Canadian Oil Sands Trust 2003 Annual Report

03

Progress builds on our Stage 3 expansion

Canadian Oil Sands Trust

Canadian Oil Sands Trust provides pure value for the long term. Through our 35.49% working interest in the expanding Syncrude project, we have an asset base with a 35-year-plus reserve life and expect growing production of a high quality, light crude oil.

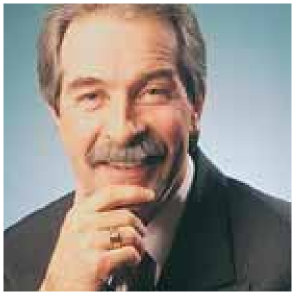
An open-ended investment trust with approximately 87.5 million units outstanding, Canadian Oil Sands trades on the Toronto Stock Exchange under the symbol COS.UN.

On the Cover:

The light gas oil and heavy gas oil splitter on the new coker being constructed as part of Syncrude's Stage 3 expansion.

Highlights

	2003	2002	% change
Financial ($ millions, except per Trust unit amounts)			
Net revenues	**932**	715	30
Per Trust unit	**11.70**	12.51	(6)
Net income	**308**	270	14
Per Trust unit (basic and diluted)	**3.87**	4.72	(18)
Funds from operations	**273**	326	(16)
Per Trust unit	**3.43**	5.71	(40)
Unitholder distributions	**170**	115	48
Per Trust unit	**2.00**	2.00	–
Weighted-average Trust units (millions)	**79.7**	57.2	39
Operations			
Syncrude Sweet Blend sales volumes			
Total (MMbbls)	**24.4**	18.2	34
Daily average (bbls)	**66,793**	49,806	34
Operating costs ($/bbl)	**21.12**	16.99	24
Capital expenditures ($ millions)	**786**	403	95
Average selling price ($/bbl, after hedging)	**38.23**	39.35	(3)
West Texas Intermediate ($US/bbl)	**31.04**	26.15	19
Average foreign exchange rate ($US/$Cdn)	**0.71**	0.64	11



President's Message: A pure value investment

Dear Unitholder,

The 2003 year marks yet another significant stage in the evolution of Canadian Oil Sands Trust. We further increased our interest in the Syncrude joint venture, making us the largest owner with a one-third interest in this world-class asset. Over the past three years, our Syncrude interest has increased from 11.74% to a current 35.49%.

And while Canadian Oil Sands has grown, we remain a pure value investment. We are exclusively an oil sands investment, providing the only undiluted opportunity to invest in Syncrude. We are a pure play on a premium quality, synthetic light crude oil. Our reserves are well defined with a production life of at least 35 years and potentially more than 50. Our growth profile is clear, deliverable and dramatic, projecting an approximate 50% increase over current production in two years. From this solid platform, we offer investors the unique opportunity to benefit from the expanding development of Canada's immense oil sands.

Underpinning the investment value of Canadian Oil Sands Trust is our Syncrude Project. Syncrude is one of the pioneers in oil sands development, celebrating its 25th year of operations in 2003.

OPERATIONAL RELIABILITY AT SYNCRUDE Oil sands production is very different from conventional crude oil production. While oil sands development has no risk in terms of finding reserves, the process of mining, extracting and upgrading this oil resource, known as bitumen, is a complex and highly technical manufacturing operation with higher operating cost risks than conventional oil production.

Q: How is the Syncrude joint venture ("JV") managed? Have things changed now that Canadian Oil Sands Trust is the largest owner?

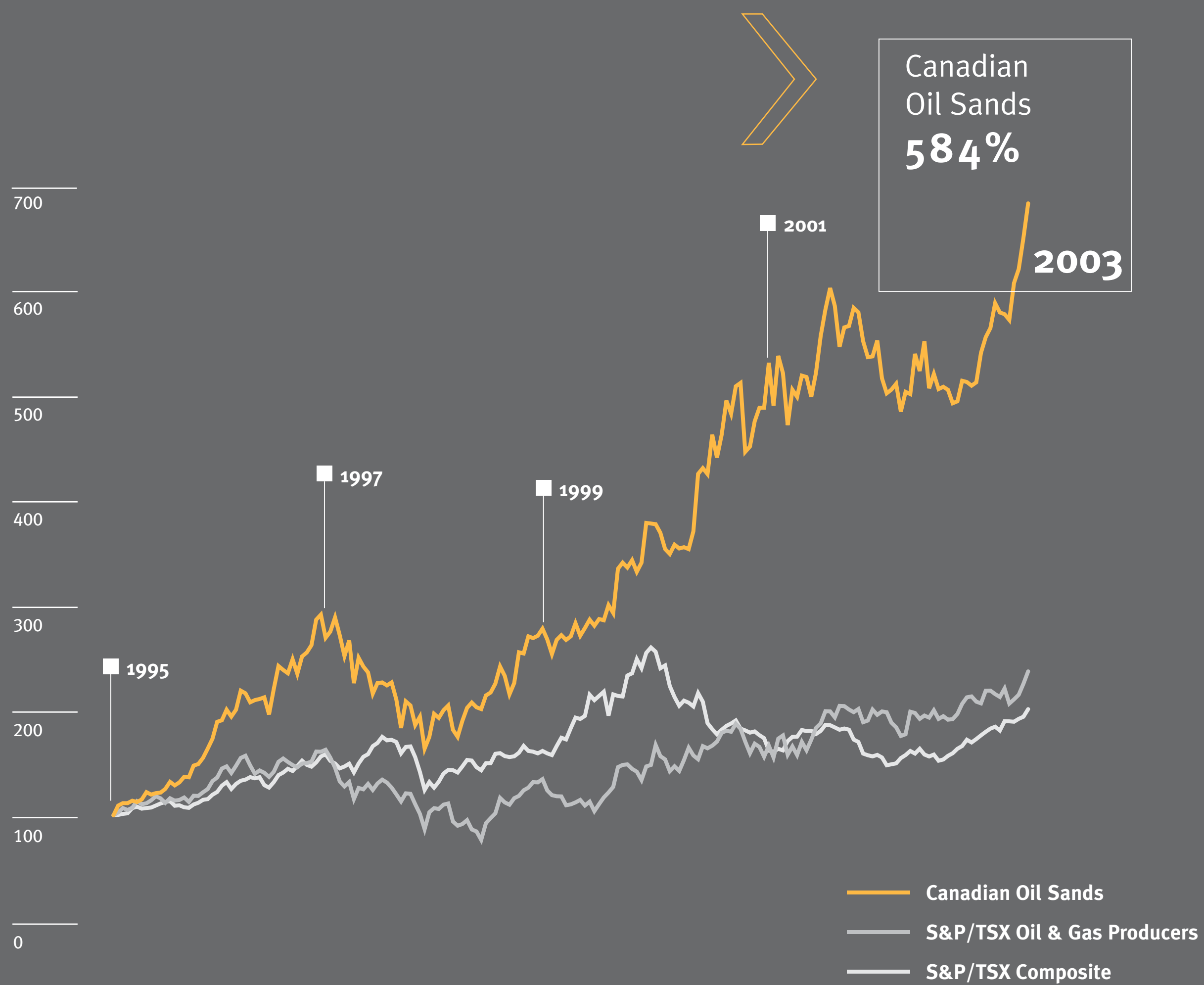
The increase in our ownership has not changed how the JV is managed. Syncrude Canada Ltd. operates the project on behalf of the 7 participants. A CEO Committee governs the strategic direction and a Management Committee oversees stewardship of the assets and expansions. Decisions regarding major expansions generally require unanimity while other approvals require a majority. Both committees are comprised of key decision makers from each JV owner, and are chaired by Canadian Oil Sands Trust.

In 2003, Syncrude experienced the unusual event of having two coker maintenance turnarounds in a single year – one of which was unscheduled. Cokers are the primary upgrading units used in the conversion of bitumen into synthetic oil. Maintenance performed on these units has the greatest impact on production because it takes the longest to perform. This double coker turnaround year, together with repairs to new equipment at the Aurora mine, reduced anticipated production by about 10% in 2003. Annual production for 2003 totalled 77 million barrels gross to Syncrude, or about 25 million barrels net to the Trust.

The lower than budgeted production volumes, together with additional maintenance costs, resulted in a per barrel of production operating cost of $21.12 in 2003. While per unit operating costs increased in 2003, relatively high crude oil prices during the year helped to preserve a healthy margin of $16.62 per barrel.

One of the ways Syncrude works to improve operational reliability is by continually evaluating third party benchmarking studies. These studies provide data collected from operations throughout North America. Syncrude aims to match the best in class in terms of maintenance practices. By continually improving and refining our procedures, we should realize optimal run cycles for each unit.

We anticipate improved performance for 2004 with Syncrude production forecast to range between 82 and 87 million barrels, or 29 to 31 million barrels net to the Trust – up about 23% from our actual 2003 production. As is our practice, we will keep our Unitholders informed throughout the year on our performance and any changes anticipated in the key variables that affect our results. One example of this practice is the Web site reporting of monthly Syncrude Sweet Blend shipments, which was initiated in mid 2003.



A $100 investment in Canadian Oil Sands Trust at its inception was worth $584 at the end of 2003 with reinvestment of all distributions. We have delivered an exceptional average annual return to our investors of 23% since 1996.

Q: Will Canadian Oil Sands increase its interest in Syncrude further?

Canadian Oil Sands is the buyer of choice for any future sale of Syncrude interests given our knowledge of the asset and our competitive access to capital. We would consider acquiring additional Syncrude interests, as well as other oil sands related opportunities, provided the economics were right.

SYNCRUDE APPOINTS NEW CEO Syncrude benefits greatly from its ability to access the expertise and technology of its joint venture owners – some of the best operators in the industry. These owners provide valuable stewardship of the base operations and the construction of Stage 3. Late in 2003, Imperial's key executive responsible for its own oil sands division succeeded Mr. Eric Newell as CEO of Syncrude. Mr. Charles Ruigrok has 22 years of experience with Imperial and has been a member of Syncrude's Management Committee for 3 years. He has a solid understanding of the operations and I believe he is exceptionally qualified to tackle this demanding role.

Mr. Newell spent 15 of his 18 years at Syncrude as the CEO, leading the project through several successful eras of change and growth while being the oil sands industry's strongest ambassador. On behalf of the Trust, I wish Eric and his family the very best in his well earned retirement.

In conjunction with Mr. Newell's retirement, I was appointed Chairman of the Board of Directors of Syncrude Canada Ltd. In this new capacity, I plan to continue working with the joint venture owners to further capitalize on their unique contributions. I would like to thank our joint venture owners for their dedication and commitment to Syncrude as we look forward to the next exciting stage in the project's growth.

STAGE 3 COSTS AND SCHEDULE REVISED Following a thorough review of the status of Stage 3 by Syncrude, supported by key people dedicated from the joint venture owners and other experts worldwide, we recently announced the completion of Stage 3 has been extended to mid 2006 and that the capital cost has increased to an estimated $7.8 billion, or $2.8 billion net to the Trust. Although we are very disappointed by this news, the benefits of the expansion – production growth, reduced operating costs and improved product quality – remain intact, preserving adequate long-term economics for Canadian Oil Sands.

Q: What is the outlook for distributions when the Stage 3 expansion is completed?

We appreciate that growth and expansion should translate into distribution increases for our Unitholders. And that is a key objective. But along with that consideration, management must also strengthen the Trust's financial position to enable the Trust to continue investing in growth opportunities that will further enhance its underlying value. We must therefore place our top priority on paying down the debt incurred to finance the Stage 3 expansion with an objective to reduce the debt to total capitalization ratio to a range of 30% to 35%. Along with the balance between raising distributions and maintaining a solid financial position, we also aim to assure that any increased level of distributions can be maintained for the long term.

Going forward, Syncrude is reorganizing the project management team to help ensure the successful completion of the project. Efforts are focused on the upgrader expansion ("UE-1"), with the mining and extraction part of the expansion ("Aurora 2") having been completed virtually on time and on budget in the fall of 2003.

I'm proud Syncrude is maintaining a first rate safety record that is world class and second to none in Alberta during the Stage 3 construction. Syncrude's safety performance is a cornerstone of its operations and part of Syncrude's reputation as a socially responsible company, which also is based on its commitment to the environment.

In 2003, Syncrude took another step in its long term strategy of environmental responsibility by announcing plans to invest an additional $400 million to reduce SO_2 emissions, which should ultimately cut emissions per barrel by about 60% from 2003 levels. Syncrude also expects a significant decline in its CO_2 emissions, and is focused on efforts to reduce these greenhouse gases, independent of the federal government's proposal related to the Kyoto Protocol. In fact, Syncrude expects to reduce its CO_2 emissions by about 25% per barrel from 1990 to 2008. More information on Syncrude's environmental and community initiatives are provided in Syncrude's "Sustainability Report," which is available through the Trust or Syncrude.

FOCUSED ON PRUDENT FINANCIAL MANAGEMENT The value of the Syncrude asset is certainly what attracts most investors to Canadian Oil Sands Trust. However, I believe it is the Trust's ability to steward the fiscal aspects of this asset ownership that will help realize the long-term value for our Unitholders.

Your Trust is managed by a small and very experienced team committed to prudent financial management. I am pleased to welcome Allen Hagerman, F.C.A. to this team, who joined as Chief Financial Officer in

2003. Allen has more than 25 years of experience in the financial management of energy companies, both in the mining business and the trust sector. Early in 2004, he also was elected Chairman of the Syncrude Audit and Pension Committee.

Canadian Oil Sands remains committed to the following main objectives:

- optimizing Unitholder value by preserving an investment grade credit rating, sustaining stable distributions and accessing equity financing only as required for acquisitions or to potentially fund Stage 3 capital expenditures;
- exploring further accretive acquisition opportunities of oil sands assets;
- maintaining one of the lowest overhead cost structures in the sector; and
- increasing our influence among Syncrude's owners to help provide direction to Syncrude on improving its operating reliability and costs.

We aim to maintain steady distribution levels so as to provide Unitholders with a predictable income stream while allowing us to reinvest a portion of the cash flow into the Stage 3 expansion. Our premium distribution, distribution reinvestment and optional unit purchase plan ("DRIP") allows Unitholders to reinvest their distributions, providing a distinct benefit to them while contributing a very cost-efficient source of equity financing for the expansion.

At the end of 2003, our net debt totalled about $1.4 billion, representing about 40% of total book capitalization. During 2004, we expect our net debt to total book capitalization will rise 5 to 10%, peaking in 2005. Our focus over this time will be to maintain our investment grade credit ratings by managing equity capitalization.

In 2003, the Canadian Oil Sands team demonstrated its ability to grow the Trust by prudently financing Stage 3, and by successfully acquiring EnCana Corporation's 13.75% Syncrude interest in a transparent, competitive process. Furthermore, we financed the acquisition through a combination of debt and equity that maintained our strong capital structure. In raising a total of $1.5 billion in equity and debt, we demonstrated the depth of investor support for our units as well as the market's acknowledgment of the acquisition's value to our Unitholders.

The impact of this acquisition, together with strong crude oil prices, maintained our solid financial position as we enter 2004, supporting our ability to continue providing distributions while funding our share of the Stage 3 expansion.

2004 OFFERS SOLID OUTLOOK We are entering a very exciting period as we move through 2004. Our Stage 3 project is progressing, our base operations are performing well and crude oil prices remain robust. We are forecasting crude oil prices to average US$27 per barrel through 2004, which I believe is a conservative outlook, framed by strengthening economies in key consuming nations, continued tensions in the Middle East, and OPEC's resolve to maintain strong world crude prices.

To reduce the risk of cash flow volatility, we have hedged 39,000 barrels per day, or approximately 46%, of our 2004 production, which completes our program for this year. Using a year-end exchange rate of US$0.77, the total weighted average price for our 2004 hedge position is about US$26.59 per barrel. Our hedging activity is consistent with the financing plan we established for Stage 3. As our funding requirements diminish and our balance sheet strengthens following Stage 3, we intend to substantially reduce crude oil hedging activity. Longer term, we seek to provide investors with the opportunity to participate more fully in the price of crude oil.

A UNIQUE ENERGY INVESTMENT The trust sector has experienced phenomenal growth over the past year. Investors have been attracted to a structure that supports growth and tax-efficient cash distributions in a low interest rate environment. Furthermore, strong commodity prices and growing U.S. and institutional interest have fueled rising values in the trust sector. As a result, many believe valuations have reached peak levels that may be unsustainable.

I believe Canadian Oil Sands Trust remains a unique energy investment in this environment. A solid asset base of a 35 year reserve life of light oil production growing in quality and value, combined with a relatively low payout of distributions to support our continued growth are unique factors that differentiate us from our peers.

Our goal is to remain a relatively low risk investment with stable, growing distributions. We seek to grow internally and through acquisitions while remaining focused exclusively on oil sands. Our success in achieving this strategy will continue to depend on the guidance provided by our Board of Directors, the hard work of the Canadian Oil Sands team, and the confidence of our Unitholders. I'm thankful for this support and look forward to a rewarding future.

Marcel R. Coutu
President and Chief Executive Officer
February 23, 2004

Expansion – Syncrude 21 timeline

Syncrude has developed a staged expansion plan called Syncrude 21 to exploit its vast oil sands resource and provide the potential for dramatic growth well into the future. Launched in 1996, Stages 1 and 2 of the expansion have been completed and Stage 3 is under construction. Stages 4 and 5 have not yet been approved and are in the conceptual planning phase.

Stage 1
North mine & Debottleneck 1

Stage 2
Aurora 1 & Debottleneck 2

Stage 3
Aurora Train 2 & Upgrader Expansion 1

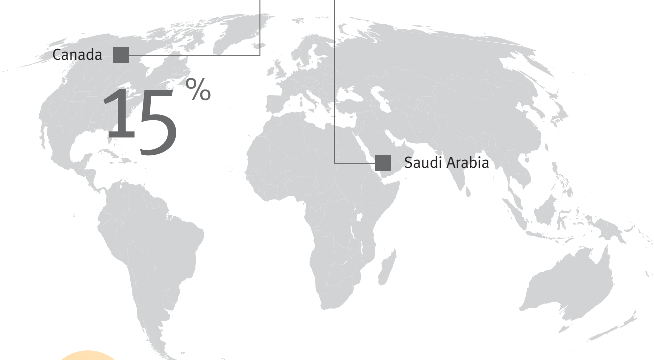
Stage 4
Aurora Train 3 & Upgrader Expansion 2

Stage 5
Aurora Train 4 & Upgrader Expansion 3

Canada's oil sands resource

Canada's potentially recoverable oil sands deposits of 315 billion barrels offer North America a secure, reliable and abundant source of energy.

Canada, with its vast oil sands deposits, represents about 15% of world crude oil reserves, second only to Saudi Arabia.



Bitumen from oil sands deposits can be recovered in two primary ways. Deposits close to the surface can be surface-mined while deeper deposits require "in-situ" methods, primarily horizontal drilling combined with steam injection. Mining technology recovers more than 90% of the bitumen compared to 25 to 75% for in-situ methods. Mining operations also tend to have more stable operating costs because they consume much less natural gas than in-situ, which needs the natural gas to create the steam.

Oil Sands: A Giant Long-Term Resource

1964

Syncrude consortium was formed with the mandate to research the economic and technical feasibility of mining oil from the Athabasca oil sands.

1967

Commercial oil sands production begins with surface mining at the Great Canadian Oil Sands project (now Suncor Energy Inc.).

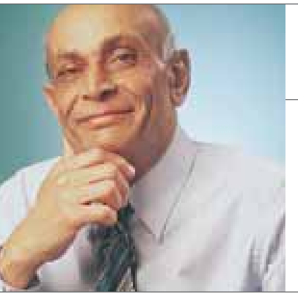
1978

Syncrude project officially opens and begins production.

1990

Introduction of steam-assisted gravity drainage technology for in-situ recovery.

Aswin Patel, P.Eng
Manager, Operations



Q: What are oil sands?

Oil sands are a mixture of bitumen, water, sand and clay. Bitumen is a highly viscous or thick form of crude oil. The high viscosity means that the material cannot flow in a pipeline without being treated or heated. Canada has the largest resource of bitumen with deposits located mainly in three areas of Alberta – Athabasca, Peace River and Cold Lake.

The oil sands in Canada are an enormous source of crude oil offering long-life reserves and non-declining production, a significant advantage over conventional crude oil sources. Oil sands reserves are on or near the surface, which means they can be more readily and accurately quantified than conventional oil, resulting in nominal exploration costs. Technology to develop this resource is continually evolving, making it increasingly economic and environmentally sustainable. Oil sands projects benefit from a supportive fiscal regime. To recognize the large scale, up-front capital investment required and the long-term payout of projects, the Government of Alberta reduces the royalty payable until after the recovery of all project costs and a return allowance.

It is estimated that $30 billion will be invested in oil sands development by some of the world's largest energy producers over the next 10 years. And during that time, Alberta's oil sands reserves are anticipated to become Canada's primary source of crude oil, offsetting the rapidly declining conventional oil supply.

Canada's estimated barrels of recoverable oil

315,000,000,000

1996

Syncrude introduces truck and shovel and hydrotransport technology to its mining operations, which helps reduce operating costs and is subsequently adopted by other mining operations.

1998

Total oil sands production for the industry averages 590,000 barrels per day. Syncrude produces its one billionth barrel.

2003

The Energy Information Agency in the U.S. recognizes Canada's oil sands, acknowledging the viability of this source of crude oil to North America.

2008

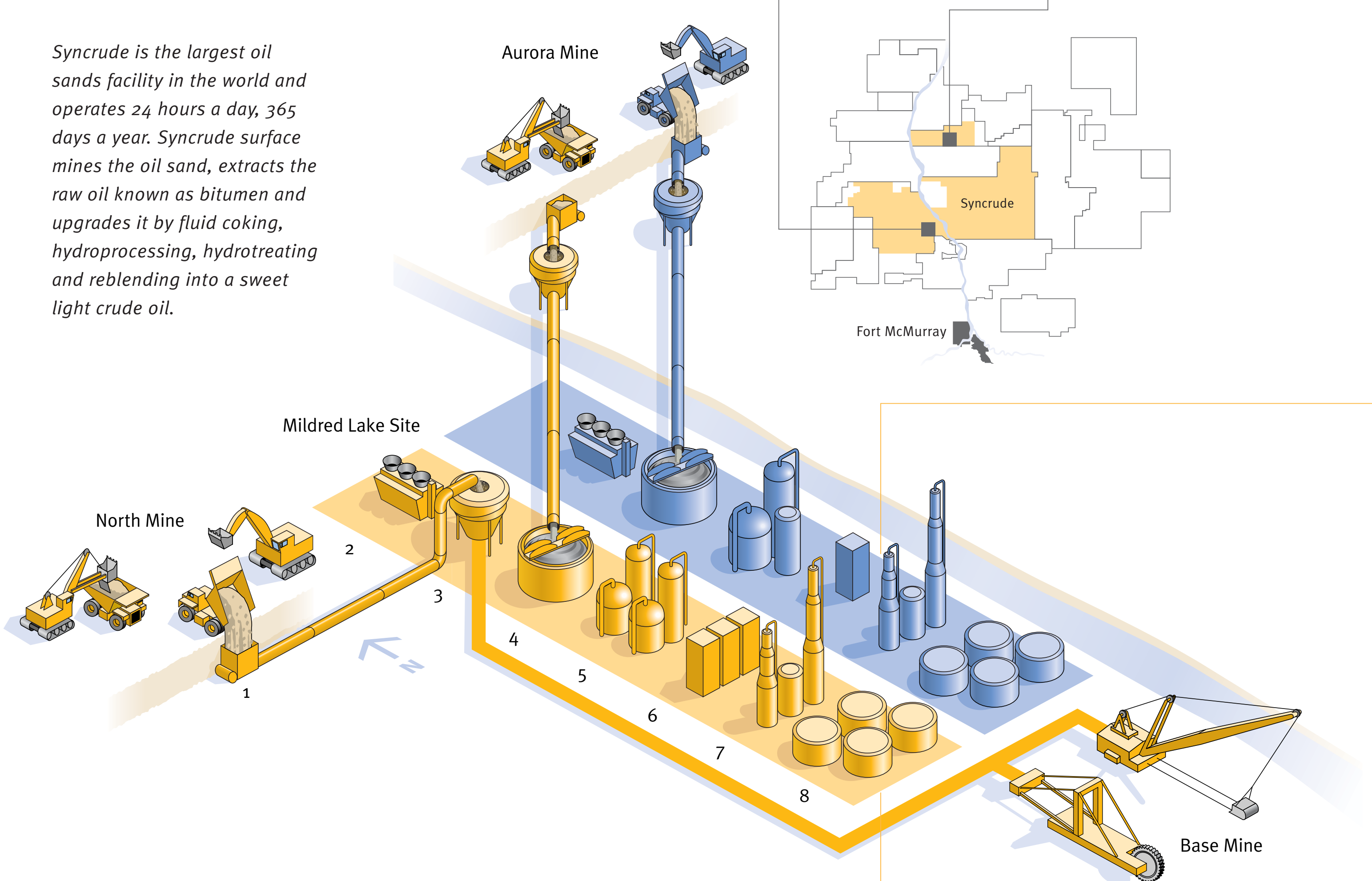
Oil sands production at about 1.4 million barrels per day is expected to exceed conventional production in Canada.

Staged growth 1, 2, 3...

Syncrude owns the largest mineable leaseholdings in Canada; its total resource is estimated at 9 billion barrels of which 3 billion are proved.

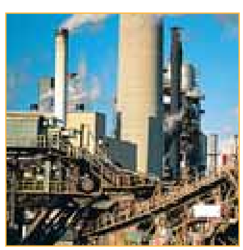
Syncrude's Aurora leases contain a richer ore body with less overburden, and as production from this area grows, operating costs are expected to decline.

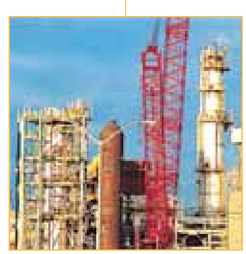
Syncrude is the largest oil sands facility in the world and operates 24 hours a day, 365 days a year. Syncrude surface mines the oil sand, extracts the raw oil known as bitumen and upgrades it by fluid coking, hydroprocessing, hydrotreating and reblending into a sweet light crude oil.



Oil Sands Process

1 *Mining, ore sizing and slurry preparation*
2 *Utilities*
3 *Primary extraction*
4 *Secondary extraction/ froth treatment*
5 *Primary upgrading (Cokers)*
6 *Hydrogen plants (3 existing, 1 in Stage 3)*
7 *Secondary upgrading*
8 *Finished products*





Charles Ruigrok
Chief Executive Officer
Syncrude Canada Ltd.

Jim Carter
President & Chief Operating Officer
Syncrude Canada Ltd.

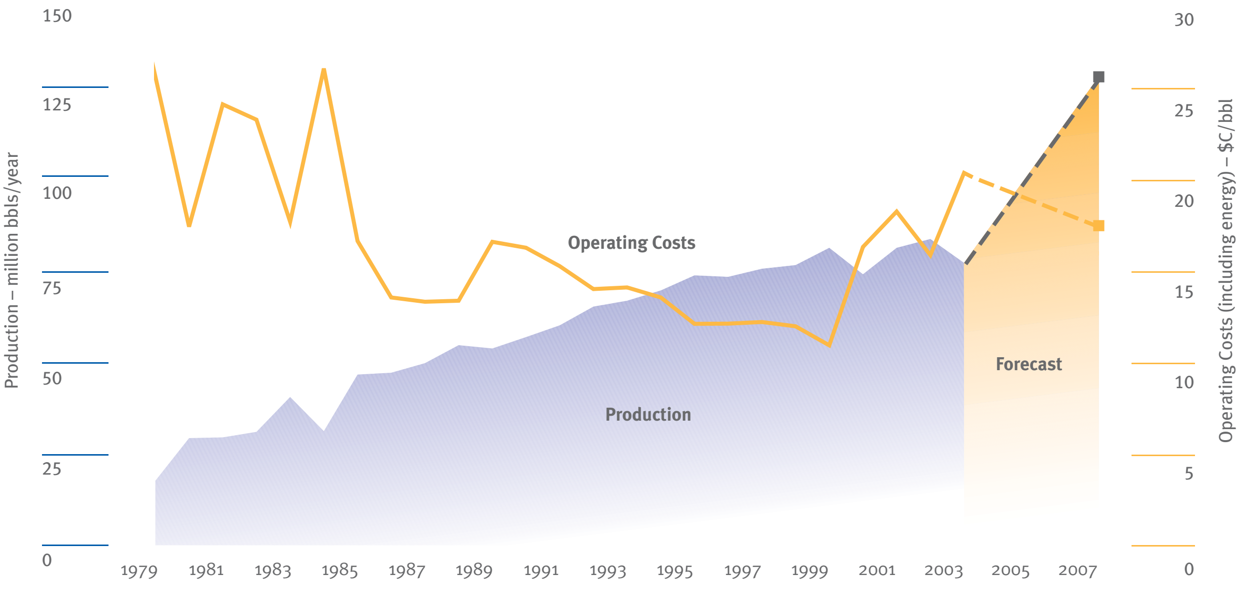
Q: How is Stage 3 expected to lead to lower operating costs?

First, economies of scale. The dramatic increase in volumes should result in lower per barrel costs. Second, lower cost bitumen production from the Aurora mine is set to grow. Combined with the expanded use of cost-saving technologies, the total impact could be a cut in operating costs of $2 to $3 per barrel.

A massive expansion project is underway at Syncrude. Stage 3 is designed to boost production by about 50% to an annual output of approximately 128 million barrels (45 million barrels net to Canadian Oil Sands Trust). The entire output will be upgraded to an even higher quality light, sweet oil, which should further enhance its value and marketability. Syncrude is estimating that this new blend, called Syncrude Sweet Premium, should receive a better price than its current blend.

The first component of Stage 3, a second mining train at Aurora, was completed in October 2003 – generally on schedule and on budget – and expands bitumen supply from Syncrude's best orebody. Construction of a third fluid coker and ancillary equipment is the major investment of Stage 3. The new coker's capacity will be about 20% larger than that of the existing 2 cokers, enabling processing of incremental volumes at a relatively lower cost, and it includes a flue gas scrubber, which essentially eliminates sulphur dioxide emissions.

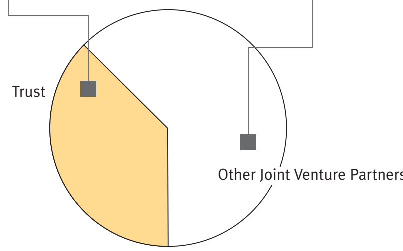
Syncrude Performance

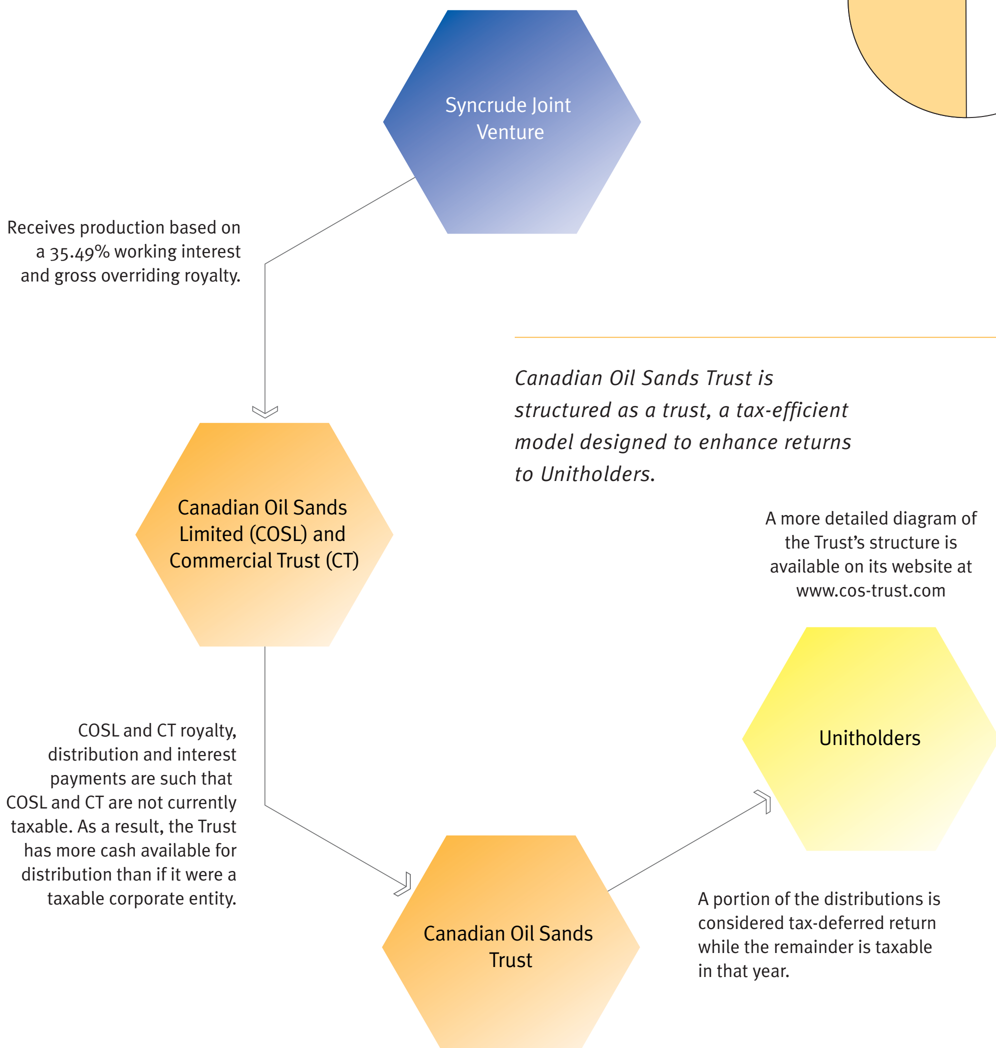


Pure investment

Canadian Oil Sands Trust is the largest owner of Syncrude with a 35.49% interest.

Six other energy companies comprise the remaining Syncrude joint venture.





Canadian Oil Sands Trust is structured as a trust, a tax-efficient model designed to enhance returns to Unitholders.

A more detailed diagram of the Trust's structure is available on its website at www.cos-trust.com

Canadian Oil Sands has provided a strong return to our Unitholders since inception. The unit price increased to $45.69 from $10 per Trust unit at the initial public offering and distributions totalled $14.66 per Trust unit at the end of 2003.

Allen Hagerman, F.C.A.

Chief Financial Officer

Q: Why are your distributions low compared to other trusts?

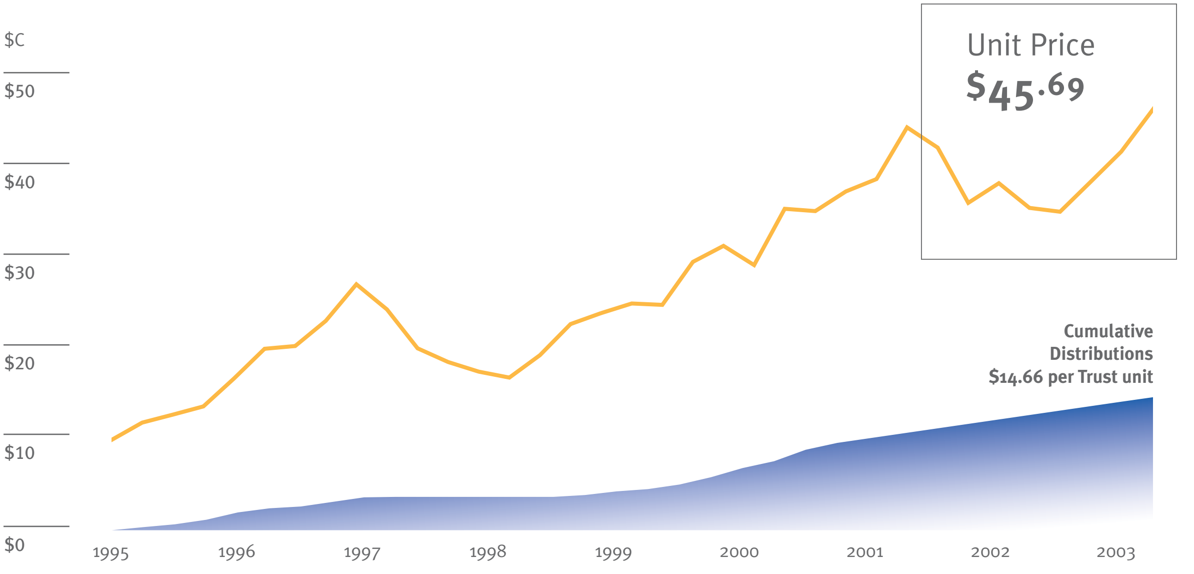
We're financing growth to increase our value and that growth is funded by the same pool of cash available for distributions. Once Stage 3 is complete and production increases, we anticipate being able to sustain some increase in distributions while also financing our growth mandate and strengthening our balance sheet by reducing debt.

Canadian Oil Sands Trust is a pure investment in the oil sands and the Syncrude project. Unique among other energy investments, our established reserve life is more than 3 times that of the average conventional energy trust. Production is set to grow significantly – both in the short term and well into the future – compared to the declining production typical of the energy sector. And we are augmenting our internal growth through acquisitions of additional oil sands assets.

Prudent financial management enables Canadian Oil Sands to manage its growth over the long term. Our Unitholders benefit from a stable distribution and the opportunity to participate in the potential future growth in value of the Syncrude project.

A premium distribution, distribution reinvestment and optional unit purchase plan (DRIP) allows Unitholders to further leverage their investment in the Trust, providing them with the option to reinvest their distribution to receive new units at a 5% discount to the average market price, or for Canadian investors, up to an extra 2% cash of the otherwise declared distribution. Complete details are available from investor relations or the Trust's Web site at www.cos-trust.com.

An Outstanding Return



Data prior to 2001 merger represent Athabasca Oil Sands Trust, the surviving entity.

ADVISORY – in the interest of providing Canadian Oil Sands Trust (Canadian Oil Sands, the Trust, we or us) 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 Management's Discussion and Analysis (MD&A) contain "forward-looking statements" under applicable securities law. Forward-looking statements in this M&DA include, but are not limited to, statements with respect to: the anticipated completion date and cost of the UE-1 construction, the expected production level at Syncrude for 2004 and the resulting oil production per day for the Trust; the expected level of oil and natural gas prices; the anticipated impact that certain factors such as natural gas and oil prices, foreign exchange, operating costs, non-production costs, depreciation and depletion costs and administrative costs have on the Trust's funds from operations and net income;

MD&A

the anticipated levels of foreign ownership; and the anticipated taxability of distributions paid by the Trust. 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 uncertainty of labour supply and costs; normal risks associated with litigation, general economic, business and market conditions; regulatory changes; risks and uncertainties described in this MD&A; and such other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by the Trust. You are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this MD&A are made as of the date of this MD&A, and 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

BUSINESS DESCRIPTION

Canadian Oil Sands Trust is an open-ended investment trust that generates income from its 35.49 per cent working interest in the Syncrude Joint Venture (Syncrude). The Trust holds the largest interest in Syncrude and is the only public instrument invested solely in the Syncrude asset.

Syncrude is operated and administered by Syncrude Canada Ltd. on behalf of seven joint venture owners. Located near Fort McMurray, Alberta, Syncrude operates large oil sands mines, electrical power utility plants, bitumen extraction plants and an upgrading complex that processes bitumen into a light sweet crude oil. Syncrude's trademark product is a high quality, light, sweet synthetic blend, referred to as "Syncrude Sweet Blend" (SSB)™, which has an average gravity of about 32° API and approximately 0.2 per cent sulphur content. Each joint venture owner receives its share of SSB production in kind and is responsible for its own marketing activities. Syncrude has been in continuous operation for 25 years.

EXECUTIVE OVERVIEW

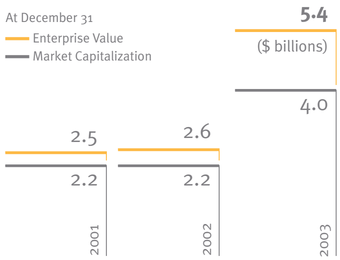
Our working interests in Syncrude are held through two operating subsidiaries: Canadian Oil Sands Limited (COSL) and Canadian Oil Sands Commercial Trust (CT). The only business of these operating subsidiaries is to manage the aggregate 35.49 per cent interest in Syncrude and, in the case of COSL, to manage the Trust on behalf of its Unitholders. Officers of COSL contribute to the governance of Syncrude operations and expansion plans through key roles on the Board and committees of Syncrude. In particular, officers of COSL chair the Audit and Pension Committee and CEO Committees as well as Syncrude Canada Ltd.'s Board of Directors. The Syncrude joint venture owners committee, known as the Management Committee, is also chaired by the President and Chief Executive Officer of Canadian Oil Sands.

The operating subsidiaries are responsible for financing their share of Syncrude's operations and their own administrative costs. Sources of financing include funds generated from operations from the sale of SSB production, and as required, debt and equity financing.

Funds generated from operations are highly dependent on net selling prices received for the SSB product, production volumes, and operating costs to produce SSB. We have contracted out the marketing of our share of Syncrude volumes to EnCana Corporation (EnCana), which markets these volumes to refineries in Canada and the U.S. for a fee. The prices we receive for our SSB product correlate closely to U.S. West Texas Intermediate (WTI) oil prices and are also impacted by movements in U.S.-Canadian foreign exchange rates. Crude oil prices can be volatile, reflecting world events and supply and demand fundamentals. During the past three years, WTI prices have fluctuated from a high of US$37.83 per barrel to a low of US$17.45 per barrel.

MARKET CAPITALIZATION AND ENTERPRISE VALUE

The acquisition of the additional Syncrude interests, combined with Stage 3 financing, resulted in significant growth in market capitalization and enterprise value for the Trust in 2003, making us the largest energy trust in Canada.



Production volumes reflect the capacity of the Syncrude facility and reliability of operations. A proved reserve life estimated at 35 years, based on current production rates, provides a secure, reliable source of bitumen for the production of SSB. However, the process of mining, extracting and upgrading bitumen is a highly technical and complex manufacturing operation that requires regular maintenance of the various operating units, which can affect production volumes, and consequently, net revenues. Production volumes have the greatest impact on per barrel operating costs as a large proportion of the costs are fixed. The most significant variable cost is natural gas which is used in the production process; therefore, operating costs are also sensitive to changes in natural gas prices.

In addition to funding ongoing operations, funds generated from operations are used to pay distributions to our Unitholders and to partially fund our share of Syncrude's expansion projects. The Trust makes distributions to its Unitholders through the trust royalties, distributions and interest payments it receives from the operating subsidiaries.

Syncrude is currently in the midst of the largest expansion project in its history, known as Stage 3. The expansion, combined with current reliability initiatives, is designed to increase annual Syncrude production to 128 million barrels, reduce per barrel operating costs and enhance the product quality of SSB. As of March 4, 2004, Stage 3 is scheduled for completion in 2006 and the total project cost is estimated at $7.8 billion, or $2.8 billion net to the Trust.

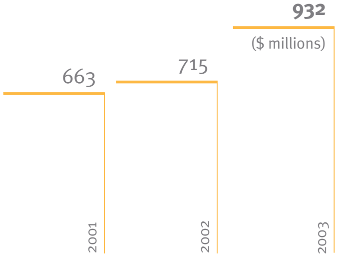
In addition to internal growth through the Stage 3 expansion, we have grown through acquisitions. In 2003, we acquired an additional 13.75 per cent interest in Syncrude from EnCana in two separate transactions. The total purchase price of $1.5 billion was financed through the issuance of additional equity and debt. These acquisitions contributed to growth in our enterprise value, calculated as market capitalization plus net debt. At December 31, 2003, based on the closing market price of $45.69 per Trust unit, our market capitalization and enterprise value was approximately $4.0 billion and $5.4 billion, respectively, up from $2.2 billion and $2.6 billion, respectively, at December 31, 2002, based on a closing Trust unit price of $38.05.

We intend to continue exploring further accretive acquisition opportunities of oil sands assets to augment Syncrude's internal growth plans. We also seek to optimize long-term Unitholder value through stable and increasing distributions. Distributions will continue to depend on crude oil prices and volumes, financing requirements for the Stage 3 capital program and our objective of maintaining an investment grade credit rating.

More information regarding Canadian Oil Sands, including our Annual Information Form, is available on SEDAR at www.sedar.com.

NET REVENUES

Production revenue was higher in 2003 due to the increase in our Syncrude working ownership interest, partially offset by lower Syncrude volumes and realized selling prices.



SELECTED ANNUAL FINANCIAL INFORMATION

($ millions, except per Trust unit amounts)	**2003**	2002	2001
Net revenues	**932**	715	663
Net income	**308**	270	146
Net income per Trust unit, Basic and Diluted	**3.87**	4.72	2.58
Total assets	**4,260**	1,850	1,589
Total long-term financial liabilities [1]	**1,875**	693	692
Unitholder distributions per Trust unit	**2.00**	2.00	2.75
Funds from operations	**273**	326	227
Funds from operations per Trust unit	**3.43**	5.71	4.00

1 Includes other liabilities, long-term debt, future reclamation and site restoration costs, deferred currency hedging gains, and future income taxes.

As a result of having acquired from EnCana a 10 per cent Syncrude working interest in February 2003 and another 3.75 per cent working interest in July 2003, our 2003 operating results reflect an average working interest ownership in Syncrude of 31.92 per cent, compared with 21.74 per cent in 2002 and 2001.

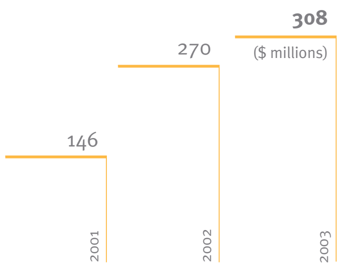
Net revenues increased 30 per cent in 2003 over 2002, reflecting the increased working interest offset by lower Syncrude production volumes in 2003 as a result of an unplanned coker turnaround during the year, which had a negative impact on both sales and operating costs. The net realized sales price was similar in both years with a stronger Canadian dollar and crude oil hedging losses offsetting higher average WTI prices in 2003.

The increase in net revenues in 2003 was more than offset by higher operating, non-production, royalty and interest expenses. Higher operating costs in 2003 were attributable to the coker turnarounds and higher energy costs compared with 2002. Significantly lower U.S.-Canadian dollar exchange rates in 2003 resulted in higher foreign exchange gains on our U.S. dollar denominated debt compared with 2002. These gains contributed to the increase in net income in 2003 from 2002 as they offset the reduction in revenues resulting from the higher Canadian dollar. While net income was higher in 2003 than in 2002, the operational difficulties combined with an increased number of Trust units outstanding in 2003, resulted in lower net income per Trust unit. Funds from operations were lower in 2003 compared to 2002 primarily as a result of the increase in operating costs, non-production costs, interest expense and income and Large Corporations tax expense, offset partially by the increase in net revenues.

In 2002, higher average realized selling prices, increased sales volumes, lower operating costs, and lower Crown royalties expense offset somewhat by a higher interest expense resulted in increased net revenues, net income and funds from operations compared with 2001. Crude oil prices strengthened from 2001 to 2003, with the WTI prices per barrel averaging US$25.92, US$26.15, and US$31.04 in 2001, 2002 and 2003, respectively. Syncrude realized record annual production volumes in 2002, which increased revenues and decreased operating costs per barrel to the Trust, compared with 2001.

NET INCOME

Net income increased in 2003 as a result of a higher Syncrude working interest ownership.



Total assets grew significantly in 2003 compared with the two prior years, with the most significant rise relating to the increase in capital assets. Capital assets increased by approximately $1.9 billion as a result of acquiring a 13.75 per cent working interest in 2003, and by another $0.8 billion for our share of Syncrude Stage 3 capital expenditures.

The increase in long-term financial liabilities is mainly attributable to the increases in long-term debt and the future income tax liability, which were $1.4 billion and $0.3 billion, respectively, at the end of 2003. Included in long-term debt is approximately $0.5 billion of debt assumed in 2003 to finance the $1.5 billion purchase of the 13.75 working interest from EnCana, and another $0.4 billion to fund our share of the Stage 3 capital program.

Annual Unitholder distributions remained stable at $2 per Trust unit in 2003. For the fourth quarter of 2001, as part of our financing strategy to maintain credit strength and financial capacity to fund our share of Syncrude's expansion program, we reduced quarterly distributions to $0.50 per Trust unit from the previous $0.75 per Trust unit.

SUMMARY OF QUARTERLY RESULTS

($ millions, except per Trust unit amounts)			2003		
	Q1	Q2	Q3	Q4	Annual
Net revenues	**176.4**	**232.9**	**300.4**	**222.4**	**932.1**
Net income	**83.3**	**63.2**	**105.2**	**56.2**	**307.9**
Net income per Trust unit, Basic and Diluted	**1.27**	**0.79**	**1.22**	**0.65**	**3.87**
Funds from operations	**51.6**	**56.3**	**120.3**	**44.7**	**272.9**
Funds from operations per Trust unit	**0.79**	**0.71**	**1.39**	**0.51**	**3.43**

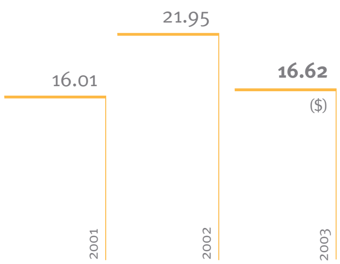
			2002		
	Q1	Q2	Q3	Q4	Annual
Net revenues	156.7	136.4	218.4	203.8	715.3
Net income	50.0	36.8	88.5	94.6	269.9
Net income per Trust unit, Basic and Diluted	0.88	0.65	1.54	1.64	4.72
Funds from operations	64.3	18.0	132.2	111.9	326.4
Funds from operations per Trust unit	1.13	0.32	2.31	1.94	5.71

In the first half of the year, the Trust realized higher per barrel selling prices in 2003 than 2002 as a result of higher crude oil prices, offset slightly by increased crude oil hedging losses. Total sales volumes increased in the first half of 2003 as a result of the 10 per cent working interest acquisition in February 2003, which combined with a higher selling price, resulted in higher net revenues in the first two quarters of 2003 compared to the same periods in 2002.

In the second half of 2003, the Trust's realized selling prices were lower than the comparable period in 2002 due to a much stronger Canadian dollar relative to the U.S. dollar and higher crude oil hedging losses, which reflected higher WTI prices and a larger hedge position in 2003

NETBACK PER BARREL

2003 netback declined as a result of a lower realized selling price, after hedging, and higher operating expenses.



compared with 2002. However, sales volumes were higher in the last six months of 2003 compared with the same period in 2002 as a result of having the additional 13.75 per cent working interest. The increased sales volumes, partially offset by the lower realized selling price, resulted in higher net revenues in the last half of 2003 compared with the same period in 2002.

Net income in the first half of 2003 exceeded net income of the comparable period in 2002 as a result of a higher working interest ownership and higher per barrel realized selling prices. Net income in the last half of 2003 was lower than the same period in 2002 despite a larger working interest. Excluding foreign exchange gains and future income tax, net income was significantly lower, reflecting the lower Syncrude production volumes as a result of the 37-day coker turnaround in October, lower realized Canadian dollar selling prices, and higher operating costs.

Significant variances in financial results between 2003 and 2002 are explained further in the following sections of this MD&A.

REVIEW OF CONSOLIDATED RESULTS

Our 2003 financial results reflect our increased ownership in Syncrude, which averaged 31.92 per cent throughout the year, compared to 21.74 per cent in 2002. The Trust reported higher net income in 2003 compared to the prior year as a result of the increased working interest. Net income before foreign exchange and future income tax, which in management's opinion more accurately reflects the Trust's operating performance, was $159 million, a decrease of $107 million from the prior year. Higher operating costs, interest expense, and depreciation and depletion expense partially offset by an increase in net revenues accounts for the majority of the decrease in net income before foreign exchange and future income tax in 2003 compared to 2002.

($ millions)	**2003**	2002	$ Change	% Change
Net income per GAAP	**307.9**	269.9	38.0	14
Deduct:				
Foreign exchange gain on long-term debt	**(147.2)**	(4.1)	(143.1)	3,490
Future income tax recovery	**(2.2)**	–	(2.2)	100
Net income before foreign exchange and future income taxes	**158.5**	265.8	(107.3)	(40)

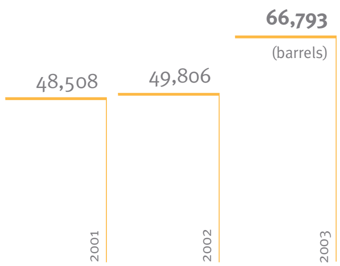
* The earnings reflected in the above table are a non-GAAP measurement, and therefore, are unlikely to be comparable to similar measures presented by other companies or trusts.

Netback

($ per barrel)	**2003**	2002	$ Change	% Change
Averaged realized selling price, after hedging	**38.23**	39.35	(1.12)	(3)
Operating costs	**(21.12)**	(16.99)	(4.13)	24
Crown royalties	**(0.49)**	(0.41)	(0.08)	20
Netback	**16.62**	21.95	(5.33)	(24)

AVERAGE DAILY SALES

The increase in 2003 sales volumes reflects the Trust's higher ownership interest, partially offset by lower Syncrude volumes.



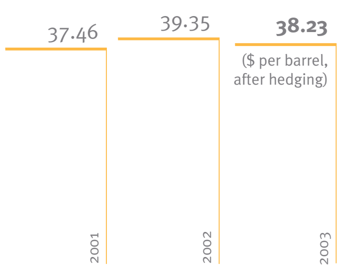
Net Revenues

($ millions)	2003	2002	$ Change	% Change
Production revenue	**1,064.2**	743.7	320.5	43
Transportation and marketing fees	**(35.8)**	(6.8)	(29.0)	426
	1,028.4	736.9	291.5	40
Crude oil hedging losses	**(99.9)**	(10.7)	(89.2)	834
Currency hedging gains (losses)	**3.6**	(10.9)	14.5	(133)
Total hedging losses	**(96.3)**	(21.6)	(74.7)	346
Net revenues	**932.1**	715.3	216.8	30
Sales volumes (MMbbls)	**24.4**	18.2	6.2	34

($ per barrel)	2003	2002	$ Change	% Change
Production revenue	**43.65**	40.91	2.74	7
Transportation and marketing fees	**(1.47)**	(0.37)	(1.10)	297
Realized selling price before hedging losses	**42.18**	40.54	1.64	4
Crude oil hedging losses	**(4.10)**	(0.59)	(3.51)	595
Currency hedging gains (losses)	**0.15**	(0.60)	0.75	(125)
Total hedging losses	**(3.95)**	(1.19)	(2.76)	232
Total realized selling price	**38.23**	39.35	(1.12)	(3)

REALIZED SELLING PRICE

The increase in the average U.S. dollar WTI price was partially offset by a stronger Canadian dollar, which combined with higher hedging losses, resulted in a lower 2003 realized selling price.



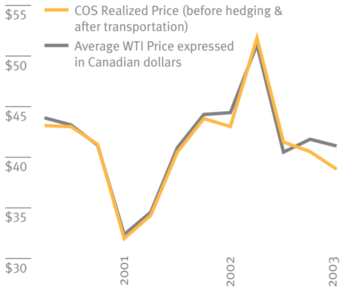
We have expanded our disclosure of production revenues and now are providing additional information on transportation and marketing fees with these costs separated on the Consolidated Statement of Income and Unitholders' Equity. In doing so, we have chosen to adopt new accounting rules established by the Canadian Institute of Chartered Accountants (CICA) in advance of their 2004 effective date. The new rules no longer permit transportation costs to be netted from revenues, which was a common energy industry practice.

Production revenue reflects sales volumes and prices at the point of delivery. Revenue after deducting transportation and marketing fees reflects the realized selling price at the Syncrude plant gate. Net revenues include the impact of crude oil and currency hedging gains and losses. Historically, the vast majority of our production was sold at Edmonton, Alberta. With additional synthetic crude oil production from other producers coming on stream during 2003, more of our sales volumes were sold into the U.S. and Eastern Canada. In the fourth quarter of 2003, approximately 52 per cent of sales volumes were sold downstream from Edmonton. We anticipate more of our production will be sold downstream from Edmonton than in the past, but it is too early to provide a reasonable estimate of what the portion may be.

In response to growing volumes of synthetic crude oil and Syncrude's own expanding volumes following the Stage 3 completion, we must expand our markets to achieve the premium price we expect for our quality product. When the upgrader expansion project of Stage 3 (UE-1) is

REALIZED PRICE DIFFERENTIAL TO WTI

More synthetic crude volumes coming into the market are resulting in a wider differential between SSB and WTI.



complete, a new aromatic saturation unit will be used to upgrade our entire production into a higher quality product called "Syncrude Sweet Premium" (SSP). We expect this higher quality blend to be more attractive to refineries, which should further enhance our price per barrel.

Also, the use of light sweet synthetics as a blend stock for bitumen to produce "synbit" is seen as a potential new market for SSB. Currently, heavy crude oil producers are shipping bitumen to U.S. refineries by adding condensate, which is expensive and in short supply. Synbit, which is similar to medium sour crude, is being considered as an alternative.

For the year ended December 31, 2003 net revenues increased approximately $217 million compared to the same period in 2002, primarily as a result of higher production revenue, partially offset by higher crude oil hedging losses.

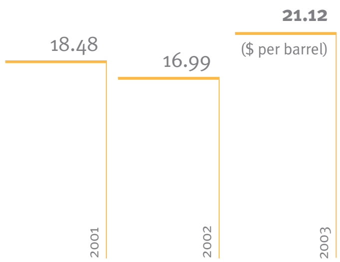
Production revenue was higher in 2003 than 2002 as a result of having acquired from EnCana the additional 10 per cent working interest on February 28, 2003 and another 3.75 per cent working interest on July 10, 2003. Canadian Oil Sands' average Syncrude working interest of approximately 32 per cent in 2003 represents an increase in ownership of approximately 47 per cent compared to the prior year. While the Trust's average ownership interest increased 47 per cent, sales volumes of 66,793 barrels per day increased only 34 per cent from 2002, reflecting the impact of the unplanned Coker 8-1 turnaround in October and November, the extended Coker 8-2 turnaround in May, and the first quarter's unscheduled and extended scheduled maintenance work. We originally budgeted daily sales volumes for 2003 based on our 21.74 per cent working interest to be 50,600 barrels, and revised our budget during the year to 68,000 barrels to reflect the increased working interests and the turnarounds and maintenance activity.

Realized selling prices before hedging in 2003 were approximately four per cent higher than in 2002, averaging $42.18 per barrel in 2003 compared to $40.54 per barrel in 2002. Although the average 2003 WTI price at US$31.04 per barrel was up 19 per cent compared to 2002, a stronger Canadian dollar offset the majority of this increase. As shown in the graph, also offsetting the increase in WTI prices was a slightly larger discount to which SSB traded against Canadian dollar WTI during the 2003 year, compared to prior years, as additional synthetic crude oil volumes came into the market. We anticipate a discount to Canadian dollar WTI to remain until we begin selling the higher quality SSP product, which we believe will receive a higher price than our current SSB product.

After hedging, the average selling price per barrel was $38.23 in 2003, compared to $39.35 in the prior year. Crude oil hedging losses of approximately $100 million in 2003, or $4.10 per barrel, reflected strong U.S. dollar crude oil prices and a larger proportion of volumes hedged compared to the same period in 2002, during which losses of $11 million, or $0.59 per barrel, were reported. Currency hedging gains of approximately $4 million, or $0.15 per barrel, compared favourably to losses of $11 million, or $0.60 per barrel, in 2002 as a result of the Canadian dollar averaging $0.71 US/Cdn and $0.64 US/Cdn in 2003 and 2002, respectively. Our crude oil and foreign currency hedging positions are outlined in the Risk Management section of this MD&A.

OPERATING COSTS

The increase in 2003 operating costs per barrel is due to additional turnaround costs, lower Syncrude production volumes and significantly higher energy costs.



Operating Costs

	2003		2002	
	$/bbl Bitumen	$/bbl SSB	$/bbl Bitumen	$/bbl SSB
Bitumen Costs [1]				
Overburden removal	**2.33**		2.17	
Bitumen production	**6.17**		5.75	
Purchased energy	**1.67**		1.02	
	10.17	**12.13**	8.94	10.43
Upgrading Costs [2]				
Bitumen processing and upgrading		**3.82**		3.24
Turnarounds and catalysts		**1.86**		1.19
Purchased energy		**2.45**		1.19
		8.13		5.62
R&D and other		**0.81**		1.00
Syncrude reported operating costs		**21.07**		17.05
Natural gas hedging gains		**(0.23)**		(0.28)
Canadian Oil Sands adjustments [3]		**0.28**		0.22
Total operating costs		**21.12**		16.99
Syncrude production volumes (thousands of barrels per day)	**252**	**212**	268	230

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

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

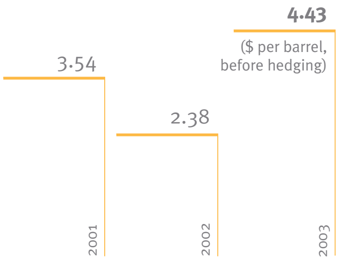
3 Canadian Oil Sands' adjustments primarily relate to pension cost adjustments and the inventory impact of moving from production to sales as Syncrude reports unit costs based on shipment volumes and we report based on sales volumes.

The above table breaks down unit operating costs into its major components and shows bitumen costs on both a per barrel of bitumen and per barrel of SSB produced. This allows investors to better compare Syncrude's unit costs to other oil sands producers. As there are no definitions of what constitutes operating costs, different cost accounting and capitalization treatments are used among producers.The increase in costs on a year-over-year basis primarily relates to the fixed cost impact on lower production volumes and the higher cost of purchased energy.

Syncrude had disappointing operating results in 2003 with production being eight per cent lower in 2003 than 2002, averaging 211,757 barrels per day, compared to 229,520 barrels per day in 2002. Production constraints, mainly the unplanned 37-day Coker 8-1 turnaround in October, the extended Coker 8-2 turnaround in May, and the first quarter's unscheduled and extended scheduled maintenance, negatively impacted production. These operational challenges contributed to lower production and increased costs for both bitumen production and upgrading, resulting in an increase in per barrel operating costs compared to 2002. In the second quarter

PURCHASED ENERGY COSTS

A 66 per cent increase in natural gas prices led to higher purchased energy costs for the Trust in 2003. Hedging gains in 2003 and 2002 reduced the Trust's natural gas costs. Approximately 0.7/mcf of natural gas is consumed to produce one barrel of SSB.



of 2002, Syncrude had a coker turnaround which took longer than anticipated, but was followed by improved operating performance and plant reliability in the second half of the year, resulting in favourable operating costs on a per barrel basis compared with 2003.

Operating costs in 2003 were also negatively impacted by a 66 per cent increase in natural gas prices from 2002. During 2003 natural gas prices averaged $6.28 per gigajoule (GJ) compared to $3.79 per GJ in 2002. Natural gas is a significant component of the bitumen production and upgrading processes, representing 21 per cent of our total operating costs in 2003, and 14 per cent in 2002. Natural gas hedging gains of approximately $6 million in 2003, relating to hedges that were in place from January 1 to March 31, 2003, helped mitigate the increased natural gas costs. For the period April 1, 2002 to December 31, 2002, natural gas hedging gains of approximately $5 million reduced 2002 operating expenses.

At the end of 2002, operating costs for 2003 were budgeted to be $16.50 per barrel with Syncrude production volumes of 85 million barrels. This budget assumed one coker turnaround in the first quarter. During the year, the operating cost budget was revised to reflect the increased working interests and the impacts of the maintenance and turnaround activities previously mentioned. By November 2003, we had revised our operating cost forecast up to $20.50 per barrel with Syncrude production of 77 million barrels. Actual Syncrude production was 77.3 million barrels in 2003, slightly higher than the latest forecast due to strong operations in December, which resulted in record production for the month of 8.2 million barrels. Actual operating costs were approximately three per cent higher than the revised budget as adjustments to our share of Syncrude's pension liability in December were higher than originally anticipated.

Non-Production Costs

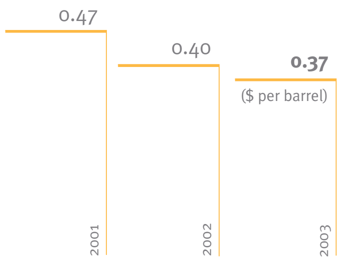
Non-production costs increased in 2003 from 2002 due to the larger working interest and higher levels of development activity associated primarily with UE-1. Non-production expenses relate mainly to Syncrude 21 development expenditures, which include costs incurred to modify, relocate or remove equipment or facilities to support the expansion. In 2003, we also reclassified certain expenses, largely related to engineering and other costs for capital projects associated with the development of the existing plant facilities, from operating costs to non-production costs to more accurately reflect operating expenses related to current production. Prior year figures have been reclassified to reflect this change in presentation.

Crown Royalty Expense

Crown royalty expense rose in 2003 as a result of higher gross revenues. Also included in 2003 is a charge of approximately $1.5 million relating to an adjustment to the calculations of Crown royalties in 2000. As Syncrude is currently undertaking a significant capital program, we expect to pay the minimum one per cent royalty on our gross revenues for the next few years. A description of the Crown royalty can be found in Note 18 of the audited consolidated financial statements.

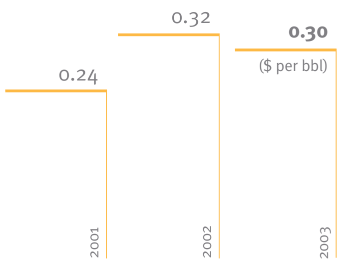
ADMINISTRATION EXPENSE

Administration expense per barrel continued to decline in 2003, demonstrating the Trust's objective to maintain one of the lowest cost structures in the trust sector.



INSURANCE EXPENSE

Insurance is a key component of the Trust's risk mitigation strategy.



Administration Expense

Administration expenses in 2003 reflect our first year of having our own staff, office space, and third party service providers after having terminated the Administrative Services Agreement with EnCana on November 1, 2002. The increase in administrative costs of approximately $2 million reflects primarily the adoption of expensing stock options, the replacement of directors' stock options with Trust units, and higher salaries. The additional Syncrude working interests did not have a significant impact on our administrative costs in 2003, reducing our costs on a per barrel basis to $0.37 in 2003 compared to $0.40 in 2002. The reduction in per barrel administrative costs demonstrates our commitment to maintaining one of the lowest cost structures in the trust sector.

Insurance Expense

The largest component of our insurance expense relates to premiums paid for business interruption (BI) insurance, which is designed to protect the Trust's cash flow from the potential of a severe property loss at Syncrude. With the acquisitions of the 10 per cent and 3.75 per cent working interests during the year, we proportionately increased our BI insurance coverage to match the additional ownership levels, resulting in higher insurance expense in 2003 compared to 2002. Insurance is an important risk management component of our Stage 3 financing plan as it helps to protect our cash flow from which our share of the capital expenditure commitments are largely funded. Once Stage 3 is complete and our debt levels have been reduced, we will re-evaluate our business interruption insurance program. Insurance is discussed more fully in the Risk Management section of this MD&A.

Interest Expense, Net

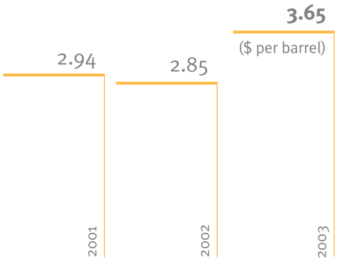
($ millions)	2003	2002	$ Change	% Change
Interest expense	**72.0**	48.6	23.4	48
Interest income and other	**(4.2)**	(9.9)	5.7	(58)
Interest expense, net	**67.8**	38.7	29.1	75

In the fourth quarter of 2003, we chose to net interest and other income from interest expense to more accurately reflect the cost of financing our operations. The increase in interest expense primarily reflects the additional debt we issued in 2003, as well as the utilization of credit facilities that were first drawn upon in March 2003. The additional debt was used to finance a portion of the $1.5 billion purchase price for the 13.75 per cent working interest acquisition and to fund our share of Syncrude's capital expenditures. The debt issues and utilization of credit facilities are explained more fully in the Liquidity and Capital Resources section of this MD&A.

Contributing to the increase in interest expense in 2003 compared to 2002 was the lower interest income earned, which primarily relates to the lower average cash balance in 2003 as a result of financing our share of the Stage 3 capital expenditures. This decrease in interest income was offset somewhat by gross overriding royalty (GORR) income of approximately $0.7 million related to the six per cent GORR acquired from EnCana in July 2003.

DEPRECIATION AND DEPLETION EXPENSE

The increase in D&D expense, excluding the reclamation provision, reflects the acquisitions of the Syncrude working interests during 2003.



Depreciation and Depletion Expense

($ millions)	2003	2002	$ Change	% Change
Depreciation and depletion	**90.5**	52.0	38.5	74
Reclamation provision	**4.3**	3.1	1.2	39
	94.8	55.1	39.7	72

Depreciation and depletion (D&D) expense for 2003 was approximately $40 million higher than in 2002 as a result of the acquisitions of the Syncrude working interests during the year. The effective D&D rate in 2003 was $3.65 per barrel compared to $2.85 per barrel in 2002. We depreciate and deplete our production assets on a unit-of-production basis. In the fourth quarter of 2003, the second mining train at the Aurora mine (Aurora 2) was put into operation, and therefore, the related costs of approximately $240 million, net to the Trust, have been included in our calculation of the D&D expense in the fourth quarter.

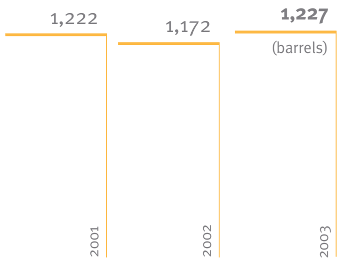
Subsequent to year-end 2003, Canadian Oil Sands' 2003 reserve report was completed by independent reserve evaluators. The reserve report resulted in no significant revisions in our proved reserve base. Including the acquisition of the 13.75 per cent working interest in 2003, our proved reserves for our 35.49 per cent working interest are approximately one billion barrels, compared to 676 million barrels in 2002. We are now reporting proved plus probable reserves, which total approximately 1.8 billion barrels.

There will be an increase to our D&D rates in 2004 as a result of the revised UE-1 costs of approximately $2.5 billion now being included in future development costs, as well as an increase to sustaining capital expenditures in our reserve report. Based on National Instrument 51-101, which provides that the total of proved plus probable reserves is the most likely estimate of an entity's reserve base, we are now depreciating and depleting our existing assets and future development costs on a proved plus probable basis. Future development costs include sustaining capital, remaining Stage 3 costs, and other costs required to produce the reserves. As a result, we estimate our 2004 D&D rate will be approximately $5.70 per barrel, or approximately $177 million in D&D expense, based on our 2004 production budget of 31 million barrels net to the Trust.

Also included in D&D expense is a future site reclamation provision, which is accrued at a rate of $0.17 per barrel of production. The reclamation provisions for 2003 and 2002 were approximately $4 million and $3 million, respectively, with the increase attributable to the higher Syncrude working interest in 2003. The current year provision combined with the liability recorded on the acquisition of the 13.75 per cent working interest resulted in a future site reclamation liability of $58 million at December 31, 2003. As more fully explained in the New Accounting Pronouncements section of this MD&A, our future site reclamation liability recorded on the Consolidated Balance Sheet will be adjusted in 2004 as a result of new accounting rules, which became effective January 1, 2004. The impact on our future site reclamation liability and D&D expense is not expected to be significant.

PROVED RESERVES PER 100 TRUST UNITS

Every 100 Trust units are backed by significant reserves, which grew in 2003 as a result of the acquisition of the additional Syncrude working interests.



Similar to our 21.74 per cent working interest in Syncrude, we will be depositing $0.1322 per barrel of current production related to our acquisition of the 13.75 per cent Syncrude interest into a mining reclamation trust account. As of December 31, amounts are included in the mining reclamation trust balance in the Consolidated Balance Sheet under the heading "Reclamation trust".

Foreign Exchange Gains

In 2003, a foreign exchange gain of $135 million was recorded, compared to a gain of $3 million in 2002. As required by Canadian generally accepted accounting principles, our U.S. denominated monetary balances are revalued at the foreign exchange rate at each period end, and the translation gains or losses are recorded in the current period's earnings. Our most significant U.S. denominated monetary balances that give rise to most of the foreign exchange impacts are the U.S. Senior Notes. At December 31, 2003 and 2002, we had US$694 million and US$394 million in U.S. denominated debt, respectively. The stronger Canadian dollar created non-cash foreign exchange gains on our U.S. denominated senior notes of $147 million and $4 million in 2003 and 2002, respectively. We also have U.S. denominated cash, accounts receivable, and interest payable accounts that are revalued at the end of each period. The remaining balance of the foreign exchange gains and losses on the income statement relate to realized foreign exchange gains and losses on the conversion of U.S. dollars to Canadian dollars.

Income and Large Corporations Tax

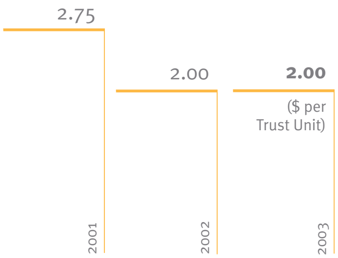
Income and Large Corporations Tax (LCT) expense in 2003 reflects the estimated LCT payable by COSL of approximately $8 million, compared with approximately $3 million in 2002. The increase in LCT expense in 2003 compared to 2002 reflects the significantly larger taxable capital base as a result of the working interest acquisitions during the year. For 2003, we estimate there to be no cash income taxes payable, other than LCT, by the Trust or any of its subsidiaries.

Also included in the 2003 income and LCT expense is a cash payment of approximately $9 million paid to Canada Customs and Revenue Agency (CCRA) for a tax liability pertaining to the 2001 income tax return of the Trust. In September 2003, the Trust paid approximately $10 million to CCRA, which included $1 million of interest charges that had accrued on the $9 million tax liability. The interest charges have been included in interest expense. As disclosed in Note 22 of the consolidated financial statements, the tax liability was a result of an error in the Trust's 2001 income tax return prepared by the Trust's former tax service provider. We are currently taking action to recover the cash payment from the former tax service provider. However, the amount of the recovery is not determinable at this time. As such, the potential recovery has been disclosed as a contingent gain with no amounts pertaining to the contingent gain recorded in our consolidated financial statements at December 31, 2003.

In 2002, in addition to LCT expense, there was a $3 million cash income tax provision related to one of the Trust's operating subsidiaries that was taxable as a result of not enough capital cost allowance deductions being available. The significant capital costs related to Stage 3 were not yet deductible because the assets were not considered available for use under the tax regulations.

UNITHOLDER DISTRIBUTIONS

The Trust reduced distributions in late 2001 to help support funding for the Stage 3 expansion, during which the Trust's objective is to maintain a stable distribution.



At the Unitholder level, distributions made from the Trust are either taxable to Unitholders or tax-deferred. Tax-deferred treatment reduces the Unitholders' tax-cost base. For the distributions related to 2003, approximately 83 per cent of distributions were taxable, and approximately 17 per cent were tax-deferred. This compares with 60 per cent being taxable and 40 per cent being tax-deferred in 2002. The increase in taxability of the distributions in 2003 compared with 2002 is due primarily to a change in tax rules where the Trust now is required to include income accruals in its current year income, as opposed to cash received. This resulted in approximately $30 million of income being included in the Trust's 2003 taxable income base which could not be sheltered by tax deductions at the Trust level.

The taxable portion of distributions is dependent upon income and tax deductions available to shelter this income at both the Trust and the corporation level. Income, and therefore, taxable distributions to Unitholders, is highly sensitive to changes in revenues and costs since the annual tax deductions available are subject to maximum amounts. The tax balances available are disclosed in Note 12 to the consolidated financial statements. It is anticipated that the majority of future distributions will be taxable to Unitholders.

Future Income Tax

As a result of having acquired the 10 per cent working interest in Syncrude from EnCana in February, Canadian Oil Sands recorded a net future income tax liability in the first quarter of 2003. The difference between the accounting basis and tax basis for assets and liabilities is referred to as a temporary difference for purposes of calculating future income taxes. As a result of the acquisition, the future income tax liability Canadian Oil Sands recorded primarily represents the temporary difference between the book value of capital assets of the Trust's subsidiaries and tax pools at the substantively enacted tax rates as at December 31, 2003. There was no future income tax impact for the 3.75 per cent acquisition in July as the working interest is held in a partnership and owned by CT, which is not required to record future income taxes because it is a trust.

In 2003, Canadian Oil Sands recorded a non-cash future income tax recovery of $2 million. Included in the $2 million recovery is a future income tax expense of approximately $13 million which reflects the increase in COSL's future income tax liability as a result of the federal government substantively enacting the phasing out of resource allowance, partially offset by the reduction of corporate tax rates, over the next five years. Offsetting this expense was a future income tax recovery of approximately $15 million, which relates primarily to the decrease in the temporary differences in the year. This future income tax liability is not expected to result in higher cash taxes being paid by COSL in the future, but rather will be recovered through non-cash future income tax reversals over time.

Dividends on Preferred Shares of Subsidiaries

On October 31, 2002, the preferred shares of the Trust's operating subsidiaries that were held by EnCana were redeemed to align with the termination of the Administrative Services Agreement with EnCana. All accrued and unpaid dividends were paid upon redemption.

Critical Accounting Estimates

A critical accounting estimate is considered to be one that requires us to make assumptions about matters that are highly uncertain at the time the accounting estimate is made, and if different estimates were used, would have a material impact on our financial results. Canadian Oil Sands makes numerous estimates in its financial results in order to provide timely information to users. However, the following estimates are considered critical:

a) Canadian Oil Sands must estimate the reserves it expects to recover in the future. Our reserves are evaluated and reported on by independent petroleum reserve evaluators who evaluate the reserves using various factors and assumptions, such as forecasts of costs based on geological and engineering data, projected future rates of production and timing and amounts of future development costs, all of which are subjective. Although reserves determination is an estimate, we believe that the factors and assumptions used in the estimates are reasonable based on information available at the time the estimate is prepared. The reserves estimates are reviewed by management, our internal engineer, our Audit Committee, which acts as our reserve committee, and our Board of Directors.

As circumstances change and new information becomes available, the reserve estimates and/or future development cost estimates could change. Our proved reserves overall have not changed significantly in the last three years after having independent reserve reports completed in 2001 and 2004 for the 2000 and 2003 years, with the exception of adding a pro rata increase to our reserve base related to the additional 13.75 per cent working interest acquisition in 2003. However, future actual results could vary greatly from our estimates, which could cause material changes in our unit-of-production D&D rates, site restoration provisions, and asset impairment tests, all of which use the reserves and/or future net cash flows in the respective calculations. If proved reserves were 10 per cent lower, D&D expense would have been approximately $10 million higher in 2003, but there would be no material impact on the site restoration provision or the asset impairment test.

b) Canadian Oil Sands estimates future site reclamation costs based on an estimate of the future liability and proved reserves which were discussed in (a). The future liability estimate is complex and is based on estimates of future costs to abandon and restore the mine sites. In order to impact the site restoration provision by $1 million, it would require more than a 30 per cent increase to the estimated future reclamation costs.

c) Canadian Oil Sands accrues its obligations for Syncrude employee post retirement benefits utilizing actuarial and other assumptions to estimate the projected benefit obligation, the return on plan assets, and the expense accrual related to the current period. The basic assumptions utilized are outlined in Note 7(a) to the consolidated financial statements. In addition, actuarial gains and losses are deferred and amortized into income over the expected annual service lives of employees estimated to be 13 years, which may differ from the actual service lives of employees when the net pension obligation is settled in the future. Actual costs related to

Syncrude's employee benefit plans could vary greatly from the amounts accrued for the pension obligation and the plan assets. If Canadian Oil Sands had recognized the actuarial losses immediately into income, pension and other post retirement expense would have increased from $23 million to approximately $33 million in 2003. In addition, the accrued benefit liability on the Consolidated Balance Sheet would have increased from $91 million to $170 million.

Change in Accounting Policies

Effective the third quarter of 2003, we changed our accounting policy for stock-based compensation. We now are recognizing the compensation expense related to stock options in our financial statements according to the fair-value method. Prior to the change in policy, we disclosed the impact of the accounting for stock options under the fair-value method on a pro forma basis. Under the transitional provisions set out by the CICA, we have chosen to adopt this change retroactively. The impact on opening retained earnings was a decrease of $0.2 million, which represents the stock option expense related to the options granted during 2002. In 2003, we recorded approximately $0.6 million as compensation expense, which is included in Administration expenses in the consolidated financial statements. Included in Unitholders' Equity is contributed surplus of $0.8 million, which is a result of recognizing the stock option expense in the financial statements.

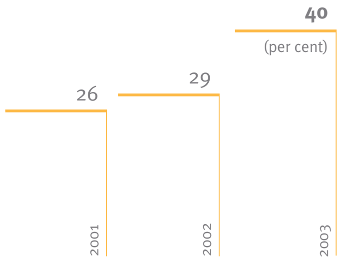
New Accounting Pronouncements

Effective January 1, 2004, Canadian Oil Sands will be applying new guidelines for hedge accounting in accordance with the CICA's Accounting Guideline 13, "Hedging Relationships" (AcG-13). AcG-13 establishes certain conditions for when hedge accounting may be applied. Under AcG-13, we will continue to apply hedge accounting for our crude oil and foreign currency hedges, which results in the hedging settlement gains or losses being included in net income in the same period the hedged items are settled. Therefore, there will be no impact to our results related to those hedge positions as a result of adopting AcG-13. However, our interest rate swap positions that were in existence at January 1, 2004 do not qualify as hedges under AcG-13 and therefore, we will be recording the fair market values of those positions on our Consolidated Balance Sheet at January 1, 2004. At December 31, 2003, the fair value of the interest rate swaps was a gain of approximately $5 million, which will be recorded as an increase to both other assets and other liabilities at January 1, 2004. The asset balance will be adjusted for any changes in the fair values of the interest rate swap positions subsequent to January 1, 2004 with the change being recorded in net income. The liability balance will be amortized over the remaining period of the swap contracts, which expire May 15, 2007.

In September 2002, the CICA approved Section 3063, "Impairment of Long-Lived Assets" (S.3063), which is effective for fiscal years beginning on or after April 1, 2003. S.3063 establishes standards for the recognition, measurement and disclosure of the impairment of long-lived assets that are held for use. An impairment loss will be recognized if the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. We do not anticipate there will be a material impact to our financial statements as a result of adopting this Section.

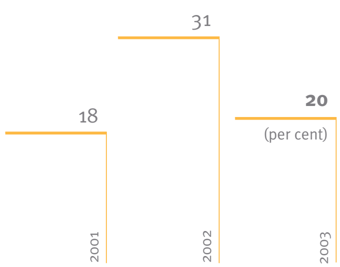
NET DEBT TO TOTAL BOOK CAPITALIZATION

Net debt to total book capitalization increased significantly in 2003, reflecting the additional debt incurred to finance the Stage 3 expansion. We aim to reduce this ratio to 30 per cent to 35 per cent following completion of Stage 3.



RETURN ON AVERAGE UNITHOLDERS' EQUITY

The Trust continued to provide a strong return on average Unitholders' equity in 2003, although down from 2002 because of lower Syncrude production volumes, higher operating costs, and the issuance of additional equity.



In December 2002, the CICA approved Section 3110, "Asset Retirement Obligations" (S.3110) with an effective date of January 1, 2004. Under S.3110, Canadian Oil Sands will be required to recognize as a liability the estimated value of our share of Syncrude's retirement obligations pertaining to property, plant and equipment. Upon initial adoption of S.3110, the fair value of the liability will be recognized as a future site reclamation liability, of which a substantial portion of the increase will be recorded as an increase to the value of our capital assets. The addition to capital assets will be depreciated in the same manner as our existing capital assets. The liability will accrete each year based on the discount rates used, with the accretion expense being recorded in net income each year. The impact on our net income is not anticipated to be significant. The initial adoption of S.3110 is considered a change in accounting policy and as such, our comparative prior period financial statements will be restated.

Liquidity and Capital Resources

($ millions)	**2003**	2002
Long-term debt	**1,437.4**	622.3
Less: Cash and short-term investments	**16.7**	230.0
Net debt	**1,420.7**	392.3
Unitholders' equity	**2,094.4**	956.5
Total capitalization [1]	**3,515.1**	1,348.8

1 Net debt plus Unitholders' equity

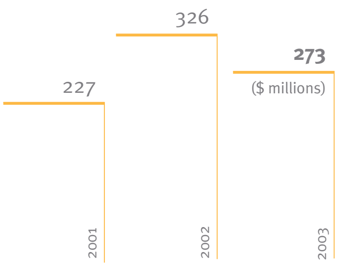
In 2003, the Trust's total capitalization increased significantly as a result of the acquisitions and related financing initiatives the Trust undertook during the year. To finance a significant portion of the 13.75 per cent Syncrude interest acquisitions from EnCana in 2003, which totalled approximately $1.5 billion, the Trust raised approximately $1.0 billion, net of issue costs, of new equity through two public offerings and two private placements, issuing a total of 28.2 million Trust units.

The balance of the acquisition of approximately $0.5 billion was financed with debt. To initially fund the Syncrude working interest acquisitions, we drew on a $560 million acquisition bridge facility. The bridge facility was repaid with a new $560 million credit facility. This new credit facility was paid down during 2003 with the issue of $150 million 5.75% medium term notes and US$300 million 5.8% Senior Notes in April and August, respectively. The terms of the debt issues are fully described in Note 9 "Long-term debt" of the consolidated financial statements. When the credit facility was fully paid down in August, it converted from a $560 million facility to a $225 million operating facility. Costs of approximately $16 million associated with issuing debt, including establishing new credit facilities, were capitalized as deferred financing charges on the Consolidated Balance Sheet.

On March 26, 2003, COSL amended the size and covenants of its bank credit facilities. As at February 16, 2004, we have $685 million of available bank facilities and lines of credit, which

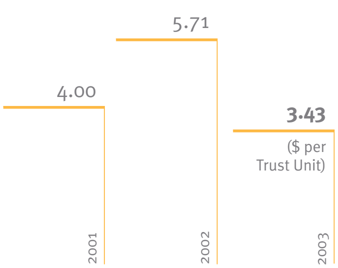
FUNDS FROM OPERATIONS

Funds from operations declined in 2003 as a result of higher operating and financing costs and slightly lower realized selling prices.



FUNDS FROM OPERATIONS

The decrease in per unit funds from operations reflects higher operating costs, higher interest costs and slightly lower realized selling prices.



include, in addition to the $225 million syndicated operating facility, a $415 million syndicated operating facility, a $20 million bilateral operating facility, and a $25 million letter of credit facility. Including letters of credit drawn, approximately $316 million of this $685 million credit facility was undrawn at February 16, 2004.

Under the bank credit facilities and trust indentures relating to various private and public debt issues, Canadian Oil Sands has certain restrictions such as a general covenant, subject to certain exceptions, not to encumber its assets. In addition, the credit facilities contain covenants which require Canadian Oil Sands to maintain senior debt to book capitalization and total debt to total book capitalization ratios of 55 per cent and 60 per cent, respectively. Under certain debt issues and bank facilities, the rate of interest paid is dependent on the long-term debt credit ratings. If Canadian Oil Sands' credit ratings fall below investment grade, COSL is restricted from making royalty payments to the Trust. The following table illustrates our financial leverage at December 31:

FINANCIAL RATIOS

	2003	2002
Net debt to cash flow (times)	**5.2**	1.2
Net debt to total capitalization (%)	**40**	29

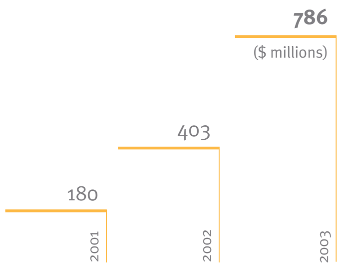
On January 15, 2004, COSL issued $20 million of floating rate and $175 million of 3.95% medium term notes. Both issues were for three year terms and are unsecured. As discussed more fully in the Risk Management section of this MD&A, interest rate swap transactions were undertaken to convert the fixed interest rate on the $175 million notes to a floating rate. The debt was used to repay a portion of the drawn credit facilities and to assist in financing our share of the Stage 3 capital expenditure program.

Our future debt levels are primarily dependent on the funds we generate from operations, our share of Syncrude's capital expenditures and distributions to Unitholders. We are estimating 2004 cash flow to approximate $275 million and capital expenditures of $1 billion based on the March 4, 2004 estimate of Stage 3 expenditures. Financing for Stage 3 capital expenditures may require the issuance of new equity in addition to drawdowns under our bank facilities and funds from our distribution reinvestment plan. We have an objective of maintaining an investment grade credit rating, which may necessitate further equity issues or distribution reductions in a lower crude oil price environment. Our current credit ratings are BBB+ with a negative outlook from Standard & Poor's and Baa2 with a negative outlook from Moody's Investor Service.

A significant component of our financing plan for the Stage 3 Syncrude expansion is the Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan (DRIP). The DRIP enables the Trust to raise new equity at a relatively low cost with no dilution to participating Unitholders, and it supports the Trust's ability to maintain distribution levels during the expansion period. DRIP participation in 2003 increased slightly from 2002, generating nearly $48 million in new

CAPITAL EXPENDITURES

The increase in capital expenditures reflects our higher ownership interest and funding for the Stage 3 expansion, with 88 per cent of 2003 expenditures relating to Stage 3.



equity in 2003 through the issuance of 1.3 million Trust units, compared with $33 million and 0.9 million Trust units in the prior year. As our capital expenditure funding requirements diminish, the need to issue equity under the DRIP will be re-evaluated.

Cash flow generated from operations is an important funding source for the Trust during the Stage 3 expansion. Funds generated from operations in 2003 of $273 million were used to pay Unitholder distributions of $170 million and fund a portion of the $786 million spent on capital expenditures. At the end of 2003, we had a working capital deficiency of $95 million, compared to a working capital balance of $153 million at the end of 2002. The decrease in working capital reflects the decrease in cash during 2003 and the increase in accounts payable and accrued liabilities, which are a result of the capital expenditures on Stage 3 and the higher Syncrude working interest.

Capital Expenditures

Capital spending in 2003 amounted to $786 million, compared with $403 million in 2002. Approximately 88 per cent of the capital expenditures were for the Stage 3 expansion for each of 2003 and 2002. The additional 13.75 per cent working interest accounted for approximately $256 million of the 2003 capital expenditures, with the remaining $127 million increase a result of higher Stage 3 capital expenditures, primarily UE-1 costs. Aurora 2 was completed in the fourth quarter of 2003, generally on time and on budget.

We originally had budgeted total 2003 capital expenditures based on our 21.74 per cent working interest of $483 million, and then revised our budget to $720 million to reflect the additional 10 per cent and 3.75 per cent working interests acquired in February and July, respectively. Actual capital expenditures were $66 million higher than budgeted due primarily to higher expenditures relating to UE-1. The variance to the last estimate was mainly a result of increased spending related to UE-1 for construction costs, fabrication costs and higher engineering costs, partially offset by favourable exchange rates. Stage 3 is the most capital intensive expansion in Syncrude's history, and our 35.49 per cent share of the project cost is currently estimated at $2.8 billion. The Outlook section of this MD&A discusses future commitments related to Stage 3. In addition to our other contractual obligations, the table on page 39 outlines the purchase commitments we have in place related to Stage 3 and Base mine replacement expenditures.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

We have assumed various contractual obligations and commitments in the normal course of our operations. Tabled below are significant financial obligations that are known as of March 4, 2004, which represent future cash payments that we are required to make under existing contractual agreements that we have entered into either directly, or as a partner in the Syncrude Joint Venture.

CONTRACTUAL OBLIGATIONS

		Payments due by period			
($ millions)	Total	< 1 year	1 – 3 years	4 – 5 years	After 5 years
Long-term debt [1]	1,437.0	–	481.0	150.0	806.0
Capital lease obligations [2]	4.5	0.4	1.3	0.9	1.9
Operating leases [3]	5.2	1.7	3.3	0.2	–
Stage 3 and Base mine replacement expenditure obligations [4]	1,479.0	930.0	549.0	–	–
Other long-term obligations [5]	140.5	88.8	10.1	6.4	35.2
	3,066.2	1,020.9	1,044.7	157.5	843.1

1 Bank credit facilities drawn at December 31, 2003 of $391 million are due after a two year term out. US$70 million 7.625% Senior Notes mature on May 15, 2007. $150 million Canadian medium term notes mature on April 9, 2008. Remaining Senior Notes are due subsequent to 2008.

2 We are responsible for our share of the Syncrude Joint Venture's capital lease obligations as described in Note 7 (b) of the consolidated financial statements.

3 In addition to our share of Syncrude's operating leases, we have a 10 year office lease agreement as described in Note 20 (e) of the consolidated financial statements.

4 The total estimated cost of the Stage 3 expansion is approximately $2.8 billion, net to the Trust, of which we have spent approximately $1.5 billion as of December 31, 2003. We are also committed to costs of approximately $0.3 billion for a third mining train at Aurora to replace the dragline/bucketwheel system at the Base mine.

5 These obligations include our 35.49 per cent share of the the minimum payments required under Syncrude's commitments for natural gas purchases, annual disposal fees for the flue gas desulphurization unit, and pipeline cost of service fees as described in Note 20 to the consolidated financial statements.

In addition to these payments, we anticipate having to fund our 35.49 per cent share of Syncrude's registered pension plan solvency deficiency, which is expected to be approximately $10 million a year, net to the Trust, over the next five years. The funding requirements will be confirmed in 2004 when an actuarial valuation of Syncrude's pension plan has been completed.

Unitholders' Capital

As of February 16, 2004, the Trust had 87.2 million Trust units outstanding and a market capitalization of approximately $4 billion based on a closing trading price on February 16, 2004 of $47.50 per Trust unit. The two equity issues completed during 2003 and Unitholder participation in the DRIP during 2003, both discussed previously, resulted in approximately $1 billion of new equity and approximately 29.5 million Trust units being issued in 2003.

During 2003, as part of Canadian Oil Sands' long-term incentive plan for employees, 127,900 Trust unit options (options) were issued, and 60,000 options previously held by the Board of Directors were surrendered for cancellation. On January 21, 2004, a further 102,500 options were granted to employees. Each option represents the right of the option holder to purchase a Trust unit at the exercise price determined at the date of grant. The options vest one-third following the date of grant for the first three years. At February 16, 2004, 426,400 options were outstanding, representing less than one per cent of Trust units outstanding, with a weighted average exercise price of $40.72 per option. The options expire seven years from the date of grant.

Unitholder distributions related to 2003 were $170 million, or $2 per Trust unit, compared with $115 million, or $2 per Trust unit, in 2002. Our objective is to maintain stable distributions during our capital intensive expansion periods by retaining a portion of our cash generated from operations to assist in funding the Stage 3 capital expenditures.

Risk Management

There are many financial and operational risks inherent in the oil sands business, which include, but are not limited to: commodity price, currency exchange, interest rate, capital, credit, regulatory, operational and environmental risks. We take specific measures to manage these risks, particularly those that affect cash flow and capital expenditures, as these have a direct impact on the Trust's distributable income available to Unitholders.

Commodity Price Risk

Crude Oil Price Risk Canadian Oil Sands is exposed to fluctuations in crude oil prices with our entire SSB production being sold at market prices. The price received for SSB historically has been highly correlated to Canadian dollar WTI prices. We have mitigated exposure to fluctuations in crude oil prices by entering into forward WTI crude oil price contracts.

As of February 16, 2004, approximately 46 per cent of our 2004 production outlook has been hedged, and up to 50 per cent of the volumes may be hedged within our current Board approved hedging limits. We continue to view the risk reduction provided by our crude oil hedging program as a necessary element of our Stage 3 financing plan. Our cash flows are impacted by changes in both the U.S. dollar denominated crude oil prices and U.S.-Canadian foreign exchange rates. As a result, management may hedge both elements to reduce our cash flow volatility. These elements can be hedged separately with US$ WTI crude oil hedges and foreign currency hedges, which are outlined in the Currency Hedging section of the Risk Management discussions in this MD&A, or by combining both elements through Canadian dollar oil price hedging transactions. Canadian Oil Sands uses both strategies and has the following hedge positions outstanding as at February 16, 2004:

2004 POSITIONS

	January 1 – December 31	
	Price ($/bbl)	Volume (bbls/day)
2004 US$ WTI Swap Positions (in US$/bbl)	24.74	25,000
2004 C$ WTI Swap Positions (in C$/bbl)	38.65	14,000
Total volumes hedged		39,000

Natural Gas Hedging We have entered into natural gas forward-purchase contracts from time to time to reduce the volatility of purchased energy costs which are a significant component of our operating costs. Currently we do not have any natural gas hedges in place, but continue to monitor natural gas hedging opportunities.

Foreign Currency Hedging Our results are affected by fluctuations in the U.S.-Canadian currency exchange rates as we generate revenue from oil sales based on a U.S. dollar benchmarked price. This revenue exposure is only partially offset by interest in U.S. dollars on our U.S.-denominated debt, and our share of Syncrude's U.S. dollar vendor payments. When our U.S. Senior Notes mature, we will have exposure to U.S. exchange rates on the repayment of the notes. We have reduced our currency exchange risk by entering into contracts that fix our exchange rate in future years. At the present time we do not intend to increase our currency hedge positions. The details of our foreign currency contracts are more fully described in Note 17(a) of the consolidated financial statements.

	2004	2005	2006	2007
U.S. dollars hedged ($ millions)	$ 92.0	$ 100.0	$ 60.0	$ 20.0
Average U.S. dollar exchange rate	$ 0.665	$ 0.664	$ 0.669	$ 0.692

In 1999, Canadian Oil Sands exchanged gains on closing certain forward currency contracts for adjustments to the terms of other currency contracts. For accounting purposes, a portion of the realized gains is being deferred and will be recognized as revenue over the period 2006 to 2016, which is when the original forward contracts would have expired. During 2003, currency hedging gains of $5 million have been deferred. Cumulatively, Canadian Oil Sands has deferred recognition of gains totalling $22 million for net income purposes, but these amounts have been included in our funds from operations. The deferred balance is reflected in the Consolidated Balance Sheet under "Deferred currency hedging gains".

Interest Rate Risk Interest rates impact our net income and cash flows based on the amount of floating rate debt outstanding. Approximately $338 million had been drawn on the credit facilities as of February 16, 2004, which bear interest at floating rates based on bankers' acceptance rates. We also have $20 million of floating rate medium term notes outstanding and have swapped $175 million of fixed rate debt into floating rate debt.

In January 2004, COSL entered into two interest rate swaps for the $175 million 3.95% Canadian medium term notes issued on January 15, 2004. The swaps effectively converted the fixed interest payments to floating rates based on three month bankers' acceptance rates plus a credit spread. The swaps will be recorded as hedges on the consolidated financial statements in 2004 with any gains or losses related to the swaps being recognized in the period the swaps are settled. Further details of our interest rate hedging are in Note 17 (b) of the consolidated financial statements.

To hedge the interest payments on the US$70 million 7.625% Senior Notes issued in 1997, we entered several interest rate swap contracts. Through these contracts, the 7.625% interest obligation was exchanged for a 5.95% fixed rate U.S. dollar payment for the remaining term of the notes. The net interest payments on the 7.625% Senior Notes were reduced by $1.5 million in 2003 and $1.8 million in 2002.

Capital Risk Inherent in the mining of oil sands and production of synthetic crude oil, there is a need to make substantial capital expenditures, such as the Stage 3 expansion. In addition to the potential of the overall Syncrude cost estimate for Stage 3 increasing from the current $7.8 billion, or $2.8 billion net to the Trust, projected amount, we are exposed to financing risks associated with the funding requirements for our 35.49 per cent interest as Syncrude progresses with the expansion. We have historically minimized this risk by accessing diverse funding sources. Credit facilities, funds generated from operations, and proceeds from the DRIP are significant sources of funding available to us. In addition, the Trust has the ability to access public debt and equity markets and this ability should be enhanced as the Trust grows.

Credit Risk Crude oil sales revenue credit risk is managed by limiting the exposure to customers based on an assigned credit rating as well as limiting the maximum exposure to any single customer. Risk is further mitigated as sales revenue receivables are due and settled in the month following the sale. We mitigate our exposure to credit risk under financial instruments, such as commodity derivatives and foreign exchange contracts, by selecting counterparties of high credit quality. We have never experienced a loss on uncollected receivables from any customers or counterparties.

Operational Risk As a partner in Syncrude, we benefit from operational risk management programs implemented by the joint venture. From an operations perspective, sustained, safe and reliable operations are the key to achieving targets for production and operating costs. Extreme cold weather can affect both ongoing operations and construction on the Stage 3 expansion by reducing worker productivity and potentially increasing natural gas consumption. Major incidents or unscheduled maintenance outages curtail production and result in significant increases to per barrel operating costs, which was evident in 2003 with the extended scheduled and unscheduled turnarounds of the two cokers at Syncrude. The largest impact came from the Coker 8-2 shutdown in October of 2003, which we estimate reduced funds from operations by $60 million, including both maintenance work costs and the lost revenue over the 37-day turnaround period. Syncrude has a history of 25 years of continuous production, and has one of the best safety records in its peer group.

We also manage our exposure to operational risks by maintaining appropriate levels of insurance, primarily BI and property insurance. We have purchased approximately US$920 million of BI insurance to protect 16 months of cash flow in case Syncrude experiences an event causing a loss or interruption of production, such as a fire or explosion. The insurance is subject to a 60 day self-retention period after which time an insurance claim can be made. We also maintain US$150 million of physical loss insurance to protect against property damages Syncrude may encounter, and course-of-construction and start-up delay insurance coverages of approximately $210 million and $160 million, respectively, as part of the Stage 3 expansion.

Syncrude Joint Venture Ownership The Syncrude Project is a joint venture that is currently owned by seven participants. Each Syncrude participant's ownership interest is equal to its *pro rata* interest in the Syncrude Project. Major capital decisions for new projects require unanimity of the owners, while other matters require only the approval of a majority and three owners. Historically, however, the Trust's subsidiaries and the other joint venture owners have sought consensus of all the owners on all matters.

Syncrude is also a single interrelated and interdependent facility. While the shutdown of one part of the facility could significantly impact the production of synthetic crude oil, the Stage 3 expansion and other capital projects provide more flexibility than historically existed in allowing continued operation of a greater portion of the facilities and thereby protecting a portion of our cash flow. Similarly, all of our Syncrude production is transported to Edmonton, Alberta through the Athabasca Oil Sands Pipeline Limited (AOSPL) system. Disruptions in service on this system could adversely affect our crude oil sales and cash flows.

Environmental Risk We are exposed to the risk of the impact of Syncrude's operations on the environment. Mitigating this risk, Syncrude remains committed to its objectives for operational, environmental and social excellence. When Stage 3 is completed it will incorporate technologies to reduce emissions, improve energy efficiency and upgrade the entire production stream to meet higher specifications for environmental and product quality. As a result, we anticipate downstream refineries, in producing products such as gasoline and diesel, will use significantly less energy than is required by lower grades of crude oil, while affording a higher value for the new SSP product.

The third fluid coker being constructed as part of Stage 3 includes a flue gas desulphurizer that will capture SO_2 for use in ammonium sulphate production. Syncrude is also retrofitting sulphur reduction technology into the operation of its two existing cokers. These initiatives are anticipated to result in a 60 per cent reduction in SO_2 emissions from the currently approved Alberta Environment regulatory limits. While total CO_2 emissions will increase as production increases, Syncrude's investments in energy consumption and environmental mitigation are anticipated to reduce CO_2 emissions by about 25 per cent per barrel from 1990 to 2008.

Syncrude produces and stores significant amounts of sulphur in a sulphur block at its plant site as there is presently a limited market for the sulphur. There can be no assurance that future environmental regulations pertaining to the use, storage, handling and/or sale of sulphur will not adversely impact the unit costs of production of synthetic oil. Syncrude is exploring the ability to bury sulphur blocks underground. Initial information indicates that this may be a viable and environmentally friendly solution for dealing with the excess sulphur. Syncrude continues to research alternatives for addressing this issue, which affects the entire petroleum industry.

Syncrude owners are liable for their share of ongoing environmental obligations for the ultimate reclamation of the Syncrude Project upon abandonment. Our share of Syncrude's ongoing environmental obligations has been and is expected to continue to be funded out of our cash flows. In addition, the owners have each directly posted letters of credit with the Province of Alberta to secure the ultimate mining reclamation obligations of the owners. In addition to the letters of credit posted with the Alberta government, Canadian Oil Sands maintains trust funds for such reclamation liability.

In 2003, we contributed approximately $4 million, including earned interest, to our reclamation trust accounts. In 2002, we contributed approximately $3 million. We anticipate that the mining reclamation trust contributions we will continue to deposit, along with the accumulating interest, will be sufficient to pay our original 21.74 per cent share of the Syncrude Joint Venture's anticipated mining environmental and reclamation costs. The 13.75 per cent Syncrude interests we acquired in 2003 historically did not have a mining reclamation trust account. Since acquisition, we have accrued and deposited an amount related to current production into one of the existing reclamation trust accounts on a basis similar to that being deposited for the 21.74 per cent interest held previously. The funding requirements of the reclamation trusts are more fully described in Note 19 to the consolidated financial statements.

A number of environmental regulations focus on limiting the emissions of gases and other substances from the Syncrude operations. The Canadian federal government has ratified the Kyoto Protocol and has indicated that total annual emissions for greenhouse gases for large industrial emitters have been capped at 55 megatonnes, with emissions to be reduced by 15 per cent from current business as usual levels. The government has limited the cost of future carbon credit purchases to a maximum of $15 per tonne. Based on these parameters, we have estimated a maximum direct cost impact of $0.22 to $0.30 per barrel from 2008 to 2012 on Syncrude's operating costs for implementing the Kyoto Protocol, without further emission improvements.

Numerous uncertainties regarding details of the Protocol's implementation make it difficult to estimate the full potential cost impact, such as third party supply chain costs related to the Protocol. While we believe that our cost estimate is a reasonable one, we have no assurance that the actual impact might not be substantially different from the estimate. However, we believe that production will continue to be profitable under the current known factors. Operationally, Syncrude also has moved towards lowering its emissions of SO_2 and CO_2. Over time, the amount of SO_2 and CO_2 has been decreased on a per barrel basis as Syncrude has adopted new technologies and refining methods, such as the SO_2 scrubbing system as part of the Stage 3 expansion. The costs of meeting these environmental thresholds, however, increases operating costs and/or capital costs, and as such, may impact the profitability of the operations.

Regulations The Syncrude Project's operations are subject to extensive Canadian federal, provincial and local laws and regulations governing exploration, development, transportation, production, exports, occupational health, protection and reclamation of the environment, safety and other matters. Currently, we believe that Syncrude is in substantial compliance with all applicable laws and regulations. During the Stage 3 construction, Syncrude has achieved very high safety ratings in both the construction and operational aspects at the plant. Additionally, Syncrude has historically obtained renewals of its licenses and permits. While there can be no assurance that government approvals required for certain licenses and permits will be provided, we do not believe that there are any significant issues pending with the governmental authorities which would cause Syncrude to lose its rights. In particular, the approval granted by the Alberta Energy and Utilities Board for the Syncrude Project facility does not expire until December 31, 2035, and may be further extended upon application to the relevant regulatory authorities at the time.

Foreign Ownership The trust indenture, under which the Trust was created, provides that no more than 49 per cent of the units of Canadian Oil Sands Trust can be held by non-Canadian residents. Depending upon the nature of the Trust's operations at the time, the potential impact of exceeding this threshold may be the loss of mutual fund status to the Trust, which may significantly impact the valuation of the Trust units. As such, the Trust continues to monitor, to the extent possible given the practical limitations regarding beneficial ownership information, the level of non-Canadian resident Unitholders. To the best of our knowledge, the Trust has always had less than 50 per cent non-Canadian resident Unitholders.

The Trust uses declarations from Unitholders and geographical searches to estimate the level of Canadian and non-Canadian resident Unitholders of the Trust at certain periods throughout the year. While the Trust believes that these results are reasonable estimations at the time they are provided, the inability of all public issuers to obtain the residency information of its beneficial holders means that issuers are reliant upon the information provided to the transfer agent. As a result, the residency information is subject to the accuracy provided by third party data and by system limitations. Accordingly, the reported level of Canadian ownership is subject to these limitations and the level of Canadian ownership may change at any time without notice.

As at February 16, 2004, based on account data at December 31, 2003, Canadian Oil Sands estimates that approximately 38 per cent of its units are held by non-Canadian residents with the remaining 62 per cent held by Canadian residents. The Trust will continue to monitor its non-resident ownership levels. If at any time the Trustee of the Trust becomes aware that the 49 per cent ownership limit is imminent, it may publish a notice and require completion of residency declarations before the Trustee will complete any transfer of units. At the time that the non-Canadian residency level exceeds 50 per cent, the Trustee may send a notice to Unitholders and require them to sell their trust units, or a portion thereof within 60 days. If the units are not sold within the 60 days or if the Unitholders are not able to provide evidence that they are not non-residents, the Trustee may sell their units on the Unitholders' behalf. The trust indenture also allows the Trustee to take any such other action that the Trustee deems necessary or appropriate, including the withholding of distributions until such time as Unitholders have satisfied the Trustee of their residency status and that such status does not violate the limitation within the trust indenture.

Unlimited Liability Unlike corporate statutes, the legislation governing the creation of trusts does not contain explicit language which limits the liability of Unitholders of the Trust to their equity investment in the Trust. As a result, there is a possibility that Unitholders of the Trust may not be protected from liabilities of the Trust to the same extent as a shareholder of a publicly traded corporation and that potentially, Unitholders could be liable for tort claims such as environmental claims. While this is a possibility, we believe that it is very remote. The trust indenture itself provides that no Unitholder will be subject to any liability in connection with the Trust or its obligations and affairs or for any act or omission of the Trustee, provided that in the event that a court determines that Unitholders are subject to such liabilities, the liabilities will be enforceable only against and will be satisfied out of the Trust's assets. The trust indenture also provides that contracts to which the Trust is a party should contain language restricting the liability of Unitholders. Based on legal analysis and how the Trust is managed, we believe that unlimited liability of Unitholders is a remote possibility. There is also a concentrated effort by members of the investment community, public trusts and the Toronto Stock Exchange to have legislation passed which would limit the liability of Unitholders. If such legislation is passed, we intend to pursue action which would enable our Unitholders to benefit from the legislation.

Sensitivities

The following table provides an estimate of the impact that the crude oil and natural gas price risks, foreign currency risk, and operational risks have on the Trust's cash flow and net income for 2004, based on our forecast for 2004 as described in the Outlook section of this MD&A:

2004 SENSITIVITY ANALYSIS

		Cash Flow Increase		Net Income Increase/(Decrease)	
Variable *	Sensitivity	$ millions	$/Trust unit	$ millions	$/Trust unit
Syncrude operating costs decrease	C$1.00/bbl	31	0.35	31	0.35
Syncrude operating costs decrease	C$50 million	18	0.21	18	0.21
WTI crude oil price increase	US$1.00/bbl	22	0.24	22	0.24
Syncrude production increase	2 million bbls	22	0.25	19	0.22
Canadian dollar weakening	US$0.01/C$	9	0.11	(3)	(0.03)
AECO natural gas price decrease	C$0.50/GJ	11	0.12	11	0.12

* An opposite change in each of these variables will result in the opposite cash flow and net income impacts.

2004 OUTLOOK

Financial Forecast

Canadian Oil Sands is forecasting annual Syncrude production to range between 82 and 87 million barrels in 2004, or 29 to 31 million barrels net to the Trust based on its 35.49 per cent interest. The upper end of the range reflects minor shutdowns to perform normal maintenance and tie-ins for the Stage 3 expansion, while the low end of this range incorporates the possibility of a turnaround of Coker 8-2 as it nears its normal maintenance cycle. Since December 2003, Syncrude has experienced reliable operations with only minimal downtime for minor repairs. Syncrude shipments during each of the months of December and January averaged 8 million barrels, or 2.8 million barrels net to the Trust.

We have established our 2004 outlook based on annual Syncrude production of 86 million barrels, or 30.5 million barrels net to the Trust. This production assumption, together with our crude oil and currency exchange forecasts and current hedge positions, results in projected net revenues of approximately $1 billion in 2004. We are projecting operating expenses at approximately $551 million, or $18.07 per barrel, for 2004, assuming a natural gas cost of $5.90 per GJ. Non-production costs are projected at approximately $50 million.

We expect crude oil prices to moderate from their recent highs but to remain strong in 2004. World oil demand is forecast to grow with strengthening economies in key consuming nations, particularly China, while crude oil inventories remain low. In addition to healthy demand and tight inventories, stable crude oil production from Iraq, Nigeria and Venezuela continues to appear uncertain due to political unrest, and OPEC remains committed to managing production quotas. Within this framework, we are forecasting crude oil prices to average US$27 per barrel WTI in 2004.

The strength of the Canadian dollar has offset the positive effects of high WTI oil prices during 2003. We are forecasting an average currency exchange rate of US$0.76/Cdn.

We expect to record higher pipeline transportation costs and lower realized prices relative to Canadian dollar WTI as more of our production is shipped beyond Edmonton, historically our largest market, in response to the impact of increased volumes of synthetic crude oil in the Edmonton market from growing Alberta oil sands production.

We are estimating our share of Syncrude capital expenditures to total approximately $1 billion in 2004, of which about 75 per cent will be directed to the Stage 3 expansion. The Stage 3 project completion date is estimated to be mid 2006, with total project costs estimated at $7.8 billion, or $2.8 billion net to the Trust. This cost estimate is approximately $2 billion higher than Syncrude's previous estimate of $5.7 billion, mainly as a result of engineering difficulties and the under-estimation of revamping existing facilities and tie-ins.

Tax Rate Changes

During 2003, there were various tax rate changes passed by the Federal and Alberta governments. At the Federal level, corporate tax rates for resource companies will be reduced to 21 per cent by 2007 from the current rate of 27 per cent. The Federal LCT rate of 0.225 per cent on a company's taxable capital base, after a $10 million exemption, will be eliminated over the next five years. With regards to Crown royalties, over the next five years the 25 per cent resource allowance deduction will be phased out and replaced with the deduction of actual Crown royalties paid in the year. Provincially, Alberta corporate tax rates are reduced to 12.5 per cent in 2003 from 13 per cent in 2002.

The reduction and elimination of LCT will save the Trust cash taxes and have a positive impact on cash flow. In 2003, LCT amounted to approximately $8 million. Even though the Trust is not expected to pay income tax, the changes to resource taxation are expected to ultimately benefit Unitholders. The deductibility of Crown royalties from Federal taxable income, particularly when the royalty rate moves to 25 per cent of net revenues after capital and operating costs recovery, will reduce the proportion of distributions that would otherwise be taxable to Unitholders.

Consolidated Financial Statements and Notes

MANAGEMENT'S REPORT

Management is responsible for the information contained in this annual report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles, and include amounts based on management's informed judgments and estimates. The financial and operating information included in this annual report is consistent with that contained in the consolidated financial statements in all material respects.

To assist management in fulfilling its responsibilities, systems of accounting and internal controls are maintained to provide reasonable, but not absolute, assurance that financial information is reliable and accurate, and that assets are adequately safeguarded.

External auditors, appointed by the Unitholders, have independently examined the consolidated financial statements and conducted a review of accounting and internal controls to the extent required under Canadian generally accepted auditing standards. They have performed such tests as they deemed necessary to enable them to express an opinion on these financial statements.

The Board of Directors has appointed a four-person Audit Committee, consisting of directors who are neither employees nor officers of the Trust and all of whom are independent. It meets regularly with management and external auditors to discuss controls over the financial reporting process, auditing and other financial reporting matters. In addition, the Audit Committee recommends the appointment of the Trust's external auditors, who are elected annually by the Trust's Unitholders. The Audit Committee has reviewed the financial statements and the contents of the annual report with management and the external auditors. The Board of Directors has approved the consolidated financial statements and the management's discussion and analysis on the recommendation of the Audit Committee.

A. R. Hagerman

Marcel R. Coutu
President & Chief Executive Officer
February 16, 2004

Allen R. Hagerman, FCA
Chief Financial Officer
February 16, 2004

AUDITORS' REPORT

To the Unitholders of
Canadian Oil Sands Trust

We have audited the consolidated balance sheets of **Canadian Oil Sands Trust** as at December 31, 2003 and 2002 and the consolidated statements of income and Unitholders' equity and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta
January 22, 2004,
except as to Note 20(c)
which is as of March 4, 2004

CONSOLIDATED STATEMENTS OF INCOME AND UNITHOLDERS' EQUITY

For the years ended December 31 ($ thousands, except per Trust unit amounts)	2003	2002
Net revenues		
Syncrude Sweet Blend revenues	**$ 967,884**	$ 722,076
Transportation and marketing expense	**(35,821)**	(6,774)
	932,063	715,302
Expenses		
Operating	**514,912**	308,877
Non-production	**38,235**	19,392
Crown royalties (Note 18)	**11,936**	7,378
Administration	**9,047**	7,355
Insurance	**7,418**	5,812
Interest, net (Note 15)	**67,832**	38,737
Depreciation and depletion	**94,750**	55,091
Foreign exchange gain	**(135,165)**	(2,956)
Income and Large Corporations Tax (Note 12)	**17,422**	5,413
Future income tax recovery (Note 12)	**(2,246)**	–
Dividends on preferred shares of subsidiaries	**–**	275
	624,141	445,374
Net income	**$ 307,922**	$ 269,928
Unitholders' equity, beginning of year		
As previously reported	**$ 956,501**	$ 804,951
Prior period adjustment (Note 3)	**(244)**	(36,886)
As restated	**956,257**	768,065
Net income	**307,922**	269,928
Issue of Trust units (Note 13)	**999,282**	33,163
Unitholder distributions (Note 16)	**(169,885)**	(114,655)
Contributed surplus (Note 14(a))	**835**	–
Unitholders' equity, end of year	**$ 2,094,411**	$ 956,501
Weighted-average Trust units	**79,656**	57,182
Trust units, end of year	**87,195**	57,684
Net income per Trust unit		
Basic and diluted	**$ 3.87**	$ 4.72

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

As at December 31 ($ thousands)	**2003**	2002
Assets		
Current assets		
Cash and short-term investments	**$ 16,702**	$ 229,970
Accounts receivable	**116,162**	93,444
Inventories (Note 5)	**57,351**	26,132
Prepaid expenses	**4,643**	4,547
	194,858	354,093
Capital assets, net (Note 6)	**4,022,927**	1,470,671
Other assets		
Reclamation trust (Note 19)	**16,553**	12,878
Deferred financing charges, net	**25,520**	12,759
	42,073	25,637
	$ 4,259,858	$ 1,850,401
Liabilities and Unitholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 245,926**	$ 169,279
Unit distribution payable	**43,598**	28,843
Current portion of other liabilities (Note 7)	**665**	2,740
	290,189	200,862
Other liabilities (Note 7)	**93,636**	22,013
Long-term debt (Note 9)	**1,437,413**	622,283
Future reclamation and site restoration costs (Note 19)	**57,565**	32,237
Deferred currency hedging gains (Note 10)	**21,886**	16,505
Future income taxes (Note 12)	**264,758**	–
	2,165,447	893,900
Unitholders' equity (Note 13)	**2,094,411**	956,501
	$ 4,259,858	$ 1,850,401

Commitments and Contingencies (Note 20)

See Notes to Consolidated Financial Statements.

Approved by the Board of Directors

Director

Director

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ thousands)	2003	2002
Cash provided by (used in)		
Operating activities		
Net income	**$ 307,922**	$ 269,928
Items not requiring outlay of cash		
Depreciation and depletion	**90,494**	51,994
Site restoration provision	**4,256**	3,097
Amortization	**3,061**	874
Foreign exchange on long-term debt	**(147,162)**	(4,065)
Future income tax recovery	**(2,246)**	–
Stock-based compensation	**591**	–
Site restoration costs	**(1,065)**	(1,150)
Net change in deferred items	**17,000**	5,766
Funds from operations	**272,851**	326,444
Change in non-cash working capital	**(51,033)**	29,321
	221,818	355,765
Financing activities		
Issuance of medium term and senior notes (Note 9)	**571,740**	–
Net drawdown of bank credit facilities (Note 9)	**390,552**	–
Unitholder distributions (Note 16)	**(169,885)**	(114,655)
Issuance of Trust units (Note 13)	**999,282**	33,163
Redemption of preferred shares (Note 11)	**–**	(4,400)
Net change in deferred items	**(16,040)**	–
Change in non-cash working capital	**14,755**	453
	1,790,404	(85,439)
Investing activities		
Acquisition of Syncrude working interests (Note 4)	**(1,475,260)**	–
Capital expenditures	**(785,587)**	(403,203)
Reclamation trust	**(3,675)**	(2,559)
Change in non-cash working capital	**39,032**	8,093
	(2,225,490)	(397,669)
Decrease in cash	**(213,268)**	(127,343)
Cash, beginning of year	**229,970**	357,313
Cash, end of year	**$ 16,702**	$ 229,970
Supplemental Information		
Income and Large Corporations Tax paid	**$ 17,765**	$ 1,507
Interest charges paid	**$ 60,858**	$ 50,519

See Notes to Consolidated Financial Statements.

1. STRUCTURE OF CANADIAN OIL SANDS TRUST

Canadian Oil Sands Trust (the Trust) is an open-ended investment trust formed under the laws of the Province of Alberta in October 1995 pursuant to a trust indenture (Trust Indenture) which has since been amended and restated. Computershare Trust Company of Canada was appointed as Trustee under the Trust Indenture. The beneficiaries of the Trust are the holders (Unitholders) of the units (Units) in the Trust.

The Trust, through its wholly owned subsidiaries, owns a 35.49 per cent interest (Working Interest) in the Syncrude Joint Venture which is involved in the mining and upgrading of bitumen from oil sands in Northern Alberta.

2. SUMMARY OF ACCOUNTING POLICIES

Consolidation

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada (GAAP) and include the accounts of the Trust and its subsidiaries (collectively, Canadian Oil Sands). The activities of the Syncrude Joint Venture are conducted jointly with others and, accordingly, these financial statements reflect only the proportionate interest in such activities, which include the production, operating costs, non-production costs, property, plant and equipment capital expenditures, inventories, other liabilities and associated amounts payable. Substantially all other activities and balances in these financial statements, including sales, are applicable directly to the activities of Canadian Oil Sands.

Cash and short-term investments

Investments with maturities of less than three months at purchase are considered to be cash equivalents and are recorded at cost, which approximates market value.

Capital assets

Property, plant and equipment Property, plant and equipment assets are recorded at cost and include the costs of acquiring the Working Interests and subsequent additions to property, plant and equipment. Repairs and maintenance costs are expensed in the period incurred. Proceeds from the sale of plant and equipment are normally deducted from the capital base without recognition of a gain or loss.

Property, plant and equipment assets are amortized on the unit-of-production method based on estimated proved reserves. For purposes of the depreciation and depletion provision, capital costs include future capital costs expected to be necessary in the mining, extraction and upgrading process to recover the estimated proved reserves.

An asset impairment test is applied to Canadian Oil Sands' property, plant and equipment assets to ensure that the capitalized costs do not exceed management's estimate of future undiscounted revenues from proved reserves, less operating expenses, future site reclamation costs, Crown royalties, and general and administrative expenses.

Other capital assets Other capital assets are recorded at cost and include primarily leasehold improvements, office furniture and computer equipment. Depreciation is provided for using the straight-line method based on the estimated useful lives of the assets, which range from three to five years.

Inventories

Product inventories are valued at the lower of the average cost of production for the period and their net realizable value. Materials and supplies inventories are valued at the lower of average cost and replacement cost.

Future reclamation and site restoration costs

Estimated future reclamation and site restoration costs are provided for on the unit-of-production method based on estimated proved reserves. Provisions for future reclamation and site restoration costs are included in depreciation and depletion expense in the Consolidated Statements of Income and Unitholders' Equity. Actual costs are charged against the accumulated provision when incurred.

Derivative financial instruments

Canadian Oil Sands enters into foreign currency exchange rate, crude oil and natural gas price contracts to hedge fluctuations in exchange rates, and the prices of crude oil and natural gas. Gains and losses on forward contracts are deferred and recognized as a component of the related transaction. Crude oil and foreign currency hedging gains and losses are included in Syncrude Sweet Blend (SSB) revenues as they are incurred. As natural gas is used in the production of SSB, any natural gas hedging gains and losses are included in Operating expenses.

Canadian Oil Sands has also entered into interest rate swap agreements to manage its interest rate risk. The gains and losses arising from these instruments are included in interest expense.

Revenues

Revenues from the sale of SSB are recorded when title passes from Canadian Oil Sands to its customer. Revenues are recorded net of hedging gains and losses from foreign currency exchange rate and crude oil price contracts.

Employee future benefits

Canadian Oil Sands accrues its obligations under Syncrude'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 management's 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 (Note 7(a)).

Future income taxes

Canadian Oil Sands follows the liability method of accounting for income taxes. Under this method, future income taxes of operating corporations are calculated as the difference between the accounting and income tax basis of an asset or liability, referred to as temporary differences, tax effected using substantively enacted income tax rates. Future income tax balances recorded on the Consolidated Balance Sheet are adjusted to reflect changes in temporary differences and income tax rates with the adjustments being recognized in net income in the period that the changes occur.

Stock-based compensation

Canadian Oil Sands recognizes stock-based compensation expense in its Consolidated Statement of Income and Unitholders' Equity for all trust unit options (options) granted during the year, with a corresponding increase to contributed surplus in Unitholders' Equity. Canadian Oil Sands determines compensation expense based on the estimated fair values of the options at the time of grant, the cost of which is recognized in net income over the vesting periods of the options.

As a partner in the Syncrude Joint Venture, Canadian Oil Sands also shares in Syncrude's stock-based compensation program. Syncrude's plan has incentive phantom share units (phantom units) which require settlement by cash payments. During the vesting period, compensation expense is recognized using the graded vesting approach when the value of the phantom units exceeds the award value. Canadian Oil Sands' share of the change in value of the phantom units is recognized in operating expense in the year the change occurs.

Measurement uncertainty

The preparation of the consolidated financial statements under Canadian generally accepted accounting principles requires management personnel to make estimates and assumptions for many of the financial statement items based on their best estimate and judgment. Significant judgments and estimates relate to depreciation, depletion, the impairment test and future site reclamation costs as they are based on reserve engineering studies, environmental studies and future price and cost estimates, which by their nature, are highly subjective.

3. CHANGE IN ACCOUNTING POLICIES

a) Stock-based compensation

During the third quarter of 2003, Canadian Oil Sands retroactively adopted the fair-value method of accounting for stock-based compensation related to options pursuant to transitional rules for stock-based compensation approved by the Canadian Institute of Chartered Accountants (CICA). Canadian Oil Sands' prior period financial statements have not been restated.

For the year ended December 31, 2003, compensation costs of $0.6 million have been included as Administration expenses in Canadian Oil Sands' net income, with a corresponding increase to contributed surplus included in Unitholders' Equity. Stock-based compensation expense of $0.2 million relating to options granted in 2002 has been charged to opening retained earnings, with a corresponding increase to contributed surplus.

Previously, Canadian Oil Sands recorded no compensation costs for unit options granted to its employees and directors. Instead, the compensation costs and impact on net income and net income per unit were disclosed on a pro forma basis in the notes to the consolidated financial statements.

b) Foreign currency exchange gains and losses

On January 1, 2002, Canadian Oil Sands retroactively adopted the new requirements of the CICA regarding accounting for foreign currency exchange gains and losses. Under those requirements, unrealized exchange gains and losses related to foreign currency denominated monetary assets and liabilities are recognized in income immediately. Prior to the adoption of these requirements, the unrealized exchange gains and losses were deferred and amortized over the life of the asset or liability. The impact on 2002 was a decrease to opening retained earnings of $36.9 million and an increase to net income of $4.1 million.

4. ACQUISITION OF SYNCRUDE WORKING INTERESTS

a) On February 28, 2003, Canadian Oil Sands closed the acquisition with EnCana Corporation (EnCana) to purchase an indirect 10 per cent Working Interest in Syncrude for approximately $1.05 billion cash, with an effective transaction date of February 1, 2003. At this time, Canadian Oil Sands also obtained an option to purchase, under similar terms and conditions, EnCana's remaining 3.75 per cent interest in Syncrude and a six per cent gross overriding royalty (GORR) on another 1.25 per cent indirect Syncrude interest in certain leases held by a third party independent oil and gas company. This option was exercised in June 2003.

b) On July 10, 2003, Canadian Oil Sands completed its purchase of EnCana's remaining 3.75 per cent interest in Syncrude and GORR on certain leases relating to a 1.25 per cent indirect Syncrude interest for approximately $430 million cash, with an effective transaction date of February 1, 2003.

The acquisitions have been accounted for as a purchase of assets in accordance with Canadian generally accepted accounting principles. The purchase price, including the working capital adjustments and purchase price adjustments, has been allocated to the assets and liabilities as follows:

	February acquisition(1)	July acquisition(2)	Total 2003 acquisitions
Net assets and liabilities assumed			
Property, plant and equipment	$ 1,403,860	$ 453,303	$ 1,857,163
Working capital deficiency	(29,892)	(477)(3)	(30,369)
Other liabilities	(44,127)	(16,095)	(60,222)
Future reclamation and site restoration costs	(15,338)	(6,799)	(22,137)
Future income taxes	(267,004)	–(4)	(267,004)
	$ 1,047,499	$ 429,932	$ 1,477,431
Consideration			
Cash	$ 1,040,999	$ 429,932	$ 1,470,931
Costs associated with acquisition	6,500	–(5)	6,500
	$ 1,047,499	$ 429,932	$ 1,477,431

(1) Acquisition of 10 per cent working interest from EnCana, which closed February 28, 2003.

(2) Acquisition of 3.75 per cent working interest and six per cent GORR from EnCana, pursuant to the option agreement. The acquisition closed July 10, 2003.

(3) Included in the working capital deficiency is cash acquired of approximately $2.2 million.

(4) There was no future income tax as a result of the 3.75 per cent acquisition as the working interest is held in a partnership, and owned by a trust.

(5) Costs associated with the acquisition were not material as many of the costs were incurred in the 10 per cent working interest acquisition.

Currently, Canadian Oil Sands has a dispute with EnCana over a purchase price adjustment of approximately $45 million regarding the value of the Syncrude pension liability relating to the Working Interest acquisition, the outcome of which was not determinable at December 31, 2003. If Canadian Oil Sands is successful, the purchase price would be reduced by $45 million, with a corresponding decrease to Property, plant and equipment.

5. INVENTORIES

	2003	2002
Materials and supplies	**$ 42,196**	$ 23,693
Product and linefill	**15,155**	2,439
	$ 57,351	$ 26,132

6. CAPITAL ASSETS

	Cost	Accumulated Depreciation and Depletion	Net Book Value
December 31, 2003			
Property, plant and equipment	**$ 4,486,654**	**$ 464,365**	**$ 4,022,289**
Other capital assets	**842**	**204**	**638**
	$ 4,487,496	**$ 464,569**	**$ 4,022,927**
December 31, 2002			
Property, plant and equipment	$ 1,844,067	$ 374,051	$ 1,470,016
Other capital assets	679	24	655
	$ 1,844,746	$ 374,075	$ 1,470,671

Depreciation and depletion expense was $90.5 million in 2003 (2002 – $52.0 million). Total Stage 3 expansion expenditures of approximately $514 million were excluded from the depreciable net asset base at December 31, 2003 (2002 – $110 million).

7. OTHER LIABILITIES

	2003	2002
Employee future benefits (a)	**$ 90,608**	$ 20,409
Capital lease obligations (b)	**2,672**	1,727
Other	**1,021**	2,617
	$ 94,301	$ 24,753
Less estimated current portion	**(665)**	(2,740)
	$ 93,636	$ 22,013

a) Employee future benefits

Syncrude Canada Ltd., the operator of the Syncrude Joint Venture, has a defined benefit and two defined contribution plans providing pension benefits, and other post-employment benefits plans covering most of its employees.

Canadian Oil Sands' share of the total expense, based on its varying working interests during 2003 and 21.74 per cent ownership in 2002, for Syncrude's defined contribution pension plans for 2003 and 2002 was $1.4 million and $0.9 million, respectively.

Canadian Oil Sands' share of Syncrude's defined benefit plan accrued liability, based on its 35.49 per cent ownership at December 31, 2003 and 21.74 per cent ownership at December 31, 2002, is as follows:

	Pension Benefit Plan		Other Benefit Plans	
	2003	2002	**2003**	2002
Accrued benefit obligation				
Balance – Beginning of year	**$ 184,938**	$ 172,074	**$ 17,892**	$ 17,102
Acquired [1]	**116,969**	–	**11,316**	–
Current service cost	**12,681**	7,498	**844**	499
Interest cost	**19,694**	11,235	**1,894**	1,103
Benefits paid	**(10,392)**	(5,869)	**(1,128)**	(812)
Actuarial loss	**27,360**	–	**2,466**	–
Balance – End of year	**$ 351,250**	$ 184,938	**$ 33,284**	$ 17,892
Plan assets				
Actuarial fair value – Beginning of year	**$ 111,115**	$ 121,915	**$ –**	$ –
Acquired [1]	**70,278**	–	**–**	–
Annual return on plan assets	**32,726**	(9,951)	**–**	–
Employer contributions	**8,946**	5,257	**–**	–
Plan costs	**–**	(483)	**–**	–
Benefits paid	**(9,938)**	(5,623)	**–**	–
Actuarial fair value – End of year	**213,127**	111,115	**–**	–
Funded status – Plan deficit	**(138,123)**	(73,823)	**(33,284)**	(17,892)
Unamortized net actuarial loss [2]	**73,995**	66,733	**5,408**	3,038
Unamortized past service costs [2]	**1,396**	1,535	**–**	–
Accrued benefit liability	**$ (62,732)**	$ (5,555)	**$ (27,876)**	$ (14,854)

1 Canadian Oil Sands assumed the employee benefit obligation relating to the additional 13.75 per cent working interest acquired from EnCana during 2003.

2 Amortized over the expected average remaining service lives of employees covered by the plan, generally 13 years.

The significant assumptions adopted in measuring Syncrude's accrued benefit obligations are as follows:

	Pension Benefit Plan		Other Benefit Plans	
	2003	2002	**2003**	2002
Discount rate – Beginning of year	**6.5%**	6.5%	**6.5%**	6.5%
Discount rate – End of year	**6.0%**	6.5%	**6.0%**	6.5%
Long-term rate of return on plan assets	**9.0%**	9.0%	**N/A**	N/A
Rate of increase in compensation levels	**4.0%**	4.0%	**4.0%**	4.0%

For measurement purposes, a 10 per cent annual rate of increase in the cost of supplemental health care benefits was assumed for 2003 and the next two years, and 5.5 per cent thereafter. In addition, annual rate increases of 3 per cent in Alberta health care premiums and 4 per cent in dental rates were used.

Canadian Oil Sands' share of Syncrude's net defined benefit plan expense for the year, based on its varying working interests during 2003 and 21.74 per cent ownership in 2002, is as follows:

	Pension Benefit Plan		Other Benefit Plans	
	2003	2002	**2003**	2002
Current service cost	**$ 11,523**	$ 7,498	**$ 763**	$ 499
Interest cost	**19,687**	11,235	**1,894**	1,103
Expected return on plan assets	**(16,316)**	(10,975)	**–**	–
Amortization of net actuarial loss	**3,711**	2,374	**96**	111
Amortization of past service costs	**160**	139	**–**	–
Net defined benefit plan expense	**$ 18,765**	$ 10,271	**$ 2,753**	$ 1,713

b) Capital lease obligations

Canadian Oil Sands is responsible for its share of the Syncrude Joint Venture's capital lease obligations, which was $2.7 million at December 31, 2003 (2002 – $1.7 million).

8. BANK CREDIT FACILITIES

	Credit facility
Extendible revolving term facility (a)	$ 20,000
Line of credit (b)	25,000
Operating credit facility (c)	225,000
Operating credit facility (d)	415,000
	$ 685,000

a) The $20 million extendible revolving term facility is a one year facility with a two year term out. 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 $25 million line of credit is a one year revolving letter of credit facility. This facility may be extended on an annual basis with the agreement of the bank. Letters of credit on this facility bear interest at a credit spread.

Letters of credit of approximately $30.6 million have been written against the extendible revolving term facility and line of credit as disclosed in Note 21.

c) The $225 million operating facility is an extendible 364-day revolving tranche with a two-year term out. 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. Initially, this facility was a $560 million acquisition credit facility used to finance the acquisition of the 10 per cent Syncrude interest and the remaining 3.75 per cent Syncrude interest and GORR. It was fully repaid on August 26, 2003, thereby converting to the current $225 million operating facility.

d) The $415 million operating credit facility consists of a $138 million extendible 364-day revolving tranche with a two-year term out, and a $277 million three-year extendible term tranche. 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.

e) 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 senior debt to book capitalization at an amount less than 0.55 to 1.0, to maintain total debt-to-total book capitalization at an amount less than 0.60 to 1.0, and restrict distributions by way of the trust royalty payments from COSL if COSL's credit ratings fall below investment grade. The Trust and certain affiliates of COSL which hold Working Interests in Syncrude guarantee the debt owing under such facilities.

As at December 31, 2003 approximately $391 million of the operating credit facilities was drawn, and is included in long-term debt on the Consolidated Balance Sheet.

9. LONG-TERM DEBT

	2003	2002
7.625% Senior Notes due May 15, 2007 (a)	**$ 90,468**	$ 110,572
5.75% medium term notes due April 9, 2008 (b)	**150,000**	–
5.8% Senior Notes due August 15, 2013 (c)	**387,720**	–
7.9% Senior Notes due September 1, 2021 (d)	**323,100**	394,900
8.2% Senior Notes due April 1, 2027 (e)	**95,573**	116,811
Credit facilities drawn, excluding letters of credit (Note 8)	**390,552**	–
	$ 1,437,413	$ 622,283

a) 7.625% Senior Notes

On May 20, 1997, a former subsidiary of the Trust, Canadian Oil Sands Investments Inc. (COSII) issued US$70 million of 7.625% Senior Notes, maturing May 15, 2007. These notes are senior unsecured obligations of COSL (successor to COSII) ranking pari passu with all other senior unsecured and unsubordinated indebtedness of COSL. There are certain covenants under the indenture, including limitations on sale of assets and granting liens or other security interests. After giving effect to the interest rate swap agreements (Note 17(b)) and exchange rate fluctuations, the effective interest rate on the 7.625% Senior Notes was 5.6% in 2003 compared with 5.9% in 2002. Interest is payable on the notes semi-annually on May 15 and November 15.

b) 5.75% Medium Term Notes

On April 8, 2003, COSL issued $150 million of 5.75% unsecured medium term notes. The notes mature on April 9, 2008. They are unsecured obligations of COSL ranking pari passu with other senior unsecured and unsubordinated indebtedness of COSL and are guaranteed by the Trust. There are certain covenants under the indenture, including limitations on sale of assets and granting liens or other security interests. Interest is payable on the notes semi-annually on April 9 and October 9.

c) 5.8% Senior Notes

On August 6, 2003, COSL issued US$300 million of 5.8% unsecured Senior Notes in the United States pursuant to a private placement exemption. The notes mature on August 15, 2013. They are unsecured obligations of COSL ranking pari passu with other senior unsecured and unsubordinated indebtedness of COSL. There are certain covenants under the indenture, including limitations on sale of assets and granting liens or other security interests. Interest is payable on the notes semi-annually on February 15 and August 15, with the first interest payment due February 15, 2004.

d) 7.9% Senior Notes

On August 24, 2001, COSL issued US$250 million of 7.9% Senior Notes, maturing September 1, 2021. The notes are unsecured obligations of COSL and rank pari passu with all other unsecured and unsubordinated indebtedness of COSL. There are certain covenants under the indenture, including limitations on debt levels, sale of assets and granting liens or other security interests. Interest is payable on the notes semi-annually on March 1 and September 1.

e) 8.2% Senior Notes

On April 4, 1997, a former subsidiary of the Trust, Athabasca Oil Sands Investments Inc. (AOSII) issued US$75 million of 8.2% Senior Notes maturing April 1, 2027, and retired US$1.05 million during 2000. These notes are senior unsecured obligations of COSL (successor to AOSII) and rank pari passu with all other senior unsecured and unsubordinated obligations. There are certain covenants under the indenture, including limitations on sale of assets and granting liens or other security interests. Interest is payable on the notes semi-annually on April 1 and October 1.

10. DEFERRED CURRENCY HEDGING GAINS

Canadian Oil Sands is exposed to fluctuations in the U.S.-Canadian currency exchange rate. 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 gain for adjustments to other existing currency contracts. For accounting purposes, the gain will be recognized as revenue over the period 2006 to 2016, which is when the hedging contracts would have expired had they not been unwound (Note 17(a)). During 2003, Canadian Oil Sands received payments totalling $5.4 million (2002 – $5.1 million) related to the unrecognized gain resulting in a cumulative deferral of $22 million in currency hedging gains.

11. PREFERRED SHARES

On October 31, 2002, in conjunction with the termination of the Administrative Services Agreement with EnCana, COSII and AOSII redeemed the preferred shares held by EnCana (formerly PanCanadian Energy Corporation). The 2,000 shares were redeemed at the retraction amount of approximately $4.5 million, being the amount of capital paid for the shares when they were issued of $4.4 million, plus the accrued unpaid dividends of approximately $0.1 million.

12. INCOME TAXES

a) Taxation of the Trust

Payments received by the Trust in the form of royalty payments, interest, distributions or other income from its subsidiaries are taxable income to the Trust. As the Trust is entitled to deduct its cost of acquiring trust royalties, its administrative costs and distributions to Unitholders to the extent of its taxable income, the Trust is not expected to be liable for income taxes either currently or in the foreseeable future.

In preparing the 2002 tax return, Canadian Oil Sands found that there was an error in the 2001 Trust tax return prepared by its former tax service provider. In September 2003, the Trust paid $10 million to CCRA being $9 million for the 2001 tax liability and the balance relating to accrued interest. Canadian Oil Sands is currently taking action to recover the cash payment from the former tax service provider. As the exact amount of the recovery is not certain at this time, the item has been disclosed as a contingent gain (see Note 22).

b) Taxation of the operating subsidiaries

Operating subsidiaries of the Trust are subject to tax in the same manner as any other corporation. However, as royalty and interest payments made by the operating subsidiaries to the Trust are deductible in computing the operating subsidiaries' taxable income, the operating subsidiaries are not expected to pay significant taxes either currently or in the future under existing tax legislation, with the exception of Large Corporations tax.

The tax provision recorded on the consolidated financial statements differs from the amount computed by applying the combined Canadian federal and provincial income tax statutory rate to income before tax as follows:

	2003	2002
Income before taxes	**$ 323,098**	$ 275,341
Statutory rates		
Federal	**38.00%**	38.00%
Federal abatement	**-10.00%**	-10.00%
Federal surtax	**1.12%**	1.12%
Alberta provincial rate	**12.62%**	13.12%
	41.74%	42.24%
Expected taxes at statutory rate	**$ 134,861**	$ 116,304
Add (Deduct) the tax effect of:		
Net income of the Trust – tax sheltered	**(127,493)**	(112,966)
Resource allowance	**(21,006)**	(23,559)
Non-deductible Crown charges	**3,140**	2,545
Capital tax	**7,764**	2,664
2001 Reassessment	**9,262**	–
Tax rate changes	**12,577**	–
Increase to valuation allowance	**–**	19,000
Other	**(3,929)**	1,425
Provision for taxes	**$ 15,176**	$ 5,413

Canadian Oil Sands' income taxes are calculated according to government tax laws and regulations, which results in different values for certain assets and liabilities for income tax purposes than for financial statement purposes. The amount shown on the Consolidated Balance Sheet as future income taxes represents the net differences between tax values and book carrying values on the operating subsidiaries' Balance Sheet at substantively enacted tax rates. GAAP requires this future tax liability to be recognized in the consolidated financial statements. These future taxes are not expected to result in cash taxes being paid as a result of expected future intercompany royalty and interest deductions at the operating subsidiary level.

As at December 31 future income taxes are comprised of the following:

	2003	2002
Capital and other assets in excess of tax value	**$ (492,335)**	$ (135,926)
Net liabilities in excess of tax value	**227,577**	227,771
Less: Valuation allowance	**–**	(91,845)
Balance at December 31	**$ (264,758)**	$ –

As at December 31, 2003 the following are the estimated balances available for deduction against future taxable income:

	2003
Canadian Oil Sands Trust:	
Canadian Development Expense [1]	**$ 84,278**
Equity Issue Costs	**17,594**
Canadian Oil Sands Limited and other operating subsidiaries:	
Undepreciated Capital Costs (UCC) [2]	
Federal UCC	**1,774,360**
Provincial UCC	**1,604,751**
Canadian Development Expense (CDE)	
Federal CDE	**8,720**
Provincial CDE	**5,842**
Debt Issue Costs	**16,257**

1 Deductible at a declining balance rate of 30% annually.

2 Majority deductible at a declining balance rate of 25% annually. Approximately $839 million is not available for use until the UE-1 upgrader is put into service.

13. UNITHOLDERS' EQUITY

	2003	2002
Unitholders' capital (a)	**$ 1,708,183**	$ 708,901
Accumulated earnings	**1,227,445**	919,523
Prior-period adjustment (Note 3)	**(244)**	–
Accumulated Unitholder distributions	**(841,808)**	(671,923)
Contributed surplus (Note 14(a))	**835**	–
	$ 2,094,411	$ 956,501

a) **Unitholders' capital**

A maximum of 500,000,000 Units have been created for issuance pursuant to the Trust Indenture. The Units represent a beneficial interest in the Trust, share equally in all distributions from the Trust and carry equal voting rights. No conversion, retraction or pre-emptive rights are attached to the Units. Units are redeemable at the option of the Unitholder at a price that is the lesser of 90 per cent of the average closing price of the Units on the principal trading market for the previous 10 trading days and the closing market price on the date of tender for redemption, subject to restrictions on the amount to be redeemed each quarter.

In February 2003, the Trust raised $756 million, $732 million net of issue costs, in new equity to finance a significant portion of the $1.05 billion acquisition of the 10 per cent Working Interest in Syncrude from EnCana. The equity issue was comprised of a public offering of 12.3 million Units for gross proceeds of $431 million, and a private placement with a large U.S. institutional investor of 9.4 million Units for gross proceeds of $325 million.

In July 2003, the Trust raised an additional $228 million, $220 million net of issue costs, in new equity to support financing of the $430 million acquisition of the 3.75 per cent Working Interest in Syncrude from EnCana. The equity issue was comprised of a public offering of 5.5 million Units for gross proceeds of $193 million, and a private placement with a large Canadian bank of one million Units for gross proceeds of $35 million.

In 2003, including public and private placement equity offerings and the Premium Distribution Reinvestment and Optional Unit Purchase Plan (DRIP), 29.5 million Units with net proceeds of $1 billion were issued (2002 – 0.9 million Units for net proceeds of $33 million). The following table summarizes the Units that have been issued for cash proceeds:

Date	Net Proceeds per Unit	Number of Units	Net Proceeds
Balance, January 1, 2002		56,779	$ 675,738
February 28, 2002	$ 36.28	168	$ 6,108
May 31, 2002	$ 39.12	262	$ 10,263
August 30, 2002	$ 36.88	258	$ 9,514
November 29, 2002	$ 33.52	217	$ 7,278
Balance, December 31, 2002		57,684	$ 708,901
February 28, 2003	$ 33.76	21,854	$ 737,855
May 29, 2003	$ 32.99	269	$ 8,880
July 3, 2003	$ 33.82	6,500	$ 219,841
August 29, 2003	$ 35.65	421	$ 15,013
November 28, 2003	$ 37.89	467	$ 17,693
Balance, December 31, 2003		87,195	$ 1,708,183

The Trust has a Unitholder Rights Plan (the Rights Plan) designed to provide the Trust and its Unitholders with sufficient time to explore and develop alternatives for maximizing Unitholder value if a takeover bid is made for the Trust. One right has been issued and attached to each Unit outstanding. Rights issued under the Rights Plan become exercisable when a person, and any related parties, has acquired or begins a takeover bid to acquire 20 per cent or more of the Units without complying with certain provisions in the Rights Plan. Should such an acquisition or announcement occur, each right entitles the holder other than the acquiring person, to purchase Units at a 50 per cent discount to the market price.

b) Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan

In January 2002, the Trust received regulatory approval in Canada for a DRIP. Eligible Unitholders may participate in the DRIP for the quarterly distributions payable subject to enrolment and certain other conditions. The DRIP allows eligible Unitholders to direct their distributions to the purchase of additional Units at 95 per cent of the Average Market Price as defined in the DRIP. The DRIP also provides an alternative whereby eligible Unitholders may, under the premium distribution component, have their distributions invested in new Units and exchanged through the Plan broker for a premium distribution equal to up to 102 per cent of the amount that the other Unitholders would otherwise have received on the distribution date. Under the terms of the DRIP, Unitholders have the option to purchase additional Units for cash at 100 per cent of the Average Market Price if they have participated in either of the premium distribution or distribution reinvestment components of the DRIP.

In 2003, 1.3 million Units were issued for proceeds of approximately $48 million. Since January 2002 when the DRIP began, 2.2 million Units have been issued for proceeds of approximately $81 million.

14. STOCK-BASED COMPENSATION

In April 2002, the Unitholders of Canadian Oil Sands approved two stock-based compensation plans as described in (a) of this note. Also included in Canadian Oil Sands' consideration of stock-based compensation is the stock-based compensation plan that Syncrude adopted in 2002.

a) Canadian Oil Sands Unit Option and Distribution Equivalent Plan

In 2002, the Unitholders approved Canadian Oil Sands' option and distribution equivalent plan (the Incentive Plan) and a Senior Employee Purchase Plan (the Senior Employee Plan) which contemplated the issuance of preferred shares of a subsidiary of the Trust. The full implementation of these plans was conditional on the receipt of acceptable tax opinions or rulings. As Canadian Oil Sands was not able to obtain the tax ruling that it originally sought regarding these plans, the preferred share component of the Incentive Plan was deleted and the Senior Employee Plan was terminated, effective February 19, 2003. Only existing provisions regarding the issuance of options under the Incentive Plan remain.

In recognition of the change to the original compensation structure offered to its employees and to recognize the contributions of the employees and directors over the period 2002 to December 31, 2003, Canadian Oil Sands paid $0.6 million in 2003 to its employees and directors. In addition to the Incentive Plan, the Board of Directors intends to continue to utilize the cash compensation components in the future to reward employees for their contributions to Canadian Oil Sands.

On October 2, 2003, the directors elected to not issue any further options to directors and to instead provide purchases of Units in the secondary market as part of the directors' annual compensation. Effective October 23, 2003, the directors also surrendered all options previously held by them in exchange for Units purchased in the secondary market with a value of approximately $1 million.

As at December 31, 2003, the following options were issued:

Date	Number of Options	Weighted Average Exercise Price
Outstanding at January 1, 2002	–	$ –
Granted in 2002	256.0	38.67
Outstanding at December 31, 2002	256.0	38.67
Granted in 2003	127.9	39.32
Cancelled in 2003	(60.0)	39.08
Outstanding at December 31, 2003	323.9	38.85
Exercisable at December 31, 2003	65.3	$ 38.55

There were no options exercisable at December 31, 2002.

The range of exercise prices of the options is $34.73 to $40.61.

The exercise price deemed for options is based on the weighted-average price of the Units for the five trading days immediately prior to the grant date which may be less than, equal to or greater than the grant date market value of such Units. For options granted in each of 2003 and 2002, the exercise price was not materially different from the price of the Units on the grant date.

The fair value of each option is estimated on the grant date using the Black-Scholes option-pricing model. The weighted-average fair values of the options granted during the various periods and the weighted-average assumptions used in their determination are as noted below:

	2003	2002
Risk-free interest rate (%)	**4.07**	4.60
Expected life (years)	**5.00**	5.00
Expected volatility (%)	**20.00**	27.00
Expected distribution per Trust unit ($)	**2.00**	2.00
Fair value per stock option ($)	**5.00**	6.79

The weighted average fair value of all options granted during the year is approximately $0.6 million (2002 – $1.7 million).

As a result of the retroactive change in accounting policy related to stock-based compensation as explained in Note 3, compensation costs of $0.6 million have been included in Administration expenses in Canadian Oil Sands' net income, with a corresponding increase to contributed surplus included in Unitholders' Equity. Stock-based compensation expense of $0.2 million relating to options granted in 2002 has been charged to opening retained earnings with a corresponding increase to contributed surplus.

b) Syncrude Incentive Phantom Share Units Plan

Syncrude implemented a stock-based compensation plan during 2002 which awarded phantom units to certain employees. The phantom units have value if the composite value of the weighted-average stock price of 60 per cent of Canadian Oil Sands Trust's Units and 40 per cent of various other joint venture owners' shares at the time of exercise by Syncrude employees exceeds the issue price of the awards. The phantom units vest based on a graded vesting schedule: after the first year of issuance, 50 per cent of the phantom units are exercisable, 25 per cent the following year and 25 per cent after year three. If the awards are exercised, they will be settled in cash. They expire after seven years from the date of issue. At December 31, 2003, a total of 124,050 Syncrude phantom units were exercisable.

At December 31, 2003, a total of 504,800 phantom units were outstanding (2002 – 249,100). In 2003, Canadian Oil Sands recorded approximately $5.1 million in operating expenses related to its share of Syncrude's stock-based compensation expense. In 2002, there was no compensation expense recognized in Canadian Oil Sands' financial statements as the market value at December 31, 2002 was less than the issue price of the phantom units when they were awarded.

15. INTEREST EXPENSE, NET

	2003	2002
Interest expense	**$ 72,054**	$ 48,654
Interest income and other	**(4,222)**	(9,917)
Interest expense, net	**$ 67,832**	$ 38,737

16. UNITHOLDER DISTRIBUTIONS

The Consolidated Statement of Distributions is provided to assist Unitholders in reconciling funds from operations to Unitholder distributions.

Distributions are paid to Unitholders on the last business day of February, May, August and November.

Consolidated Statements of Unitholder Distributions

For the years ended December 31 ($ thousands, except per Unit amounts)	**2003**	2002
Funds from operations	**$ 272,851**	$ 326,444
Add (Deduct):		
Capital expenditures	**(785,587)**	(403,203)
Non-acquisition financing, net [1]	**683,542**	156,106
Change in non-cash working capital	**2,754**	37,867
Reclamation trust funding	**(3,675)**	(2,559)
Unitholder distributions	**$ 169,885**	$ 114,655
Unitholder distributions per Unit	**$ 2.00**	$ 2.00

(1) Represents financing to fund Canadian Oil Sands' share of Syncrude's Stage 3 expansion.

17. DERIVATIVE FINANCIAL INSTRUMENTS

The fair values of financial instruments that are included in the Consolidated Balance Sheet, with the exception of the Senior Notes and medium term notes, approximate their recorded amount. The fair values of the Senior Notes and medium term notes are as follows:

	2003		2002	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
7.625% Senior Notes due May 15, 2007	**$ 90,468**	**$ 110,543**	$ 110,572	$ 122,578
5.75% medium term notes due April 9, 2008	**150,000**	**157,080**	–	–
5.8% Senior Notes due August 15, 2013	**387,720**	**393,109**	–	–
7.9% Senior Notes due September 1, 2021	**323,100**	**363,811**	394,900	429,813
8.2% Senior Notes due April 1, 2027	**95,573**	**112,661**	116,811	127,388
	$ 1,046,861	**$ 1,137,204**	$ 622,283	$ 679,779

Canadian Oil Sands has entered into currency exchange contracts, interest rate swap agreements, and forward contracts for crude oil and natural gas to minimize the impact of fluctuations in currency exchange rates, interest rates, and prices of natural gas and crude oil. Unrecognized gains (losses) on these risk management activities and the fair values of the derivative financial instruments were as follows:

December 31	**2003**		2002	
	Unrecognized Gains (Losses)	Estimated Fair Value	Unrecognized Gains (Losses)	Estimated Fair Value
Currency exchange contracts (a)	**$ 49,733**	**$ 47,497**	$ (42,651)	$ (39,271)
Interest rate swaps (b)	**5,408**	**5,092**	8,553	7,874
Crude oil price contracts (c)	**(68,603)**	**(67,968)**	(43,488)	(42,948)
Natural gas price contracts (d)	**–**	**–**	2,968	2,956
Total gains (losses)	**$ (13,462)**	**$ (15,379)**	$ (74,618)	$ (71,389)

a) Currency exchange contracts

As at December 31, 2003, Canadian Oil Sands had entered into foreign exchange contracts to sell approximately US$272 million at rates averaging US$0.665 to US$0.692 over the years 2004 to 2007. As at December 31, 2003, the gain on forward foreign currency exchange contracts not recognized in income was $49.7 million (2002 – loss of $42.7 million). In 1996, Canadian Oil Sands entered into currency exchange contracts, fixing the exchange rate on US$1.5 billion at approximately US$0.694 per Canadian dollar with quarterly cash settlements until June 2016. During 1999, Canadian Oil Sands exchanged gains on closing certain forward currency contracts for adjustments to the terms of existing currency contracts. These transactions eliminated currency exchange commitments beyond June 30, 2006, and swapped the underlying value for currency exchange contracts, which reduced the exchange rate to US$0.658 from US$0.694 on the remaining US$466 million of currency commitments.

In 2003, Canadian Oil Sands settled US$88 million of currency exchange contracts at a net gain of $9.0 million, and in 2002, it settled US$84 million in currency exchange contracts at a net cost of $5.8 million. A gain of $3.6 million in 2003 and a loss of $10.9 million in 2002 has been recognized in the income statement as an adjustment to SSB revenues. The remaining portion of these realized gains of $5.4 million and $5.1 million for 2003 and 2002, respectively, relate to the unwound positions and has been deferred. Cumulatively, Canadian Oil Sands has deferred recognition of gains totalling $21.9 million (2002 – $16.5 million) to 2006 and beyond for accounting purposes. The deferred balance is reflected in the Consolidated Balance Sheet under "Deferred currency hedging gains" and is more fully described in Note 10.

The following are the currency hedge positions as of December 31, 2003:

	2004	2005	2006	2007
U.S. dollars hedged ($ millions)	$ 92.0	$ 100.0	$ 60.0	$ 20.0
Average U.S. dollar exchange rate	$ 0.665	$ 0.664	$ 0.669	$ 0.692

b) Interest rate swap agreements

Canadian Oil Sands has entered into interest rate swap agreements which effectively converted the fixed rate U.S. dollar payments on the 7.625% Senior Notes to a 5.95% fixed rate U.S. dollar payment for the remaining term of the notes.

In 2003, Canadian Oil Sands received payments totalling $1.5 million in cash settlements on these interest rate swap agreements, resulting in an effective interest rate on the 7.625% Senior Notes of 5.6% in 2003. In 2002 net cash settlements totalling $1.8 million were received, resulting in an effective interest rate of 5.9%. The settlements on these contracts have been recorded as a reduction to interest expense in the financial statements.

c) Crude oil hedging contracts

In 2003, Canadian Oil Sands entered additional crude oil hedging contracts to manage 2004 cash flow volatility during the Stage 3 capital program.

As of December 31, 2003, the following crude oil swap positions were in place:

2004 Positions

	January 1 – December 31	
	Price ($/bbl)	Volume (bbls/day)
2004 US$ WTI Swap Positions (in US$/bbl)	$ 24.74	25,000
2004 C$ WTI Swap Positions (in C$/bbl)	$ 38.65	14,000
Total volumes hedged		39,000

In 2003, Canadian Oil Sands' revenues were reduced by $99.9 million (2002 – $10.7 million) from crude oil price hedging losses.

d) Natural gas price contracts

Purchased energy costs represent a significant component of Canadian Oil Sands' operating cost. To assist in protecting cash flows associated with changes in natural gas prices, Canadian Oil Sands entered into a forward purchase of 20,000 gigajoules (GJ) per day of natural gas at an average AECO price of $3.44 per gigajoule in January 2002. This represented approximately 60 per cent of its share of Syncrude's consumption. The contracts began April 2002 and extended to March 2003. During 2003, natural gas hedging gains of $5.7 million were recorded as a reduction to operating expenses (2002 – $5.2 million).

e) Credit risk

Crude oil sales revenue credit risk is managed by limiting the exposure to customers with a credit rating below investment grade to a maximum of 25 per cent of Canadian Oil Sands consolidated accounts receivable. The maximum exposure to any one customer is limited based on the credit rating of that customer. Risk is further mitigated as sales revenue receivables are due and settled in the month following the sale. The use of financial instruments involves a degree of credit risk which Canadian Oil Sands manages through its credit policies and by selecting counterparties of high credit quality. Canadian Oil Sands does not expect any counterparty to fail to meet its obligations.

18. CROWN ROYALTIES

The Alberta Crown Agreement created a Joint Venture (the Alberta Joint Venture) between the Province of Alberta as lessor and the Syncrude participants as lessees. Its purpose was to annually establish, using a deemed net profit concept, the basis on which Syncrude's annual production is to be shared by the lessor and each of the lessees.

Beginning in 2002, the Alberta Crown royalty agreement was replaced with Alberta's generic Oil Sands Royalty. Under this regime, the Crown royalty is calculated as the greater of one per cent of gross revenue or 25 per cent of net revenue before hedging, after deducting applicable operating and capital costs. In each of 2003 and 2002, the Crown royalty was calculated at one per cent of gross revenue. As Syncrude is in a significant capital program, Canadian Oil Sands expects to pay only the minimum one per cent royalty for the next few years. As at December 31, 2003, carry forward deductions for royalty purposes were approximately $1.2 billion, $0.4 billion net to Canadian Oil Sands.

19. FUTURE RECLAMATION AND SITE RESTORATION COSTS

Canadian Oil Sands and each of the other owners of Syncrude are liable for their share of ongoing environment obligations for the ultimate reclamation of the Syncrude Joint Venture on abandonment. Canadian Oil Sands has agreed to deposit $0.1322 per barrel of SSB produced attributable to its 21.74 per cent Working Interest to mining reclamation trusts established for the purpose of funding the operating subsidiaries' share of environmental and reclamation obligations. Funding for the remaining 13.75 per cent Working Interests owned by Canadian Oil Sands has been accrued and deposited on production since the Working Interests were acquired, however, mining reclamation trust accounts for the 13.75 per cent Working Interest did not exist prior to the acquisition by Canadian Oil Sands. Including interest earned on contributions, the reclamation trusts have accumulated $16.6 million to December 31, 2003 (2002 – $12.9 million).

Canadian Oil Sands also has posted a letter of credit with the Province of Alberta in the amount of $31 million to secure its pro rata share of the ultimate reclamation obligations of the Syncrude Joint Venture participants.

A provision of $0.17 per barrel of production for future reclamation and site restoration costs, aggregating to $4.3 million and $3.1 million in 2003 and 2002, respectively, has been included in the provision for depreciation and depletion. The current year provisions combined with the liability recorded on the acquisition of the 13.75 per cent Working Interest resulted in a future site reclamation liability on the Consolidated Balance Sheet of $57.6 million at December 31, 2003. Management reviews the rate of $0.17 per barrel annually to ensure it is adequate based on the estimated costs of future reclamation and site restoration costs provided by Syncrude and the proved reserves. Total future reclamation and site restoration costs are estimated to be $223 million, net to the Trust based on its 35.49 per cent ownership. Canadian Oil Sands spent $1.1 million in 2003 (2002 – $1.2 million) on actual Syncrude reclamation expenditures, which have been recorded as a reduction to the Consolidated Balance Sheet liability.

20. COMMITMENTS AND CONTINGENCIES

a) Marketing agreement

Under the terms of the Marketing Services Agreement between COSL and EnCana, EnCana markets all of the production attributable to Canadian Oil Sands' Working Interests for a fee of $0.05 per barrel, with a minimum monthly fee of $33,333. The marketing fees are included in Canadian Oil Sands' Transportation and marketing fees expense on the Consolidated Statement of Income and Unitholders' Equity. The agreement expires on June 30, 2006, unless it is extended. For the period February 1, 2002 until January 31, 2003, pursuant to the Marketing Services Agreement, EnCana was buying all of Canadian Oil Sands' operating subsidiaries' production attributable to their Working Interests at the deemed unit price for SSB, less a monthly marketing fee of $16,667.

b) Natural gas purchase commitments

Syncrude has entered into purchase commitments for natural gas deliveries in 2004 at market-related prices. Canadian Oil Sands' 35.49 per cent share of this commitment is for 11.9 million GJ's which, based on NYMEX natural gas future prices, amounts to approximately $67 million.

c) Capital expenditure commitments

In 2002, the Syncrude Joint Venture owners approved the Stage 3 expansion plans. On March 4, 2004, the estimated total project cost was revised to $7.8 billion. Canadian Oil Sands' 35.49 per cent share of the remaining expenditures based on the revised cost estimate of $7.8 billion is approximately $1.3 billion.

d) Desulphurization unit

Syncrude has entered into an agreement with Marsulex Inc. to utilize flue gas from Coker 8-3 of Stage 3 to make fertilizer. Under the agreement, which begins in 2005 and has a minimum term of 15 years, Syncrude is committed to provide the waste stream from the Flue Gas Desulphurization Unit and pay an annual disposal fee. Syncrude receives a portion of the proceeds from the fertilizer sales as a cost recovery. Canadian Oil Sands' share of this commitment, before any recovery, is approximately $3 million per year.

e) Office lease

Canadian Oil Sands entered into a 10-year office lease agreement, beginning December 1, 2002, with a right to terminate the lease after five years. The lease and Canadian Oil Sands' share of operating costs are paid on a monthly basis. Total annual lease costs, including operating costs, are anticipated to average approximately $370,000 per year over the next four years.

f) Tax assessment

In December 2002, Canada Customs and Revenue Agency (CCRA) reassessed the 1997 tax year of COSII. The nature of the reassessment pertained to the Syncrude Remission Order (SRO) and the deductibility of certain royalties' credits. Since December 2002, CCRA has audited the years up to 2000 for both COSII and AOSII. CCRA is still reviewing the SRO reassessments of both companies, but it is expected that there will be no cash income taxes owing on the reassessments. The reassessments will result in changes to various tax pool balances carried forward for deduction in subsequent years, however, the timing of when the assessments will be resolved and the impact on the tax pool balances are not yet determinable.

g) Pipeline commitments

Canadian Oil Sands has a long-term agreement with Athabasca Oil Sands Pipeline Limited (AOSPL) to transport production from the Syncrude plant gate to Edmonton, Alberta, Canada. The agreement provides for reimbursement on a cost of service basis, including operating expenses, cash taxes paid, and a return on the depreciated rate base. The agreement commits Canadian Oil Sands to pay its proportionate share of the cost of service whether or not it ships any production on the pipeline. The cost of service in 2003, based on Canadian Oil Sands' varying working interests during the year, was $15.3 million (2002 – $6.4 million, based on a 21.74 per cent Working Interest). The projected cost of service for 2004 is $21 million, based on Canadian Oil Sands' 35.49 per cent Working Interest at December 31, 2003 and is expected to remain around this level through 2008.

h) General

Various suits and claims arising in the ordinary course of business are pending against Syncrude Canada Ltd., the agent for the participants. While the ultimate effect of such actions cannot be ascertained at this time, in the opinion of the management, the liabilities which could reasonably be expected to arise from such actions would not be significant in relation to the operations of Syncrude. Syncrude Canada Ltd. as well as Canadian Oil Sands and the other Syncrude Joint Venture owners also have claims pending against various parties, the outcomes of which are not yet determinable.

21. GUARANTEES

Canadian Oil Sands has posted performance standby letters of credit with the Province of Alberta which are renewed annually. The letters of credit guarantee to the Province of Alberta the reclamation obligations of Canadian Oil Sands' interest in future reclamation of the Syncrude mine sites. The Province of Alberta can draw on the letters of credit if Syncrude fails to perform its reclamation duties on its mine sites. The maximum potential amount of payments Canadian Oil Sands may be liable for pursuant to these letters of credit is $31 million. Canadian Oil Sands accrues a future site reclamation liability, which was $57.6 million at December 31, 2003.

22. CONTINGENT GAIN

In preparing its 2002 income tax returns, Canadian Oil Sands found that there was an error in the 2001 Trust tax return prepared by its former service provider, PanCanadian Petroleum Limited (PanCanadian). In April of 2003, Canadian Oil Sands disclosed this error to CCRA and undertook discussions with CCRA to rectify the incorrect filing. EnCana (successor in interest to PanCanadian) was advised of the error in April and has been in discussions with Canadian Oil Sands regarding the error since that time. In September 2003, CCRA provided their decision regarding the issue, which resulted in the Trust paying approximately $9 million for the tax liability related to the 2001 filing error, and approximately $1 million in interest that had accrued on the liability.

As Canadian Oil Sands believes the tax liability was resultant of an incorrect tax filing by its former tax service provider, it is taking action to recover the $10 million cash payment from EnCana. The amount of the potential cash recovery was not determinable at December 31, 2003, and therefore, is considered to be a contingent gain. No amounts pertaining to the contingent gain have been recorded in the consolidated financial statements at December 31, 2003.

23. SUBSEQUENT EVENT

On January 15, 2004, COSL issued $20 million of floating rate unsecured medium term notes as well as $175 million of 3.95% unsecured medium term notes. Both of the floating rate and 3.95% medium term notes mature on January 15, 2007, rank pari passu with other senior unsecured debt of COSL, and are guaranteed by the Trust. The 3.95% notes were swapped into floating rate debt with two interest rate swaps.

24. RECLASSIFICATION

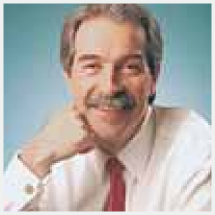
Certain prior year's figures have been reclassified to conform to the presentation adopted for 2003.

STATISTICAL SUMMARY

($ thousands, except as indicated)	2003	2002	2001	2000	1999	1998
Net revenues	**932,063**	715,302	663,053	665,495	468,488	328,653
Operating costs	**514,912**	308,877	327,116	276,231	216,105	219,432
Non-production costs	**38,235**	19,392	17,794	7,198	5,961	5,622
Crown royalties	**11,936**	7,378	52,540	124,830	9,471	120
Administration	**9,047**	7,355	8,381	9,497	7,847	3,878
Insurance	**7,418**	5,812	4,243	2,083	2,128	2,148
Interest, net	**67,832**	38,737	20,326	13,495	11,231	13,174
Depreciation and depletion	**94,750**	55,091	60,451	55,235	66,019	57,266
Foreign exchange loss (gain)	**(135,165)**	(2,956)	23,538	5,588	(11,541)	13,604
Income and Large Corporations Tax	**17,422**	5,413	1,852	1,584	1,286	867
Future income tax recovery	**(2,246)**	–	–	–	–	–
Dividends on preferred shares of subsidiaries	**–**	275	420	660	660	660
Net income	**307,922**	269,928	146,392	169,094	159,321	11,882
Per Trust unit ($)	**3.87**	4.72	2.58	2.98	2.81	0.22
Funds from operations	**272,851**	326,444	226,908	232,635	206,418	81,368
Per Trust unit ($)	**3.43**	5.71	4.00	4.10	3.64	1.51
Unitholder distributions	**169,885**	114,655	156,121	132,562	71,820	18,900
Per Trust unit ($)	**2.00**	2.00	2.75	2.34	1.27	0.35
Capital expenditures	**785,587**	403,203	179,514	110,441	163,202	107,715
Reserves (million bbls, net to COS)						
Proved reserves	**1,070**	676	694	713	598	597
Proved and probable reserves	**1,810**	N/A	N/A	N/A	N/A	N/A
Resource (includes proved and probable reserves)	**3,240**	1,794	1,808	1,831	1,830	1,847
Average daily sales (bbls)	**66,793**	49,806	48,508	44,145	48,456	45,497
Operating netback ($/bbl)						
Average realized sales price	**38.23**	39.35	37.46	41.15	26.50	19.93
Operating costs	**21.12**	16.99	18.48	17.14	12.22	13.21
Crown royalties	**0.49**	0.41	2.97	7.75	0.54	0.01
Netback price	**16.62**	21.95	16.01	16.26	13.74	6.71
Financial ratios						
Net debt to cash flow (times)	**5.2**	1.2	1.2	0.5	0.5	1.9
Net debt to total capitalization (%)	**40.4**	29.1	25.9	12.0	11.4	20.9
Return on average Unitholders' equity (%)	**20.2**	31.3	18.3	20.8	22.4	2.1
Number of Trust units outstanding (in thousands)	**87,195**	57,684	56,779	56,750	56,750	54,000
$/Unit prices*						
High	**45.70**	44.85	41.95	33.00	25.90	24.50
Low	**32.26**	33.28	29.25	23.50	16.90	14.00
Close	**45.69**	38.05	38.50	29.10	24.90	16.80
Trading volume (thousands of Trust units)*	**45,417**	33,296	20,360	12,673	8,657	9,657

* Data prior to the July 5, 2001, merger date represent Athabasca Oil Sands Trust, the surviving entity.

Marcel Coutu
President & Chief Executive Officer



Marie Fenez
Executive Assistant

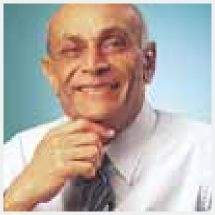
Trudy Curran
General Counsel & Corporate Secretary

Allen Hagerman
Chief Financial Officer

An experienced and energized team is leading Canadian Oil Sands Trust. Under the direction of Marcel Coutu, President, Chief Executive Officer and Director of Canadian Oil Sands, a core team manages all aspects of the Trust's business. Although a small group, this team contributes a comprehensive set of skills and experience. With a diversity of expertise from engineering to finance and a common thread of energy industry experience, this group has all of the core competencies for the Trust to achieve greater success.

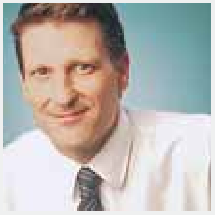
Siren Fisekci
Director,
Investor Relations

Aswin Patel
Manager, Operations



Laureen DuBois
Controller

Ryan Kubik
Treasurer



Cathy Jones
Office Administration

Katrina Rupert
Assistant Manager,
Accounting

INVESTOR INFORMATION

Officers

C. E. (Chuck) Shultz
Chairman of the Board

Marcel R. Coutu
President and Chief Executive Officer

Allen R. Hagerman, F.C.A.
Chief Financial Officer

Trudy M. Curran
General Counsel and Corporate Secretary

Ryan M. Kubik
Treasurer

Laureen C. DuBois
Controller

Board of Directors

C. E. (Chuck) Shultz
(Chairman of the Board)
Chairman and Chief Executive Officer
Dauntless Energy Inc.
Calgary, Alberta

Marcel R. Coutu
President and Chief Executive Officer
Canadian Oil Sands Trust

E. Susan Evans, Q.C. [1, 2]
Calgary, Alberta

The Honourable Donald F. Mazankowski [2]
Vegreville, Alberta

Wayne M. Newhouse [2]
President, Morgas Ltd.
Calgary, Alberta

Walter B. O'Donoghue, Q.C. [1]
Counsel, Bennett Jones LLP
Calgary, Alberta

Wesley R. Twiss [2]
Calgary, Alberta

John B. Zaozirny, Q.C. [1]
Counsel, McCarthy Tétrault LLP
Calgary, Alberta

1 Member of the Corporate Governance and Compensation Committee
2 Member of the Audit Committee

Units Listed

The Toronto Stock Exchange: COS.UN

Registrar and Transfer Agent

Computershare Trust Company of Canada, with offices in Vancouver, Calgary, Toronto, Montreal and Halifax is the registrar and Transfer Agent for Canadian Oil Sands Trust. Computershare is also Trustee of the Trust.

Computershare Trust Company of Canada
710, 530 – 8th Avenue SW
Calgary, Alberta, T2P 3S8
Attention: Corporate Trust Department
Telephone: 1 (800) 564-6253
Fax: (403) 267-6598
E-mail: service@computershare.com

Auditors

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

Annual and Special Meeting

The Annual and Special Meeting of Unitholders will take place in the Glenview Room of the TELUS Convention Centre, Calgary, Alberta, on Monday, April 26, 2004, at 2:00 p.m.

Canadian Oil Sands Limited

2500 First Canadian Centre
350 – 7th Avenue SW
Calgary, Alberta, T2P 3N9
Telephone: (403) 218-6200
Fax: (403) 218-6201

Investor and Media Relations Contact

Siren Fisekci
Telephone: (403) 218-6228
Fax: (403) 218-6201
E-mail: investor_relations@cos-trust.com

Website: www.cos-trust.com

Canadian Oil Sands' website contains a variety of investor information including:

- Current Unit Price
- Annual and Interim Reports
- News Releases
- Investor Presentations
- Distribution Information
- Syncrude Project Information
- Tax Information

DRIP

For more information on, or to enroll in the Trust's Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan (DRIP), please contact investor relations at (403) 218-6220 or Computershare Trust Company of Canada at 1 (800) 564-6253.

GLOSSARY

Bitumen
The molasses-like substance that comprises up to 18% of oil sands.

Carbon dioxide (CO_2)
A non-toxic gas produced from decaying materials, respiration of plant and animal life, and combustion of organic matter, including fossil fuels; carbon dioxide is the most common greenhouse gas produced by human activities.

Cokers
Vessels in which bitumen is cracked into its fractions and from which coke is withdrawn to start the process of converting bitumen to upgraded crude oil.

Conventional oil
Petroleum found in liquid form, flowing naturally, or capable of being pumped without further processing or dilution.

Debottleneck
Debottlenecking systematically removes plant capacity limitations through modifications of existing facilities and/or addition of capital facilities. Debottlenecking commonly provides a modest (10-20%) capacity improvement versus a major capital intensive expansion.

Dragline
A large machine that digs oil sand from the mine pit and piles it into windrows.

Extraction
The process of separating bitumen from oil sand.

Flue gas scrubber
Equipment that removes sulphur dioxide and other emissions from a coker.

Fluid coking
A major part of the upgrading process whereby high temperatures in a coker remove carbon and cause bitumen molecules to reformulate into lighter products that become the main ingredients in upgraded crude oil.

Greenhouse gases
Any of various gases that contribute to the greenhouse effect.

Gross overriding royalty (GORR)
Six percent gross overriding royalty on revenues from the working interest in respect of certain leases included in the Syncrude project.

Oil sand(s)
A composition of sand, bitumen, mineral rich clays and water. Bitumen, in its raw state, is black, asphalt-like oil – as thick as molasses. It requires upgrading to make it transportable by pipeline and usable by conventional refineries.

Alberta oil sand(s) deposits
The four deposits, Athabasca, Peace River, Cold Lake and Wabasca, have total resource in place estimated at more than 1.7 trillion to 2.5 trillion barrels. The Athabasca Oil Sands deposit, Alberta's largest and most accessible source of bitumen, contains more than one trillion barrels of bitumen over an area encompassing more than 30,000 square kilometres.

Oil sand(s) lease
A long-term agreement with the provincial government which permits the leaseholder to extract bitumen, other metals and minerals contained in the oil sands in the specified lease area.

Overburden
A layer of rocky, clay-like material beneath muskeg.

Sulphur dioxide (SO_2)
A compound of sulphur and oxygen produced by burning sulphur.

Syncrude 21
In 1996, Syncrude embarked on a 5-stage expansion plan, which is anticipated to more than double production of a higher-quality oil at lower operating costs.

Syncrude joint venture
Formed for the purpose of exploiting the Athabasca Oil Sands, which includes the Syncrude plant, facilities and leases acquired or developed in connection therewith; participants include: Canadian Oil Sands Limited Partnership (5%); Canadian Oil Sands Limited (31.74%); Conoco Phillips Oilsands Partnership II (9.03%); Imperial Oil Resources (25%); Mocal Energy Limited (5%); Murphy Oil Company Ltd. (5%); Nexen Inc. (7.23%); and Petro-Canada (12%).

Syncrude Sweet Blend (SSB)
A 100% upgraded, high-quality product with 31° to 33° API, low sulphur (0.1% to 0.2%), low residuals and excellent low-temperature pour qualities.

Syncrude Sweet Premium (SSP)
A new product that is expected to be introduced with the startup of Syncrude's UE-1 expansion project; the quality of the distillate cuts will improve significantly with lower sulphur and nitrogen levels as well as higher diesel cetane numbers and kerosene smoke points.

Synthetic crude oil
A high-quality product resulting from the mining, extraction and upgrading of thick, tar-like bitumen.

Tailings
A combination of water, sand, silt and fine clay particles that is a by-product of removing bitumen from oil sand.

Turnaround
A regular event essential for good maintenance of the mining, producing and upgrading facilities. A turnaround(s) may reduce SSB production but does not usually halt it entirely as the various operating units are duplicated.

Upgrading
The conversion of heavy bitumen into a lighter crude oil by increasing the ratio of hydrogen to carbon, either by removing carbon (coking) or adding hydrogen (hydroprocessing).

Abbreviations

barrel(s)	bbl, bbls
barrel(s)/day	bbl/d, bbls/d
millions of barrels	MMbbls
carbon dioxide	CO_2
New York Mercantile Exchange	NYMEX
sulphur dioxide	SO_2
Syncrude Sweet Blend	SSB
Syncrude Sweet Premium	SSP
West Texas Intermediate	WTI

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Canadian Oil Sands Limited
2500 350 – 7th Avenue SW
Calgary, Alberta T2P 3N9
Telephone: 403.218.6200
Web Site: www.cos-trust.com

TSX: COS.UN