These credit agreements contain typical covenants relating to the restriction on Canadian Oil Sands' ability to sell all or substantially all of its assets or to change the nature of its business. In addition, Canadian Oil Sands has agreed to maintain its total debt-to-total book capitalization at an amount less than 0.6 to 1.0, or 0.65 to 1.0 in certain circumstances involving acquisitions.

5) INTEREST, NET

($ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	2006	2005
Interest expense	$ 25	$ 28	$ 51	$ 54
Interest income and other	-	(2)	(1)	(2)
Interest expense, net	$ 25	$ 26	$ 50	$ 52

6) ASSET RETIREMENT OBLIGATION ("ARO")

($ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	2006	2005
Asset retirement obligation, beginning of period	$ 148	$ 43	$ 148	$ 44
Liabilities settled	-	(1)	(2)	(2)
Accretion expense	2	1	4	1
Asset retirement obligation increases	-	-	-	-
Asset retirement obligation, end of period	$ 150	$ 43	$ 150	$ 43

The Trust and each of the other Syncrude owners are liable for their share of ongoing environmental obligations for the ultimate reclamation of the Syncrude Joint Venture and the ARO represents the present value estimate of Canadian Oil Sands' share of the cost to reclaim the mines. The timing and amount of reclamation expenditures related to Syncrude's upgrader facilities and sulphur blocks cannot presently be determined. Consequently, the ARO relating to the upgrader facilities and the sulphur blocks will be recognized in the year in which the settlement amounts and dates can be reasonably estimated.

7) UNITHOLDER DISTRIBUTIONS

This statement is provided to assist Unitholders in reconciling funds from operations to Unitholder distributions.

Pursuant to Section 5.1 of the Trust Indenture, the Trust is required to distribute all the income received or receivable by the Trust in a quarter less expenses and any other amounts required by law or under the terms of the Trust Indenture. The amount of income that the Trust receives by way of royalty from its subsidiaries has discretionary amounts relating to funds required or expected to be required for capital and operational matters, all as more particularly set out in the annual information form dated March 15, 2006 under the heading Distributable Income.

In 2005, distributions were paid to Unitholders on the last business day of the second month following the quarter and were recorded as payable at each quarter end even though they were not declared. Commencing in the fourth quarter of 2005, distributions are recorded in the quarter declared and paid. The change in recording Unitholder distributions has no impact on the ultimate distributions declared and paid to the Unitholders or to the timing of such payments nor does it impact Canadian Oil Sands' net income or funds from operations.

CANADIAN OIL SANDS TRUST
CONSOLIDATED STATEMENTS OF UNITHOLDER DISTRIBUTIONS
(unaudited)
($ millions, except per unit amounts)

	Three Months Ended June 30		Six Months Ended June 30	
	2006	**2005**	**2006**	**2005**
Funds from operations	$ 324	$ 284	$ 465	$ 377
Add (Deduct):				
Capital expenditures	(59)	(205)	(196)	(393)
Non-acquisition financing, net [1]	7	52	78	182
Change in non-cash working capital	(132)	(84)	(113)	(72)
Reclamation trust funding	(1)	(1)	(2)	(2)
Unitholder distributions	$ 139	$ 46	$ 232	$ 92
Unitholder distributions per Trust unit	**$ 0.30**	**$ 0.10**	**$ 0.50**	**$ 0.20**

[1] *Represents financing to fund the Trust's share of Syncrude's Stage 3 expansion and is a discretionary item.*

8) HEDGING INSTRUMENTS

Unrecognized gains (losses) and the fair values of Canadian Oil Sands' hedging instruments at June 30, 2006 are as follows:

($ millions)	**Unrecognized gains (losses)**	**Fair value**
Currency exchange contracts	$ 10	$ 10
3.95% Interest rate swap contracts	(1)	(2)
	$ 9	$ 8

9) SUBSEQUENT EVENTS

On June 19, 2006, the Trust announced that its wholly-owned subsidiaries, Canadian Oil Sands Limited and 1212707 Alberta Limited, had agreed to make an offer to purchase all of the outstanding common shares of Canada Southern Petroleum Ltd. for cash consideration of US$9.75 per common share (or approximately Cdn$165 million in aggregate). The offer has been increased to US$13.10 per common share, representing an aggregate cost of approximately Cdn$224 million.

Canadian Oil Sands Limited
Marcel Coutu
President & Chief Executive Officer

Units Listed – Symbol: COS.UN
Toronto Stock Exchange

For further information:
Siren Fisekci
Director, Investor Relations
(403) 218-6228

Canadian Oil Sands Trust
2500 First Canadian Centre
350 – 7 Avenue S.W.
Calgary, Alberta T2P 3N9
Ph: (403) 218-6200
Fax: (403) 218-6201

investor_relations@cos-trust.com

web site: www.cos-trust.com