Canadian Oil Sands

third quarter report 3

Canadian Oil Sands Trust raises its quarterly distribution 38 per cent to $0.55 per Trust unit

All financial figures are unaudited and in Canadian dollars unless otherwise noted. The Trust's 2007 financial results reflect a 36.74 per cent working interest in the Syncrude Joint Venture, which represents the Trust's increased ownership following its acquisition of a 1.25 per cent Syncrude interest from Talisman Energy Inc. on January 2, 2007. Prior year comparative information is based on the Trust's previous ownership of 35.49 per cent.

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Calgary, Alberta (Oct. 31, 2007) – Canadian Oil Sands Trust ("Canadian Oil Sands" or the "Trust" or "we") today announced cash from operating activities in the third quarter of 2007 totalled $484 million, up 45 per cent over the same period last year. Third quarter cash from operating activities of $1.01 per Trust unit ("Unit") represents almost half of the Trust's year-to-date amount of $2.11 per Unit. Total cash from operating activities year-to-date in 2007 was $1,010 million, an increase of 38 per cent over the same period in 2006.

The Trust has declared a 38 per cent increase in the quarterly distribution amount to $0.55 per Unit from $0.40 per Unit for Unitholders of record on November 16, 2007, payable on November 30, 2007.

CANADIAN OIL SANDS TRUST
Highlights

(millions of Canadian dollars, except Trust unit and volume amounts)	Three Months Ended September 30 2007	Three Months Ended September 30 2006	Nine Months Ended September 30 2007	Nine Months Ended September 30 2006
Net Income	$ 361	$ 278	$ 228	$ 706
Per Trust unit- Basic	$ 0.75	$ 0.60	$ 0.48	$ 1.52
Per Trust unit- Diluted	$ 0.75	$ 0.59	$ 0.48	$ 1.51
Cash from Operating Activities	$ 484	$ 334	$ 1,010	$ 730
Per Trust unit	$ 1.01	$ 0.72	$ 2.11	$ 1.57
Unitholder Distributions	$ 192	$ 140	$ 527	$ 372
Per Trust unit	$ 0.40	$ 0.30	$ 1.10	$ 0.80
Sales Volumes (1)				
Total (MMbbls)	11.5	8.8	30.3	23.4
Daily average (bbls)	124,904	95,438	110,927	85,662
Operating Costs per barrel	$ 20.84	$ 19.68	$ 24.48	$ 28.57
Net Realized Selling Price per barrel				
Realized selling price before hedging	$ 81.23	$ 78.14	$ 75.66	$ 75.61
Currency hedging gains	0.25	0.29	0.28	0.76
Net realized selling price	$ 81.48	$ 78.43	$ 75.94	$ 76.37
West Texas Intermediate (average $US per barrel) (2)	$ 75.15	$ 70.60	$ 66.22	$ 68.29

(1) The Trust's sales volumes differ from its production volumes due to changes in inventory, which are primarily in-transit pipeline volumes, and are net of purchased crude oil volumes.
(2) Pricing obtained from Bloomberg.

Net income in the third quarter of 2007 increased to $361 million ($0.75 per Unit) from $278 million ($0.60 per Unit) in last year's third quarter. Year-to-date in 2007, net income decreased to $228 million ($0.48 per Unit) from $706 million ($1.52 per Unit) in the same period of 2006. The decline reflects a future income tax and other expense of $665 million recorded in the second quarter of 2007, primarily as a result of a 31.5 per cent tax to be applied to publicly traded income trusts in Canada, effective 2011. Earnings before taxes increased by $239 million to $926 million in 2007 compared to the same nine-month period in 2006. Future income tax is a non-cash item that has no current impact on our cash from operating activities.

Strong financial results in the third quarter of 2007 primarily reflected a 31 per cent increase in sales volumes, which averaged about 124,900 barrels per day, combined with a net realized selling price that was roughly $3 per barrel higher than last year's third quarter. Syncrude posted record volumes in August 2007, averaging close to 375,000 barrels per day. During the third quarter of 2007, Coker 8-3 operated at or near design capacity, whereas in the same quarter of 2006, the coker contributed only about one month of incremental production. On a year-to-date basis, Canadian Oil Sands' sales volumes averaged about 110,900 barrels per day in 2007, up 29 per cent over 2006. Both years were impacted by coker maintenance but 2007 benefited more from Coker 8-3 incremental volumes. The higher production volumes were also largely responsible for a $4.09 per barrel decline in 2007 year-to-date operating costs, which averaged $24.48 per barrel, compared to the same period last year.

Energy efficiency at Syncrude improved by 21 per cent year-to-date in 2007 over last year, reflecting better operational performance following the completion of the Stage 3 expansion and energy management initiatives introduced under the Management Services Agreement. In particular, purchased energy consumption declined to 0.75 GJs per barrel of crude oil produced during the 2007 third quarter when Coker 8-3 was operating at or near design capacity. Improved energy efficiency lessens operating costs and carbon dioxide emissions per barrel.

Also during the third quarter of 2007, Syncrude began producing the higher quality Syncrude™ Sweet Premium ("SSP") blend. We believe the new blend has greater market potential than our previous SSB product because of its markedly higher distillate cetane and smoke point characteristics.

"Strong operational performance is the key factor behind our robust third quarter results. While crude oil prices have strengthened, so has the Canadian dollar, reducing the positive contribution of rising prices," said Marcel Coutu, President and Chief Executive Officer. "We are pursuing our plan of optimizing distributions within the context of our $1.6 billion net debt target, continued variability of operations during the lineout of Stage 3, volatility in commodity prices, and importantly, uncertainty regarding Syncrude's Crown royalty terms."

Alberta government announces changes to oil sands royalties

On October 25, 2007 the Alberta government introduced significant increases to royalty terms for Alberta's oil sands sector, effective in 2009, as explained more fully on page 26 of the Management's Discussion and Analysis ("MD&A") section of this report. The Syncrude joint venture owners have a legal contract with the Alberta government that codifies today's royalty rates for Syncrude through to the end of 2015. The government has established a 90-day period to renegotiate the terms of this contract. Canadian Oil Sands and the other Syncrude owners are willing to discuss fair and equitable amendments but any transition to the new royalty terms must recognize and preserve our legal rights to the embedded value in our contract. In the absence of a renegotiated agreement with the government, the Syncrude owners fully expect that this contract and all of its terms will continue until the December 31, 2015 expiry date, maintaining the current royalty rate and allowing Syncrude to convert to a bitumen-based royalty.

Said Mr. Coutu: "We are confident that we can have a productive discussion with the Alberta government that provides a value for value exchange in revising the terms of our legal agreement because the government guides itself by principles of law, which is fundamental to the 'Alberta Advantage'."

In commenting on the revised royalty terms, Mr. Coutu added: "Higher oil sands royalties undoubtedly reduce project economics and the consequent impact on new investment is yet to be determined. At least the government astutely resisted calls for an oil sands severance tax, instead continuing to apply a formula tied to profitability where returns vary with crude oil price levels. A revenue less cost royalty structure recognizes the unique challenges of the oil sands business. While Alberta's oil sands represent a significant resource in what has been historically a politically stable region of the world, they also are technically challenging and expensive to extract and upgrade into a marketable commodity."

"Our unit price performance over the past year has not reflected our improved operating performance over the period and the robust global crude oil price environment. I believe the disjoint is the result of the many government policy changes, which began exactly one year ago today, and include: new taxation to eliminate trust structures; penalties for environmental targets; abolishment of accelerated capital cost allowance, reducing capital investment incentive; and most recently, increases in the royalty burden."

Outlook

The Trust has increased its single point estimate for 2007 production to 111 million barrels, or about 41 million barrels net to the Trust, and tightened the production range to 108 to 114 million barrels, or 40 to 42 million barrels net to the Trust. More information on the Trust's Outlook is provided in the MD&A section of the third quarter 2007 report and the October 31, 2007 guidance document, which is available on the Trust's web site at www.cos-trust.com under "investor information". Canadian Oil Sands plans to release its overview of the 2008 budget in December.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") was prepared as of October 31, 2007 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 months ended September 30, 2007 and September 30, 2006, as well as the audited consolidated financial statements and MD&A of the Trust for the year ended December 31, 2006.

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 belief that the Trust will not be restricted by its net debt to total capitalization financial covenant; the expectation that no crude oil hedges will be entered into in the future; the expected impact on the Trust from announced changes by the Alberta government regarding its royalty regime; any expectations regarding the enforceability of legal rights; the expected timeframe that current tax pools will allow Canadian Oil Sands to shelter income post-2010; the plan to move to fuller payout of cash from operating activities; the potential alternatives to the Trust's current structure post-2010; the expected realized selling price, which includes the anticipated differential to WTI, to be received in 2007 for Canadian Oil Sands' product; the potential amount payable in respect of any future income tax liability; the expected increased reliability and other benefits from the Management Services Agreement between Syncrude Canada Ltd. and Imperial Oil Resources; 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 in 2007 and beyond; the expectation that the SER project will significantly reduce total sulphur dioxide and other emissions; capital expenditures for 2007; the anticipated cost and completion date for the SER project; the level of natural gas consumption in 2007 and beyond; the expectations regarding discussions with the Alberta government over Crown royalties applicable to Syncrude; the expected price for crude oil and natural gas in 2007; the expected production, revenues and operating costs for 2007; the anticipated impact that certain factors such as natural gas and oil prices, foreign exchange and operating costs have on the Trust's cash from operating activities and net income; and the expected impact of any current and future environmental legislation or changes to the Crown royalties regime. 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 impacts of regulatory changes especially as such relate to royalties, taxation, and environmental charges; 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. No assurance can be given that the final legislation implementing the federal tax changes regarding income trusts will not be further changed in a manner which adversely affects the Trust and its Unitholders. To the extent that changes, including the Bill C-52 tax changes, are implemented, such changes could result in the income tax considerations described in this MD&A being materially different in certain respects. 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 2007, oil production from the Syncrude Joint Venture ("Syncrude") totalled 32.1 million barrels, or an average of about 348,400 barrels per day, compared to 26 million barrels, or approximately 283,100 barrels per day, during the same period of 2006. Third quarter 2007 production was seven per cent higher than the 30 million barrel estimate provided in our July 24, 2007 guidance document. Net to the Trust, production totalled 11.8 million barrels in the third quarter of 2007 based on our 36.74 per cent working interest compared with 9.2 million barrels in 2006 based on a 35.49 per cent interest.

The increase in production during the third quarter of 2007 relative to the same quarter in the previous year reflected Coker 8-3 operating at or near design capacity rates following maintenance completed on the unit in June. The improved performance of Coker 8-3 enabled Syncrude to reduce production rates on Cokers 8-1 and 8-2, as planned, early in the third quarter, with the aim of extending their run lengths. August was a record production month with Syncrude posting volumes averaging close to 375,000 barrels per day, although about 20,000 barrels per day were attributable to an inventory drawdown. During the comparable quarter of 2006, along with solid operating performance from the base facility, production from the new Stage 3 expansion commenced at the end of August, contributing roughly one month of incremental volumes in the quarter.

Canadian Oil Sands' operating costs were $20.84 per barrel in the third quarter of 2007, up slightly from $19.68 per barrel in the same quarter last year. Both periods had strong production volumes, minimal maintenance activity, and purchased energy costs of less than $5 per barrel (see the "Operating Costs" section of this MD&A for further discussion).

During the third quarter of 2007, Syncrude began producing the higher quality Syncrude™ Sweet Premium ("SSP") blend. Our recent expectation was that the quality transition from Syncrude Sweet Blend ("SSB") to SSP would occur in 2008 following repairs to the new hydrogen plant; however, the transition occurred earlier than anticipated as a result of the removal of some hydrogen constraints on various units. As discussed in previous disclosures, the new hydrogen plant repairs are still expected to occur in 2008 to secure additional hydrogen feedstock for the continued production of SSP for when the operations reach design capacity rates.

Commencing in this quarterly report we will use the term "synthetic crude oil", or "SCO", to refer to Syncrude's production and our sales volumes in the current and prior periods in lieu of the terms SSB and SSP.

On a year-to-date basis, Syncrude produced 82.6 million barrels in 2007, or an average of 302,400 barrels per day, compared to 66.4 million barrels in the same period of 2006, or a daily average of 243,300 barrels. Net to the Trust, production totalled 30.3 million barrels in 2007 based on our 36.74 per cent working interest, compared with 23.6 million barrels in 2006 based on a 35.49 per cent interest. The increase in year-over-year volumes primarily reflects the additional Stage 3 volumes. While 2007 production from Coker 8-3 was affected by constrained throughput rates until maintenance was performed on the unit in May/June, the coker operated for only about one month during the same nine-month period of 2006. Production in 2007 was also impacted by unplanned maintenance on Coker 8-2 and planned maintenance on various other units, including a turnaround of the LC-Finer. During the same 2006 period, an extensive maintenance program, including an extended turnaround of Coker 8-1, reduced volumes.

Operating costs year-to-date 2007 were $24.48 per barrel, a decrease of $4.09 a barrel from the same 2006 period. Costs in both years reflect coker turnarounds; however, higher volumes resulting from less extensive turnaround and maintenance activity, and lower Syncrude long-term incentive compensation and purchased energy costs resulted in lower per barrel operating costs in 2007 compared to 2006. The decrease in operating costs year-over-year also reflects the improved efficiency and additional volumes from Stage 3 (discussed more fully in the "Operating Costs" section of this MD&A).

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". Syncrude is still lining out the Stage 3 facilities, and therefore is not producing at design rates on a consistent basis. All references to Syncrude's productive capacity in this report refer to barrels per calendar day, unless stated otherwise.

The Trust's production volumes differ from its sales volumes due to changes in inventory, which are primarily in-transit pipeline volumes. These in-transit volumes vary with current production. The growth in production from the Stage 3 facilities also has required Canadian Oil Sands to access more distant markets on additional pipelines to sell its volumes, which generally increases pipeline inventory volumes. The impact of Syncrude's 2007 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)	2007 Q3	2007 Q2	2007 Q1	2006 Q4	2006 Q3	2006 Q2	2006 Q1	2005 Q4
Revenues [1]	$ 936	$ 690	$ 674	$ 646	$ 689	$ 624	$ 473	$ 519
Net income (loss)	$ 361	$ (395)	$ 262	$ 128	$ 278	$ 337	$ 91	$ 174
Per Trust Unit, Basic [2]	$ 0.75	$ (0.82)	$ 0.55	$ 0.27	$ 0.60	$ 0.72	$ 0.20	$ 0.38
Per Trust Unit, Diluted [2]	$ 0.75	$ (0.82)	$ 0.55	$ 0.27	$ 0.59	$ 0.72	$ 0.20	$ 0.37
Cash from operating activities	$ 484	$ 324	$ 202	$ 412	$ 334	$ 209	$ 187	$ 281
Per Trust Unit [2]	$ 1.01	$ 0.68	$ 0.42	$ 0.88	$ 0.72	$ 0.45	$ 0.40	$ 0.61
Unitholder distributions [3]	$ 192	$ 191	$ 144	$ 140	$ 140	$ 139	$ 93	$ -
Per Trust Unit [2]	$ 0.40	$ 0.40	$ 0.30	$ 0.30	$ 0.30	$ 0.30	$ 0.20	$ -
Daily average sales volumes (bbls)	124,904	98,720	108,981	110,185	95,438	86,394	74,929	78,318
Net realized selling price ($/bbl) [4]	$ 81.48	$ 76.81	$ 68.69	$ 63.71	$ 78.43	$ 79.35	$ 70.24	$ 72.07
Operating costs ($/bbl)	$ 20.84	$ 30.13	$ 23.56	$ 23.60	$ 19.68	$ 28.48	$ 40.26	$ 25.54
Purchased natural gas price ($/GJ)	$ 4.99	$ 6.78	$ 6.99	$ 6.51	$ 5.42	$ 5.72	$ 7.42	$ 10.73
Foreign exchange rates (US$/Cdn$):								
Average	$ 0.96	$ 0.91	$ 0.85	$ 0.88	$ 0.89	$ 0.89	$ 0.87	$ 0.85
Quarter- end	$ 1.00	$ 0.94	$ 0.87	$ 0.86	$ 0.90	$ 0.90	$ 0.86	$ 0.86

(1) Revenues after crude oil purchases and transportation expense.

(2) Trust Unit information has been adjusted to reflect the 5:1 Unit split that occurred on May 3, 2006.

(3) Commencing in the fourth quarter of 2005, distributions were recorded in the quarter declared and paid. Previously, distributions were recorded as payable at the end of each quarter even though they were not declared. The change in recording Unitholder distributions did not have any impact on the ultimate distributions declared and paid to the Unitholders or to the timing of such payments nor did it impact Canadian Oil Sands' net income or cash from operating activities.

(4) Net realized selling price after foreign currency hedging.

Five significant changes have occurred over the last eight quarters that have impacted the Trust's financial results:

- The substantive enactment in June 2007 of Bill C-52 Budget Implementation Act, 2007 ("Bill C-52" or "trust taxation") resulted in the recording of a future income tax expense of $665 million in the second quarter of 2007. Canadian Oil Sands is now required to record future income tax related to temporary differences at the Trust level, which represent the differences between the accounting and tax basis of the Trust's net assets. This is a non-cash expense that has no current impact on the Trust's cash from operating activities.
- Syncrude's Stage 3 expansion came on-line at the end of August 2006, increasing Syncrude's productive capacity by about 100,000 barrels per day with a corresponding pro-rata impact on the Trust's revenues, operating costs, and depletion, depreciation and accretion ("DD&A") expense.
- During the second quarter of 2006, Crown royalties shifted to the higher rate of 25 per cent of net revenue, compared to the one per cent of gross revenue rate that had applied since January 1, 2002, increasing Crown royalties expense and somewhat offsetting the revenue increases to net income and cash from operating activities in the latter half of 2006 and all of 2007. As the transition occurred in May 2006, Crown royalties in the second quarter of 2006 did not reflect the full impact of the rate increase.
- Starting in 2007, the Trust's financial results reflect a 36.74 per cent working interest in Syncrude, which represents its increased ownership following the acquisition of Talisman Energy Inc.'s

("Talisman") 1.25 per cent working interest on January 2, 2007. Prior year comparative information is based on the Trust's previous ownership of 35.49 per cent.

- In the last six months, the Canadian dollar has strengthened considerably relative to the U.S. dollar, which has resulted in significant unrealized foreign exchange gains on the revaluation of our U.S. dollar denominated debt and related interest payable, but has resulted in reduced revenues as our sales are priced relative to U.S. dollar West Texas Intermediate ("WTI") prices. The unrealized foreign exchange gains related to our long-term debt are non-cash and therefore only impact net income.

Quarterly variances in revenues, net income, and cash from operating activities are caused mainly by fluctuations in crude oil prices, production and sales volumes, 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 volumes. 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 particularly high per barrel operating costs in the second quarter of 2007 and first quarter of 2006. Natural gas prices are typically higher in winter months as heating demand rises, but this seasonality is significantly influenced by weather conditions and North American natural gas inventory levels.

REVIEW OF FINANCIAL RESULTS

In the third quarter of 2007, net income of $361 million, or $0.75 per Trust unit ("Unit"), exceeded net income of $278 million, or $0.60 per Unit, recorded in the comparable quarter in 2006, primarily as a result of higher revenues and larger foreign exchange gains, offset somewhat by an increase in operating costs, Crown royalties, DD&A and future income tax expenses. Revenues (after crude oil purchases and transportation expense) totalled $936 million, an increase of $247 million, in the third quarter of 2007 relative to 2006. This significant increase was attributable to a 31 per cent increase in sales volumes, a higher net realized selling price and a larger Syncrude working interest. Foreign exchange gains increased earnings before taxes in the third quarter of 2007 relative to the same period of 2006 by $41 million, primarily related to unrealized foreign exchange gains on the translation of U.S. dollar denominated long-term debt.

The revenue and foreign exchange increases were somewhat offset by higher operating costs, which increased to $239 million from $173 million in the comparable quarter of 2006. On a per barrel basis, operating costs in the third quarter of 2007 were $20.84, slightly higher than $19.68 recorded in the same quarter of 2006. Crown royalties were $50 million higher in the third quarter of 2007 relative to the same quarter of 2006 as a result of the increase in net revenues. DD&A expense rose by $31 million quarter-over-quarter, reflecting increased production volumes and a higher depreciation and depletion rate.

Cash from operating activities increased 45 per cent quarter-over-quarter and totalled $484 million in the third quarter of 2007. Nearly half of the Trust's year-to-date cash from operating activities of $2.11 per Unit was generated in the third quarter of 2007, which amounted to $1.01 per Unit, compared to $0.72 per Unit in the same quarter of 2006. Excluding the non-cash increases to unrealized foreign exchange gains, DD&A and future income tax expense, cash from operating activities was affected by the same variables as net income as described above.

Also impacting the Trust's cash from operating activities in the third quarter of 2007 relative to the same quarter of 2006 was a decrease in non-cash working capital requirements, which increased cash from operating activities by $39 million, as shown in the following table. The most significant component of the working capital increase quarter-over-quarter was the $33 million change in inventories, resulting mainly from a decrease in crude oil in the pipelines at September 30, 2007 relative to June 30, 2007, compared to an increase in volumes at September 30, 2006 relative to June 30, 2006. Pipeline volumes will fluctuate depending on production and the volume of crude oil in transit in the pipelines.

	Three Months Ended September 30			Nine Months Ended September 30		
	2007	**2006**	**Variance**	**2007**	**2006**	**Variance**
Cash from (used in) changes in:						
Accounts receivable	$ (32)	$ (21)	$ (11)	$ (98)	$ (120)	$ 22
Inventories	15	(18)	33	4	(4)	8
Prepaid expenses	(6)	(5)	(1)	(2)	(4)	2
Accounts payable and accrued liabilities	30	11	19	67	(16)	83
Less: A/P reclassed to investing and other	7	8	(1)	6	50	(44)
Change in operating non-cash working capital	$ 14	$ (25)	$ 39	$ (23)	$ (94)	$ 71

On a year-to-date basis in 2007, the Trust recorded net income of $228 million, or $0.48 per Unit, compared with net income of $706 million, or $1.52 per Unit, in the same nine-month period of 2006. Cash from operating activities increased 38 per cent and totalled $1,010 million, or $2.11 per Unit, in the nine months ended September 30, 2007 relative to the same period of 2006. Changes in non-cash working capital increased cash from operating activities by $71 million year-over-year.

Net income year-over-year was significantly reduced by the $665 million future income tax expense recorded in the second quarter of 2007. On an earnings before taxes basis, the Trust's results improved by $239 million year-over-year, primarily reflecting the net positive contributions of the incremental Stage 3 volumes and larger foreign exchange gains. Revenues (after crude oil purchases and transportation expense) and foreign exchange gains increased by $514 million and $67 million, respectively, on a year-to-date basis in 2007 relative to the same period in the prior year. The increase in sales volumes on a year-to-date basis contributed to the substantial rise in revenues, which totalled $2.3 billion in 2007. The larger foreign exchange gains are primarily attributable to an increase in unrealized gains recorded on the revaluation of our U.S. dollar denominated debt, reflecting the continued strengthening of the Canadian dollar relative to the U.S. dollar. The 2007 revenue and foreign exchange gains increases were offset somewhat by higher operating expenses of $73 million, Crown royalties of $199 million, and DD&A expense of $80 million year-over-year. The changes in revenues, operating expenses and Crown royalties also impacted cash from operating activities, unlike the unrealized foreign exchange gains, DD&A expense, and future income tax expense which are all non-cash items.

	Three Months Ended September 30			Nine Months Ended September 30		
($ per bbl)	2007	2006	Variance	2007	2006	Variance
Net realized selling price	81.48	78.43	3.05	75.94	76.37	(0.43)
Operating costs	(20.84)	(19.68)	(1.16)	(24.48)	(28.57)	4.09
Crown royalties	(14.32)	(13.01)	(1.31)	(11.49)	(6.37)	(5.12)
Netback	46.32	45.74	0.58	39.97	41.43	(1.46)
Non-production costs	(1.40)	(1.24)	(0.16)	(1.62)	(2.37)	0.75
Administration and insurance	(0.54)	(0.60)	0.06	(0.67)	(0.76)	0.09
Interest, net	(1.83)	(2.78)	0.95	(2.24)	(3.18)	0.94
Depletion, depreciation and accretion	(8.76)	(8.00)	(0.76)	(8.60)	(7.70)	(0.90)
Foreign exchange gain	3.59	0.15	3.44	3.69	1.95	1.74
Future income tax recovery (expense) and other	(5.94)	(1.48)	(4.46)	(23.01)	0.95	(23.96)
	(14.88)	(13.95)	(0.93)	(32.45)	(11.11)	(21.34)
Net income per barrel	31.44	31.79	(0.35)	7.52	30.32	(22.80)
Sales volumes (MMbbls)	11.5	8.8	2.7	30.3	23.4	6.9

Non-GAAP Financial Measure

In previous disclosures, we referred to free cash flow as an indicator of the Trust's ability to repay debt and pay distributions to its Unitholders. It was a measure that did not have any standardized meaning under Canadian generally accepted accounting principles ("GAAP"). However, commencing in the third quarter of 2007, we are no longer discussing free cash flow, but rather refer to the GAAP measure of cash from operating activities, which is derived from our Consolidated Statements of Cash Flows. We also refer to the Trust's cash from operating activities on a per Unit basis, which does not have any standardized meaning under Canadian GAAP. Cash from operating activities per Unit is derived from cash from operating activities reported on the Trust's Consolidated Statement of Cash Flows divided by the weighted-average number of Units outstanding in the period, as used in the Trust's net income per Unit calculations. Cash from operating activities on a per Unit basis determines the Trust's capacity to fund capital expenditures, distributions, and other investing activities without incremental financing. In addition, the Trust refers to various per barrel figures, such as net realized selling prices, operating costs and Crown royalties, which are also considered non-GAAP measures, but provide meaningful information on the operational performance of the Trust. We derive per barrel figures by dividing the relevant revenue or cost figure by our sales net of purchased crude oil volumes in a period. Cash from operating activities per Unit and per barrel figures may not be directly comparable to similar measures presented by other companies or trusts.

Revenues after Crude Oil Purchases and Transportation Expense

	Three Months Ended September 30			Nine Months Ended September 30		
($ millions)	**2007**	**2006**	**Variance**	**2007**	**2006**	**Variance**
Sales revenue [1]	$ 1,033	$ 722	$ 311	$ 2,618	$ 1,938	$ 680
Crude oil purchases	(91)	(27)	(64)	(299)	(141)	(158)
Transportation expense	(8)	(9)	1	(27)	(29)	2
	934	686	248	2,292	1,768	524
Currency hedging gains [1]	2	3	(1)	8	18	(10)
	$ 936	$ 689	$ 247	$ 2,300	$ 1,786	$ 514
Sales volumes (MMbbls) [2]	11.5	8.8	2.7	30.3	23.4	6.9

[1] *The sum of sales revenue and currency hedging gains equals Revenues on the Trust's Consolidated Statement of Income and Comprehensive Income. Sales revenue includes revenue from the sale of purchased crude oil.*
[2] *Sales volumes, net of purchased crude oil volumes.*

($ per barrel)						
Realized selling price before hedging [3]	$ 81.23	$ 78.14	$ 3.09	$ 75.66	$ 75.61	$ 0.05
Currency hedging gains	0.25	0.29	(0.04)	0.28	0.76	(0.48)
Net realized selling price	$ 81.48	$ 78.43	$ 3.05	$ 75.94	$ 76.37	$ (0.43)

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

Sales revenue after crude oil purchases and transportation expense and before currency hedging in the third quarter and first nine months of 2007 primarily reflects increased sales volumes relative to the comparable periods of 2006. The incremental production from the Stage 3 facilities and the Trust's larger Syncrude ownership during the third quarter and year-to-date periods in 2007 resulted in the higher 2007 sales volumes.

The increase in 2007 sales volumes on both a quarterly and year-to-date basis relative to 2006 was complemented by a robust realized selling price before currency hedging in both periods of 2007. Our average realized selling price before currency hedging of $81.23 per barrel in the third quarter of 2007 was $3.09 per barrel higher than the comparable period in 2006. WTI prices, which our SCO pricing has historically closely followed, averaged approximately US$75 per barrel in the third quarter of 2007, an increase of almost $5 per barrel compared to the same quarter of 2006. However, this increase was diluted by a strengthening of the Canadian dollar relative to the U.S. dollar, which averaged $0.96 US/Cdn in the third quarter of 2007 compared to $0.89 US/Cdn in the same quarter of 2006. Also contributing to the higher realized selling price before hedging quarter-over-quarter was a $2.71 per barrel improvement in our pricing differential relative to Canadian dollar WTI. Our SCO realized a weighted-average premium of $2.60 per barrel compared to average Canadian dollar WTI in the third quarter of 2007 versus a discount of $0.11 per barrel in the same period in 2006. We believe the positive differential in the third quarter of 2007 reflected the following factors:

- A continued disconnect of the relationship between WTI and other benchmark light, sweet crude oils that began during the second quarter of 2007. This disconnect somewhat reverted in the third quarter of 2007 contributing to the reduction in the weighted-average premium that we received for our product in the third quarter compared to the second quarter of 2007, but still resulting in a premium over the third quarter of 2006;
- Various crude oil producers experienced operational issues during the third quarter of 2007, which led to market uncertainty and reduction of synthetic crude oil supply; and
- A temporary increase in demand for light, sweet crude (including our synthetic blend) from a major refinery that typically processes more heavy and sour crude oils, due to certain refinery unit processing issues.

On a year-to-date basis, our net realized selling price before currency hedging gains averaged $75.66 per barrel, relatively unchanged from the same period in 2006. While average WTI prices were US$2.07 per barrel lower on a year-to-date basis in 2007 compared to the same period in 2006, averaging US$66.22 per barrel, we realized a premium to average Canadian dollar WTI of $2.40 per barrel in 2007 relative to a discount of $1.62 per barrel in 2006. Foreign exchange rates averaged $0.90 US/Cdn and $0.88 US/Cdn on a year-to-date basis in 2007 and 2006, respectively. The price differential in the first nine months of 2007 substantially reflected the same factors that impacted pricing in the third quarter of 2007. By comparison, in the first nine months of 2006, primarily in the first quarter, the discount from Canadian dollar WTI reflected reduced product demand as a result of refinery outages, increased supply of light crude oil resulting from a pipeline reconfiguration, and downward pressure on SCO prices due to limited pipeline capacity to move crude oil to extended markets. The shift in differentials from discounts to premiums can happen quickly depending on the short-term supply/demand dynamics in the marketplace and pipeline availability for transporting the crude oil.

Operating costs

	Three Months Ended September 30				Nine Months Ended September 30			
	2007		**2006**		**2007**		**2006**	
	$/bbl Bitumen	$/bbl SCO	$/bbl Bitumen	$/bbl SCO	$/bbl Bitumen	$/bbl SCO	$/bbl Bitumen	$/bbl SCO
Bitumen Costs [1]								
Overburden removal	1.38		1.60		1.70		2.30	
Bitumen production [2]	8.33		7.29		8.44		8.08	
Purchased energy [2,4]	1.23		1.84		2.13		2.69	
	10.94	12.31	10.73	12.67	12.27	14.49	13.07	15.26
Upgrading Costs [3]								
Bitumen processing and upgrading [2]		3.83		4.54		4.58		4.80
Turnaround and catalysts		0.25		0.30		1.26		2.92
Purchased energy [4]		2.34		2.21		2.48		3.07
		6.42		7.05		8.32		10.79
Other and research [2]		0.87		0.18		1.05		1.77
Change in treated and untreated inventory		0.63		(0.22)		0.10		0.36
Total Syncrude operating costs		20.23		19.68		23.96		28.18
Canadian Oil Sands adjustments [5]		0.61		-		0.52		0.39
Total operating costs		20.84		19.68		24.48		28.57
(thousands of barrels per day)	Bitumen	SCO	Bitumen	SCO	Bitumen	SCO	Bitumen	SCO
Syncrude production volumes	392	348	334	283	357	302	284	243

[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 SCO based on the effective yield of SCO from the processing and upgrading of bitumen.
[2] Prior year information has been restated for comparative purposes to conform to a revised presentation of costs between bitumen, upgrading and other and research starting in the second quarter of 2007.
[3] Upgrading costs include the production and ongoing maintenance costs associated with processing and upgrading of bitumen to SCO. It also includes the costs of major refining equipment turnarounds and catalyst replacement, all of which are expensed as incurred.
[4] Natural gas prices averaged $4.99/GJ and $5.42/GJ in the third quarters of 2007 and 2006, respectively. For the first nine months of the year, natural gas prices averaged $6.25/GJ and $6.16/GJ in 2007 and 2006, respectively.
[5] Canadian Oil Sands' adjustments mainly pertain to Syncrude-related pension costs, opportunity assessment team costs related to the Management Services Agreement between Syncrude Canada Ltd. and Imperial Oil Resources, 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	
($/bbl of SCO)	**2007**	**2006**	**2007**	**2006**
Production costs	17.12	15.30	19.48	22.36
Purchased energy	3.72	4.38	5.00	6.21
Total operating costs	20.84	19.68	24.48	28.57
(GJs/bbl of SCO)				
Purchased energy consumption	0.75	0.81	0.80	1.01

In the third quarter of 2007, operating costs averaged $20.84 per barrel, an increase from $19.68 per barrel recorded in the same period of 2006. Syncrude's long-term incentive plan changes, which are based on the market return performance of several of Syncrude owners' units/shares and included in operating costs, resulted in an almost $0.80 per barrel increase quarter-over-quarter. The costs that were incurred in 2007 related to the Management Services Agreement between Syncrude Canada Ltd. ("Syncrude Canada") and Imperial Oil increased operating costs by approximately $0.40 per barrel quarter-over-quarter, and the accrual for the Alberta Greenhouse Gas Emissions legislation, which started in July 2007, was approximately $0.30 per barrel in the third quarter of 2007. The Alberta legislation is discussed in further detail in the "Greenhouse Gas Emissions Reduction Requirements" section of this MD&A.

These increases were somewhat offset by a reduction in purchased energy costs, which totalled $3.72 per barrel in the third quarter of 2007 compared to $4.38 per barrel in the same quarter of 2006. Natural gas consumption on a per barrel basis decreased by seven per cent quarter-over-quarter, as a result of efficiencies in the Stage 3 operations and improvements in fuel gas conservation at Syncrude. A reduction in natural gas prices from $5.42 per gigajoule ("GJ") in the third quarter of 2006 to $4.99/GJ in the same quarter of 2007 also contributed to lower purchased energy costs.

On a year-to-date basis, operating costs averaged $24.48 per barrel in 2007, a reduction of $4.09 per barrel compared to the same period in 2006. While coker turnarounds occurred in both years, 2007 experienced less turnaround and maintenance activity and more production in the first nine months relative to the prior year, which reduced operating costs by $1.66 per barrel and is reflected in the decrease in "Turnaround and catalysts" costs in the previous detailed operating cost table. Production costs, excluding turnarounds, have fallen by almost $1 per barrel in 2007 relative to 2006 as a result of more efficient operations and the additional Stage 3 production volumes. A smaller increase in the value of Syncrude's long-term incentive plan relative to 2006 also lowered operating costs year-to-date 2007 by $0.73 per barrel and is reflected in the "Other and research" line in the operating costs table.

Purchased energy costs fell by $1.21 per barrel on a year-to-date basis in 2007 relative to 2006 due to lower per barrel consumption volumes, offset somewhat by higher natural gas prices. Energy consumption decreased by 21 per cent on a per barrel basis in 2007, primarily due to improved operational efficiency. During the first nine months of 2006, Stage 3 units were being commissioned, increasing energy requirements without an offsetting production increase as Stage 3 production did not commence until September 2006.

Non-production costs

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 ("R&D"), and regulatory and stakeholder consultation expenditures. Accordingly, non-production costs can vary depending on the number of projects on-going and the status of the projects. In the third quarter of 2007, non-production costs totalled $16 million, an increase of $5 million from the same quarter in 2006. On a year-to-date basis, non-production costs totalled $49 million in 2007, a decrease of $7 million compared to the same period in 2006. More spending has been incurred in the current year for planning for the next stage of Syncrude's growth, such as drilling for further delineation of current and new mines, as well as Canadian Oil Sands' larger working interest ownership. However, non-production costs in the same period of 2006 included $19 million of Stage 3 commissioning and start-up costs.

Crown Royalties

Under Alberta's current generic Oil Sands 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 net revenues, calculated as gross plant gate revenue before hedging, less allowed Syncrude operating, non-production and capital costs. Crown royalties increased by $50 million to $165 million, or $14.32 per barrel, in the third quarter of 2007 from $115 million, or $13.01 per barrel, in the comparable 2006 quarter. On a year-to-date basis, Crown royalties increased by $199 million to total $348 million, or $11.49 per barrel in 2007, relative to the prior year which reported $149 million, or $6.37 per barrel. The increase in 2007 Crown royalties reflects: a shift to the higher 25 per cent royalty rate, which occurred in the second quarter of 2006; higher net revenues; and a larger Syncrude working interest. The shift to the higher Crown royalty rate is triggered once a project reaches payout by recovering its costs and a return allowance equal to a Government of Canada long-term bond rate. The Alberta government recently announced significant changes to Alberta's oil sands royalty regime effective in 2009, as discussed in further detail in the "Alberta Government Announces New Royalty Terms" section of this MD&A.

Depreciation, depletion and accretion expense

($ millions)	Three Months Ended September 30 2007	Three Months Ended September 30 2006	Nine Months Ended September 30 2007	Nine Months Ended September 30 2006
Depreciation and depletion expense	$ 98	$ 67	$ 252	$ 173
Accretion expense	3	3	8	7
	$ 101	$ 70	$ 260	$ 180

Depreciation and depletion ("D&D") expense for the third quarter and first nine months of 2007 rose by $31 million and $79 million, respectively, compared to the same periods of 2006, reflecting an increase in production volumes and a higher per barrel D&D rate. In 2007 our D&D rate increased by about $1 per barrel from the prior year to approximately $8.30 per barrel. The increase reflects the additional assets and reserves acquired in the January acquisition of an additional 1.25 per cent Syncrude working interest, as well as the updated reserve and higher future development cost estimates provided for in the Trust's December 31, 2006 independent reserves report, which reflect a higher cost environment relative to the prior year.

The Trust's reserves report is summarized in its 2006 Annual Information Form and can be found at www.sedar.com, or on our website at www.cos-trust.com under "investor information".

__Foreign exchange gain__

($ millions)	Three Months Ended September 30 2007		Three Months Ended September 30 2006		Nine Months Ended September 30 2007		Nine Months Ended September 30 2006	
Unrealized foreign exchange (gain)	$	(59)	$	-	$	(146)	$	(48)
Realized foreign exchange loss (gain)		17		(1)		34		3
Total foreign exchange (gain)	$	(42)	$	(1)	$	(112)	$	(45)

Foreign exchange rates as at:

($US/$Cdn)	2007		2006		2005	
September 30	$	1.00	$	0.90		
June 30	$	0.94	$	0.90		
March 31	$	0.87	$	0.86		
December 31			$	0.86	$	0.86

Foreign exchange ("FX") gains/losses are primarily the result of revaluations of our U.S. dollar denominated long-term debt caused by fluctuations in U.S. and Canadian dollar exchange rates. The resulting unrealized FX gains/losses impact net income but do not affect cash from operating activities as they are non-cash items. Other FX gains/losses are created through the revaluation of cash, accounts receivable and payable balances denominated in U.S. dollars, which impact both net income and cash from operating activities as these gains/losses are considered realized. Realized FX gains/losses also result from repayment of U.S. dollar denominated balances, such as long-term debt, in which case the resulting FX impacts are included in financing activities on the Trust's Consolidated Statement of Cash Flows.

In the third quarter of 2007, Canadian Oil Sands' total FX gains primarily related to the revaluation of our U.S. dollar denominated debt. The debt revaluation in the third quarter of 2007 resulted in an unrealized FX gain of $59 million, reflecting continued strengthening of the Canadian dollar on September 30, 2007 from June 30, 2007. By comparison, the value of the Canadian dollar relative to the U.S. dollar was unchanged from September 30, 2006 compared with June 30, 2006, resulting in no unrealized FX amounts in the third quarter of 2006.

On a year-to-date basis in 2007, FX gains increased by $67 million relative to the same period in 2006. Unrealized foreign exchange gains resulting from debt revaluations accounted for $146 million and $48 million of the total FX gains in each of the first nine month periods of 2007 and 2006, respectively, reflecting a stronger Canadian dollar at the end of September relative to December 31 in each year of 2006 and 2005, respectively. Also included in the nine months ended September 30, 2007 was a FX gain of $18 million realized upon repayment of US$70 million of Senior Notes in May 2007. The debt was originally issued in 1997 when the FX rate was $0.73 US/Cdn and was repaid in 2007 when the Canadian dollar had strengthened considerably to $0.91 US/Cdn. Excluding the realized gains on debt repayment, the significant strengthening of the Canadian dollar in 2007 resulted in a realized loss of $52 million, compared to a $3 million loss in the same period of 2006, primarily attributable to U.S. dollar denominated accounts receivable and cash balances.

Future Income Tax and other

The Trust's future income taxes on its Consolidated Balance sheet represent the net difference between tax values and accounting values, referred to as temporary differences, tax-effected at substantively enacted tax rates expected to apply when the differences reverse. In the third quarter of 2007, Canadian Oil Sands' future income tax and other expense increased by $57 million relative to the comparable quarter in 2006. In the third quarter of 2007, Canadian Oil Sands utilized more of its tax pools to shelter current quarter income relative to the comparable quarter of 2006, thereby increasing our taxable temporary differences and creating additional future income tax expense quarter-over-quarter. There were no tax rate changes that impacted the tax provision in the third quarters of 2007 and 2006.

The Trust's year-to-date 2007 future income tax and other expense includes an additional $701 million future income tax expense and corresponding future income tax liability related to the Trust's temporary differences, reflecting the substantive enactment of Bill C-52 in June 2007. Prior to this legislation, which introduces a new 31.5 per cent tax on distributions from Canadian public trusts starting in 2011, Canadian Oil Sands' future income taxes reflected only those temporary differences in the Trust's subsidiaries. While net income on a year-to-date basis in 2007 was reduced significantly by this future tax adjustment, there was no impact on cash from operating activities. This significant expense was partially offset by a future income tax recovery at the subsidiary level relating to the federal tax rate reduction to 18.5 per cent in 2011, and changes to taxable temporary differences relative to the comparable period in 2006.

In response to the income trust tax changes, Canadian Oil Sands is evaluating alternatives as to the best structure for its Unitholders, including consideration of a corporate structure. In Alberta where the Trust is registered, a corporation is subject to a lower overall tax rate than the 31.5 per cent tax that will apply to income trusts post-2010. We also will consider other options that may emerge based on further information from the federal government on details of the legislation and the transition rules. Canadian Oil Sands continues to be a long-term value investment in the oil sands and does not rely on the tax efficiency of a flow-through trust model to sustain our business. Our long-life reserves and non-declining production profile provide a solid foundation to generate cash from operating activities.

In the first quarter of 2007, Canadian Oil Sands recorded an additional future income tax liability on its Consolidated Balance Sheet totalling $327 million, with a corresponding increase to property, plant and equipment, as a result of the 1.25 per cent Syncrude working interest acquisition on January 2 and the subsequent dissolution of the partnership in which the working interest was held. The future income tax liability represents the temporary differences between the book values of the net assets and the related tax pools acquired.

CHANGE IN ACCOUNTING POLICIES

Effective January 1, 2007, the Trust prospectively adopted the Canadian Institute of Chartered Accountant's ("CICA") Handbook Section 3855, *Financial Instruments- Recognition and Measurement*; Section 3865, *Hedges*; Section 1530, *Comprehensive Income* and Section 3861, *Financial Instruments-Disclosure and Presentation*. The impacts of adopting the new standards are reflected in the Trust's 2007 results, and prior year comparative financial statements have not been restated. While the new rules resulted in changes to how the Trust accounts for its financial instruments, there were no material impacts on the Trust's current year financial results. For a description of the new accounting rules and the impact on the Trust's financial statements of adopting such rules, including the impact on the Trust's deferred financing charges, long-term debt, and deferred currency hedging gains, see Note 2 to the unaudited Consolidated Financial Statements for the quarter ending September 30, 2007.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	September 30 2007	December 31 2006
Long-term debt	$ 1,209	$ 1,644
Cash and cash equivalents	(201)	(353)
Net debt	$ 1,008	$ 1,291
Unitholders' equity	$ 3,920	$ 3,956
Total capitalization [1]	$ 4,928	$ 5,247

[1] Net debt plus Unitholders' equity

Net debt to total capitalization (%)	20	25

In January 2007, Canadian Oil Sands made a $237.5 million cash payment and issued 8.2 million Units valued at $237.5 million to Talisman as consideration for the purchase of Talisman's 1.25 per cent indirect Syncrude working interest. The acquisition was followed by the maturity of $195 million of medium term notes on January 15, 2007 and US$70 million of Senior Notes on May 15, 2007, resulting in debt repayments of $272 million in the first half of 2007. The debt repayments were financed by drawing on the Trust's $800 million operating credit facility, all of which has been paid down, leaving no amounts drawn at September 30, 2007. As discussed in Note 2 to the unaudited Consolidated Financial Statements, the Trust recorded a $16 million reduction to its long-term debt as a result of adopting the new financial instruments accounting standards. The reduction reflected the reclassification of deferred financing charges against long-term debt, which were previously recorded in other assets on the Trust's Consolidated Balance Sheet. Including an unrealized foreign exchange gain of $146 million, the Trust's long-term debt decreased by $435 million to $1.2 billion at quarter-end and net debt dropped to $1.0 billion.

As at September 30, 2007, the Trust's unutilized credit facilities amounted to $824 million, net of letters of credit issued against its $40 million revolving term facility and an additional $45 million line of credit. The Trust has a $150 million medium term note maturing on April 9, 2008, which the Trust currently anticipates refinancing on maturity using its available credit facilities.

In response to the income trust tax changes, Canadian Oil Sands adjusted its financial plan by raising its long-term net debt target to $1.6 billion from $1.2 billion, which supports fuller payout of cash from operating activities and conserves tax pools. The Trust believes this net debt target maintains its strong balance sheet, allowing it to remain unhedged on crude oil production and providing the capacity to fund growth opportunities. The Trust's actual net debt will fluctuate around this level as factors such as crude oil prices, FX rates and Syncrude operational performance vary from our assumptions.

The Units issued from treasury in January to partially fund the additional Syncrude working interest acquisition increased Unitholders' equity. However, as the Units were issued directly to Talisman, there was no cash impact. The investing section of the Trust's cash flow statement, therefore, only reflects the cash paid to Talisman for the additional working interest less cash balances acquired. Unitholders' equity was increased by net income of $228 million, but reduced by distributions of $527 million recorded on a year-to-date basis.

UNITHOLDER DISTRIBUTIONS

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	2007	2006	2007	2006
Cash from operating activities	$ 484	$ 334	$ 1,010	$ 730
Net income	$ 361	$ 278	$ 228	$ 706
Unitholder distributions	$ 192	$ 140	$ 527	$ 372
Excess (shortfall) of cash from operating activities over Unitholder distributions [1]	$ 292	$ 194	$ 483	$ 358
Excess (shortfall) of net income over Unitholder distributions [2]	$ 169	$ 138	$ (299)	$ 334

[1] *Cash from operating activities less Unitholder distributions.*
[2] *Net income less Unitholder distributions.*

Cash from operating activities and net income can fluctuate dramatically from period to period, reflecting operational performance and potentially volatile WTI prices, SCO differentials and FX rates. We strive to smooth out this variability by taking a longer-term view of distributions in the context of our outlook for our operating and business environment, including monitoring of our net debt relative to our target and assessing our capital expenditure commitments. In that regard, we may distribute more or less in a period than we generate in cash from operating activities or net income. The distribution depends on numerous factors including our financial and operational performance, working capital requirements and future capital expenditures. Despite management's goal to strive for distribution stability, the highly variable nature of these considerations introduces risk in our ability to sustain or stabilize distributions. Therefore, unwarranted expectations in the stability or sustainment of distributions should not be implied. In addition, the taxation of income trusts commencing January 1, 2011 may materially alter our distribution levels.

A Unitholder distributions schedule pertaining to the quarter ended September 30 is included in Note 11 to the unaudited Consolidated Financial Statements. The Trust uses debt and equity financing to the extent that cash from operating activities is insufficient to fund distributions, capital expenditures, mining reclamation trust contributions, acquisitions and working capital changes from financing and investing activities. Cash from operating activities exceeded distributions by $292 million in the third quarter of 2007. This excess amount was sufficient to pay the Trust's capital expenditures of $45 million and repay $70 million of its drawn credit facilities in the third quarter of 2007. On a year-to-date basis, the $483 million excess of cash from operating activities over Unitholder distributions exceeded capital expenditures totalling $128 million and debt repayments of $272 million. Capital expenditures are discussed more fully in the "Capital Expenditures" section of this MD&A.

Net income exceeded distributions in the third quarters of 2007 and 2006, but to a lesser extent than the cash from operating activities excess as a result of non-cash expenses, such as future income tax and DD&A expense. On a year-to-date basis, distributions exceeded net income in 2007 as a result of the $655 million future income tax expense recorded in the second quarter, primarily related to the enactment of Bill C-52. Despite the net income shortfall, a distribution was paid out as the future tax adjustment was a non-cash item and we do not expect to pay cash taxes for several years because the Trust is not expected to be taxable until at least 2011. As well, we currently have approximately $2 billion in tax pools available to shelter taxable income. The future income tax adjustment was a non-recurring charge and primarily related to the substantive enactment of trust taxation. As such, the excess of distributions over net income in 2007 is not expected to continue. As indicated in previous disclosures, the Trust suspended its Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan ("DRIP") and, as such, the DRIP did not provide additional equity financing in 2007.

In determining the Trust's distributions, Canadian Oil Sands also considers funding for its significant operating obligations, which are included in cash from operating activities. Such obligations include the Trust's share of Syncrude's pension and reclamation funding, which amounted to approximately $30 million and $23 million in the first nine months of 2007 and 2006, respectively, and approximated the related expense for both pension and reclamation of $32 million and $25 million in each of the same year-to-date periods, respectively. While our share of Syncrude's annual pension funding has increased modestly as a result of the most recent actuarial valuation, we do not anticipate material reclamation funding increases for several years.

Debt covenants do not specifically limit the Trust's ability to pay distributions and are not expected to influence the Trust's liquidity in the foreseeable future. Aside from the typical covenants relating to restrictions on Canadian Oil Sands' ability to sell all or substantially all of its assets or to change the nature of its business, the most restrictive financial covenant limits total debt-to-book capitalization at an amount less than 0.55 to 1.0. With a current net debt-to-book capitalization of approximately 20 per cent, a significant increase in debt or decrease in equity would be required to negatively impact the Trust's financial flexibility.

On October 31, 2007, the Trust declared a 38 per cent increase to its quarterly distribution to $0.55 per Unit for total distributions of $263 million. The distribution will be paid on November 30, 2007 to Unitholders of record on November 16, 2007. With the substantial completion of the Stage 3 project, the Trust has increased its quarterly distribution by 175 per cent since the first quarter of 2006. The rise in the Trust's distribution levels is consistent with our previous indications that we would be moving to a fuller payout of cash from operating activities unless capital investment or acquisition opportunities exist that we believe offer Unitholders enhanced value. With the existing productive capacity, we are targeting a long-term net debt level of about $1.6 billion by the end of 2010 and will reconsider this target in light of future Syncrude growth and other acquisition opportunities. In addition, our fourth quarter distribution also considers the continued variability of the operations during lineout of the Stage 3 facilities and uncertainty of the financial impact that the recently announced changes to the Crown royalties and the fiscal regime in Alberta will have on our cash from operating activities.

Capital expenditures

With the completion of Syncrude's Stage 3 project in 2006, Canadian Oil Sands' expansion capital expenditures have been reduced significantly and, as such, current capital costs are essentially all related to sustaining capital. The Trust defines expansion capital expenditures as the costs incurred to grow the productive capacity of the operation, such as the Stage 3 project, while sustaining capital is effectively all other capital and includes the costs required to maintain the current productive capacity of Syncrude's mines and upgraders. Sustaining capital may fluctuate considerably year-to-year due to timing of equipment replacement and other factors. The productive capacity of Syncrude's operations was defined previously in the "Review of Syncrude Operations" section of this MD&A.

In the third quarter of 2007, capital expenditures totalled $45 million, comparable to expenditures of $47 million in the same quarter of 2006. The Syncrude Emissions Reduction ("SER") project accounted for $17 million of the capital spent in the third quarter of 2007 with the remaining $28 million pertaining to the maintenance of Syncrude's existing plant and facilities, all of which are considered sustaining capital. Comparatively, in the same period of 2006, sustaining capital costs of $39 million accounted for most of that period's capital expenditures, which included $10 million related to the SER project. Sustaining capital expenditures on a per barrel basis were $3.95 and $4.44 in the third quarters of 2007 and 2006, respectively.

On a year-to-date basis, capital expenditures totalled $128 million in 2007, about half of the capital costs incurred in the same period of 2006, as a result of the Stage 3 completion in 2006. In the same nine-month period in 2006, Stage 3 costs accounted for $120 million of the $243 million in total capital expenditures. Sustaining capital expenditures year-to-date 2007 were $4.21 per barrel compared with $4.79 per barrel recorded in the same period in 2006. Canadian Oil Sands' revised capital expenditure guidance, as discussed in the Outlook section of this MD&A, estimates sustaining capital expenditures in 2007 will be slightly less than $5 per barrel.

Syncrude is undertaking the SER project to retrofit technology into the operation of Syncrude's original two cokers to significantly reduce total sulphur dioxide and other emissions. While expenditures on the SER project are currently estimated at approximately $772 million, or $284 million net to the Trust based on its 36.74 per cent working interest, as noted in our second quarter 2007 report, there are indications of upward cost pressure on the project. Syncrude is currently performing a full review of the project and will provide updates to cost estimates and timing after such review has been completed. The Trust's share of the SER project expenditures incurred to date is approximately $87 million, with the remaining costs to be incurred in the next three years to coordinate with equipment turnaround schedules.

We estimate sustaining capital expenditures will average approximately $6 per barrel, including the SER project, over the next three years. Excluding major sustaining capital expenditure projects which occur from time to time, such as the SER project, we anticipate average sustaining capital expenditures of approximately $5 per barrel, or about $240 million annually, net to the Trust, based on annual Syncrude productive capacity of 128 million barrels, or 47 million barrels net to the Trust.

The next significant growth stage for Syncrude's facilities is anticipated to be the Stage 3 debottleneck. We estimate the project will increase Syncrude productive capacity by 30,000 to 50,000 barrels per day. Based on the current business environment, this incremental production is expected to be achieved by 2012. Following the Stage 3 debottleneck, the Stage 4 expansion is planned to grow Syncrude capacity by a further 100,000 barrels per day, resulting in total productive capacity of approximately 500,000 barrels per day post-2016. Spending on each of these respective projects is expected to commence several years prior to the incremental production coming on-stream. The plans for these projects are preliminary and have not been approved by the Syncrude owners, and as such, may change. No cost estimates have been provided for either of these projects because they are still in the early planning stages.

At the end of May 2007, Canadian Oil Sands completed the sale of the remaining conventional properties that it acquired in 2006 from Canadian Arctic Gas Ltd, formerly Canada Southern Petroleum Ltd. The conventional properties which the Trust owned up to May 31, 2007 did not generate material income in 2007 and is reflected in "Discontinued operations" on the Trust's Consolidated Statements of Income and Comprehensive Income.

UNITHOLDERS' CAPITAL AND UNIT TRADING ACTIVITY

The Trust's Units trade on the Toronto Stock Exchange under the symbol COS.UN. The Trust had a market capitalization of approximately $16 billion with 479 million Units outstanding and a closing price of $33.00 per Unit on September 28, 2007.

Canadian Oil Sands Trust - Trading Activity	**Third Quarter 2007**	**September 2007**	**August 2007**	**July 2007**
Unit price				
High	$ 35.27	$ 34.08	$ 33.24	$ 35.27
Low	$ 28.65	$ 30.35	$ 28.65	$ 31.13
Close	$ 33.00	$ 33.00	$ 30.49	$ 32.58
Volume traded (millions)	98.8	27.5	28.2	43.1
Weighted average Trust units outstanding (millions)	479	479	479	479

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

As of September 30, 2007, excluding current year spending, the Trust's share of Syncrude's capital expenditure commitments totalled $301 million, increasing by $40 million from December 31, 2006. The incremental capital expenditure commitments are expected to be incurred over the next two years. Syncrude's pension plan actuarial valuation for December 31, 2006 was completed in the second quarter of 2007, which confirmed an increase to our share of Syncrude's pension funding of approximately $5 million per year for the next five years. There have been no other significant changes to the Trust's contractual obligations and commitments in 2007 from our 2006 year-end disclosure, other than reductions to the capital expenditure and various payment obligation commitments as a result of expenditures incurred in the first nine months of the year and changes in long-term debt.

FINANCIAL RISK MANAGEMENT

Crude Oil Price Risk

As Canadian Oil Sands did not have any crude oil price hedges in 2007 and 2006, revenues were not impacted by crude oil hedging gains or losses and benefited fully from strong WTI prices. As at September 30, 2007 and, based on current expectations, the Trust remains unhedged on its crude oil price exposure. However, we may hedge our crude oil production in the future as part of our growth financing strategies.

Foreign Currency Hedging

As at September 30, 2007, we had US$5 million hedged at an average FX rate of $0.69 US/Cdn. At the present time, we do not intend to increase our currency hedge positions. However, the Trust may hedge foreign exchange rates in the future, depending on the business environment and growth opportunities.

Interest Rate Risk

Canadian Oil Sands' net income and cash from operating activities are impacted by interest rate changes based on the amount of floating rate debt outstanding. At September 30, 2007, we did not have any amounts drawn on our credit facilities, which bear interest at a floating rate based on bankers' acceptances plus a credit spread. The Trust's other floating rate debt was repaid in January.

With the adoption of the new financial instrument accounting rules, all of the Trust's financial risk management activities are now recorded on its Consolidated Balance Sheet at fair value. The Trust did not have any significant financial derivatives outstanding at September 30, 2007.

FOREIGN OWNERSHIP

Based on information from the statutory declarations by Unitholders, we estimate that, as of August 7, 2007, approximately 31 per cent of our Unitholders are non-Canadian residents with the remaining 69 per cent being Canadian residents. Canadian Oil Sands' Trust Indenture provides that not more than 49 per cent of its Units can be held by non-Canadian residents.

The Trust continues to monitor its foreign ownership levels on a regular basis through declarations from Unitholders. The next declarations to be requested will be as of November 16, 2007. The Trust posts 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, as well as the Trust's Annual Information Form dated March 15, 2007, describe the Trust's steps for managing its non-Canadian resident ownership levels.

ALBERTA GOVERNMENT ANNOUNCES NEW ROYALTY TERMS

On October 25, 2007 the Alberta government announced significant changes to the province's Crown royalty framework, establishing new royalty terms for Alberta's energy sector that will be effective in 2009. The new royalty regime for oil sands projects, like Syncrude, would be based on a sliding scale royalty rate ranging from one to nine per cent pre-payout and 25 to 40 per cent post-payout that responds to WTI price levels. The pre-payout rate will start at one per cent of revenue and increase for every dollar oil is priced above $55 per barrel, to a maximum of nine per cent of revenue when oil is priced at $120 or higher. The net royalty applied post-payout will start at 25 per cent of net revenue and increase for every dollar oil is priced above $55 per barrel up to a maximum of 40 per cent of net revenue when oil reaches $120 a barrel or higher.

Syncrude is in the post-payout period and is currently paying Crown royalties at the rate of 25 per cent of net revenues from the sale of fully upgraded product. This rate is based on a legal contract the Syncrude joint venture owners have with the Alberta government which establishes current Crown royalty terms to December 31, 2015. While the government, in its October 25, 2007 announcement, indicated there would be no grandfathering provisions, it did recognize the existing contract with Syncrude's owners and has established a 90 day negotiation period to renegotiate the terms of the contract. Canadian Oil Sands and other Syncrude owners are willing to discuss any fair and equitable treatment but any transition to the new generic royalty terms must recognize and preserve our legal rights to the significant embedded value in our contract.

Under its Crown Agreement, Syncrude also retains the option to 2010 to convert to a bitumen-based royalty, consistent with the rest of the industry. Syncrude is currently assessing the merits of exercising this option, which is dependent upon certain items being resolved, including details regarding recapture of upgrader growth capital investment. Prior to the option being elected, a market-based bitumen valuation methodology needed to be established, which now appears to have been addressed under the new royalty framework. The government has indicated that it will adopt a permanent generic "bitumen valuation methodology" by June 30, 2008 after consulting with stakeholders and independent advisors.

Canadian Oil Sands, as one of the Syncrude owners, is willing to negotiate with the Alberta government in good faith, both the conversion to a bitumen-based royalty plus an equitable solution to offset Syncrude's transition to the higher generic royalty rate prior to 2016, as long as our legal rights are protected.

Canadian Oil Sands believes the royalty regime changes announced by the government likely will result in reducing oil sands development activity and thereby have a significant negative impact on Alberta and Canada's economy. Some projects may not proceed over their planned timeframe, if at all, and some of the lower grade oil sand resource, which form part of every project, may never be recovered due to a now higher economic threshold. The future success of the oil sands industry depends on its ability to continually attract major investment capital. The development of the oil sands has unique challenges: multi-billion dollar capital construction costs, multi-year lead times before costs are recovered and a profit can be realized, and higher operating costs compared to conventional crude oil production. As such, a stable fiscal regime that does not add incremental risks, while providing a rate of return that is competitive with other regimes around the world is critical to attracting and retaining investment capital.

GREENHOUSE GAS EMISSIONS REDUCTION REQUIREMENTS

Bill 3, the Alberta government's legislation to reduce greenhouse gas ("GHG") emission intensity, came into effect on July 1, 2007. Bill 3 states that facilities emitting more than 100,000 tonnes of GHGs a year ("Large Emitters") must reduce their emissions intensity by 12 per cent over the average emissions intensity levels of 2003, 2004 and 2005; if they are not able to do so, these facilities will be required to pay $15 per tonne for every tonne above the 12 per cent target, beginning July 1, 2007. The payments will be deposited into an Alberta-based technology fund for developing infrastructure to reduce emissions or support research into climate change solutions. Large Emitters also have the option of investing in projects outside of their operations that reduce or offset emissions on their behalf, providing these projects are Alberta-based and the emission reductions follow a quantification protocol established by the province and are independently verified.

During the third quarter of 2007, Syncrude began accruing approximately $0.30 per barrel, which is reflected in the Trust's operating costs. This cost is a preliminary estimate based on Syncrude's expected CO_2 emission intensity and is pending clarification from the Alberta government regarding details of the Bill's implementation, the calculation of the base-line emissions target and the actual 2007 emissions measurements. No cost estimates are available yet for future years. Syncrude has initiated a number of studies and programs to reduce CO_2 intensity, such as process unit optimization and flare system management, which have achieved some early results. However, it is still too preliminary in the process to determine the success of the emission reduction efforts.

On April 27, 2007, the federal government released the Regulatory Framework for Air Emissions (the "Framework") which also sets out new GHG and air pollutant emission reduction targets. The Framework establishes an emission-intensity reduction target for existing facilities of six per cent per year to 2010, resulting in an initial enforceable reduction of 18 per cent from 2006 emission-intensity levels starting in 2010. Every year thereafter, a two per cent continuous emission-intensity improvement will be required. In addition to GHGs, the Framework requires reduction in air pollutants such as nitrogen oxides (NOx), Sulphur Oxides (SOx), Volatile Organic Compounds (VOCs), and Particulate Matter (PM) post-2012. Compliance with the new requirements would allow contribution to a technology fund until 2017 at a rate of $15 per tonne from 2010 to 2012, increasing to $20 per tonne and escalating by the rate of GDP growth from 2013 to 2017. Maximum compliance can be met through contributions to the technology fund of up to 70 per cent in 2010 declining to 10 per cent by 2017. After 2017, contributions to the technology fund are no longer possible, and an emissions trading market within Canada and the active pursuit of linkages with U.S. and Mexico and possibly international markets is envisioned. The Framework expressly contemplates funding projects including carbon capture and sequestration and a carbon dioxide (CO_2) pipeline in Alberta. Syncrude Canada is a member of the Integrated CO_2 Network (ICON), a group formed to explore the viability of developing a large scale Canadian CO_2 capture, transportation and storage network.

The federal government's Framework forms the basis for consultations, with draft regulations anticipated to be released in spring 2008. Specifics regarding implementation of the Framework and harmonization between the Framework and Alberta's Bill 3 remain unresolved, making it difficult for Canadian Oil Sands to provide an accurate estimate of the cost impact for compliance with the proposed federal regulations; however, the Framework is a challenging plan that could have a significant adverse effect on operating costs and/or require significant capital investment.

2007 OUTLOOK

We have increased our single point estimate for 2007 production to 111 million barrels, or approximately 41 million barrels net to the Trust with a production range of 108 to 114 million barrels, or 40 to 42 million barrels based on our 36.74 per cent interest. The one million barrel increase in our annual single point estimate reflects Syncrude's actual production to the end of September 2007 exceeding our previous guidance for that nine-month period, resulting from better than anticipated operational reliability, combined with our fourth quarter production estimate of about 28 million barrels.

On September 30, 2007 an operational upset occurred with Coker 8-3 that led to an unplanned outage of the unit for approximately one week. Bitumen feed was reintroduced into the coker on October 5, but it has been operating below design capacity with production rates increased on the other two cokers to partially mitigate the production loss. Consequently, the low end of our production range continues to reflect the possibility that another coker turnaround may be required later this year, as well as the contingency that Coker 8-3 may need to be taken down for maintenance to remove coke deposits within the unit. The high end of the production range has been reduced by one million barrels from our previous guidance to reflect the impact of the Coker 8-3 operational upset in October, but continues to reflect: no coker turnaround for the remainder of the year, as currently planned; Coker 8-3 returning to full production rates; and higher than budgeted operational reliability and stability for the other units.

We have increased our WTI crude oil price estimate for the year to average US$70 per barrel with a positive $1.50 per barrel 2007 price differential between SCO and average Canadian dollar WTI. The improvement to the estimated differential reflects the $2.40 per barrel positive differential realized in the first nine months of the year and an estimated discount of approximately $1 per barrel for the last quarter of 2007, reflecting a more stable market than the first three quarters of the year. These estimates, together with a stronger average foreign exchange rate of $0.94 US/Cdn for the year, are expected to result in 2007 revenues totalling $3.1 billion.

Operating costs are estimated at $24.87 per barrel, which includes $5.60 per barrel for purchased energy based on an average AECO natural gas price of $6.50/GJ for 2007. Going forward, we expect to see upward pressure on operating costs as a result of increases in globally-priced inputs, such as steel, cement and equipment, and inflation in the Fort McMurray region. Syncrude's focus is to improve operational reliability, which is supported by implementation of performance initiatives under the Management Services Agreement, as we believe that this effort has the best potential to contribute to lower per barrel operating costs and mitigate the effect of inflation.

We estimate cash from operating activities to total $1,426 million, or $2.98 per Unit. We estimate Crown royalties expense to total $454 million, or $11.14 per barrel, in 2007 (including $10.13 per barrel in the fourth quarter). We also have reduced our capital expenditures estimate from $226 million to $199 million as Syncrude has deferred spending on some of the Stage 3 completion and modification costs, which we had originally anticipated to occur in 2007. The revised 2007 estimate is substantially related to sustaining capital, including $68 million for the SER project. Guidance for 2008 will be provided by the Trust in December 2007.

We estimate that virtually all of the distributions paid in 2007 will be taxable as other income. The actual taxability of the 2007 distributions will be determined and reported to Unitholders prior to the end of the first quarter of 2008. The Trust's 2006 distributions were 97 per cent taxable.

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 and pipeline access for synthetic crude oil in the North American markets could impact the price differential for SCO relative to crude benchmarks; however, these factors are difficult to predict.

2007 Outlook Sensitivity Analysis

Variable [1]	Annual [2] Sensitivity	Cash from Operating Activities Increase $ millions	$/Trust unit
Syncrude operating costs decrease	C$1.00/bbl	31	0.06
Syncrude operating costs decrease	C$50 million	14	0.03
WTI crude oil price increase	US$1.00/bbl	27	0.06
Syncrude production increase	2 million bbls	39	0.09
Canadian dollar weakening	US$0.01/C$	22	0.05
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 cash from operating activities impacts.
[2] Sensitivities assume a larger change in unrealized quarters to result in the annual impact.

More information on the Trust's outlook is provided in the October 31, 2007 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 COMPREHENSIVE INCOME

(unaudited)

($ millions, except per Unit amounts)	Three Months Ended September 30 2007	Three Months Ended September 30 2006	Nine Months Ended September 30 2007	Nine Months Ended September 30 2006
Revenues	$ 1,035	$ 725	$ 2,626	$ 1,956
Crude oil purchases and transportation expense	(99)	(36)	(326)	(170)
	936	689	2,300	1,786
Expenses:				
Operating	239	173	741	668
Non-production	16	11	49	56
Crown royalties	165	115	348	149
Administration	4	3	14	12
Insurance	2	1	6	5
Interest, net (Note 10)	21	24	68	74
Depreciation, depletion and accretion	101	70	260	180
Foreign exchange gain	(42)	(1)	(112)	(45)
	506	396	1,374	1,099
Earnings before taxes	430	293	926	687
Future income tax expense (recovery) and other (Note 9)	69	12	697	(22)
Net income from continuing operations	361	281	229	709
Loss from discontinued operations	-	(3)	(1)	(3)
Net income	361	278	228	706
Other comprehensive loss, net of income taxes				
Reclassification of derivative gains to net income	(2)	-	(6)	-
Comprehensive income	$ 359	$ 278	$ 222	$ 706
Weighted average Trust Units (millions)	479	467	479	465
Trust Units, end of period (millions)	479	468	479	468
Net income (loss) per Trust Unit :				
Net income from continuing operations				
Basic	$ 0.75	$ 0.60	$ 0.48	$ 1.52
Diluted	$ 0.75	$ 0.60	$ 0.48	$ 1.52
Net income (loss) from discontinued operations				
Basic	$ -	$ (0.01)	$ -	$ (0.01)
Diluted	$ -	$ (0.01)	$ -	$ (0.01)
Net income				
Basic	$ 0.75	$ 0.60	$ 0.48	$ 1.52
Diluted	$ 0.75	$ 0.59	$ 0.48	$ 1.51

CANADIAN OIL SANDS TRUST

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY

(unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2007**	**2006**	**2007**	**2006**
Retained earnings				
Balance, beginning of period, as previously reported	$ 1,223	$ 1,566	$ 1,692	$ 1,370
Transition adjustment on adoption of Financial Instruments standards (Note 2)	-	-	(1)	-
Balance, beginning of period, adjusted	1,223	1,566	1,691	1,370
Net income	361	278	228	706
Unitholder distributions (Note 11)	(192)	(140)	(527)	(372)
Balance, end of period	1,392	1,704	1,392	1,704
Accumulated other comprehensive income				
Balance, beginning of period	26	-	-	-
Transition adjustment on adoption of Financial Instruments standards (Note 2)	-	-	30	-
Other comprehensive loss	(2)	-	(6)	-
Balance, end of period	24	-	24	-
Unitholders' capital				
Balance, beginning of period	2,499	2,121	2,260	2,010
Issuance of Trust Units (Note 5)	-	69	239	180
Balance, end of period	2,499	2,190	2,499	2,190
Contributed surplus				
Balance, beginning of period	4	3	4	3
Stock-based compensation	1	-	1	-
Balance, end of period	5	3	5	3
Total Unitholders' equity	$ 3,920	$ 3,897	$ 3,920	$ 3,897

CANADIAN OIL SANDS TRUST
CONSOLIDATED BALANCE SHEETS
(unaudited)

($ millions)	September 30 2007	December 31 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 201	$ 353
Accounts receivable	342	244
Inventories	80	84
Prepaid expenses	9	7
Derivative assets (Note 2)	2	-
	634	688
Property, plant and equipment, net	6,423	5,739
Other assets		
Goodwill	52	52
Assets held for sale	-	6
Reclamation trust	35	30
Deferred financing charges, net and other (Note 2)	-	17
	87	105
	$ 7,144	$ 6,532
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 371	$ 304
Current portion of employee future benefits	16	11
	387	315
Employee future benefits and other liabilities	99	100
Long-term debt (Note 2)	1,209	1,644
Asset retirement obligation	186	173
Deferred currency hedging gains (Note 2)	-	35
Future income taxes (Note 9)	1,343	309
	3,224	2,576
Unitholders' equity	3,920	3,956
	$ 7,144	$ 6,532

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

($ millions)	Three Months Ended September 30 2007	Three Months Ended September 30 2006	Nine Months Ended September 30 2007	Nine Months Ended September 30 2006
Cash provided by (used in):				
Cash from (used in) operating activities				
Net income	$ 361	$ 278	$ 228	$ 706
Items not requiring outlay of cash:				
Depreciation, depletion and accretion	101	70	260	180
Foreign exchange on long-term debt	(59)	-	(146)	(48)
Future income tax expense (recovery)	68	13	696	(21)
Other	1	-	(3)	3
Net change in deferred items	(2)	(2)	(2)	4
Funds from operations	470	359	1,033	824
Change in non-cash working capital	14	(25)	(23)	(94)
Cash from operating activities	484	334	1,010	730
Cash from (used in) financing activities				
Repayment of medium term and Senior Notes (Note 8)	-	-	(272)	-
Net drawdown (repayment) of bank credit facilities	(70)	(30)	-	(92)
Unitholder distributions (Note 11)	(192)	(140)	(527)	(372)
Issuance of Trust Units (Note 5)	(1)	69	1	180
Cash used in financing activities	(263)	(101)	(798)	(284)
Cash from (used in) investing activities				
Capital expenditures	(45)	(47)	(128)	(243)
Acquisition of additional Syncrude working interest (Note 4)	-	-	(231)	-
Acquisition of Canadian Arctic Gas Ltd.	-	(151)	-	(151)
Disposition of properties	-	-	4	-
Reclamation trust funding	(1)	(2)	(4)	(4)
Change in non-cash working capital	(7)	(6)	(5)	(50)
Cash used in investing activities	(53)	(206)	(364)	(448)
Increase (decrease) in cash and cash equivalents	168	27	(152)	(2)
Cash and cash equivalents at beginning of period	33	59	353	88
Cash and cash equivalents at end of period	$ 201	$ 86	$ 201	$ 86
Cash and cash equivalents consist of:				
Cash			$ 1	$ 17
Short-term investments			200	69
			$ 201	$ 86

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS
FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2007
(Tabular amounts expressed in millions of Canadian dollars, except where otherwise noted.)

1) BASIS OF PRESENTATION

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 ("GAAP"). 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, 2006, except as discussed in Note 2. 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, 2006.

2) CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2007, Canadian Oil Sands adopted the requirements of the Canadian Institute of Chartered Accountants ("CICA") related to the new financial instruments accounting framework, which encompasses the following new CICA Handbook sections: 3855 *Financial Instruments – Recognition and Measurement*, 1530 *Comprehensive income*, and 3861 *Financial Instruments – Disclosure and Presentation*. The CICA Handbook section 3865 *Hedges* is effective January 1, 2007, however, Canadian Oil Sands has elected not to apply hedge accounting on a go-forward basis, and, therefore, has only applied the transitional provisions of this Handbook section.

These new Handbook sections provide comprehensive requirements for the recognition and measurement of financial instruments, and introduce a new component of equity referred to as accumulated other comprehensive income ("AOCI"). In accordance with the transitional provisions of all of the new sections, the comparative interim consolidated financial statements have not been restated.

Under these new standards, all financial instruments, including derivatives, are recognized on the Trust's Consolidated Balance Sheet. Derivatives are measured at fair value with unrealized gains and losses reported in net income. Short-term investments are measured at fair value with unrealized gains and losses reported in AOCI. The Trust's other financial instruments (accounts receivable, accounts payable, and long-term debt) are measured at amortized cost using the effective interest rate method. Transaction costs are added to the amount of the associated financial instrument and amortized accordingly.

Several adjustments to the Trust's consolidated financial statements were required upon transition to the new financial instruments framework, which were the following:

Deferred currency hedging gains

In 1996, Canadian Oil Sands entered into currency hedging contracts to fix the exchange rate in future years. During 1999, Canadian Oil Sands unwound various positions and exchanged the resulting gains for adjustments to other existing currency contracts. These gains were deferred and as at December 31, 2006, the remaining cumulative deferral of the unrecognized gains was $35 million. Prior to the adoption of the new standards, the remaining deferral was to be recognized as revenue over the period 2007 to 2016 which is when the hedging contracts would have expired had they not been unwound.

On transition, the deferred currency hedging gains of $35 million were reclassified to opening AOCI. The related future income tax asset of $10 million was reclassified from Canadian Oil Sands' future income tax liability to AOCI. The deferred gains included in AOCI will be amortized on a straight-line basis into net income and recorded as currency hedging gains in the Trust's revenues over the period 2007 to 2016, with a corresponding decrease to other comprehensive income, net of future income tax.

Long-term debt and deferred financing charges

Prior to the adoption of the new standards, the Trust's long-term debt was recorded at cost. The related financing charges were included in "Deferred financing charges, net and other" on the Trust's Consolidated Balance Sheet, and recognized in net income over the life of the debt.

Under the transitional provisions of Handbook section 3855 *Financial Instruments – Recognition and Measurement*, the Trust's long-term debt is now recorded at amortized cost using the effective interest rate method. The related financing charges have been included in the cost of the long-term debt. As a result of these changes, "Deferred financing charges, net and other" of $16 million, which was previously recorded as assets of the Trust, were reclassified to "Long-term debt" on the Consolidated Balance Sheet, and $1 million was recorded as a decrease to opening retained earnings.

Currency exchange contracts and interest rate swaps

Prior to the adoption of the new standards, one foreign currency exchange contract with an estimated fair value gain of $6 million was outstanding. The derivative had been designated as a hedge, and therefore was not recorded on the Trust's Consolidated Balance Sheet. Beginning January 1, 2007, Canadian Oil Sands is no longer applying hedge accounting to any of its hedging activities.

Based on the transitional provisions of Handbook section 3865 *Hedges,* the Trust's foreign currency exchange contract was recognized on the Consolidated Balance Sheet and included in "Derivative assets" at its estimated fair value of $6 million on January 1, 2007, with a corresponding increase to opening AOCI. On adoption, a $2 million increase to the Trust's future income tax liability and a corresponding reduction to AOCI were also recorded related to the foreign currency hedge. This foreign currency contract will be settled by December 31, 2007.

The Trust also had an interest rate swap on its US$70 million Senior Notes, which did not qualify for hedge accounting prior to January 1, 2007. The $1 million liability representing the unrecognized gains on the swap was recorded on the Trust's Consolidated Balance Sheet and included in "Employee future benefits and other liabilities" at December 31, 2006. On adoption of the new accounting rules on January 1, 2007, the liability balance was reclassed to opening AOCI. This interest rate swap was settled May 15, 2007.

Determination of fair value

The fair value of the Trust's long-term debt, which is disclosed in the notes to the Trust's 2006 annual financial statements, and derivatives are determined based on market price indications.

Comprehensive income

The Consolidated Statements of Income and Comprehensive Income include a new line item for comprehensive income, which includes both net income and other comprehensive income. Other comprehensive income includes recognition of unrealized gains and losses on derivatives and hedging gains that were previously deferred, net of the related future income tax on those items.

3) FUTURE CHANGES IN ACCOUNTING POLICIES

Capital disclosures

The CICA issued a new accounting standard, Section 1535 *Capital Disclosures*, which requires the disclosure of both qualitative and quantitative information that provides users of financial statements with information to evaluate the entity's objectives, policies and processes for managing capital. This new section is effective for the Trust beginning January 1, 2008.

Financial Instruments – Disclosure and Financial Instruments – Presentation

Two new accounting standards were issued by the CICA, Section 3862 *Financial Instruments – Disclosures*, and Section 3863 *Financial Instruments – Presentation*. These sections will replace Section 3861 *Financial Instruments – Disclosure and Presentation* once adopted. The objective of Section 3862 is to provide users with information to evaluate the significance of the financial instruments on the entity's financial position and performance, the nature and extent of risks arising from financial instruments, and how the entity manages those risks. The provisions of Section 3863 deal with the classification of financial instruments, related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset. These new sections are effective for the Trust beginning January 1, 2008.

Inventories

In June 2007, the CICA issued a new accounting standard – Section 3031 *Inventories*, which replaces the existing standard for inventories, Section 3030. The main features of the new Section are as follows:

- Measurement of inventories at the lower of cost and net realizable value
- Consistent use of either first-in, first-out or a weighted average cost formula to measure cost
- Reversal of previous write-downs to net realizable value when there is a subsequent increase to the value of inventories

The new Section is effective for the Trust beginning January 1, 2008. Application of the new Section is not expected to have an impact on the financial statements.

4) ACQUISITION OF ADDITIONAL SYNCRUDE WORKING INTEREST

On January 2, 2007, a subsidiary of the Trust closed an acquisition with Talisman Energy Inc. ("Talisman") to purchase an additional 1.25 per cent indirect working interest in the Syncrude Joint Venture ("Syncrude") for total consideration of $476 million ($468 million net of $8 million cash acquired), including acquisition-related costs of approximately $1 million. The transaction price was comprised of $237.5 million in cash and 8,189,655 Units issued from treasury with an approximate value at the time of entering the acquisition agreement of $29 per Unit.

The acquisition has been accounted for as a purchase of assets in accordance with Canadian GAAP. The Trust has allocated the purchase price to the assets and liabilities as follows:

Net assets and liabilities assumed		
Property, plant and equipment	$	668
Cash		8
Working capital		1
Employee future benefits and other liabilities		(8)
Asset retirement obligation		(6)
Future income taxes		(187)
	$	476
Consideration		
Cash	$	238
Issuance of Trust Units		237
Acquisition costs		1
	$	476

The additional 1.25 per cent working interest that Canadian Oil Sands acquired was held in a partnership owned by Talisman and a subsidiary of the Trust. Immediately following Canadian Oil Sand's acquisition of Talisman's interest in the partnership, the partnership was dissolved. The dissolution resulted in an adjustment, which increased Canadian Oil Sands' future income tax liability by $140 million and correspondingly increased its property, plant and equipment on the Consolidated Balance Sheet, which was accounted for prospectively.

5) ISSUANCE OF TRUST UNITS

In the nine months ended September 30, 2007, approximately 8.2 million Units were issued for proceeds of $238 million related to the acquisition of the 1.25 per cent indirect working interest in Syncrude.

The following table summarizes Units that have been issued:

Date	Number of Units		Amount
Balance, January 1, 2007	470.9	$	2,260
Issued for acquisition of additional Syncrude working interest (non-cash)	8.2		237
Issued on exercise of employee options	0.2		2
Balance, September 30, 2007	479.3	$	2,499

6) 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 to most of its employees. Other 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, 2007 and 2006 is based on its 36.74 per cent and 35.49 per cent working interests in each of those periods, respectively. The costs have been recorded in operating expense as follows:

	Three Months Ended September 30				Nine Months Ended September 30			
		2007		2006		2007		2006
Defined benefit plans:								
Pension benefits	$	6	$	7	$	20	$	15
Other benefit plans		1		1		3		2
	$	7	$	8	$	23	$	17
Defined contribution plans		-		-		1		1
Total Benefit cost	$	7	$	8	$	24	$	18

7) BANK CREDIT FACILITIES

		Credit facility
Extendible revolving term facility (a)	$	40
Line of credit (b)		45
Operating credit facility (c)		800
	$	885

a) The $40 million extendible revolving term facility is a 364-day facility with a one year term out, expiring April 24, 2008. 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 $45 million line of credit is a one year revolving letter of credit facility. The amount of this facility was increased during the first quarter to $45 million from $35 million at December 31, 2006. 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 $61 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, 2012. 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. As at September 30, 2007 and 2006, no amounts were drawn on this facility.

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.

8) LONG-TERM DEBT

On January 15, 2007, the Trust repaid $175 million of 3.95% medium term notes and $20 million of floating rate medium term notes. On May 15, 2007, the Trust repaid US$70 million of 7.625% Senior Notes.

9) FUTURE INCOME TAX

On June 12, 2007, the new Trust taxation rules previously announced by the Canadian federal government on October 31, 2006 became substantively enacted. As a result, the future income tax payable on the Trust's temporary differences between the accounting basis and the tax basis of its assets and liabilities was recorded starting in the second quarter of 2007.

10) INTEREST, NET

	Three Months Ended September 30		Nine Months Ended September 30	
	2007	**2006**	**2007**	**2006**
Interest expense on long-term debt	$ 22	$ 26	$ 71	$ 77
Interest income and other	(1)	(2)	(3)	(3)
Interest expense, net	$ 21	$ 24	$ 68	$ 74

11) UNITHOLDER DISTRIBUTIONS

The Consolidated Statements of Unitholder Distributions is provided to assist Unitholders in reconciling cash from operating activities 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 Trust primarily receives income by way of a royalty and interest on intercompany loans from its operating subsidiary, Canadian Oil Sands Limited ("COSL"). The royalty is designed to capture the cash generated by COSL, after the deduction of all costs and expenses including operating and administrative costs, income taxes, capital expenditures, debt interest and principal repayments, working capital and reserves for future obligations deemed appropriate. The amount of royalty income that the Trust receives in any period has a considerable amount of flexibility through the use of discretionary reserves and debt borrowings or repayments (either intercompany or third party). Quarterly distributions are determined by the Board of Directors after considering the current and expected economic and operating conditions, ensuring financing capacity for Syncrude's expansion projects and/or Canadian Oil Sands acquisitions, and with the objective of maintaining an investment grade credit rating.

CANADIAN OIL SANDS TRUST
CONSOLIDATED STATEMENTS OF UNITHOLDER DISTRIBUTIONS
(unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
	2007	**2006**	**2007**	**2006**
Cash from operating activities	$ 484	$ 334	$ 1,010	$ 730
Add (Deduct):				
Capital expenditures	(45)	(47)	(128)	(243)
Acquisition of additional Syncrude working interest	-	-	(231)	-
Disposition of properties	-	-	4	-
Change in non-cash working capital [1]	(7)	(6)	(5)	(50)
Reclamation trust funding	(1)	(2)	(4)	(4)
Change in cash and cash equivalents and financing, net [2]	(239)	12	(119)	90
Unitholder distributions	$ 192	$ 140	$ 527	$ 372
Unitholder distributions per Trust Unit [3]	**$ 0.40**	**$ 0.30**	**$ 1.10**	**$ 0.80**

[1] *From investing activities.*
[2] *Primarily represents the change in cash and cash equivalents and net financing to fund the Trust's share of investing activities.*
[3] *Unit information has been adjusted to reflect the 5:1 Unit split, which occurred on May 3, 2006.*

12) SUPPLEMENTARY INFORMATION

	Three Months Ended September 30		Nine Months Ended September 30	
	2007	**2006**	**2007**	**2006**
Income tax paid	$ -	$ -	$ 1	$ 5
Interest charges paid	$ 27	$ 31	$ 81	$ 82

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