fourth quarter report

Canadian Oil Sands Trust announces 2009 fourth quarter results

All financial figures are unaudited and in Canadian dollars unless otherwise noted.

TSX - COS.UN

Calgary, Alberta (January 28, 2010) – Canadian Oil Sands Trust ("Canadian Oil Sands", the "Trust" or "we") today announced cash from operating activities of $328 million ($0.68 per Trust Unit ("Unit")) for the fourth quarter of 2009 compared with cash from operating activities of $466 million ($0.97 per Unit) for the same period last year. The decrease reflects increases in non-cash working capital and higher Crown royalties, partially offset by higher revenues.

For the year ended December 31, 2009 cash from operating activities decreased to $547 million ($1.13 per Unit) from $2,241 million ($4.66 per Unit) in 2008. The decrease reflects the significant decline in crude oil prices in 2009 versus 2008, as well as lower production and increases in non-cash working capital, partially offset by lower Crown royalties.

In the fourth quarter of 2009, the Trust reported net income of $96 million ($0.20 per Unit) compared with net income of $124 million ($0.26 per Unit) recorded in the same period of 2008. Excluding impairment charges on the Trust's Arctic assets, net income in the fourth quarter of 2009 was $244 million ($0.50 per Unit), reflecting higher sales volumes, oil prices and foreign exchange gains, partially offset by higher Crown royalties. On an annual basis, net income totaled $432 million ($0.89 per Unit) in 2009, down from $1,523 million ($3.17 per Unit) in 2008. The decline primarily reflects lower crude oil prices and production, partially offset by lower Crown royalties.

The Trust has declared a quarterly distribution amount of $0.35 per Unit for Unitholders of record on February 18, 2010, payable on February 26, 2010.

Net debt at the end of 2009 was $1,041 million, similar to net debt of $979 million at the end of 2008. The Trust continues to maintain a strong financial position with net debt to total capitalization of 21 per cent.

"Unplanned downtime and maintenance exceeded our budgeted allowance during 2009, impacting both production and costs," said Marcel Coutu, President and Chief Executive Officer. "Although 2009 production was 12 per cent below our budget, we once again demonstrated that the plant can run at robust rates with December production running at 360,000 barrels per day. Syncrude's priority is to improve operational reliability to achieve design capacity rates more consistently."

Sales volumes in 2009 averaged 103,000 barrels per day compared with 106,000 barrels per day in 2008. Production in 2009 was impacted by: turnaround and modification work on Syncrude's Coker 8-3 complex; bitumen constraints; and reliability issues in the mining and upgrading processes, including circulation issues with Coker 8-1 and unplanned repairs to the vacuum distillation unit. Production in 2008 was impacted by planned turnarounds of Cokers 8-2 and 8-1, bitumen production constraints and a disruption in operations during the first quarter.

Following repairs to the vacuum distillation unit during November 2009, production ramped up significantly, resulting in fourth quarter 2009 sales volumes averaging 119,000 barrels per day. By comparison, sales volumes in 2008 averaged 110,000 barrels per day during the fourth quarter.

Operating costs in 2009 were $35.29 per barrel, virtually the same as 2008 costs of $35.26 per barrel. Operating costs in both years reflect coker turnarounds and unplanned maintenance.

Capital expenditures in 2009 were $409 million compared with $281 million in 2008. Expenditures in both years relate mainly to sustaining capital, as Syncrude currently is not incurring meaningful expansion-related capital to grow productive capacity. In 2009, the expenditures related to the Syncrude Emissions Reduction project, equipment purchases to improve bitumen production, modifications to the Coker 8-3 complex, construction of tailings facilities, and other infrastructure projects.

Syncrude's total recordable injury rate for 2009 was 0.36 compared with a rate of 0.59 for 2008. While the recordable injury rate declined, the fatality that occurred in November 2009 marred the improvement in our overall safety performance. An investigation into the fatality is underway to determine what occurred and to prevent a similar tragedy in the future. Syncrude is committed to protecting and promoting the safety and well being of its employees and contractors. Investment in training, awareness activities, and other initiatives is continuing in order to foster further improvements in workplace safety.

CANADIAN OIL SANDS TRUST
Highlights

(millions of Canadian dollars, except per Trust unit and per barrel volume amounts)	Three Months Ended December 31 2009	Three Months Ended December 31 2008	Twelve Months Ended December 31 2009	Twelve Months Ended December 31 2008
Net Income	$ 96	$ 124	$ 432	$ 1,523
Per Trust unit- Basic	$ 0.20	$ 0.26	$ 0.89	$ 3.17
Per Trust unit- Diluted	$ 0.20	$ 0.26	$ 0.89	$ 3.16
Cash from (used in) Operating Activities	$ 328	$ 466	$ 547	$ 2,241
Per Trust unit	$ 0.68	$ 0.97	$ 1.13	$ 4.66
Unitholder Distributions	$ 169	$ 361	$ 435	$ 1,804
Per Trust unit	$ 0.35	$ 0.75	$ 0.90	$ 3.75
Sales Volumes (1)				
Total (MMbbls)	10.9	10.1	37.6	38.8
Daily average (bbls)	119,287	110,197	103,129	105,986
Operating Costs ($/bbl)	$ 30.18	$ 32.10	$ 35.29	$ 35.26
Net Realized SCO Selling Price ($/bbl)	$ 78.67	$ 69.40	$ 69.47	$ 106.91
West Texas Intermediate (average $US/bbl) (2)	$ 76.13	$ 59.08	$ 62.09	$ 99.75

(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.

2010 Outlook

Canadian Oil Sands is estimating Syncrude production of 115 million barrels with a range of 110 to 120 million barrels for 2010. While our annual production estimate remains unchanged from the Outlook provided on October 28, 2009, we expect first quarter production will be impacted by unplanned outages in the upgrader during January and an advancement of the planned LC finer turnaround into the first quarter. We expect this lost production will be recaptured later in the year, as outages were factored into our annual production estimate.

Canadian Oil Sands' operating costs are estimated at $1,480 million, or $35 per barrel, with capital expenditures of $541 million, mainly related to sustaining the Syncrude operation.

We are estimating 2010 cash from operating activities of $1,013 million, or $2.09 per Unit. After deducting capital expenditures, we are estimating $472 million of remaining cash from operating activities, or $0.97 per Unit.

Distributions paid in 2010 are expected to be 100 per cent taxable as other income. The actual taxability of 2010 distributions will be determined and reported to Unitholders prior to the end of the first quarter of 2011.

More information on the Trust's outlook is provided in the Management's Discussion and Analysis section of this report and the January 28, 2010 guidance document, which is available on the Trust's web site at www.cos-trust.com under "Investor".

Canadian Oil Sands speaks with Canadians about the oil sands

Marcel Coutu, President and Chief Executive Officer of Canadian Oil Sands, was in Halifax, Nova Scotia and St. John's, Newfoundland on January 13th and 14th to speak with Canadians about the oil sands. Mr. Coutu provided frank insights into how the oil sands are meeting the challenge of improving their environmental performance, the impact of the oil sands on the economy of Canada and local communities, and what all this means to Canadians. To read a copy of his speech and view video clips, please visit www.OilSandsNow.ca.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") was prepared as of January 28, 2010 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 three and twelve months ended December 31, 2009 and December 31, 2008, and the audited consolidated financial statements and MD&A of the Trust for the year ended December 31, 2008 and the Trust's Annual Information Form ("AIF") dated March 13, 2009. Additional information on the Trust, including its AIF, is available on SEDAR at www.sedar.com or on the Trust's website at www.cos-trust.com.

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 and the related press release contain "forward-looking statements" under applicable securities law. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to expectations regarding the impact on future costs as a result of the economic downturn; the cost estimate for the Sulphur Emissions Reduction project and the expectation that the Sulphur Emissions Reduction project will significantly reduce total sulphur dioxide and other emissions; the completion date for the Sulphur Emissions Reduction project; future distributions and any increase or decrease from current payment amounts; the Trust's plans with regard to its net debt level by the end of 2010; plans regarding crude oil hedges and currency hedges in the future; the expected production, revenues and operating costs for 2010; the belief that operational reliability will improve over time and with that improvement that operating costs will be reduced; the expected level of sustaining capital for the next few years and longer term; the expectations regarding capital expenditures and operating costs; the plans regarding conversion to a corporate structure and the timing of seeking Unitholder approval; the plans and expected impact of adopting International Financial Reporting Standards; the expected impact of any current and future environmental legislation, including without limitation, regulations relating to tailings; the expectation that there will not be any material funding increases relative to Syncrude's future reclamation costs or pension funding for the next year; the expected realized selling price, which includes the anticipated differential to WTI, to be received in 2010 for Canadian Oil Sands' product; the potential amount payable in respect of any future income tax liability; the plans regarding future expansions of the Syncrude project and in particular all plans regarding future development; the level of energy consumption in 2010 and beyond; capital expenditures for 2010; the level of natural gas consumption in 2010 and beyond; the expected price for crude oil and natural gas in 2010, and 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. 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; skilled 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 unanimous joint venture owner approval for major expansions; the variances of stock market activities generally; global economic environment/volatility of markets; normal risks associated with litigation, general economic, business and market conditions; regulatory change, 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. 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 fourth quarter of 2009, crude oil production from the Syncrude Joint Venture ("Syncrude") totaled 30.1 million barrels, or 327,000 barrels per day, compared with 28.4 million barrels, or 308,000 barrels per day, during the same period of 2008. Net to the Trust, production totaled 11.1 million barrels in the fourth quarter of 2009 compared with 10.4 million barrels in 2008, based on our 36.74 per cent working interest.

Production volumes in the fourth quarter of 2009 were impacted by unplanned maintenance in Syncrude's vacuum distillation unit. By comparison, production during the fourth quarter of 2008 was impacted by a planned turnaround of Coker 8-2, which commenced in September 2008 and was completed in the first week of November 2008.

In 2009, Syncrude produced 102.2 million barrels, or 280,000 barrels per day, compared with 105.8 million barrels, or 289,000 barrels per day in 2008. Net to the Trust, production totaled 37.5 million barrels in 2009 compared with 38.9 million barrels in 2008. Syncrude's 2009 production was negatively affected by an extended turnaround and modification work on Coker 8-3 and related units, which began in mid-March and was completed in early June. As well, unplanned outages in the mining operations, coke circulation difficulties in Coker 8-1, maintenance on the vacuum distillation unit, and first quarter bitumen constraints reduced 2009 production. By comparison, production in 2008 was impacted by the planned turnarounds of Coker 8-2 and Coker 8-1, bitumen production constraints and a disruption in several operating units during the first quarter.

Syncrude's 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. Under normal operating conditions, scheduled downtime is required for maintenance and turnaround activities and unscheduled downtime will occur as a result of operational and mechanical problems, unanticipated repairs and other slowdowns. When allowances for such downtime are included, the daily design productive capacity of Syncrude's facilities is approximately 350,000 barrels per day on average and is referred to as "barrels per calendar day". All references to Syncrude's productive capacity in this report refer to barrels per calendar day, unless stated otherwise.

Operating costs were $30.18 per barrel in the fourth quarter of 2009, down $1.92 per barrel from the same quarter of 2008. Annual operating costs for 2009 were $35.29 per barrel, essentially flat in comparison with 2008 operating costs of $35.26 per barrel (see the "Operating costs" section of this MD&A for further discussion).

The Trust's production volumes differ from its sales volumes due to changes in inventory, which are primarily in-transit pipeline volumes. The impact of Syncrude's 2009 operations on Canadian Oil Sands' financial results is more fully discussed later in this MD&A.

BUSINESS ENVIRONMENT

Prices for U.S. dollar West Texas Intermediate ("WTI") oil continued to strengthen during the fourth quarter of 2009, averaging U.S. $76.13 per barrel versus U.S. $57.32 per barrel for the first nine months of 2009. Partially offsetting the oil price rise, the Canadian dollar increased to an average of $0.95 U.S./Cdn in the fourth quarter versus $0.85 U.S./Cdn for the first nine months of 2009. Compared to 2008, however, commodity prices during 2009 were substantially lower with U.S. dollar WTI prices averaging $62.09 per barrel versus $99.75 per barrel in 2008.

The deterioration of economic conditions during late 2008 and early 2009 resulted in the deferral or cancellation of several oil sands projects in the Fort McMurray region. With the improvement in market conditions in more recent months, announcements have been made that indicate development of some of these projects is expected to resume. While it is reasonable to expect any continued industry slowdown to contribute to lower costs over time through more competitive access to labour and materials, we have yet to experience material declines in production costs. A significant portion of costs in the oil sands industry are associated with labour, and these costs respond much slower to changing market conditions, particularly as industry-wide labour agreements exist that stipulated wage increases in 2009. We continue to believe the most significant factor in achieving cost reductions at Syncrude is better operational reliability.

SUMMARY OF QUARTERLY RESULTS

($ millions, except per Trust Unit and volume amounts)	2009 Q4	2009 Q3	2009 Q2	2009 Q1	2008 Q4	2008 Q3	2008 Q2	2008 Q1
Revenues [1]	$ 863	$ 773	$ 467	$ 512	$ 704	$ 1,381	$ 1,177	$ 907
Net income (loss)	$ 96	$ 247	$ 46	$ 43	$ 124	$ 604	$ 497	$ 298
Per Trust Unit, Basic & Diluted	$ 0.20	$ 0.51	$ 0.10	$ 0.09	$ 0.26	$ 1.25	$ 1.04	$ 0.62
Cash from operating activities	$ 328	$ 213	$ (44)	$ 50	$ 466	$ 921	$ 413	$ 441
Per Trust Unit [2]	$ 0.68	$ 0.44	$ (0.09)	$ 0.10	$ 0.97	$ 1.91	$ 0.86	$ 0.92
Unitholder distributions	$ 169	$ 121	$ 73	$ 72	$ 361	$ 602	$ 481	$ 360
Per Trust Unit	$ 0.35	$ 0.25	$ 0.15	$ 0.15	$ 0.75	$ 1.25	$ 1.00	$ 0.75
Daily average sales volumes (bbls) [3]	119,287	114,544	75,553	102,825	110,197	116,656	97,744	99,181
Net realized SCO selling price ($/bbl) [4]	$ 78.67	$ 73.31	$ 67.92	$ 55.32	$ 69.40	$ 127.55	$ 131.32	$ 100.41
Operating costs ($/bbl) [5]	$ 30.18	$ 27.80	$ 50.23	$ 38.78	$ 32.10	$ 32.15	$ 41.92	$ 35.93
Purchased natural gas price ($/GJ)	$ 4.33	$ 2.90	$ 3.09	$ 4.96	$ 6.41	$ 7.86	$ 9.38	$ 7.30
West Texas Intermediate (avg. US$/bbl) [6]	$ 76.13	$ 68.24	$ 59.79	$ 43.31	$ 59.08	$ 118.22	$ 123.80	$ 97.82
Foreign exchange rates (US$/Cdn$):								
Average	$ 0.95	$ 0.91	$ 0.86	$ 0.80	$ 0.83	$ 0.96	$ 0.99	$ 1.00
Quarter- end	$ 0.96	$ 0.93	$ 0.86	$ 0.79	$ 0.82	$ 0.94	$ 0.98	$ 0.97

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

(2) Cash from operating activities per Trust Unit is a non-GAAP measure that is derived from cash from operating activities reported on the Trust's Consolidated Statements of Cash Flows divided by the weighted-average number of Trust Units outstanding in the period, as used in the Trust's net income per Unit calculations.

(3) Daily average sales volumes after crude oil purchases.

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

(5) Derived from operating costs, as reported on the Trust's Consolidated Statements of Income and Comprehensive Income, divided by the sales volumes during the period.

(6) Pricing obtained from Bloomberg.

During the last eight quarters, the following items have had a significant impact on the Trust’s financial results:

- Fluctuations in U.S. dollar WTI oil prices have impacted the Trust’s revenues, Crown royalties, net income and cash from operating activities;
- Net income was reduced in the fourth quarter of 2009 by $148 million due to an impairment charge and goodwill write-down on the Arctic natural gas assets;
- Planned and unplanned maintenance activities as well as turnarounds have impacted quarterly production volumes, sales revenues and operating costs;
- U.S. to Canadian dollar exchange rate fluctuations have resulted in foreign exchange gains and losses on the revaluation of U.S. dollar denominated debt and have impacted commodity pricing; and
- Tax rate reductions substantively enacted in the first quarter of 2009 resulted in additional future income tax recoveries of $63 million.

The above items are discussed in greater detail later in this MD&A.

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 also is impacted by unrealized foreign exchange gains and losses, impairment charges and by future income tax amounts. A large proportion of operating costs are fixed and, as such, per barrel operating costs are 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. Natural gas prices are typically higher in winter months as heating demand rises, but this seasonality is influenced by weather conditions and North American natural gas inventory levels. In addition, production levels may not display seasonal patterns or trends. While maintenance and turnaround activities are typically scheduled to avoid the winter months, the exact timing of unit shutdowns cannot be precisely scheduled, and unplanned outages may occur.

Maintenance and turnaround activities impact both production volumes and operating costs. The costs associated with these activities are expensed in the period they are incurred, which can lead to significant increases in operating costs. The effect on per barrel operating costs of these maintenance activities is amplified as the facility is generally producing at reduced rates when maintenance work is occurring.

REVIEW OF FINANCIAL RESULTS

In the fourth quarter of 2009, the Trust reported net income of $96 million, or $0.20 per Unit, compared with $124 million, or $0.26 per Unit, recorded in the fourth quarter of 2008. Excluding after-tax impairment charges of $148 million on the Trust's Arctic assets, 2009 net income was $244 million or $0.50 per Unit, reflecting higher sales volumes, oil prices and foreign exchange gains, partially offset by higher Crown royalties.

On an annual basis, net income totaled $432 million, or $0.89 per Unit compared with $1,523 million, or $3.17 per Unit, recorded in 2008. The decline in net income primarily reflects lower revenues, net of lower Crown royalties in 2009.

Revenues after crude oil purchases and transportation costs totaled $863 million in the fourth quarter of 2009 versus $704 million in the fourth quarter of 2008. On an annual basis, revenues after crude oil purchases and transportation costs totaled $2,615 million in 2009 versus $4,169 million in 2008. The decrease in annual revenues was due mainly to lower crude oil prices as well as lower production and sales volumes in 2009 (see "Revenues after Crude Oil Purchases and Transportation Expense" section of this MD&A for further discussion).

Cash from operating activities was $328 million for the fourth quarter of 2009 versus $466 million for the fourth quarter of 2008. The decrease in quarter-over-quarter cash from operating activities was due to increases in non-cash working capital and Crown royalties, partially offset by higher revenues. On an annual basis, cash from operating activities in 2009 decreased to $547 million versus $2,241 million for 2008. The decrease in the yearly cash from operating activities was due to the decrease in revenues and increases in non-cash working capital, partially offset by lower Crown royalties.

Non-cash working capital decreased cash from operating activities by $38 million in the fourth quarter of 2009, primarily as a result of higher accounts receivable, reflecting higher oil production and prices for December 2009 compared to September 2009. In the fourth quarter of 2008, non-cash working capital increased cash from operating activities by $174 million, primarily as a result of lower accounts receivable at December 31, 2008 relative to September 30, 2008.

On an annual basis, increases in non-cash working capital decreased cash from operating activities by $207 million, primarily as a result of higher accounts receivable and higher inventory levels at December 31, 2009 relative to December 31, 2008. In 2008, non-cash working capital increased cash from operating activities by $202 million, primarily as a result of lower accounts receivable at December 31, 2008 relative to December 31, 2007.

Non-cash working capital and changes therein can vary significantly on a period-by-period basis as a result of the timing and settlements of accounts receivable and accounts payable balances, and are impacted by a number of factors including changes in: revenue, operating expenses, Crown royalties, capital expenditures, and inventory fluctuations.

Non-GAAP Financial Measures

In this MD&A we refer to financial measures that do not have any standardized meaning as prescribed by Canadian Generally Accepted Accounting Principles ("GAAP"). These non-GAAP financial measures include cash from operating activities on a per Unit basis, net debt, total capitalization and certain per barrel measures. Non-GAAP financial measures provide additional information that we believe is meaningful regarding the Trust's operational performance, its liquidity and its capacity to fund distributions, capital expenditures and other investing activities. Users are cautioned that non-GAAP financial measures presented by the Trust may not be comparable with measures provided by other entities.

Net Income per Barrel

($ per bbl) [1]	Three Months Ended December 31 2009	2008	Variance	Twelve Months Ended December 31 2009	2008	Variance
Revenues after crude oil purchases and transportation expense	78.67	69.43	9.24	69.47	107.47	(38.00)
Operating costs	(30.18)	(32.10)	1.92	(35.29)	(35.26)	(0.03)
Crown royalties	(8.47)	(5.84)	(2.63)	(6.06)	(15.44)	9.38
	40.02	31.49	8.53	28.12	56.77	(28.65)
Non-production costs	(3.26)	(2.36)	(0.90)	(3.75)	(2.00)	(1.75)
Administration and insurance	(0.75)	(0.35)	(0.40)	(0.87)	(0.61)	(0.26)
Interest, net	(2.03)	(1.80)	(0.23)	(2.45)	(1.75)	(0.70)
Depreciation, depletion and accretion [2]	(23.78)	(11.73)	(12.05)	(15.16)	(11.46)	(3.70)
Goodwill impairment	(4.73)	-	(4.73)	(1.38)	-	(1.38)
Foreign exchange gain (loss)	2.10	(10.40)	12.50	4.28	(4.09)	8.37
Future income tax (expense) recovery and other	1.16	7.33	(6.17)	2.67	2.39	0.28
	(31.29)	(19.31)	(11.98)	(16.66)	(17.52)	0.86
Net income per barrel	8.73	12.18	(3.45)	11.46	39.25	(27.79)
Sales volumes (MMbbls) [3]	10.9	10.1	0.8	37.6	38.8	(1.2)

[1] Unless otherwise specified, net income and other per barrel measures in this MD&A have been derived by dividing the relevant revenue or cost item by the sales volumes in the period.
[2] Includes impairment of Arctic assets.
[3] Sales volumes, net of purchased crude oil volumes.

Revenues after Crude Oil Purchases and Transportation Expense

($ millions)	Three Months Ended December 31 2009	2008	Variance	Twelve Months Ended December 31 2009	2008	Variance
Sales revenue [1]	$ 894	$ 767	$ 127	$ 2,775	$ 4,539	$ (1,764)
Crude oil purchases	(24)	(54)	30	(133)	(337)	204
Transportation expense	(8)	(10)	2	(31)	(37)	6
	862	703	159	2,611	4,165	(1,554)
Currency hedging gains [1]	1	1	-	4	4	-
	$ 863	$ 704	$ 159	$ 2,615	$ 4,169	$ (1,554)
Sales volumes (MMbbls) [2]	10.9	10.1	0.8	37.6	38.8	(1.2)

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

($ per barrel)						
Realized SCO selling price before hedging [3]	$ 78.59	$ 69.31	$ 9.28	$ 69.37	$ 106.81	$ (37.44)
Currency hedging gains	0.08	0.09	(0.01)	0.10	0.10	-
Net realized SCO selling price	$ 78.67	$ 69.40	$ 9.27	$ 69.47	$ 106.91	$ (37.44)

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

The increase in sales revenue in the fourth quarter of 2009 versus 2008 primarily reflects a higher realized selling price for our synthetic crude oil ("SCO") as well as higher sales volumes. During the fourth quarter of 2009, WTI averaged U.S. $76.13 per barrel compared to U.S. $59.08 per barrel in the fourth quarter of 2008. The impact of the higher U.S. dollar WTI price in the fourth quarter of 2009 was offset somewhat by a stronger Canadian dollar, which averaged $0.95 U.S./Cdn for the fourth quarter of 2009 versus $0.83 U.S./Cdn for the fourth quarter of 2008.

The decrease in sales revenue on an annual basis was due mainly to lower realized selling prices for SCO and lower sales volumes in 2009. WTI prices averaged U.S. $62.09 per barrel in 2009 versus U.S.

$99.75 per barrel in 2008. The impact of the lower 2009 U.S. dollar WTI price was offset somewhat by a weaker Canadian dollar, which averaged $0.88 U.S./Cdn in 2009 versus $0.94 U.S./Cdn in 2008.

The Trust's SCO price is also affected by the premium or discount realized relative to Canadian dollar WTI (the "differential"). In the fourth quarter of 2009, the Trust realized a weighted-average SCO discount of $1.69 per barrel versus a discount of $1.63 per barrel for the same period of 2008. In 2009, the Trust realized a weighted-average SCO discount of $1.08 per barrel relative to the average Canadian dollar WTI price versus a premium of $1.94 per barrel in 2008. The differential is dependent upon the supply and demand for SCO and, accordingly, can change quickly depending upon the short-term supply and demand dynamics in the market and pipeline availability for transporting crude oil.

The Trust's fourth quarter sales volumes averaged 119,000 barrels per day and 110,000 barrels per day in 2009 and 2008, respectively. On an annual basis, sales volumes averaged 103,000 barrels per day in 2009 versus an average of 106,000 barrels per day in 2008. Sales volumes for 2009 were impacted by the same factors that impacted Syncrude production including a longer than expected planned turnaround and modifications on the Coker 8-3 complex, reliability issues in mining and upgrading operations, and constrained bitumen production during the first quarter. Sales volumes in 2008 were impacted by the disruption of several operating units in January, the scheduled turnarounds of Coker 8-2 and Coker 8-1, and bitumen production constraints.

From time to time the Trust purchases crude oil from third parties to support the sales of internally produced SCO by fulfilling sales commitments with customers when there are shortfalls in Syncrude's production and by facilitating certain transportation arrangements and operations. The decrease in value of crude oil purchases during 2009 was due to the decrease in commodity prices and purchased volumes.

Operating Costs

	Three Months Ended December 31				Twelve Months Ended December 31			
	2009 [1]		2008 [1]		2009 [1]		2008 [1]	
	$/bbl Bitumen	$/bbl SCO	$/bbl Bitumen	$/bbl SCO	$/bbl Bitumen	$/bbl SCO	$/bbl Bitumen	$/bbl SCO
Bitumen production [2]	$ 16.55	$ 19.23	$ 18.41	$ 21.09	$ 19.32	$ 22.81	$ 19.18	$ 22.19
Internal fuel allocation [4]	2.34	2.72	3.54	4.06	2.32	2.74	4.04	4.67
Total produced bitumen costs	18.89	21.95	21.95	25.15	21.64	25.55	23.22	26.86
Upgrading costs [3]		10.96		12.13		12.53		12.27
Less: Internal fuel allocation to bitumen [4]		(2.72)		(4.06)		(2.74)		(4.67)
Bitumen purchases		-		-		0.32		1.04
Total Syncrude operating costs		30.19		33.22		35.66		35.50
Canadian Oil Sands' adjustments [5]		(0.01)		(1.12)		(0.37)		(0.24)
Total operating costs		30.18		32.10		35.29		35.26
(thousands of barrels per day)	Bitumen	SCO	Bitumen	SCO	Bitumen	SCO	Bitumen	SCO
Syncrude production volumes [6]	380	327	353	308	330	280	334	289

[1] Information shown above allocates costs to bitumen production and upgrading based on deductibility for bitumen royalty purposes. In-order to allow time to fully develop an allocation methodology for common costs, the Syncrude Royalty Amending Agreement provides for allowed bitumen costs to be 64.5 per cent of Syncrude total operating costs until December 31, 2010. Prior year information has been reclassified to conform to the new format.

[2] Bitumen production costs relate to the removal of overburden, oil sands mining, bitumen extraction, tailings dyke construction and disposal costs and purchased energy. 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.

[3] Upgrading costs include the production, ongoing maintenance, and purchased energy costs associated with processing and upgrading of bitumen to SCO. They also include the costs of major upgrading equipment turnarounds and catalyst replacement, all of which are expensed as incurred.

[4] Estimate of internal fuel produced in upgrading operations and consumed in bitumen production. Allocation is based on the Syncrude Royalty Amending Agreement.

[5] Canadian Oil Sands' adjustments mainly pertain to asset retirement costs, Syncrude-related pension costs, as well as the inventory impact of moving from production to sales as Syncrude reports per barrel costs based on production volumes and the Trust reports based on sales volumes.

[6] Syncrude SCO production volumes include the impact of processed purchased bitumen volumes. Bitumen production volumes exclude the impact of purchased bitumen.

	Three Months Ended December 31		Twelve Months Ended December 31	
($/bbl of SCO)	**2009**	**2008**	**2009**	**2008**
Production costs	26.41	25.89	31.39	28.01
Purchased energy	3.77	6.21	3.90	7.25
Total operating costs	30.18	32.10	35.29	35.26
(GJs/bbl of SCO)				
Purchased energy consumption	0.87	0.97	0.99	0.95

In the fourth quarter of 2009, operating costs were $331 million, averaging $30.18 per barrel, in line with fourth quarter 2008 operating costs of $326 million. On an annual basis, operating costs were $1,328 million in 2009, averaging $35.29 per barrel, a decrease of $40 million from 2008.

The decrease in annual operating costs was primarily due to the following:

- Lower energy costs as a result of a decline in natural gas prices to $3.95 per gigajoule ("GJ") in 2009 compared with $7.66 per GJ in 2008; and

- A decrease in the value of bitumen purchased by Syncrude to $33 million in 2009 ($12 million net to the Trust) compared with $110 million during the same period of 2008 ($40 million net to the Trust).

These cost reductions were offset by:

- Additional maintenance activities at Syncrude on mining, upgrading, utilities and extraction facilities in 2009 relative to 2008;
- Additional mining activities, including increased material movement in 2009 relative to 2008;
- Increased costs for contractors and wages for Syncrude staff; and
- An increase in the value of Syncrude's long-term incentive plans in 2009 versus 2008. A portion of Syncrude's long-term incentive plans is based on the market return performance of several Syncrude owners' shares and units, the market performance of which was stronger in 2009 relative to 2008.

Operating costs in 2009 and 2008 were also impacted by turnarounds on Syncrude's cokers. In 2009 Syncrude performed significant maintenance and modification work on the Coker 8-3 complex. In 2008 Syncrude performed turnarounds on Coker 8-1 and Coker 8-2. The cost of the single 2009 turnaround was similar to the combined cost for the 2008 turnarounds as a result of the larger 2009 scope.

Non-Production Costs

Non-production costs totaled $35 million and $24 million in the fourth quarters of 2009 and 2008, respectively. On an annual basis, non-production costs totaled $141 million for 2009 and $78 million for 2008. The increase in non-production costs over 2008 was due to additional development activities undertaken with respect to future mine train relocations, initiatives to manage tailings ponds, ESP fire repairs and planning for growth initiatives.

Non-production costs consist primarily of development expenditures relating to capital programs, such as pre-feasibility engineering, technical and support services, research and development, and regulatory and stakeholder consultation expenditures. Non-production costs can vary on a periodic basis depending on the number of projects underway and the status of the projects.

Crown Royalties

Pursuant to an agreement reached in 2008 ("Amended Royalty Agreement") with the Alberta government, Syncrude's Crown royalties after 2008 are based on deemed bitumen revenues and allowed bitumen operating, non-production and capital costs. Additional amounts for upgrader growth capital deducted in computing royalties for prior years, and transition payments for the period 2010 to 2015, are also to be factored into the royalty calculation. For 2009 Syncrude was subject to royalties based on a net 25 per cent bitumen royalty rate. A copy of the 2008 Amended Royalty Agreement is available at www.sedar.com under the Trust's company information.

In the fourth quarter of 2009, Crown royalties increased to $93 million, or $8.47 per barrel, from $59 million, or $5.84 per barrel, in the comparable 2008 quarter as a result of increased deemed bitumen revenues resulting from higher commodity prices. On an annual basis, Crown royalties decreased to $228 million, or $6.06 per barrel, in 2009 from $599 million, or $15.44 per barrel in 2008. The decrease in Crown royalties on an annual basis was primarily due to lower deemed bitumen revenues resulting from lower commodity prices and higher capital costs during 2009.

The deemed bitumen revenue under the Amended Royalty Agreement requires that bitumen be valued by a formula that references the value of bitumen based on a Canadian heavy oil price adjusted for reasonable quality, transportation and handling deductions (including diluent costs) to reflect the quality and location differences between Syncrude's bitumen and the reference price of bitumen. The Alberta government, Syncrude, and the Syncrude joint venture owners are in discussions to determine the appropriate adjustments for quality, transportation and handling. For estimating and paying royalties, Syncrude has used a bitumen value based on Syncrude and its owners' interpretation of the Amended Royalty Agreement and estimates of the appropriate quality, transportation and handling adjustments. These adjustments are different than those provided under the generic bitumen valuation methodology. Based on discussions to date among the parties to the Amended Royalty Agreement, the royalty amount for 2009 net to Canadian Oil Sands is about $40 million less than the amount calculated under the Alberta government's generic bitumen valuation methodology. The Syncrude joint venture owners and the Alberta government continue to discuss the basis for these reasonable adjustments but if such discussions do not result in an agreed upon solution, either party may seek judicial determination of the matter.

Syncrude also has recorded an additional $29 million for 2009, net to the Trust, of royalties in respect of upgrader growth capital recapture under its Amended Royalty Agreement.

Interest Expense, Net

	Three Months Ended December 31		**Twelve Months Ended December 31**	
($ millions)	**2009**	**2008**	**2009**	**2008**
Interest expense on long-term debt	$ 23	$ 20	$ 94	$ 76
Interest income and other	-	(1)	(1)	(8)
Interest expense, net	$ 23	$ 19	$ 93	$ 68

The increase in interest expense on long-term debt was mainly due to the refinancing of 2009 debt maturities with the U.S. $500 million 7.75 per cent Senior Notes issue in the second quarter of 2009.

Depreciation, Depletion and Accretion Expense

($ millions)	Three Months Ended December 31 2009		Three Months Ended December 31 2008		Twelve Months Ended December 31 2009		Twelve Months Ended December 31 2008	
Depreciation and depletion expense-Syncrude	$	124	$	115	$	423	$	430
Impairment of Arctic assets	$	130	$	-	$	130	$	-
Accretion expense		6		4		17		14
	$	260	$	119	$	570	$	444

The change in depreciation and depletion ("D&D") expense on the Trust's Syncrude assets was due to lower production volumes offset by a slight increase in the per barrel D&D rate for 2009. The D&D rate per barrel of production increased to $11.27 in 2009 from $11.07 in 2008.

Refer to page 17 of this MD&A for a discussion related to the impairment of Arctic assets.

Foreign Exchange (Gain) Loss

($ millions)	Three Months Ended December 31 2009		Three Months Ended December 31 2008		Twelve Months Ended December 31 2009		Twelve Months Ended December 31 2008	
Foreign exchange (gain) loss-long term debt	$	(28)	$	142	$	(200)	$	204
Foreign exchange (gain) loss-other		5		(36)		39		(45)
Total foreign exchange (gain) loss	$	(23)	$	106	$	(161)	$	159

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 FX gains on long-term debt in 2009 were due to a strengthening in the value of the Canadian dollar relative to the U.S. dollar to $0.96 U.S./Cdn at December 31, 2009 from $0.93 U.S./Cdn at September 30, 2009 and $0.82 U.S./ Cdn at December 31, 2008. The FX losses in 2008 were due to the weakening of the Canadian dollar relative to the U.S. dollar to $0.82 U.S./Cdn at December 31, 2008 from $0.94 U.S./Cdn at September 30, 2008 and $1.01 U.S./Cdn at December 31, 2007.

In addition to the foreign exchange gain on long-term debt, Canadian Oil Sands also reported a foreign exchange loss of $39 million on other items during 2009. This loss was primarily due to a foreign exchange loss of $19 million on U.S. dollar cash held by Canadian Oil Sands from its May, 2009 financing to retire U.S. $250 million of debt in August.

Future Income Tax and Other

In the fourth quarter of 2009, a future income tax recovery of $13 million was recorded versus a future income tax recovery of $75 million in the same period of 2008. A future income tax recovery of $101 million was recorded in 2009 versus a future income tax recovery of $93 million in 2008. In addition to the future income tax amounts recorded on changes in temporary differences between accounting and tax values of Canadian Oil Sands' assets and liabilities, a future income tax recovery of $63 million was recorded during the first quarter of 2009 on the substantive enactment of tax rate reductions.

CAPITAL EXPENDITURES

Canadian Oil Sands' expansion-related capital expenditures have declined in recent years and capital costs for 2009 and 2008 were mainly related to sustaining capital. Expansion-related capital are costs incurred to grow the productive capacity of the operation while sustaining capital is effectively all other capital. Capital expenditures may fluctuate considerably year-to-year due to the timing of expansions, equipment replacement and other factors. The productive capacity of Syncrude's operations was previously described in the "Review of Syncrude Operations" section of this MD&A.

In the fourth quarter of 2009, capital expenditures totaled $101 million compared with expenditures of $86 million in the same quarter of 2008. The Syncrude Emissions Reduction ("SER") project accounted for $28 million and $17 million of the capital spent in the fourth quarters of 2009 and 2008, respectively, with the remaining fourth quarter expenditures related to other sustaining capital activities, including the purchase of trucks and shovels, construction of tailings facilities, and other infrastructure projects.

On an annual basis, capital expenditures in 2009 totaled $409 million versus $281 million in 2008. The SER project accounted for $115 million and $73 million of the capital spent in 2009 and 2008, respectively. The remaining expenditures related to other sustaining capital activities, including the purchase of trucks and shovels, modifications to Coker 8-3 and related units, construction of tailings facilities, and other infrastructure projects. Sustaining capital expenditures on a per barrel basis were $10.86 and $7.23 in 2009 and 2008, respectively. Sustaining capital on a per barrel basis is also affected by the Trust's sales volumes, which were lower in 2009 relative to 2008.

Syncrude is undertaking the SER project, which commenced in 2006, to retrofit technology into the operation of Syncrude's original two cokers by the end of 2011 in order to reduce total sulphur dioxide and other emissions. The estimate of the total cost of the SER project remains at $1.6 billion ($590 million net to the Trust) and the Trust's share of SER expenditures to date is approximately $300 million.

IMPAIRMENT OF ARCTIC ASSETS

During the fourth quarter of 2009, the Trust assessed its Arctic assets and related goodwill for impairment. Along with recent technological innovations that have increased access to natural gas shale resources, there continues to be delays in other Arctic developments. The Trust has a "carried interest" in its Arctic resource which reduces risk; however, resource development is dependent on uncertain operator approvals.

As a result of these uncertainties, the Trust extended its assumed timing for development of the Arctic assets. Based on a net present value analysis which assumes a deferred project start date, additional depreciation and depletion of $130 million ($96 million after tax) was recorded by the Trust. A goodwill impairment of $52 million has also been recorded. The remaining net book value recorded by the Trust for the Arctic assets is $35 million and net income during the quarter was reduced by $148 million after tax ($182 million pre-tax).

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The following table outlines the significant financial obligations that are known as of January 28, 2010, which represent future cash payments that the Trust is required to make under existing contractual arrangements that it has entered into directly, or as a 36.74 per cent owner in the Syncrude Joint Venture.

		Payments due by period			
($ millions)	Total	< 1 year	1 - 3 years	4 - 5 years	After 5 years
Long-term debt [1]	1,993	86	571	135	1,201
Capital expenditure commitments [2]	303	147	156	-	-
Pension plan solvency deficiency payments [3]	94	14	31	17	32
Management services agreement [4]	125	17	51	34	23
Pipeline commitments [5]	528	19	59	39	411
Asset retirement obligations [6]	903	45	129	54	675
Other obligations [7]	424	223	128	20	53
	4,370	551	1,125	299	2,395

[1] Actual payments differ from the carrying value as the amounts are stated at amortized cost plus interest payment commitments on the long-term debt.

[2] Capital expenditure commitments are primarily comprised of our 36.74 per cent share of Syncrude's Emissions Reduction project.

[3] We are responsible for funding our 36.74 per cent share of Syncrude Canada's registered pension plan solvency deficiency, which was confirmed in the December 31, 2006 actuarial valuation that was completed in 2007.

[4] Reflects our 36.74 per cent share of Syncrude Canada's annual fixed service fees under the agreement.

[5] Reflects our 36.74 per cent share of the AOSPL pipeline commitment as a Syncrude Joint Venture owner, and various other Canadian Oil Sands pipeline commitments for transportation access beyond Edmonton.

[6] Reflects our 36.74 percent share of the undiscounted estimated cash flows required to settle Syncrude's environmental obligations upon reclamation of the Syncrude Joint Venture properties.

[7] These obligations primarily include our 36.74 per cent share of the minimum payments required under Syncrude's commitments for natural gas purchases. Other items include, but are not limited to, annual disposal fees for the flue gas desulphurization unit and tire supply agreements.

During 2009, Syncrude entered into new natural gas purchase commitments that expire between 2009 and 2011. The value of this commitment will fluctuate with changes to natural gas prices. The natural gas commitments above are based on an estimated AECO price of $6.00/GJ.

During 2009, the Trust increased its estimated asset retirement obligation as a result of revisions to cost estimates, the expected timing of reclamation expenditures, and revised material movement assumptions to reflect mine plan changes. The estimated present value of the obligation at December 31, 2009 was $389 million ($235 million at December 31, 2008), while the estimated undiscounted cash flows associated with the obligation are $903 million ($774 million at December 31, 2008).

UNITHOLDER DISTRIBUTIONS

	Three Months Ended December 31		Twelve Months Ended December 31	
($ millions)	2009	2008	2009	2008
Cash from operating activities	$ 328	$ 466	$ 547	$ 2,241
Net income	$ 96	$ 124	$ 432	$ 1,523
Unitholder distributions	$ 169	$ 361	$ 435	$ 1,804
Excess (shortfall) of cash from operating activities over Unitholder distributions	$ 159	$ 105	$ 112	$ 437
Excess (shortfall) of net income over Unitholder distributions	$ (73)	$ (237)	$ (3)	$ (281)

In 2009, cash from operating activities exceeded Unitholder distributions by $112 million. Cash from operating activities along with opening cash balances, equity issued by the Trust's Premium Distribution, Distribution Re-Investment and Optional Unit Purchase Plan ("DRIP"), and the U.S. $500 million Senior Note issue in the second quarter were sufficient to fund the Trust's capital expenditures, debt repayments, reclamation trust fund contributions, and distributions.

Unitholder distributions in the fourth quarter of 2009 exceeded net income primarily as a result of the goodwill impairment and additional D&D expense that was recorded by the Trust on the impairment of its Arctic assets. In 2008 Unitholder distributions exceeded net income on both a quarterly and an annual basis as a result of D&D expense and unrealized foreign exchange losses. D&D expense, the goodwill impairment and unrealized foreign exchange losses are non-cash items that do not affect the Trust's cash from operating activities or ability to pay distributions over the near term.

The Trust may use debt and equity financing in addition to cash from operating activities and existing cash balances to fund capital expenditures, reclamation trust contributions, debt repayments, acquisitions, distributions and working capital changes from financing and investing activities.

In early 2009, Canadian Oil Sands reinstated its DRIP to help preserve balance sheet equity during a time of lower crude oil prices, higher maintenance activities, and tight credit markets. In the third quarter, we suspended the DRIP as a result of strengthening crude oil prices, the U.S. $500 million Senior Notes issue, and stabilized capital markets. For the first and second quarters of 2009, participation in the DRIP was about 46 per cent and 41 per cent, respectively, and a total of 2.9 million Units were issued in 2009.

In establishing its distribution levels, the Trust considers its outlook for crude oil prices and Syncrude's operational performance, the Trust's financial obligations, and access to capital markets. We also consider funding for other operating obligations that are included in cash from operating activities. These obligations include the Trust's share of Syncrude's pension and reclamation funding, which amounted to $69 million and $55 million in 2009 and 2008, respectively.

On January 28, 2010 the Trust declared a quarterly distribution of $0.35 per Unit in respect of the first quarter of 2010 for a total distribution of $170 million. The distribution will be paid on February 26, 2010 to Unitholders of record on February 18, 2010. Quarterly distributions are approved by our Board of Directors after considering the current and expected economic conditions, ensuring financing capacity for Canadian Oil Sands' capital requirements and with the objective of maintaining an investment grade credit rating.

Cash from operating activities and net income can fluctuate from period to period due to Syncrude's operating performance, WTI pricing, SCO differentials to WTI, FX rates and other factors. The Trust strives to reduce the impact of these fluctuations on distributions by taking a longer-term view of the operating and business environment, our net debt level, and our capital expenditure and other commitments. In that regard, the Trust may distribute more or less in a period than is generated in cash from operating activities or net income. The variable nature of cash from operating activities introduces risk in the ability to sustain or provide stability in distributions. Expectations regarding the stability or sustainability of distributions are unwarranted.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	December 31 2009	December 31 2008
Long-term debt	1,163	1,258
Cash and cash equivalents	(122)	(279)
Net debt [1]	$ 1,041	$ 979
Unitholders' equity	$ 3,969	$ 3,910
Total capitalization [2]	$ 5,010	$ 4,889
Net debt to total capitalization (%)	21	20

[1] Non-GAAP measure

[2] Net debt plus Unitholders' equity

During the second quarter of 2009, the Trust issued U.S. $500 million of Senior Notes. The notes have an annual interest rate of 7.75 per cent payable semi-annually and mature May 15, 2019. Proceeds from the notes were used to repay $200 million of Medium Term Notes that matured during the second quarter of 2009, U.S. $250 million of Senior Notes that matured during the third quarter of 2009, and for general corporate purposes. The next debt maturity occurs in 2013.

Net debt at December 31, 2009 was $1.0 billion, which is consistent with the balance at December 31, 2008. Net debt remained constant as a result of approximately $200 million in foreign exchange gains on our U.S. dollar denominated debt, which offset the impact of the decrease in cash and cash equivalents.

During the first quarter of 2009, the Trust's $67 million line of credit was increased to $70 million and the term on the Trust's $40 million bilateral credit facility was extended to April 22, 2010.

With the refinancing of the 2009 debt maturities, the Trust's liquidity position has significantly improved. While we believe a slightly higher leverage level may provide a more efficient capital structure and conserve tax pools prior to trust taxation, the Trust must also consider a prudent liquidity position, access to capital markets, and future investing and financing requirements. In 2009 the Trust paid distributions in excess of cash from operating activities less capital expenditures. Non-cash foreign exchange gains on our U.S. dollar denominated debt, however, served to offset these net debt increases. While we are comfortable in 2010 paying distributions in excess of cash from operations less capital expenditures, increasing net debt towards $1.6 billion will depend on actual operating results, economic conditions, future investing activities, foreign exchange rates and distribution payments based on these expectations. As a result, actual net debt levels may vary from the target net debt and the net debt target may also change if a more conservative balance sheet is deemed prudent.

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 $14 billion with 484 million Units outstanding and a closing price of $29.91 per Unit on December 31, 2009.

Canadian Oil Sands Trust - Trading Activity	**Fourth Quarter 2009**	**December 2009**	**November 2009**	**October 2009**
Unit price				
High	$ 34.89	$ 30.74	$ 31.67	$ 34.89
Low	$ 27.76	$ 28.23	$ 28.05	$ 27.76
Close	$ 29.91	$ 29.91	$ 29.25	$ 29.18
Volume of Trust units traded (millions)	91.2	19.2	32.0	40.0
Weighted average Trust units outstanding (millions)	484.4	484.4	484.4	484.4

FOREIGN OWNERSHIP

Based on information from the statutory declarations by Unitholders, we estimate that, as of November 20, 2009 approximately 72 per cent of our Units were held by Canadian residents with the remaining 28 per cent of Units being held by non-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 regularly monitors its foreign ownership levels through declarations from Unitholders, and the next declarations will be requested as of February 18, 2010. The Trust posts its foreign ownership levels on its web site at www.cos-trust.com under "Investor/Unit Information". The steps to manage foreign ownership levels are described in the Trust's AIF.

CORPORATE CONVERSION

In 2009, legislation for the conversion of income and royalty trusts into corporations was enacted. This legislation is designed to permit income and royalty trusts to convert into public corporations without triggering adverse Canadian tax consequences to the trusts or their unitholders. A number of income and royalty trusts in Canada have either converted or announced their intention to convert to a corporate structure.

On January 28, 2010, Canadian Oil Sands' Board approved converting to a corporate structure on or about December 31, 2010. Canadian Oil Sands plans to bring the conversion plan forward for Unitholder approval in conjunction with the Annual General Meeting to be held April 29, 2010. As part of its conversion to a corporate structure, Canadian Oil Sands has reviewed its distribution/dividend strategies. Based on current conditions, Canadian Oil Sands expects to determine dividend payments once it becomes a corporation on a similar basis as its current approach to distributions. Accordingly, future dividends that may be paid by Canadian Oil Sands following its conversion to a corporate structure are expected to vary depending on Syncrude's operational performance, Canadian Oil Sands' operating and capital obligations, crude oil prices and access to capital markets. Further, the taxability of Canadian Oil Sands after conversion will impact earnings and cash from operating activities in future periods.

FINANCIAL RISK MANAGEMENT

The Trust did not have any financial derivatives outstanding at December 31, 2009.

Crude Oil Price Risk

Canadian Oil Sands' revenues are impacted by changes in both the U.S. dollar denominated crude oil prices and U.S./Cdn FX rates. The Trust did not have any crude oil price hedges in place during 2009 and 2008, and does not currently intend to enter into any crude oil hedge positions. The Trust may hedge this exposure in the future, however, depending on the business environment and our growth opportunities.

Foreign Currency Risk

Canadian Oil Sands' results are affected by fluctuations in the U.S./Cdn currency exchange rates, as revenues generated are based on a U.S. dollar WTI benchmark price while certain obligations are denominated in Canadian dollars. The Trust did not have any foreign currency hedges in place during 2009 or 2008, and does not currently intend to enter into any new currency hedge positions. The Trust may, however, hedge foreign currency 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 or upon the refinancing of maturing long-term debt at prevailing interest rates. As at December 31, 2009 there was no floating interest rate debt outstanding.

Liquidity Risk

Liquidity risk is the risk that Canadian Oil Sands will not be able to meet its financial obligations as they fall due. Canadian Oil Sands actively manages its liquidity risk through its cash, debt and equity strategies. As a result of the U.S. $500 million 7.75 per cent Senior Note issue in the second quarter of 2009, the Trust's liquidity position improved significantly. The next long-term debt maturity is in 2013, and the $800 million credit facility does not expire until April, 2012.

Credit Risk

Canadian Oil Sands is exposed to credit risk primarily through customer accounts receivable balances and financial counterparties with whom the Trust has invested its cash or purchased term deposits from. The maximum exposure to any one customer or financial counterparty is controlled through a credit policy that limits exposure based on credit ratings.

The financial condition of some of our U.S. based refinery customers has come under pressure during 2009, reflecting low refinery margins during the economic downturn. Canadian Oil Sands carries credit insurance to help mitigate the impact should a loss occur and continues to transact primarily with investment grade customers, with the vast majority of accounts receivable at December 31, 2009 being due from investment grade energy producers and refinery based customers.

At December 31, 2009, our cash and cash equivalents were held in either cash or term deposits with high-quality senior Canadian banks. As of January 28, 2010, there are no financial assets that are past their maturity or impaired due to credit risk-related defaults.

CHANGES IN ACCOUNTING POLICIES

Goodwill and Intangible Assets

In February 2008, the Canadian Institute of Chartered Accountants ("CICA") issued a new accounting standard, Section 3064 – Goodwill and Intangible Assets, which replaces Section 3062 – Goodwill and Other Intangible Assets, and Section 3450 – Research and Development costs. The new section establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The section is effective for the Trust beginning January 1, 2009. Application of the new section did not have a material impact on the Trust's financial statements.

NEW ACCOUNTING PRONOUNCEMENTS

There were no new accounting pronouncements by the CICA during 2009 that are expected to have a material impact on the Trust.

The Trust will be converting to international financial reporting standards ("IFRS"), which will replace Canadian GAAP starting in 2011. The Trust is analyzing accounting policy alternatives and system changes required for impact areas, including available first time adoption alternatives. Existing standards that may impact the Trust on adoption include asset retirement obligations, employee future benefits and property plant and equipment.

Assessments of the final impacts of conversion to IFRS, including the adoption of potential IFRS standards under development that might impact the Trust, have not been determined.

In addition to existing IFRS standards, new or revised IFRS standards are being developed by the International Accounting Standards Board ("IASB") which may impact the Trust depending on the timing of their implementation. These standards include Joint Ventures, Income Taxes, Financial Instruments, Emissions Trading Schemes, Extractive Industries, Employee Future Benefits, and Measurement of Liabilities. The Trust continues to monitor the developments within IFRS which might impact its conversion.

The final impacts to the Trust's consolidated financial statements upon the adoption of IFRS will depend on IFRS standards existing in 2011, as well as the accounting policy choices made by Canadian Oil Sands.

2010 OUTLOOK

(millions of Canadian dollars, except volume and per barrel amounts)	January 28, 2010	October 28, 2009
Syncrude production (MMbbls)	115	115
Canadian Oil Sands Sales (MMbbls)	42.3	42.3
Revenues, net of crude oil purchases and transportation	3,029	2,986
Operating costs	1,480	1,479
Operating costs per barrel	35.04	35.01
Crown royalties	317	272
Capital expenditures	541	541
Cash from operating activities	1,013	969
Business environment assumptions		
West Texas Intermediate (US$/bbl)	$ 70	$ 70
Premium (Discount) to average C$ WTI prices (C$/bbl)	$ (2.00)	$ (3.00)
Foreign exchange rate (US$/Cdn$)	$ 0.95	$ 0.95
AECO natural gas (Cdn$/GJ)	$ 6.00	$ 6.00

Canadian Oil Sands is estimating Syncrude production of 115 million barrels with a range of 110 to 120 million barrels for 2010. While our annual production estimate remains unchanged from the Outlook provided on October 28, 2009, we expect first quarter production will be impacted by unplanned outages in the upgrader during January and an advancement of the planned LC finer turnaround into the first quarter. We expect this lost production will be recaptured later in the year, as outages were factored into our annual production estimate.

Canadian Oil Sands' operating costs are estimated at $1,480 million, or $35 per barrel, with capital expenditures of $541 million, mainly related to sustaining Syncrude operations.

The outlook continues to incorporate an estimated U.S. $70 per barrel WTI price and a $0.95 U.S./Cdn foreign exchange rate, but the SCO discount to Cdn dollar WTI has been reduced to $2 per barrel from $3 per barrel. These assumptions result in estimated revenues of $3,029 million, or $72 per barrel in 2010. In addition, we have increased our assumed bitumen value in calculating Crown royalties to 70 per cent of Canadian dollar WTI, from 65 per cent. Working capital estimates have also been revised to reflect actual year end balances.

Based on the above assumptions, our 2010 outlook for cash from operating activities is $1,013 million, or $2.09 per Unit. After deducting budgeted 2010 capital expenditures of $541 million, we are estimating $472 million of remaining cash from operating activities, or $0.97 per Unit.

Distributions paid in 2010 are expected to be 100 per cent taxable as other income. The actual taxability of 2010 distributions will be determined and reported to Unitholders prior to the end of the first quarter of 2011.

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 North American markets could impact the differential for SCO relative to crude benchmarks; however, these factors are difficult to predict.

2010 Outlook Sensitivity Analysis (January 28, 2010)

		Cash from Operating Activities Increase	
Variable [1]	**Annual Sensitivity**	**$ millions**	**$/Trust unit**
Syncrude operating costs decrease	C$1.00/bbl	35	0.07
Syncrude operating costs decrease	C$50 million	15	0.03
WTI crude oil price increase	US$1.00/bbl	33	0.07
Syncrude production increase	2 million bbls	39	0.08
Canadian dollar weakening	US$0.01/C$	23	0.05
AECO natural gas price decrease	C$0.50/GJ	17	0.04

[1] An opposite change in each of these variables will result in the opposite cash from operating activities impacts.
Canadian Oil Sands may become subject to minimum Crown royalties at a rate of one per cent of gross bitumen revenue.
The sensitivities presented herein assume royalties are paid at 25 per cent of net bitumen revenue.

CANADIAN OIL SANDS TRUST

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

(unaudited)

	Three Months Ended December 31		Twelve Months Ended December 31	
($ millions, except per Unit amounts)	**2009**	**2008**	**2009**	**2008**
Revenues	$ 895	$ 768	$ 2,779	$ 4,543
Expenses:				
Operating	331	326	1,328	1,368
Non-production	35	24	141	78
Crude oil purchases and transportation expense	32	64	164	374
Crown royalties	93	59	228	599
Administration	6	1	24	17
Insurance	3	1	9	6
Interest, net (Note 9)	23	19	93	68
Depreciation, depletion and accretion (Note 5)	260	119	570	444
Goodwill impairment (Note 5)	52	-	52	-
Foreign exchange loss (gain)	(23)	106	(161)	159
	812	719	2,448	3,113
Earnings before taxes	83	49	331	1,430
Future income tax expense (recovery) and other (Note 10)	(13)	(75)	(101)	(93)
Net income	96	124	432	1,523
Other comprehensive loss, net of income taxes				
Reclassification of derivative gains to net income	(1)	(1)	(3)	(3)
Comprehensive income	$ 95	$ 123	$ 429	$ 1,520
Weighted average Trust Units (millions)	484	482	484	481
Trust Units, end of period (millions)	484	482	484	482
Net income per Trust Unit:				
Basic	$ 0.20	$ 0.26	$ 0.89	$ 3.17
Diluted	$ 0.20	$ 0.26	$ 0.89	$ 3.16

See Notes to Unaudited Consolidated Financial Statements

CANADIAN OIL SANDS TRUST

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY

(unaudited)

($ millions)	Three Months Ended December 31 2009	Three Months Ended December 31 2008	Twelve Months Ended December 31 2009	Twelve Months Ended December 31 2008
Retained earnings				
Balance, beginning of period	$ 1,432	$ 1,599	$ 1,362	$ 1,643
Net income	96	124	432	1,523
Unitholder distributions (Note 12)	(169)	(361)	(435)	(1,804)
Balance, end of period	1,359	1,362	1,359	1,362
Accumulated other comprehensive income				
Balance, beginning of period	19	22	21	24
Other comprehensive loss	(1)	(1)	(3)	(3)
Balance, end of period	18	21	18	21
Unitholders' capital				
Balance, beginning of period	2,587	2,524	2,524	2,500
Issuance of Trust Units (Note 4)	-	-	63	24
Balance, end of period	2,587	2,524	2,587	2,524
Contributed surplus				
Balance, beginning of period	5	3	3	5
Exercise of employee stock options	-	-	-	(3)
Stock-based compensation	-	-	2	1
Balance, end of period	5	3	5	3
Total Unitholders' equity	$ 3,969	$ 3,910	$ 3,969	$ 3,910

See Notes to Unaudited Consolidated Financial Statements

CANADIAN OIL SANDS TRUST
CONSOLIDATED BALANCE SHEETS
AS AT
(unaudited)

($ millions)		**December 31 2009**		**December 31 2008**
ASSETS				
Current assets:				
Cash and cash equivalents	$	122	$	279
Accounts receivable		354		184
Inventories		133		93
Prepaid expenses		7		5
		616		561
Property, plant and equipment, net		6,289		6,277
Goodwill (Note 5)		-		52
Reclamation trust (Note 13)		48		43
	$	6,953	$	6,933
LIABILITIES AND UNITHOLDERS' EQUITY				
Current liabilities:				
Accounts payable and accrued liabilities	$	284	$	284
Current portion of employee future benefits (Note 6)		17		17
		301		301
Employee future benefits and other liabilities (Note6)		104		99
Long-term debt (Note 8)		1,163		1,258
Asset retirement obligation (Note 13)		389		235
Future income taxes		1,027		1,130
		2,984		3,023
Unitholders' equity		3,969		3,910
	$	6,953	$	6,933

See Notes to Unaudited Consolidated Financial Statements

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

($ millions)	Three Months Ended December 31 2009	Three Months Ended December 31 2008	Twelve Months Ended December 31 2009	Twelve Months Ended December 31 2008
Cash from (used in) operating activities				
Net income	$ 96	$ 124	$ 432	$ 1,523
Items not requiring outlay of cash:				
Depreciation, depletion and accretion (Note 5)	260	119	570	444
Goodwill impairment (Note 5)	52	-	52	-
Foreign exchange loss (gain) on long-term debt	(28)	142	(200)	204
Future income tax expense (recovery)	(13)	(75)	(101)	(93)
Net change in deferred items and other	(1)	(18)	1	(39)
	366	292	754	2,039
Change in non-cash working capital	(38)	174	(207)	202
Cash from (used in) operating activities	328	466	547	2,241
Cash from (used in) financing activities				
Issuance of Senior Notes (Note 8)	-	-	574	-
Repayment of medium term and Senior Notes (Note 8)	-	-	(471)	(150)
Net drawdown (repayment) of bank credit facilities	-	-	-	(16)
Unitholder distributions (Note 12)	(169)	(361)	(372)	(1,804)
Issuance of Trust Units (Note 4)	-	-	-	21
Cash from (used) in financing activities	(169)	(361)	(269)	(1,949)
Cash from (used in) investing activities				
Capital expenditures	(101)	(86)	(409)	(281)
Reclamation trust funding	(2)	(2)	(5)	(6)
Change in non-cash working capital	(8)	(16)	(2)	6
Cash used in investing activities	(111)	(104)	(416)	(281)
Foreign exchange loss on Cash and Cash equivalents held in foreign currency	-	-	(19)	-
Increase (decrease) in cash and cash equivalents	48	1	(157)	11
Cash and cash equivalents at beginning of period	74	278	279	268
Cash and cash equivalents at end of period	$ 122	$ 279	$ 122	$ 279
Cash and cash equivalents consist of:				
Cash			$ 18	$ 18
Short-term investments			104	261
			$ 122	$ 279

Supplementary Information (Note 15)

See Notes to Unaudited Consolidated Financial Statements

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

FOR THE THREE AND TWELVE MONTHS ENDED DECEMBER 31, 2009
(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, 2008, except as discussed in Note 2. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed or omitted. 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, 2008.

2) CHANGES IN ACCOUNTING POLICIES

In 2009 the Trust adopted the requirements of the Canadian Institute of Chartered Accountants ("CICA") – Section 3064 Goodwill and Intangible Assets, which replaced Section 3062 Goodwill and Other Intangible Assets, and Section 3450 Research and Development Costs. The new section establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. Application of the new section did not have a material impact on the Trust's financial statements.

3) FUTURE CHANGES IN ACCOUNTING POLICIES

The Trust will be subject to International Financial Reporting Standards ("IFRS") commencing in 2011. The Trust is currently assessing the impact conversion to IFRS may have on its financial statements.

4) ISSUANCE OF TRUST UNITS

In the twelve months ended December 31, 2009, approximately 2.9 million Trust Units were issued pursuant to the Trust's Premium Distribution, Distribution Re-investment and Optional Unit Purchase Plan ("DRIP") for $63 million.

In the twelve months ended December 31, 2008, approximately two million Trust Units were issued for $24 million on the exercise of employee stock options.

5) GOODWILL AND DEPRECIATION, DEPLETION, AND ACCRETION EXPENSE

During the fourth quarter of 2009, the Trust assessed its Arctic assets and related goodwill for impairment. Along with recent technological innovations that have increased access to natural gas shale resources, there continues to be delays in other Arctic developments. The Trust has a "carried interest" in its Arctic resource which reduces risk; however, resource development is dependent on uncertain operator approvals.

As a result of these uncertainties, the Trust extended its assumed timing for development of the Arctic assets. Based on a net present value analysis which assumes a deferred project start date, additional depreciation and depletion of $130 million ($96 million after tax) was recorded by the Trust. A goodwill impairment of $52 million has also been recorded. As a result, net income during the quarter was reduced by $148 million after tax ($182 million pre-tax).

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 post-employment benefit plans ("OPEB") covering most of its employees. Other post-employment benefits include certain health care and life insurance benefits for retirees, their beneficiaries and covered dependents. The OPEB plan is not funded.

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 twelve months ended December 31, 2009 and 2008 is based on its 36.74 per cent working interest. The costs have been recorded in operating expense as follows:

	Three Months Ended December 31		Twelve Months Ended December 31	
	2009	2008	2009	2008
Defined benefit plans:				
Pension benefits	$ 12	$ 6	$ 40	$ 29
Other benefit plans	1	2	4	5
	$ 13	$ 8	$ 44	$ 34
Defined contribution plans	1	-	3	2
Total benefit cost	$ 14	$ 8	$ 47	$ 36

7) BANK CREDIT FACILITIES

Extendible revolving term facility (a)	$ 40
Line of credit (b)	70
Operating credit facility (c)	800
	$ 910

Each of the Trust's credit facilities is unsecured. These credit agreements contain covenants restricting 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 60 per cent, or 65 per cent in certain circumstances involving acquisitions.

a) The $40 million extendible revolving term facility is a 364-day facility with a one-year term out, expiring April 22, 2010. This facility may be extended on an annual basis with the agreement of the bank. Amounts borrowed through this facility bear interest at a floating rate based on bankers' acceptances plus a credit spread, while any unused amounts are subject to standby fees. As at December 31, 2009, no amounts were drawn on this facility ($Nil – December 31, 2008).

b) The $70 million line of credit is a one-year revolving letter of credit facility. Letters of credit drawn on the facility mature April 30th each year and are automatically renewed, unless notification to cancel is provided by Canadian Oil Sands or the financial institution providing the facility at least 60 days prior to expiry. Letters of credit on this facility bear interest at a credit spread.

Letters of credit of approximately $70 million were written against the line of credit as at December 31, 2009.

c) The $800 million operating facility is a multi-year facility, expiring April 27, 2012. Amounts borrowed through this facility bear interest at a floating rate based on either prime interest rates or bankers' acceptances plus a credit spread, while any unused amounts are subject to standby fees. As at December 31, 2009, no amounts were drawn against this facility ($Nil – December 31, 2008).

8) LONG-TERM DEBT

On May 11, 2009, the Trust issued U.S. $500 million of 7.75 per cent Senior Notes, maturing May 15, 2019. Interest is payable on the notes semi-annually on May 15 and November 15.

On June 29, 2009 the Trust repaid $200 million of 5.55 per cent Medium Term Notes.

On August 10, 2009 the Trust repaid U.S. $250 million of 4.8 per cent Senior Notes.

9) INTEREST, NET

	Three Months Ended December 31		Twelve Months Ended December 31	
($ millions)	2009	2008	2009	2008
Interest expense on long-term debt	$ 23	$ 20	$ 94	$ 76
Interest income and other	-	(1)	(1)	(8)
Interest expense, net	$ 23	$ 19	$ 93	$ 68

10) FUTURE INCOME TAXES

During the first quarter of 2009, an additional $63 million future income tax recovery was recorded on the substantive enactment of legislation to reduce the tax rates applicable to the Trust in 2011.

11) STOCK BASED COMPENSATION

During 2009, 486,542 options were issued by the Trust to employees with an average exercise price of $19.77 pursuant to the Trust's Unit Incentive Option Plan. The options have an estimated value of $2 million.

12) UNITHOLDER DISTRIBUTIONS

Pursuant to Section 5.1 of the Trust Indenture, the Trust is required to distribute all the Distributable Income, as defined by the Trust Indenture, received or receivable by the Trust in a quarter. The Trust's Distributable Income primarily consists of a royalty 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 COSL's 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.

	Three Months Ended December 31		Twelve Months Ended December 31	
	2009	2008	2009	2008
Cash from operating activities	$ 328	$ 466	$ 547	$ 2,241
Add (Deduct):				
Capital expenditures	(101)	(86)	(409)	(281)
Change in non-cash working capital [1]	(8)	(16)	(2)	6
Reclamation trust funding	(2)	(2)	(5)	(6)
Change in cash and cash equivalents and financing, net [2]	(48)	(1)	304	(156)
Unitholder distributions	$ 169	$ 361	$ 435	$ 1,804
Unitholder distributions per Trust Unit	**$ 0.35**	**$ 0.75**	**$ 0.90**	**$ 3.75**

[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.*

Unitholder distributions during 2009 were funded by cash payments of $372 million and by the issuance of 2.9 million Trust Units for $63 million.

13) ASSET RETIREMENT OBLIGATION AND RECLAMATION TRUST

Canadian Oil Sands and each of the other Syncrude owners are liable for their share of ongoing environmental obligations related to the ultimate reclamation of the Syncrude properties on abandonment. The Trust estimates reclamation expenditures will be made over approximately the next 60 years and has applied an average credit-adjusted risk-free discount rate of six per cent (2008-six per cent) in deriving the asset retirement obligation.

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the Trust’s share of the obligation associated with the retirement of Syncrude properties.

	As at December 31, 2009	As at December 31, 2008
Asset retirement obligation, beginning of year	$ 235	$ 226
Liabilities settled	(25)	(14)
Accretion expense	17	14
Change in estimated future cash flows	162	9
Asset retirement obligation, end of period	$ 389	$ 235

During the third quarter of 2009, the Trust increased its estimated asset retirement obligation as a result of revisions to cost estimates, the expected timing of reclamation expenditures, and revised material movement assumptions to reflect mine plan changes.

The total undiscounted estimated cash flows required to settle the Trust’s share of Syncrude‘s obligation was $903 million at December 31, 2009 (December 31, 2008 – $774 million).

The reclamation expenditures will be funded from Canadian Oil Sands’ cash from operating activities and reclamation trust. In addition to annual funding for reclamation expenditures, Canadian Oil Sands deposits $0.1322 per barrel of production attributable to its Working Interest to a reclamation trust established for the purpose of funding the operating subsidiary’s share of environmental and reclamation obligations. As at December 31, 2009, including interest earned on investments, the balance of the reclamation trust was $48 million (December 31, 2008 - $43 million).

The Trust has posted letters of credit with the Province of Alberta in the amount of $70 million (December 31, 2008 - $67 million) to secure its pro rata share of the reclamation obligations of the Syncrude joint venture owners.

14) COMMITMENTS

During 2009, Syncrude entered into new natural gas purchase commitments that expire between 2009 and 2011. The value of this commitment will fluctuate with changes to natural gas prices. Based on an estimated AECO price of $6.00/GJ, the remaining commitment to the Trust for these contracts at December 31, 2009 is approximately $169 million.

Syncrude has also entered into other new commitments during 2009, which expire between 2013 and 2035. The total value of these commitments at December 31, 2009 was $72 million, or $26 million net to the Trust.

During 2009 Canadian Oil Sands entered into oil storage commitments which will expire in 2013. The remaining commitment as at December 31, 2009 was $12 million.

15) SUPPLEMENTARY INFORMATION

	Three Months Ended December 31		Twelve Months Ended December 31	
	2009	2008	2009	2008
Income tax paid	$ -	$ -	-	$ -
Interest paid	$ 24	$ 18	92	$ 74

Canadian Oil Sands Limited
Marcel Coutu
President & Chief Executive Officer

Units Listed – Symbol: COS.UN
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