third quarter report 3

Canadian Oil Sands Trust reports results for the third quarter of 2006 and a distribution of $0.30 per Trust unit

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, AB. (October 24, 2006) – Canadian Oil Sands Trust ("Canadian Oil Sands" or the "Trust" or "we") (TSX - COS.UN) today announced funds from operations declined slightly to $359 million, or $0.77 per Trust unit ("Unit"), in the third quarter of 2006 compared to $364 million, or $0.79 per Unit, for the same 2005 quarter. For the nine months ended September 30, funds from operations rose to $824 million, or $1.77 per Unit, from $741 million, or $1.61 per Unit, in 2005. The increase in funds from operations year-to-date 2006 primarily reflects higher realized Syncrude TM Sweet Blend ("SSB") selling prices and sales volumes. For the 2006 three month period, the higher volumes and selling prices were offset by an increase in Crown royalties, which rose to $115 million, or $13.01 per barrel, in the third quarter of 2006 from $6 million, or $0.77 per barrel, in the comparable 2005 quarter. The increase in 2006 Crown royalties reflects the shift in royalty rate to 25 per cent of net revenues during the second quarter of the year. The Trust is declaring a quarterly distribution of $0.30 per Unit for Unitholders of record on November 3, 2006 payable on November 30, 2006.

"In the past quarter we began to see the impact of the Stage 3 expansion with a substantial lift in our production volumes," said Marcel Coutu, President and Chief Executive Officer. "During September when Stage 3 came on-line, Syncrude production averaged 340,000 barrels per day. Our new environmental unit, the flue gas desulphurizer, which suspended Stage 3 operations after its brief start-up in May, is now performing well with the use of purchased ammonia."

Third Quarter 2006 overview

- Net income declined 27 per cent to $278 million, or $0.60 per Unit, in the third quarter of 2006, from $380 million, or $0.83 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 $291 million, or $0.62 per Unit, in the third quarter of 2006 compared to $312 million, or $0.68 per Unit, in the same period of 2005.

- The decrease in quarter-over-quarter net income before unrealized foreign exchange and future income tax primarily reflects the full impact of the increase in Crown royalties to the 25 per cent rate of net revenue, which offset the higher sales volumes and average realized SSB selling price, and lower operating and non-production costs reported in the third quarter of 2006. An increase to depreciation, depletion and accretion ("DD&A") also reduced net income in the third quarter of 2006 compared to the same 2005 period.
- Crown royalties increased to $115 million, or $13.01 per barrel, in the third quarter of 2006 from $6 million, or $0.77 per barrel, in the comparable 2005 quarter. For the nine months ended September 30, Crown royalties were $149 million, or $6.37 per barrel, and $14 million, or $0.70 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.
- Net income year-to-date rose seven per cent to $706 million, or $1.52 per Unit, compared to $657 million, or $1.43 per Unit in 2005. Higher production and strong SSB selling prices contributed to the improvement in net income, partially offset by an increase in operating costs, Crown royalties and higher DD&A expense.
- Canadian Oil Sands' 2006 sales volumes averaged approximately 95,000 barrels per day in the third quarter and 86,000 barrels per day year-to-date, substantially higher than the 86,000 barrels per day and 75,000 barrels per day reported for the respective 2005 periods. The increase in volumes reflects the resumption of Stage 3 operations late in the third quarter and better reliability and operating performance of the original Mildred Lake upgrading facility.
- Operating costs in the third quarter of 2006 decreased to $19.68 per barrel from $23.61 per barrel in 2005. Lower long-term employee incentive costs and purchased energy costs contributed to the approximately 17 per cent decline in quarter-over-quarter unit operating costs. Year-to-date, operating costs were $28.57 per barrel in 2006 compared to $26.63 per barrel in 2005, primarily as a result of an expanded operating facility to support the Stage 3 project without significant volume increases prior to the resumption of Stage 3 operations.
- Capital expenditures declined to $47 million in the third quarter of 2006 from $230 million in 2005 with the Stage 3 project being essentially complete.
- Net debt to book capitalization at September 30, 2006 decreased to 28 per cent 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 September 30		Nine Months Ended September 30	
	2006	2005	2006	2005
Net Income	$ 278	$ 380	$ 706	$ 657
Per Trust unit- Basic	$ 0.60	$ 0.83	$ 1.52	$ 1.43
Per Trust unit- Diluted	$ 0.59	$ 0.83	$ 1.51	$ 1.43
Funds From Operations	$ 359	$ 364	$ 824	$ 741
Per Trust unit	$ 0.77	$ 0.79	$ 1.77	$ 1.61
Unitholder Distributions	$ 140	$ 92	$ 372	$ 184
Per Trust unit	$ 0.30	$ 0.20	$ 0.80	$ 0.40
Syncrude Sweet Blend Sales Volumes *				
Total (MMbbls)	8.8	7.9	23.4	20.5
Daily average (bbls)	95,438	85,942	85,662	75,210
Per Trust unit (bbls/Trust unit)	-	-	0.1	-
Operating Costs per barrel	$ 19.68	$ 23.61	$ 28.57	$ 26.63
Net Realized Selling Price per barrel				
Realized selling price before hedging	$ 78.14	$ 76.67	$ 75.61	$ 69.71
Currency hedging gains (losses)	0.29	0.76	0.76	0.80
Net realized selling price	$ 78.43	$ 77.43	$ 76.37	$ 70.51
West Texas Intermediate ($US per barrel)	$ 70.60	$ 63.31	$ 68.29	$ 55.61

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

Third quarter operations marked by restart of Stage 3

Figures provided below are the gross Syncrude numbers and are not the Trust's 35.49 per cent net share.

Syncrude's post-Stage 3 facilities now have a design productive capacity of approximately 350,000 barrels per day. Referred to as "barrels per calendar day", this figure reflects the average daily production rate under normal operating conditions, which include scheduled downtime required for maintenance and turnaround activities and unscheduled downtime as a result of mechanical problems, unanticipated repairs and other slowdowns. The maximum rate a facility can produce when operating at full capacity under optimal conditions and with no downtime for maintenance or turnarounds is referred to as "barrels per stream day". Syncrude's post-Stage 3 facilities have the design capability to produce about 375,000 barrels per stream day. All references to Syncrude's daily production in the following discussions refer to Syncrude's "barrels per calendar day", unless stated otherwise.

SSB production during the third quarter of 2006 totalled 26 million barrels, or approximately 283,000 barrels per day, compared to 21.9 million barrels, or approximately 238,000 barrels per day in the third quarter of last year. Third quarter 2006 production reflects solid operations from the base plant supplemented by new volumes from the Stage 3 facilities during September. The same quarter of 2005 was impacted by the start of maintenance and revamp activities on the vacuum distillation unit.

For the nine months ended September 30, 2006 production totalled 66.4 million barrels, or about 243,000 barrels per day, compared to 57.3 million barrels, or approximately 210,000 barrels per day, in the same 2005 period. Year-to-date 2006 volumes reflect an extended turnaround of Coker 8-1 earlier in the year offset by the start-up of Stage 3 and improved reliability of the Base Plant operations. The same period of 2005 reflects the extended turnaround of Coker 8-2 and repairs to a hydrogen plant.

Syncrude employees and contractors recorded a lost time injury rate of 0.15 per 200,000 workforce hours for the nine-month period ended September 30, 2006. While still reflecting a good safety record, the 2006 rate is up from the outstanding LTI performance of 0.04 during the same time period last year.

Stage 3 commences production

Syncrude resumed its Stage 3 operations with the introduction of bitumen feed into Coker 8-3 on August 30, 2006. Production volumes gradually ramped up during the month of September to allow for regular monitoring and testing of the flue gas desulphurization ("FGD") and other units. Investigations into the odorous emissions that occurred during the operation of Syncrude's new FGD unit and coker in May determined that the ammonia being used in the FGD was largely responsible for these emissions. Analysis indicated the ammonia produced at the Syncrude operation contains impurities, including odour-causing compounds. In order to support the operation of the FGD, Syncrude will be processing purchased aqueous ammonia while it investigates a long-term strategy to use the on-site produced ammonia. Certain other modifications also were undertaken on the FGD to help improve its performance.

In addition to enabling the re-start of the Stage 3 facilities, the use of purchased ammonia is expected to help prevent odours and realize the FGD's environmental benefit of significantly reducing sulphur dioxide emissions from the expansion facilities. Syncrude has been testing the FGD using purchased ammonia since late July with good results. The cost to import the ammonia is expected to total about $3 million per month. No estimates are available at this time for any potential costs associated with developing permanent changes to enable Syncrude to use its internally produced ammonia.

Syncrude continues to focus on lining out and optimizing the new Stage 3 operating units in order to ramp up to full annual productive capability of 128 million barrels, or 45 million barrels net to the Trust. During the introduction of the Stage 3 units into full operations in 2006, Syncrude's first priority has been the safe and reliable expansion of volumes. The next area of focus will be on improving product quality from SSB to Syncrude™ Sweet Premium ("SSP"). Syncrude has identified unanticipated hydrogen limitations, which will require modifications to the steam generation unit of the new hydrogen plant before SSP can be produced. Syncrude plans to implement these modifications during planned turnarounds in the fall of 2007; accordingly, the transition to the fully upgraded, higher quality SSP product is now not expected to occur until the fourth quarter of 2007. We believe that SSP's higher quality should enable some of our existing customers to increase the amount of Syncrude production they process and potentially attract new customers. With the delay in producing SSP, we expect more of our production will now have to be shipped to further markets, potentially resulting in a wider price discount to WTI going forward; however, the supply/demand equation for synthetic oil is difficult to predict and quantify.

With the Stage 3 project being essentially complete, Syncrude has expended approximately $8.45 billion on the project. Ancillary costs of about $100 million, gross to Syncrude, remain to be incurred.

Offer to acquire Canada Southern Petroleum Ltd.

Canadian Oil Sands' offer to purchase all of the outstanding common shares of Canada Southern Petroleum Ltd. ("Canada Southern") expired on September 6, at which time we had taken up about 78 per cent of the common shares outstanding. A special meeting of the shareholders of Canada Southern is planned for October 25 to vote on the amalgamation, which will enable Canadian Oil Sands to take up the remaining common shares.

Canadian Oil Sands is in the process of disposing Canada Southern's conventional natural gas assets and expects to conclude this process by the end of the year, after which point Canadian Oil Sands would continue to hold only the natural gas interests in the Arctic Islands.

Brant Sangster appointed director

Mr. Brant Sangster was appointed as a Director of Canadian Oil Sands Limited, a wholly owned subsidiary of the Trust, effective September 6, 2006. Mr. Sangster brings to Canadian Oil Sands' Board nearly 40 years of operations experience in the energy industry, most recently focused in the oil sands sector. On August 31, 2006 he retired as Senior Vice President, Oil Sands with Petro-Canada where he was responsible for managing the company's oil sands businesses, including their 12 per cent interest in the Syncrude Joint Venture and participation in the Fort Hills mining and upgrading project. In addition to his 25-year career as a senior executive with Petro-Canada, Mr. Sangster held various strategic planning and operating positions with Imperial Oil Ltd. for 13 years. He holds a B. Sc. in Chemical Engineering from Dalhousie University.

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 November 3, 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 November 3, 2006. Information on the plan and enrolment forms are available on the Trust's web site or by calling Investor Relations.

The Trust intends to suspend the DRIP once it reaches its net debt target of $1.2 billion, which based on our Outlook as at October 24, 2006 and the current crude oil price environment, we now expect to occur in the latter half of 2007. The Trust had previously indicated its intention to modify the DRIP's terms to provide Unitholders with the ability to reinvest quarterly distributions at the volume weighted average price ("VWAP"); however, the Trust has since decided to suspend the DRIP entirely to reduce administrative burden and costs, and to allow for an easier possible reinstatement of the DRIP in its current form if required in the future to fund new investing activities.

Foreign ownership update

Based on information from the statutory declarations by Unitholders, we estimate that, as of August 4, 2006 approximately 43 per cent of our Unitholders are non-Canadian residents with the remaining 57 per cent being Canadian residents. The current foreign ownership level has increased considerably from the last declaration date of May 8, 2006, which was approximately 36 per cent at that time, as disclosed in our July 25, 2006 second quarter report. 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 November 3, 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.

Outlook for 2006

The following provides Canadian Oil Sands' Outlook for 2006 as of October 24, 2006 and is subject to change without notice. Certain information regarding the Trust and Syncrude set forth below, including management's assessment of the timing to start producing SSP; the remaining costs to finish clean-up of Stage 3; the suspension of the DRIP; the timing on reaching the Trust's debt target; the expectation for the net cost of Canada Southern Petroleum Ltd.; 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 level of taxability of Units 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 third quarter 2006 report and the October 24, 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, highlights of which are as follows. More information on the Trust's outlook is available in its Guidance Document dated October 24, 2006, which is posted on the Trust's website at http://www.cos-trust.com/investor/guidance.aspx.

- Syncrude production to range between 90 and 98 million barrels, or 32 to 35 million barrels net to the Trust based on our 35.49 per cent interest, with a single point estimate of 95 million barrels, or 33.5 million barrels net to the Trust.
- Funds from operations totalling $1.1 billion, or $2.32 per Unit, based on: annual average WTI crude oil price of US$65.00 per barrel, a foreign exchange rate of $0.89 US/Cdn, an average SSB to WTI discount of $3.00 per barrel for the year and the higher production levels.
- Operating costs of $881 million, or $26.29 per barrel, which includes $6.51 per barrel of purchased energy at an estimated $6.50/GJ natural gas price.
- Capital expenditures totalling $315 million.
- Based on our expectation of being successful in our offer to acquire all of the outstanding shares of Canada Southern at a price of US$13.10 per share, we expect a cost for the acquisition of about $165 million, net of disposal proceeds for the conventional natural gas properties, acquisition and disposition costs, and liquidation of working capital.
- Based on the Trust's 2006 Outlook and extension of the current crude oil price environment, we expect to reach our net debt target of $1.2 billion in the latter half 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).

- 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 October 24, 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 nine-month periods ended September 30, 2005 and September 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 timing to reach full production rates from Coker 8-3 and to modify the FGD unit and hydrogen plant; the anticipated costs of the new marketing group being comparable to the fees paid to EnCana Corporation for marketing services; the anticipated differential to WTI to be received in 2006 for Canadian Oil Sands' product; the expectation that higher Syncrude staffing levels and operating costs in 2006 will be reduced on a per barrel basis by higher production from Stage 3; the expected timing of reaching the net debt target; the expected impact that increased supplies of synthetic crude oil will have on the net realized selling price that Canadian Oil Sands receives for its product; the level of energy consumption post-Stage 3; capital expenditures for the remainder of 2006; the anticipated cost for the SER project; the expectation not to enter into crude oil hedges in the future; production estimates for 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, the anticipated capital expenditures for 2006 including the amount attributable to the Stage 3 expansion and the SER project; the expected timing to produce SSP; the plans to revise the DRIP; the expected price for crude oil and natural gas in 2006, the expected production, 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 timing and net sales proceeds of the disposition of Canada Southern Petroleum Ltd.'s conventional assets; 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 third quarter of 2006, Syncrude oil production totalled 26.0 million barrels, or 9.2 million barrels net to the Trust based on its 35.49 per cent working interest, compared to 21.9 million barrels, or 7.8 million barrels net to the Trust, in the third quarter of 2005.

Syncrude's post-Stage 3 facilities have the design capability to produce approximately 375,000 barrels per day when operating at full capacity under optimal conditions and with no downtime for maintenance or turnarounds. This daily production capacity is referred to as "barrels per stream day". However, under normal operating conditions, scheduled downtime is required for maintenance and turnaround activities and unscheduled downtime will occur as a result of mechanical problems, unanticipated repairs and other slowdowns. When allowances for such downtime are included, the daily design productive capacity of Syncrude's post-Stage 3 facilities is approximately 350,000 barrels per day on average and is referred to as "barrels per calendar day". All references to Syncrude's daily production and productive capacity in the following discussions refer to barrels per calendar day, unless stated otherwise.

Syncrude's third quarter 2006 production of approximately 283,000 barrels per day, or 100,000 barrels per day net to the Trust, substantially exceeded that of the same period of 2005, which averaged 238,000 barrels per day, or 84,000 barrels per day net to the Trust. The increase in quarter-over-quarter production reflects incremental production from the new Stage 3 facilities and better reliability and operating performance of the original Mildred Lake upgrading facility (the "Base Plant"). During the original startup of Stage 3 in May 2006, odorous emissions were detected that resulted in the shutdown of Stage 3 operations 10 days following startup. The odorous emissions were believed to be associated with the flue gas desulphurizer ("FGD"), an environmental unit designed to significantly reduce sulphur dioxide emissions. Following modifications to the FGD and a decision to use purchased ammonia in its operations the Stage 3 facilities came back on-line. In addition to enabling the re-start of the Stage 3 facilities, the use of imported ammonia is expected to help prevent odours and realize the FGD's environmental benefit of significantly reducing sulphur dioxide emissions from the expansion facilities. Syncrude has been testing the FGD using purchased ammonia since late July with good results. The cost to import the ammonia is expected to total about $3 million per month, or approximately $1 million net to the Trust.

Syncrude restarted Stage 3 operations at the end of August with volumes averaging approximately 340,000 barrels per day in September, or 121,000 barrels per day net to the Trust, which approximates 90 per cent of Stage 3 stream-day capacity of 375,000 barrels per day. The Stage 3 restart took approximately three months to complete, which was longer than anticipated as Syncrude implemented a phased approach to ensure regular monitoring and to establish stable operations.

Operating costs on a per barrel basis in the third quarter of 2006 decreased to $19.68 per barrel, compared to $23.61 per barrel in the third quarter of 2005, mainly due to lower Syncrude incentive compensation costs and purchased energy costs, partially offset by an increase in bitumen production and processing costs.

For the nine months ended September 30, 2006 Syncrude production was 66.4 million barrels, or 23.6 million barrels net to the Trust, relative to 57.3 million barrels, or 20.3 million barrels net to the Trust in the same period of 2005. Daily production levels year-to-date in 2006 averaged approximately 243,000 barrels per day, or 86,000 barrels per day net to the Trust, versus 210,000 barrels per day, or 74,000 barrels per day net to the Trust, in the same period of 2005. While production in both years was impacted by extended coker turnarounds, the increase in 2006 production over 2005 is mainly attributable to the incremental volumes from Coker 8-3 and better reliability and throughput rates on other upgrading units compared to the prior year. In 2005, production was reduced by repairs to Hydrogen Plant 9-2 following a tube rupture, feed restrictions in the vacuum distillation unit and sulphur pump repairs. Operating costs of $28.57 per barrel and $26.63 per barrel for the nine months of 2006 and 2005, respectively, reflect the extensive maintenance activity in both years; however, increased production costs primarily related to bitumen production and upgrading contributed to higher per barrel operating costs in the first nine months of 2006 compared to the same period in 2005, as more fully explained in the operating costs section of this MD&A.

The Trust's production volumes will differ from its sales volumes due to changes in inventory, which are primarily in-transit pipeline volumes. In the third quarter of 2006, SSB inventory levels rose relative to the same quarter of 2005 as a result of higher production levels and larger volumes of in-transit crude oil batches. The growth in SSB volumes from the Stage 3 facilities has required Canadian Oil Sands to access new markets located further south to sell these volumes. More volumes and the longer time it takes to deliver the product to more distant markets results in a larger amount of in-transit crude oil batches. 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
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Revenues [1]	$ 689	$ 624	$ 473	$ 519	$ 612	$ 492	$ 344	$ 333
Net income	$ 278	$ 337	$ 91	$ 174	$ 380	$ 218	$ 59	$ 122
Per Trust unit, Basic	$ 0.60	$ 0.72	$ 0.20	$ 0.38	$ 0.83	$ 0.48	$ 0.13	$ 0.27
Per Trust unit, Diluted	$ 0.59	$ 0.72	$ 0.20	$ 0.37	$ 0.83	$ 0.48	$ 0.13	$ 0.27
Funds from operations	$ 359	$ 324	$ 141	$ 264	$ 364	$ 284	$ 94	$ 122
Per Trust unit	$ 0.77	$ 0.70	$ 0.30	$ 0.57	$ 0.79	$ 0.62	$ 0.20	$ 0.27
Daily average sales volumes (bbls)	95,438	86,394	74,929	78,318	85,942	79,506	59,897	78,294
Net realized selling price, after hedging ($/bbl)	$ 78.43	$ 79.35	$ 70.24	$ 72.07	$ 77.43	$ 68.03	$ 63.66	$ 46.29
Operating costs ($/bbl)	$ 19.68	$ 28.48	$ 40.26	$ 25.54	$ 23.61	$ 21.35	$ 38.13	$ 21.27
Purchased natural gas price ($/GJ)	$ 5.42	$ 5.72	$ 7.42	$ 10.73	$ 8.31	$ 6.94	$ 6.45	$ 6.40

[1] Revenues after crude oil purchases, transportation and marketing expense

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. Net income is also impacted by non-cash foreign exchange gains and losses caused by fluctuations in foreign exchange rates on our U.S. dollar denominated debt and by future income tax changes. 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.

During the second quarter of 2006, Crown royalties shifted to the higher royalty rate of 25 per cent of net revenues, compared to the minimum one per cent of gross revenue that had been in place since January 1, 2002. The 2006 third quarter results reflect the full impact of the higher Crown royalty expense compared to the second quarter of 2006, which included only one month at the higher rate.

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 that became effective May 3, 2006. During the third quarter of 2006, Canadian Oil Sands acquired approximately 78 per cent of Canada Southern Petroleum Ltd. ("Canada Southern"), as more fully discussed later in this MD&A. The results of operations related to Canada Southern's conventional oil and gas assets are reflected in "Discontinued operations" on the Trust's Consolidated Statement of Income and Unitholders' Equity.

Canadian Oil Sands' funds from operations in the third quarter of 2006 of $359 million, or $0.77 per Unit, was comparable to the same period of 2005, which generated $364 million, or $0.79 per Unit. Net income was $278 million, or $0.60 per Unit, in the third quarter of 2006, down from $380 million, or $0.83 per Unit, in the same period of 2005.

The incremental production from Coker 8-3 and the improved Base Plant reliability in the third quarter of 2006 were the primary reasons for an increase in revenues of $80 million, before hedging, from the same period in 2005. Total sales volumes were 8.8 million and 7.9 million barrels in each of the third quarters of 2006 and 2005, respectively. The increase in production was supported by a slightly higher realized selling price for our Syncrude™ Sweet Blend ("SSB") product, which averaged $78.14 per barrel, before hedging, in the third quarter of 2006, compared to $76.67 per barrel, before hedging, in the same period of 2005. The Trust benefited from full exposure to robust market prices in both years as there were no crude oil hedges in place.

Operating and non-production costs incurred in the third quarter of 2006 decreased by $14 million and $9 million, respectively, compared to the same period in 2005, as more fully discussed later in this MD&A. However, the increase in revenues and the decrease in operating and non-production costs was more than offset by a $109 million increase in Crown royalties over the third quarter of 2005 due to the shift from the one per cent minimum royalty rate to the 25 per cent rate of net revenue royalty in 2006.

In addition, net income in the third quarter of 2006 was impacted by a $52 million reduction in foreign exchange gains as compared to the same quarter in 2005, which included significant unrealized gains on U.S. dollar denominated debt. Further reducing net income in the current quarter was an increase to depreciation, depletion and accretion of $22 million compared to the same period of 2005 as a result of the increased production and a higher per barrel depreciation and depletion ("D&D") rate. Finally, third quarter 2006 net income included a $13 million future income tax expense compared to a $7 million future tax recovery in the third quarter of 2005.

On a year-to-date basis, funds from operations in 2006 increased 11 per cent to $824 million, or $1.77 per Unit, compared to the same nine-month period in 2005. Net income in 2006 was $706 million, or $1.52 per Unit, compared to $657 million, or $1.43 per Unit in 2005. Contributing favourably to the increase in both funds from operations and net income was a $338 million increase in revenues (after crude oil purchases, transportation and marketing expense, and hedging), which reflects both an increase in sales volumes and a higher realized selling price. Total sales volumes in the first nine months of 2006 of 23.4 million barrels were 14 per cent higher than in the comparable 2005 period. The year-to-date realized selling price in 2006 was $75.61 per barrel, before hedging, an increase of $5.90 per barrel, before hedging, compared to the same period in 2005.

Higher revenues were partly offset by an increase in operating costs and Crown royalties in 2006 of $121 million and $135 million, respectively, compared to the nine-month results in 2005. The increase in Crown royalties reflects the shift to a higher royalty rate in 2006 from the minimum one per cent rate that applied throughout 2005. Net income in 2006 was further reduced by a $54 million increase in DD&A compared to the prior year, which reflects higher production volumes combined with a higher per barrel D&D rate. Foreign exchange gains and future income tax recovery increases in 2006 of $12 million and $8 million, respectively, increased net income compared to the prior year.

Net income before unrealized foreign exchange and future income taxes, which management believes is a better measure of operational performance than net income, was $291 million, or $0.62 per Unit in the third quarter of 2006, compared to $312 million, or $0.68 per Unit, in the same period of 2005. For the first nine months of 2006 and 2005, respectively, net income before unrealized foreign exchange and future income taxes increased to $637 million, or $1.37 per Unit, from $604, or $1.32 per Unit. The table below reconciles this measure to net income.

($ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2006	**2005**	**2006**	**2005**
Net income per GAAP	$ 278	$ 380	$ 706	$ 657
Add (Deduct):				
Foreign exchange loss (gain) on long-term debt	-	(61)	(48)	(40)
Future income tax expense (recovery)	13	(7)	(21)	(13)
Net income before foreign exchange and future income taxes	$ 291	$ 312	$ 637	$ 604

The net income before unrealized foreign exchange and future income taxes 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 and free cash flow 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 taxes, funds from operations, and free cash flow may not be directly comparable to similar measures presented by other companies or trusts.

Revenues after Crude Oil Purchases, Transportation and Marketing Expense

($ millions)	Three Months Ended September 30			Nine Months Ended September 30		
	2006	2005	Variance	2006	2005	Variance
Sales revenue [1]	$ 722	$ 619	$ 103	$ 1,938	$ 1,469	$ 469
Crude oil purchases	(27)	(2)	(25)	(141)	(7)	(134)
Transportation and marketing expense	(9)	(11)	2	(29)	(31)	2
	686	606	80	1,768	1,431	337
Currency hedging gains [1]	3	6	(3)	18	17	1
	$ 689	$ 612	$ 77	$ 1,786	$ 1,448	$ 338
Sales volumes (MMbbls)	8.8	7.9	0.9	23.4	20.5	2.9

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

($ per barrel)	2006	2005	Variance	2006	2005	Variance
Realized selling price before hedging [2]	$ 78.14	$ 76.67	$ 1.47	$ 75.61	$ 69.71	$ 5.90
Currency hedging gains	0.29	0.76	(0.47)	0.76	0.80	(0.04)
Net realized selling price	$ 78.43	$ 77.43	$ 1.00	$ 76.37	$ 70.51	$ 5.86

[2] *Sales revenue, after crude oil purchases, transportation and marketing expense divided by SSB sales volumes, net of crude oil volumes purchased*

During the third quarter of 2006, Canadian Oil Sands began marketing its share of Syncrude's production utilizing its own marketing department following the expiry of the marketing services agreement between Canadian Oil Sands and EnCana Corporation ("EnCana") on August 31, 2006. The costs of this new marketing group are included in Administration expenses. These expenses are expected to be comparable to the costs Canadian Oil Sands previously paid to EnCana to market its crude oil and related products, which were included in "Transportation and marketing expense".

Also commencing in the third quarter of 2006, the Trust is separately disclosing its crude oil purchases, which had previously been netted from sales revenue. Prior year information has been similarly reclassified for comparative purposes. Canadian Oil Sands purchases crude oil from third parties to fulfill sales commitments with customers when there are shortfalls in Syncrude's production forecasts, to expand and develop long-term markets for our synthetic crude oil, and to optimize future transportation flexibility and costs to support the sales of our SSB product.

The $80 million quarter-over-quarter increase in revenues after crude oil purchases, transportation and marketing expense and before hedging was due primarily to the 11 per cent increase in sales volumes, as well as a modest increase in the average realized selling price. While the average West Texas Intermediate ("WTI") price, a benchmark crude price that our SSB product closely follows, was 11 per cent higher at US$70.60 per barrel in the third quarter of 2006 compared to US$63.31 in the same period of 2005, the full benefit of this increase was partially offset by a stronger Canadian dollar in 2006 and a weaker differential our SSB product received relative to the WTI price. The Canadian dollar averaged $0.89 US/Cdn in the third quarter of 2006, compared to $0.83 US/Cdn in the same quarter of 2005.

Our SSB crude oil realized a weighted-average discount of $0.11 per barrel relative to average Canadian dollar WTI in the third quarter of 2006 compared to an $0.85 per barrel premium in the same quarter of 2005. The differential can move from a premium to a discount depending on the supply/demand dynamics in the market. During the third quarter of 2006, our monthly SSB product differential ranged from a premium of $3 per barrel during the shut-down of the Stage 3 operations to a discount of $4 per barrel as refiners underwent turnarounds and required less SSB in their operations. By comparison, in the same quarter of 2005 the premium reflected the lower supply of light synthetic crude oil from a number of producers.

On a year-to-date basis, revenues after crude oil purchases, transportation and marketing expense and before hedging, increased by $337 million in 2006 compared to the similar period in 2005. The increase in revenues reflected both an increase in sales volumes, driven by the increase in production volumes as explained in the review of Syncrude operations, and a higher average realized selling price. In 2006, the realized selling price, before hedging, averaged $75.61 per barrel, an increase of eight per cent from the prior year. The increase in the average realized selling price reflected the improvement in WTI prices, which rose 23 per cent to US$68.29 per barrel in 2006, partially offset by a stronger Canadian dollar and a weaker differential. The foreign exchange rate in the first nine months of 2006 averaged $0.88 US/Cdn compared to $0.82 US/Cdn in the comparable period in 2005. Our SSB product realized a weighted-average discount of $1.62 per barrel compared to a premium of $1.15 per barrel realized in 2005, which primarily reflected the additional supply of synthetic crude oil in the market in 2006 compared to 2005. With the anticipated incremental Coker 8-3 production volumes projected in the fourth quarter, we continue to anticipate an average annual discount to WTI of $3.00 per barrel in our 2006 Outlook, as discussed later in this MD&A.

Operating costs

	Three Months Ended September 30				Nine Months Ended September 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	1.59		1.44		2.29		1.86	
Bitumen production	7.30		6.73		8.09		7.63	
Purchased energy [3]	1.84		2.72		2.69		2.79	
	10.73	12.67	10.89	12.63	13.07	15.27	12.28	14.69
Upgrading Costs [2]								
Bitumen processing and upgrading		4.31		3.09		4.70		3.95
Turnaround and catalysts		0.53		1.22		3.01		3.07
Purchased energy [3]		2.21		3.08		3.07		2.83
		7.05		7.39		10.78		9.85
Other and research		0.18		3.04		1.77		2.17
Change in treated and untreated inventory		(0.22)		0.21		0.36		(0.33)
Total Syncrude operating costs		19.68		23.27		28.18		26.38
Canadian Oil Sands adjustments [4]		-		0.34		0.39		0.25
Total operating costs		19.68		23.61		28.57		26.63
	Bitumen	SSB	Bitumen	SSB	Bitumen	SSB	Bitumen	SSB
Syncrude production volumes (thousands of barrels per day)	334	283	279	238	284	243	251	210

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 $5.42/GJ and $8.31/GJ in the third quarter of 2006 and 2005, respectively. For the nine months ended September 30, natural gas costs averaged $6.16/GJ and $7.29/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 September 30		Nine Months Ended September 30	
	2006	2005	2006	2005
	$/bbl SSB	$/bbl SSB	$/bbl SSB	$/bbl SSB
Production costs	15.30	17.38	22.36	20.46
Purchased energy	4.38	6.23	6.21	6.17
Total operating costs	19.68	23.61	28.57	26.63
	GJs/bbl SSB	GJs/bbl SSB	GJs/bbl SSB	GJs/bbl SSB
Purchased energy consumption	0.81	0.75	1.01	0.85

Equipment and staff to support Syncrude's Stage 3 operations were in place throughout 2006, although production from the new facility was not established until September 2006. 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 operating costs.

Operating costs in the third quarter of 2006 decreased to $173 million, or $19.68 per barrel, from $187 million, or $23.61 per barrel, in the same quarter of 2005. A reduction in value of Syncrude's incentive compensation and a decrease in both purchased energy and turnaround and catalyst costs were partially offset by an increase in production costs, which lead to the overall decrease in per barrel operating costs in the third quarter of 2006 relative to the same period in 2005.

A portion of Syncrude's long-term incentive compensation is based on the market return performance of several Syncrude owners' units/shares. The resulting incentive plan valuation changes are recorded as operating cost increases or decreases at each period end. In the third quarter of 2006, the market return performance of many of the Syncrude owners' units/shares declined due to the recent decrease in commodity prices, which lowered operating costs by approximately $3.44 per barrel quarter-over-quarter. Partially offsetting the per barrel decrease in incentive compensation costs was an increase of $0.63 per barrel related to an employee retention program Syncrude introduced in 2006, similar to other operators in the area to reduce staff turnover. The results of the incentive compensation and retention costs are included in the "Other and research" line of the operating costs table.

Purchased energy costs per barrel declined by 30 per cent to $4.38 per barrel from $6.23 per barrel in the third quarter of 2006 and 2005, respectively. The decreased purchased energy expense, consisting mainly of natural gas, reflects a 35 per cent decline in natural gas prices, which averaged $5.42 per gigajoule ("GJ") in the third quarter of 2006, compared to $8.31/GJ in the comparable quarter of 2005. The decrease in prices was offset marginally by an eight per cent increase in consumption volumes to 0.81 GJs per barrel in the third quarter of 2006 relative to the third quarter of 2005. 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.

Turnaround and catalysts costs also reduced operating costs in the third quarter of 2006 by $0.69 per barrel relative to the same quarter of 2005. Syncrude experienced better Base Plant reliability in the third quarter of 2006, and while some work was performed on its FGD unit in the quarter, more turnaround and maintenance costs were incurred in the comparable quarter of 2005 related to repairs to Hydrogen Plant 9-2, the vacuum distillation unit and the sulphur pumps.

An increase in bitumen mining, extracting and upgrading costs of approximately $2.00 per barrel partially offset lower purchased energy, incentive compensation, and turnaround and catalyst costs in the third quarter of 2006, compared to the same quarter of 2005. The costs related to the Stage 3 infrastructure and workforce increase were in place during most of 2006; however, production from Coker 8-3 did not begin until September, which resulted in higher bitumen production and upgrading costs on a per barrel basis in the three and nine-month periods ending September 30, 2006, compared to the same periods in 2005.

Year-to-date, operating costs increased to $668 million in 2006, or $28.57 per barrel, from $547 million, or $26.63 per barrel, in the same nine month period of the prior year. The increase in per barrel operating costs was primarily due to an increase in production costs, excluding purchased energy, partly offset by a reduction in Syncrude's incentive compensation. The production costs increase accounted for approximately $2.80 per barrel of the rise in operating costs in 2006 compared to 2005, and was primarily related to Stage 3 bitumen production, extraction, and upgrading, as explained above. Syncrude's incentive compensation valuation change in 2006 relative to the prior year reduced year-to-date operating costs by $0.88 per barrel, which was partially offset by an increase in costs related to the new employee retention program in 2006 of $0.58 per barrel.

Purchased energy costs per barrel of $6.21 in the nine months ending September 30, 2006 were comparable to the same period in 2005, which averaged $6.17 per barrel. While purchased energy consumption rose to 1.01 GJs per barrel from 0.85 GJs per barrel in 2006 and 2005, respectively, the 16 per cent decrease in natural gas prices to an average cost of $6.16 per GJ in 2006 helped mitigate the overall increase in purchased energy costs. The increase in consumption volumes was mainly a result of reduced energy efficiency experienced during Stage 3 start-up activities. Also contributing to the increase in consumption were repairs on a hot water line during the first quarter of 2006 that 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 nine months of 2006 once the Stage 3 operations have stabilized, but consumption is expected to remain higher than historical norms of about 0.7 GJs per barrel. We estimate that long-term consumption going forward will be about 0.85 GJs per barrel as additional hydrogen, which is derived from natural gas, is eventually to be used to increase product quality from SSB to Syncrude Sweet Premium™ ("SSP") and as 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 remote location from the Base Plant.

Non-production costs

Non-production costs in the third quarter of 2006 decreased by $9 million from the same quarter of 2005 as there were fewer costs incurred related to the commissioning and start-up of Stage 3 with the substantial completion of that project earlier in the year. In the prior year, the project was nearing completion and additional costs were being incurred as more of the units associated with the project were being commissioned and handed over to the ready-for-operations team. 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 $115 million, or $13.01 per barrel, in the third quarter of 2006 from $6 million, or $0.77 per barrel, in the comparable 2005 quarter. For the nine months ended September 30, Crown royalties were $149 million, or $6.37 per barrel, and $14 million, or $0.70 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 September 30		Nine Months Ended September 30	
	2006	**2005**	**2006**	**2005**
Depreciation and depletion expense	$ 67	$ 48	$ 173	$ 125
Accretion expense	3	-	7	1
	$ 70	$ 48	$ 180	$ 126

D&D expense for the three months ended September 30, 2006 rose by $19 million compared to the same period in 2005 as a result of a 19 per cent increase in Syncrude production volumes and a higher per barrel D&D rate. In the first nine months, D&D expense increased by $48 million, reflecting a 16 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 nine months 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 an increase in the estimate for 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 third quarter and first nine months 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 nine months of 2006 and 2005 are mainly the result of revaluations of our U.S. dollar denominated long-term debt caused by fluctuations in U.S. and Canadian exchange rates. Canadian Oil Sands recorded a $1 million foreign exchange gain in the third quarter of 2006 compared to a $53 million gain in the same period of 2005. These figures reflect insignificant unrealized losses in the third quarter of 2006 compared to $61 million of unrealized gains in the same period of 2005 as a result of long term debt revaluations. On a year-to-date basis, $45 million and $33 million of gains were recorded in 2006 and 2005, respectively. Revaluations of U.S. dollar denominated debt contributed $48 million and $40 million of unrealized gains in the first nine months of 2006 and 2005, respectively. The remaining foreign exchange gains and losses relate to the conversion of U.S. dollar denominated cash, receivable, and payable balances.

The Canadian dollar was unchanged at $0.90 US/Cdn at September 30, 2006 from June 30, 2006 and strengthened from $0.86 US/Cdn at December 31, 2005. Similarly, the dollar strengthened to $0.86 US/Cdn at September 30, 2005 from $0.82 US/Cdn at June 30, 2005 and from $0.83 US/Cdn at December 31, 2004, respectively.

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.

Future Income Tax

In the third quarter of 2006, there was a future income tax expense of $13 million compared to a $7 million future tax recovery in the same quarter of 2005. Year-to-date, future income tax recoveries in 2006 increased to $21 million from $13 million in 2005. The changes in the future income tax expense and recovery amounts quarter-over-quarter pertain to changes in temporary differences. A future income tax recovery of $29 million was recorded in 2006 as a result of substantively enacted reductions to future provincial and federal corporate tax rates and elimination of the federal surtax during the second quarter of 2006. The remaining variance from the prior year relates to changes in temporary differences.

In the third quarter of 2006, Canadian Oil Sands acquired approximately 78 per cent of Canada Southern, as more fully discussed later in this MD&A, which resulted in a $45 million increase to the Trust's total future tax liability on its Consolidated Balance Sheet at September 30, 2006. The additional future tax liability reflects the temporary differences between the book value of the Arctic Island assets and the related tax pools at the substantively enacted tax rates at the time of acquisition. The future tax liability is not expected to result in higher cash taxes being paid by the Trust’s subsidiaries in the future.

Capital expenditures

Capital spending in the third quarter of 2006 decreased to $47 million from $230 million in the same period of 2005. Only 14 per cent of third quarter 2006 expenditures pertained to Stage 3 as the project was essentially complete. The Trust spent $148 million less on Stage 3 in the third quarter of 2006 compared to the same 2005 period. In addition, 2005 third quarter capital expenditures included $45 million related to the South West Quadrant Replacement (“SWQR”) project, which was largely complete at the end of 2005. Partially offsetting the reduction in capital spending on the Stage 3 and SWQR projects was an increase in capital spending in the third quarter of 2006 on Syncrude’s sulphur emissions reduction (“SER”) project of approximately $9 million compared to the comparable quarter in 2005.

For the nine months ended September 30, capital spending decreased to $243 million in 2006 from $623 million in 2005, again reflecting the completion of the Stage 3 and SWQR projects, partially offset by an increase in spending on the SER project of approximately $20 million. The SER project is being undertaken to retrofit technology into the operation of Syncrude’s original two cokers to significantly reduce total sulphur dioxide and other emissions. Expenditures on the SER project were expected to ramp up following completion of the Stage 3 expansion and to total approximately $772 million, or $274 million net to the Trust. The Trust’s share of the SER project expenditures incurred to date, including amounts expensed, is approximately $36 million, with the remaining costs to be incurred over the next three years to coordinate with equipment turnaround schedules.

As at September 30, 2006 the Syncrude Joint Venture had expended approximately $8.45 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 totalling approximately $100 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 $315 million, which is approximately $485 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.

ACQUISITION OF CANADA SOUTHERN PETROLEUM LTD.

In the third quarter of 2006 Canadian Oil Sands made an offer to purchase all of the outstanding common shares of Canada Southern for US$13.10 per common share, or total consideration of approximately Cdn$224 million. The offer expired on September 6, at which time Canadian Oil Sands had taken up approximately 78 per cent of the common shares outstanding at a cost of approximately $174 million. A special meeting of the shareholders of Canada Southern is planned for October 25 to vote on an amalgamation resolution to enable Canadian Oil Sands to take up the remaining common shares.

Canadian Oil Sands is in the process of disposing of Canada Southern's conventional natural gas assets and expects to conclude this process by the end of 2006. Subsequently, Canadian Oil Sands would continue to hold only the natural gas interests in the Arctic Islands (the "Arctic assets") as a long-term hedge for Canadian Oil Sands' natural gas requirements at Syncrude as well as the potential opportunity to participate in the development of another long-life energy resource.

As a result of acquiring Canada Southern and the related accounting requirements of such a business acquisition, Canadian Oil Sands' Consolidated Balance Sheet now includes Goodwill, Assets Held for Sale, and Non-Controlling interest. Each of these is explained more fully in the following discussions. Canadian Oil Sands' approximate 78 per cent interest in Canada Southern's net losses since acquisition is reflected in "Discontinued operations" on the Consolidated Statement of Income, net of non-controlling interest losses. The $3 million loss from discontinued operations primarily reflects the administrative costs incurred by Canada Southern related to its acquisition by Canadian Oil Sands. The Arctic assets are undeveloped and not currently producing; therefore, no net income impact is associated with those properties.

Goodwill

Goodwill is the excess amount that results when the purchase price of an acquired business exceeds the accounting fair value of the net identifiable assets and liabilities of that acquired business. At September 30, 2006 goodwill related to the acquisition of Canada Southern was $45 million and arose as a result of the $45 million future income tax liability on the Arctic assets. The goodwill balance will be subject to an annual impairment assessment, or more frequently if events or changes in circumstances occur that would reasonably be expected to reduce the fair value below the carrying value.

Assets Held for Sale

Since the Trust intends to sell the conventional natural gas assets of Canada Southern and the sale process has commenced, the fair value of the assets and related liabilities less the estimated costs to sell the assets has been classified as "Held for sale" on the Trust's Consolidated Balance Sheet.

Non-Controlling Interest

At September 30, 2006 the Trust owned approximately 78 per cent of Canada Southern. The remaining shares of Canada Southern, representing approximately 22 per cent owned by other shareholders, are reflected on the Trust's Consolidated Balance Sheet at Canada Southern's carrying values. As such, the non-controlling interest does not reflect the fair value of the assets and liabilities recorded by the Trust for its interest in Canada Southern.

CHANGE IN ACCOUNTING POLICIES

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

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	September 30 2006	December 31 2005
Current portion of long-term debt	$ 273	$ -
Long-term debt	1,324	1,737
Cash and short-term investments	(86)	(88)
Net debt	$ 1,511	$ 1,649
Unitholders' equity	$ 3,897	$ 3,383
Total capitalization [1]	$ 5,408	$ 5,032

[1] Net debt plus unitholders' equity

Canadian Oil Sands' capital structure improved at September 30, 2006 compared to December 31, 2005. The $706 million of net income generated year-to-date in 2006 was more than sufficient to cover the $192 million of distributions, net of the Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan ("DRIP"), paid in the first nine months, leading to an increase in Unitholders' equity.

Net debt decreased to $1,511 million at September 30, 2006 as a result of credit facility repayments and foreign exchange gains on our U.S. dollar denominated long-term debt. Accordingly, net debt to total capitalization at September 30, 2006 decreased to 28 per cent from 33 per cent at December 31, 2005. The DRIP generated $180 million in new equity in the first nine months of 2006 at an average price of $31.76 per Unit.

Funds from operations in the third quarter of 2006 totalled $359 million, or $0.77 per Unit, relatively unchanged from $364 million, or $0.79 per Unit for the same period in 2005. In the third quarter of 2006 the Trust required $371 million to fund capital expenditures and mining reclamation trust contributions, the costs of acquiring Canada Southern, working capital requirements, and to pay distributions, leaving a $12 million funding shortfall. The $69 million of DRIP equity generated in the quarter was used to fund this shortfall and $30 million of credit facility repayments, resulting in a $27 million increase in the cash balance over the second quarter of 2006.

Year-to-date, funds from operations in 2006 totalled $824 million, or $1.77 per Unit, an $83 million increase over the $741 million, or $1.61 per Unit, recorded in the same period of 2005. Canada Southern acquisition costs, capital expenditures, reclamation trust contributions, distributions and working capital requirements totalled $914 million in the first nine months of 2006, leaving $90 million of required financing. DRIP proceeds of approximately $180 million were used to fund this shortfall in addition to $92 million of credit facility repayments, resulting in a $2 million cash draw since December 31, 2005.

The Trust expects cash balances to build with capital spending remaining low relative to the Stage 3 capital expansion period. We intend to use these cash balances to repay the current portion of long-term debt as the various debt tranches reach maturity. To the extent cash balances are insufficient to repay these maturities, it is expected that bank credit facilities will be used to bridge the repayments until funds are available.

The Trust's financing strategy remains unchanged with a continued focus on debt reduction towards a net debt target of about $1.2 billion. Considering the recent reduction in crude oil prices, we now anticipate this net debt target will be achieved in the latter half of 2007, compared to the first quarter of 2007 that we had estimated at July 25, 2006. Once our net debt target is reached, the Trust intends to suspend the DRIP. The Trust had previously indicated that it intended to modify the DRIP's terms to provide Unitholders with the ability to reinvest quarterly distributions at 100 per cent of the volume weighted average price ("VWAP"). However, the Trust has since decided to suspend the DRIP entirely to reduce administrative burden and costs and to allow for an easier possible reinstatement of the DRIP in its current form if required to fund future investing activities.

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 5 of the Notes to the Unaudited Consolidated Financial Statements.

UNITHOLDERS' CAPITAL AND UNIT TRADING ACTIVITY

Canadian Oil Sands Units trade on the Toronto Stock Exchange under the symbol COS.UN. The Trust had a market capitalization of approximately $14 billion with 468 million Units outstanding and a closing price of $29.82 per Unit on September 30, 2006.

Canadian Oil Sands Trust - Trading Activity	Third Quarter 2006	September 2006	August 2006	July 2006
Unit price				
High	$ 38.75	$ 34.59	$ 38.75	$ 37.35
Low	$ 28.15	$ 28.15	$ 33.20	$ 31.50
Close	$ 29.82	$ 29.82	$ 33.80	$ 37.22
Volume traded (millions)	105.8	34.0	51.7	20.1
Weighted average Trust units outstanding (millions)	467.1	468.3	466.4	466.3

On October 24, 2006 the Trust declared a distribution of $0.30 per Unit for total distributions of approximately $140 million. The distribution will be paid on November 30, 2006 to Unitholders of record on November 3, 2006. A Unitholder distribution schedule pertaining to the quarter and nine month periods ending September 30 is included in Note 8 of the Notes to the Unaudited Consolidated Financial Statements. The Trust utilizes debt and equity financing to the extent funds from operations are insufficient to fund distributions, capital expenditures, mining reclamation trust contributions, acquisitions and working capital changes. In the third quarter of 2006, $12 million of equity from the DRIP was used to finance these items as disclosed in “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 198,840 options granted year-to-date in 2006 with an average exercise price of $29.70 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 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 September 30, 2006 reductions to capital expenditure and other obligations and commitments resulted from expenditures incurred in the first nine months of the year. However, an increase to the Trust’s contractual obligations and commitments of approximately $77 million was related to a new Syncrude employee retention program to be earned and paid over a three-year period. In addition, the

Trust's pipeline commitments were increased by $15 million during the third quarter of 2006. Under take or pay contracts, Canadian Oil Sands is committed to pay for pipeline space regardless of whether any volumes are shipped on the pipeline during the contract period. The contract expiry dates range from August 2007 to August 2008.

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. As at September 30, 2006 and based on current expectations, the Trust remains unhedged on its crude oil price exposure.

Foreign Currency Hedging

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

Canadian Oil Sands Trust **Exchange Hedging Activities**	**2006**	**2007**
U.S. dollars hedged *($ millions)*	$ 5	$ 20
Average U.S. dollar exchange rate	$ 0.692	$ 0.692

Canadian Oil Sands' revenues in the third quarter of 2006 include foreign currency hedging gains of $3 million, or $0.29 per barrel, compared to gains of $6 million, or $0.76 per barrel, in the comparable 2005 quarter. For the nine months ended September 30, currency hedging gains of $18 million and $17 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, and a smaller hedge position in the third quarter of 2006 since US$15 million of foreign exchange contracts had expired at the end of the second quarter of 2006. The Canadian dollar averaged $0.88 US/Cdn and $0.82 US/Cdn in the first nine months 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 September 30, 2006 we had $195 million of floating rate debt with maturities of less than one year, comprised of $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 September 30, 2006 the unrecognized gain relating to our foreign currency hedges was $8 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 9 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 August 4, 2006 approximately 43 per cent of our Unitholders are non-Canadian residents with the remaining 57 per cent being Canadian residents. The current foreign ownership level has increased considerably from the last declaration date of May 8, 2006, which was approximately 36 per cent at that time, as disclosed in our July 25, 2006 second quarter report. 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 November 3, 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

We have increased our Outlook for 2006 annual Syncrude production from the guidance provided on July 25, 2006 to range between 90 and 98 million barrels, or 32 to 35 million barrels net to the Trust based on our 35.49 per cent interest. The increase reflects the likelihood of realizing higher volumes based on the strong production reported during the third quarter of 2006 and renewed confidence regarding Stage 3 operations. The high end of the range reflects the potential of production averaging Stage 3 design capacity of 350,000 barrels per calendar day, while the low end assumes a further upset of Stage 3 operations due to issues commonly associated with the ramp-up of new units with no incremental production from the expansion for the remainder of the year. No significant maintenance activity is expected to impact production in the last quarter of 2006 with the Coker 8-2 turnaround scheduled in the second half of 2007. As well, the tire shortage that had been identified as a production and cost risk earlier in the year is not expected to impact our 2006 production Outlook as Syncrude has implemented various measures to reduce tire wear and damage in order to more conservatively manage consumption.

We have raised our single point 2006 estimate from 90 to 95 million barrels of Syncrude production, or 34 million barrels net to the Trust. The revised estimate assumes production averaging 315,000 barrels per day for the remainder of the year, which is equivalent to 90 per cent of post-Stage 3 design capacity of 350,000 barrels per calendar day and our previously disclosed anticipated exit rate for 2006. Correspondingly, production in the fourth quarter of 2006 is estimated at 28.6 million barrels, or 10 million barrels net to the Trust.

Syncrude continues to focus on lining out and optimizing the different Coker 8-3 operating units in order to ramp up to full annual productive capability of 128 million barrels, or 45 million barrels net to the Trust. During the introduction of the Stage 3 units into full operations in 2006, Syncrude's first priority has been on the safe and reliable expansion of volumes. Syncrude's next area of focus will be on improving product quality from SSB to SSP. Syncrude has identified unanticipated hydrogen limitations, which will require modifications to the steam generation unit of the new hydrogen plant, before SSP can be produced. Syncrude plans to implement these modifications during planned turnarounds in the fall of 2007; accordingly, the transition to the higher quality SSP product is now not expected to occur until the fourth quarter of 2007. We believe that SSP's higher quality should enable some of our existing customers to increase the amount of Syncrude production they process and potentially attract new customers. With the delay in producing SSP, we expect more of our production may now have to be shipped to further markets, potentially resulting in a wider price discount to WTI going forward; however, the supply/demand equation for synthetic oil is difficult to predict and quantify. For 2006, we are continuing to estimate an average SSB to WTI discount of $3.00 per barrel.

Funds from operations in 2006 are anticipated to total $1.1 billion, or $2.32 per Unit, based on a lower forecast for an average WTI crude oil price of US$65.00 per barrel, a foreign exchange rate of $0.89 US/Cdn for the year and the higher production levels.

Revenues, after crude oil purchases, transportation and marketing expense are estimated at approximately $2.4 billion in 2006, with operating costs of $881 million, or $26.29 per barrel, which includes $6.51 per barrel of purchased energy at an estimated $6.50/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 $212 million, or $6.32 per barrel in 2006.

Purchased energy consumption is expected to average approximately 1.0 GJs per barrel in 2006 due to the start-up of Stage 3 operations. Once Stage 3 is fully lined-out, per barrel energy consumption is expected to be approximately 0.85 GJs per barrel.

We estimate 2006 capital expenditures to total $315 million due to a reduction in maintenance of business projects and deferral of a portion of the Stage 3 and SER 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 assets estimated at approximately $165 million, net of disposal proceeds, acquisition and disposition costs, and liquidation of working capital.

Based on the latest Outlook and the current crude oil price environment, we expect to reach our net debt target of approximately $1.2 billion in the second half 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). Guidance for 2007 will be provided by the Trust later in the fourth quarter of 2006.

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 relative to crude benchmarks; however, this factor is difficult to predict and quantify.

2006 Outlook Sensitivity Analysis

Variable [1]	Annual [2] Sensitivity	Funds from Operations Increase $ millions	Funds from Operations Increase $/Trust unit
Syncrude operating costs decrease	C$1.00/bbl	25	0.05
Syncrude operating costs decrease	C$50 million	13	0.03
WTI crude oil price increase	US$1.00/bbl	28	0.06
Syncrude production increase	2 million bbls	36	0.08
Canadian dollar weakening	US$0.01/C$	18	0.04
AECO natural gas price decrease	C$0.50/GJ	13	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 October 24, 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 September 30		Nine Months Ended September 30	
	2006	**2005**	**2006**	**2005**
Revenues	$ 725	$ 625	$ 1,956	$ 1,486
Crude oil purchases, transportation and marketing expense	(36)	(13)	(170)	(38)
	689	612	1,786	1,448
Expenses:				
Operating	173	187	668	547
Non-production	11	20	56	53
Crown royalties	115	6	149	14
Administration	3	2	12	8
Insurance	1	1	5	5
Interest, net (Note 6)	24	26	74	79
Depreciation, depletion and accretion	70	48	180	126
Foreign exchange loss (gain)	(1)	(53)	(45)	(33)
Large Corporations Tax and other	(1)	2	(1)	5
Future income tax expense (recovery)	13	(7)	(21)	(13)
	408	232	1,077	791
Net income from continuing operations	281	380	709	657
Discontinued operations (Note 2)	(3)	-	(3)	-
Net income for the period	$ 278	$ 380	$ 706	$ 657
Unitholders' equity, beginning of period	$ 3,690	$ 2,859	$ 3,383	$ 2,636
Net income for the period	278	380	706	657
Issue of Trust units (Note 3)	69	21	180	58
Unitholder distributions (Note 8)	(140)	(92)	(372)	(184)
Contributed surplus	-	-	-	1
Unitholders' equity, end of period	$ 3,897	$ 3,168	$ 3,897	$ 3,168
Weighted average Trust units (millions)	467	460	465	459
Trust units, end of period (millions)	468	461	468	461
Net income (loss) per Trust unit:				
Net income from continuing operations				
Basic	$ 0.60	$ 0.83	$ 1.52	$ 1.43
Diluted	$ 0.60	$ 0.83	$ 1.52	$ 1.43
Net income (loss) from discontinued operations				
Basic	$ (0.01)	$ -	$ (0.01)	$ -
Diluted	$ (0.01)	$ -	$ (0.01)	$ -
Net income for the period				
Basic	$ 0.60	$ 0.83	$ 1.52	$ 1.43
Diluted	$ 0.59	$ 0.83	$ 1.51	$ 1.43

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

	September 30 2006	December 31 2005
ASSETS		
Current assets:		
Cash and short-term investments	$ 86	$ 88
Accounts receivable	317	197
Inventories	91	87
Prepaid expenses	7	3
	501	375
Capital assets, net	5,715	5,502
Other assets		
Goodwill (Note 2)	45	-
Assets held for sale (Note 2)	22	-
Reclamation trust	29	25
Deferred financing charges, net and other	18	23
	114	48
	$ 6,330	$ 5,925
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 265	$ 281
Current portion of long-term debt	273	-
Current portion of employee future benefits	10	10
	548	291
Employee future benefits and other liabilities	98	93
Long-term debt	1,324	1,737
Asset retirement obligation (Note 7)	153	148
Deferred currency hedging gains	36	34
Future income taxes	263	239
Non-controlling interest (Note 2)	11	-
	2,433	2,542
Unitholders' equity	3,897	3,383
	$ 6,330	$ 5,925

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2006	**2005**	**2006**	**2005**
Cash provided by (used in):				
Operating activities				
Net income	$ 278	$ 380	$ 706	$ 657
Items not requiring outlay of cash:				
Depreciation, depletion and accretion	70	48	180	126
Amortization	1	-	2	2
Foreign exchange on long-term debt	-	(61)	(48)	(40)
Future income tax expense (recovery)	13	(7)	(21)	(13)
Other	(1)	1	1	2
Net change in deferred items	(2)	3	4	7
Funds from operations	359	364	824	741
Change in non-cash working capital	(25)	-	(94)	(73)
	334	364	730	668
Financing activities				
Net drawdown (repayment) of bank credit facilities	(30)	(117)	(92)	56
Unitholder distributions (Note 8)	(140)	(92)	(372)	(184)
Issuance of Trust units (Note 3)	69	21	180	58
Change in non-cash working capital	-	46	-	46
	(101)	(142)	(284)	(24)
Investing activities				
Acquisition of Canada Southern Petroleum Ltd. (Note 2)	(151)	-	(151)	-
Capital expenditures	(47)	(230)	(243)	(623)
Reclamation trust	(2)	(1)	(4)	(3)
Change in non-cash working capital	(6)	1	(50)	2
	(206)	(230)	(448)	(624)
Increase (decrease) in cash	27	(8)	(2)	20
Cash at beginning of period	59	46	88	18
Cash at end of period	$ 86	$ 38	$ 86	$ 38
Supplemental Information				
Large Corporations Tax and income tax paid	$ -	$ 2	$ 5	$ 7
Interest charges paid	$ 31	$ 33	$ 82	$ 86

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

FOR THE NINE MONTHS ENDED SEPTEMBER 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) ACQUISITION OF CANADA SOUTHERN PETROLEUM LTD.

On June 18, 2006 Canadian Oil Sands entered into a pre-acquisition agreement with Canada Southern Petroleum Ltd. ("Canada Southern"), pursuant to which Canadian Oil Sands offered to purchase 100 per cent of the outstanding common shares of Canada Southern, a Canadian oil and gas exploration and development company. In the third quarter of 2006, through a normal take-over bid process, Canadian Oil Sands acquired approximately 78 per cent of the common shares of Canada Southern for US$13.10 per share, for total consideration of approximately Cdn$174 million ($151 million net of $23 million cash acquired), including acquisition-related costs of approximately $1 million. Canadian Oil Sands plans to take up the remaining shares by way of an amalgamation to be voted on at a special meeting of the Canada Southern shareholders on October 25, 2006.

Canadian Oil Sands intends to dispose of Canada Southern's conventional oil and gas exploration and development properties (the "conventional natural gas assets") by December 31, 2006, and will continue to hold the varying interests in natural gas licenses located in the Arctic Islands in Northern Canada (the "Arctic assets"). The conventional natural gas assets are currently being marketed for sale. As such, the conventional natural gas assets and related working capital and liabilities have been recorded at fair values, less the estimated costs to sell the assets, and classified as "Held for sale" in the Trust's Consolidated Balance Sheet at September 30, 2006. The results of operations of Canada Southern are considered discontinued operations on the Trust's Consolidated Statement of Income and Unitholders' Equity as there will be no continuing involvement by Canadian Oil Sands in the operations of the conventional assets once they have been sold.

The acquisition has been accounted for as a business acquisition in accordance with Canadian generally accepted accounting principles. The Trust has allocated the purchase price to the assets and liabilities based on its 78 per cent ownership as follows:

Net assets and liabilities assumed		
Property, plant and equipment	$	143
Cash		23
Goodwill [1]		45
Assets held for sale [2]		19
Minority interest		(11)
Future income taxes		(45)
	$	174
Consideration		
Cash	$	173
Costs associated with acquisition		1
	$	174

[1] Goodwill is entirely due to the temporary differences created between the tax basis of the Arctic assets compared to the fair value of such assets. Goodwill is not subject to amortization, but is tested annually for impairment, or more frequently if events or circumstances arise that could result in impairment.

[2] Assets held for sale include $25 million of oil and gas properties and equipment, less a working capital deficiency of $2 million, asset retirement obligations of $3 million, and estimated costs to sell the properties of $1 million.

3) UNITHOLDERS' EQUITY

In the three months ended September 30, 2006 approximately two million Units were issued for proceeds of $69 million primarily related to the Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan ("DRIP") with respect to the distributions paid on August 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
August 31, 2006 (DRIP)	$ 34.44	2.0	$ 69
Balance, September 30, 2006		468.3	$ 2,190

4) 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 nine months ended September 30, 2006 and 2005, which is recorded in operating expense, is as follows:

($ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	2006	2005
Defined benefit plans:				
Pension benefits	$ 7	$ 6	$ 15	$ 18
Other benefit plans	1	1	2	3
	$ 8	$ 7	$ 17	$ 21
Defined contribution plan	-	1	1	2
Total Benefit cost	$ 8	$ 8	$ 18	$ 23

5) 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.

6) INTEREST, NET

($ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	2006	2005
Interest expense	$ 26	$ 27	$ 77	$ 81
Interest income and other	(2)	(1)	(3)	(2)
Interest expense, net	$ 24	$ 26	$ 74	$ 79

7) ASSET RETIREMENT OBLIGATION ("ARO")

($ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	2006	2005
Asset retirement obligation, beginning of period	$ 150	$ 43	$ 148	$ 44
Liabilities settled	-	-	(2)	(2)
Accretion expense	3	-	7	1
Asset retirement obligation, end of period	$ 153	$ 43	$ 153	$ 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.

8) 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 September 30		Nine Months Ended September 30	
	2006	**2005**	**2006**	**2005**
Funds from operations	$ 359	$ 364	$ 824	$ 741
Add (Deduct):				
Acquisition of Canada Southern Ltd.	(151)	-	(151)	-
Capital expenditures	(47)	(230)	(243)	(623)
Non-acquisition financing, net [1]	12	(88)	90	94
Change in non-cash working capital	(31)	47	(144)	(25)
Reclamation trust funding	(2)	(1)	(4)	(3)
Unitholder distributions	$ 140	$ 92	$ 372	$ 184
Unitholder distributions per Trust unit	**$ 0.30**	**$ 0.20**	**$ 0.80**	**$ 0.40**

[1] *Primarily represents net financing to fund the Trust's share of investing activities and is a discretionary item.*

9) HEDGING INSTRUMENTS

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

($ millions)	**Unrecognized gains (losses)**	**Fair value**
Currency exchange contracts	$ 8	$ 8
3.95% Interest rate swap contracts	(1)	(1)
	$ 7	$ 7

Canadian Oil Sands Limited
Marcel Coutu
President & Chief Executive Officer

Units Listed – Symbol: COS.UN
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