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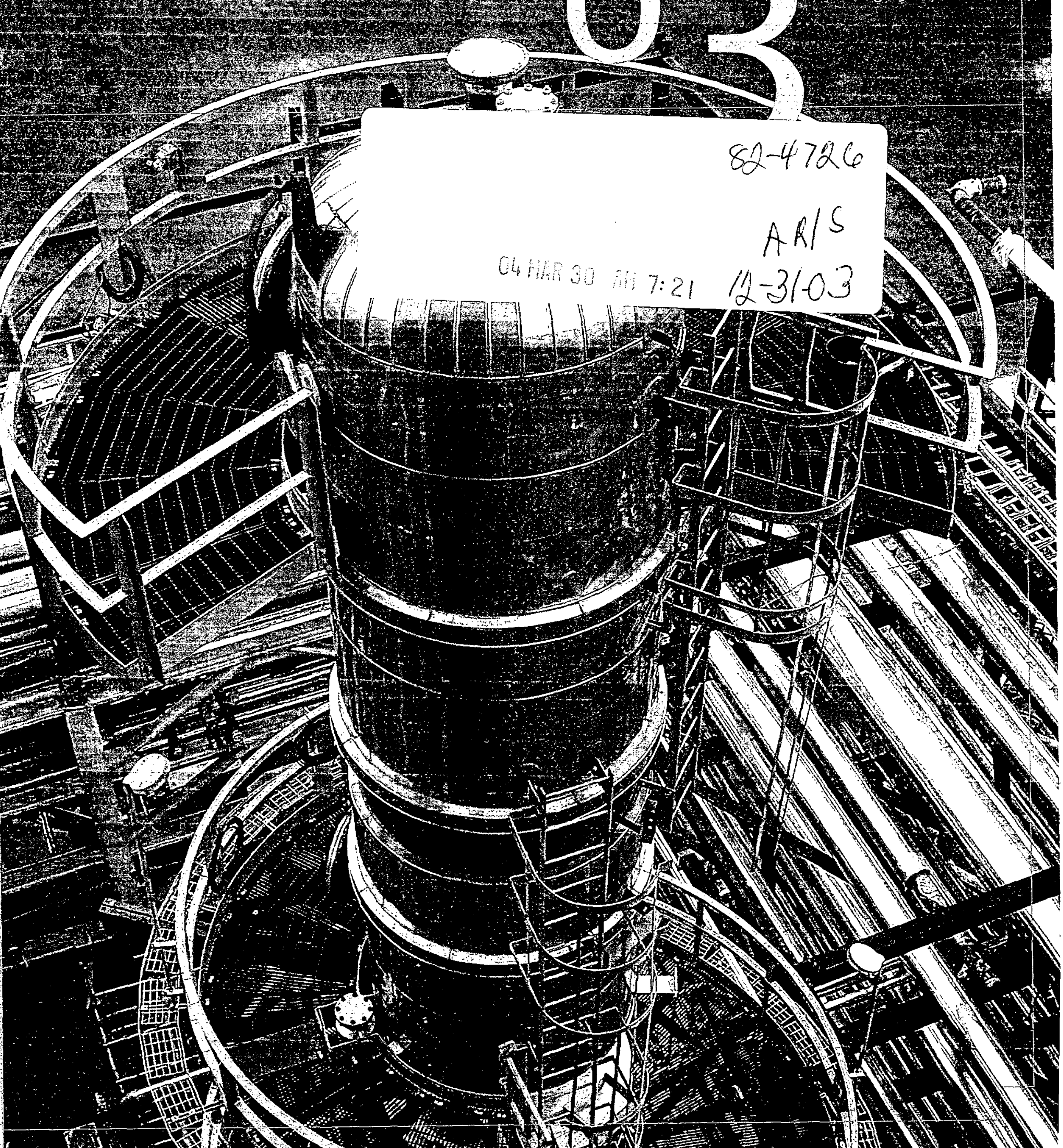
Canadian Oil Sands Trust 2003 Annual Report

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.

DA

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.

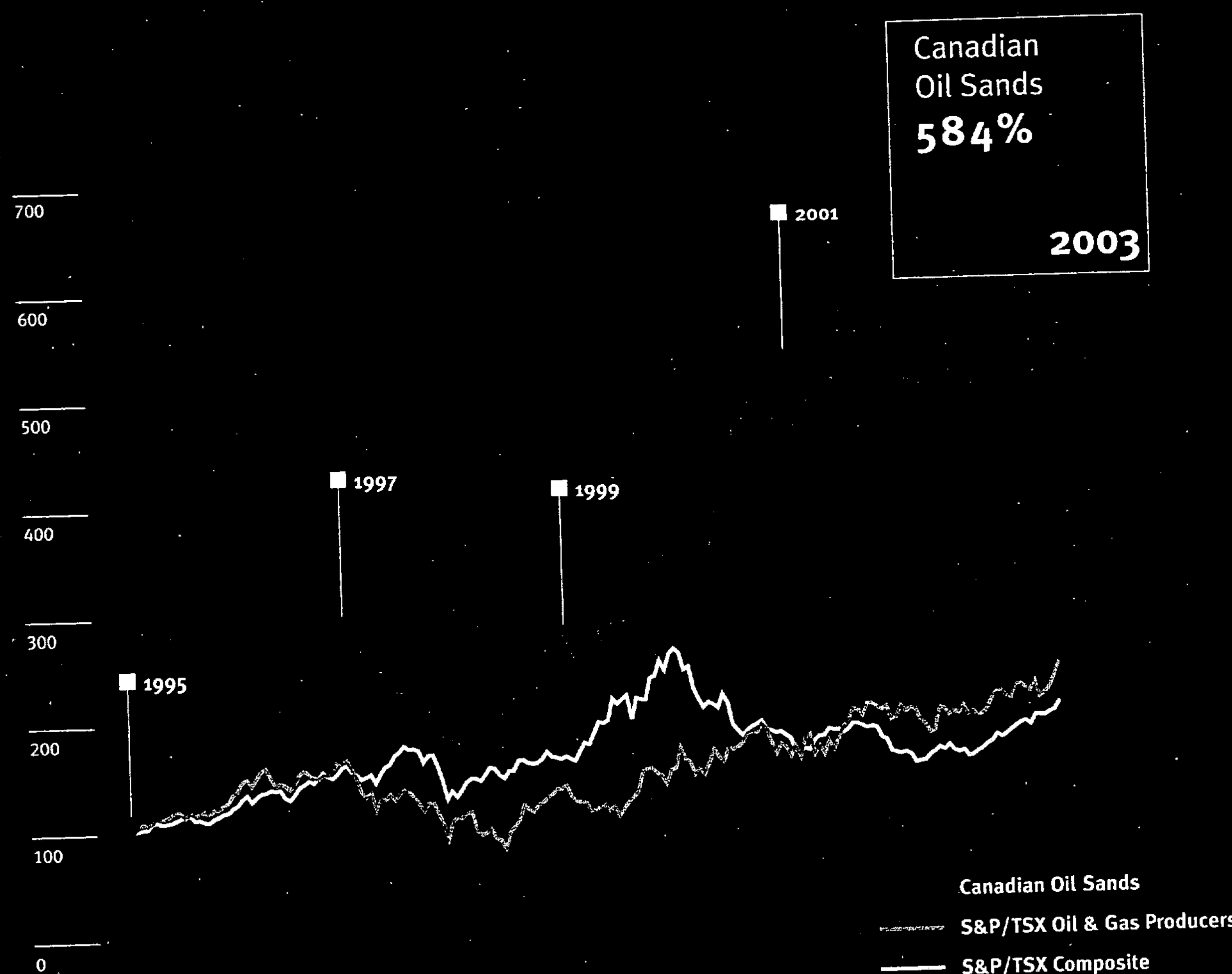
Q:	How is the Syncrude joint venture ("JV") managed? Have things changed now that Canadian Oil Sands Trust is the largest owner?
	The increase in our ownership has not changed how the JV is managed. Syncrude Canada Ltd. operates the project on behalf of the 7 participants. A CEO Committee governs the 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

Stage
1
North mine &
Debottleneck 1

Stage
2
Aurora 1 &
Debottleneck 2

Expansion – Syncrude 21 timeline

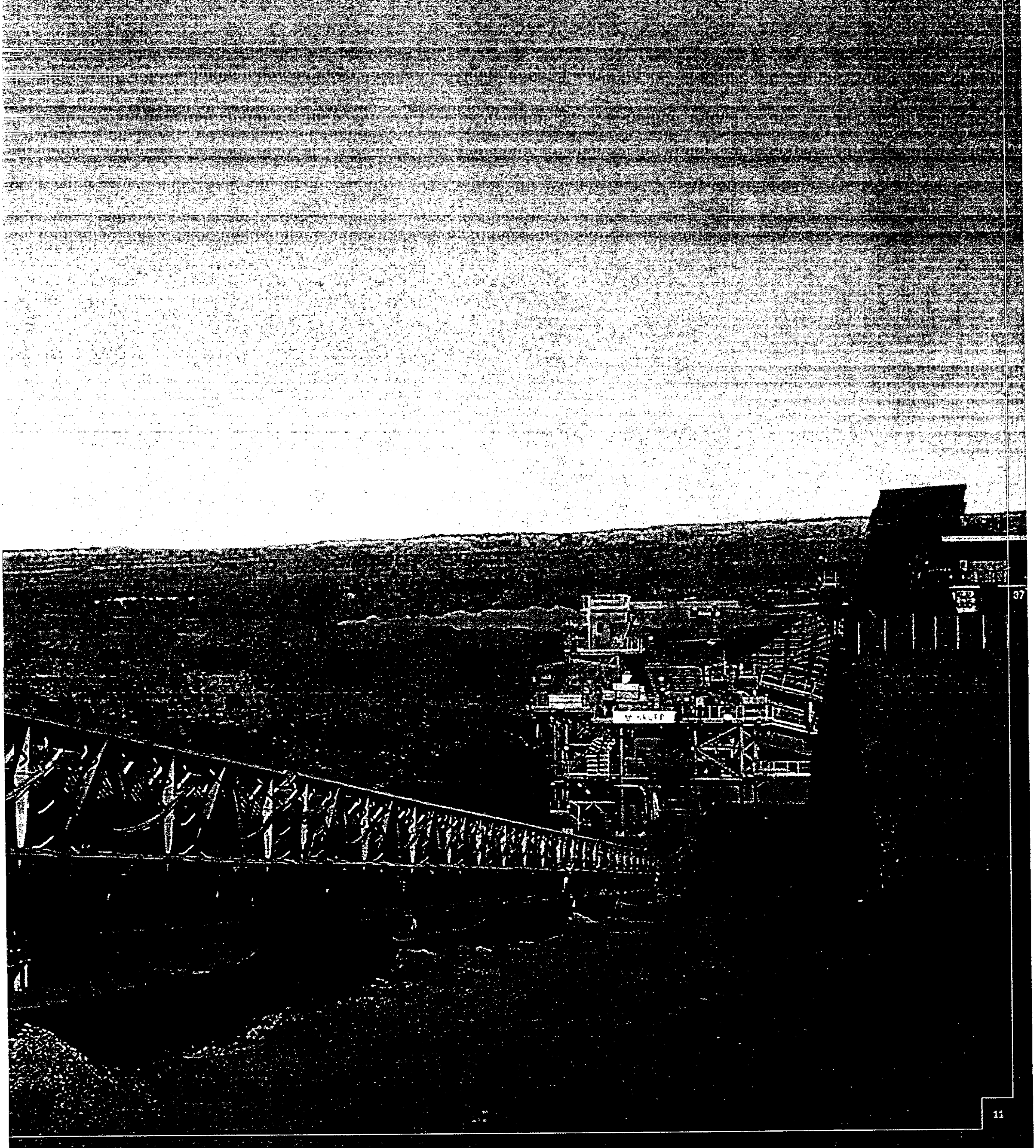
Syncrude has developed a staged expansion plan called Syncrude 21 to exploit its vast oil sands resource and provide the potential for dramatic growth well into the future. Launched in 1996, Stages 1 and 2 of the expansion have been completed and Stage 3 is under construction. Stages 4 and 5 have not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

Stage
3
Aurora Train 2
& Upgrader
Expansion 1

Stage
4
Aurora Train 3
& Upgrader
Expansion 2

Stage
5
Aurora Train 4
& Upgrader
Expansion 3

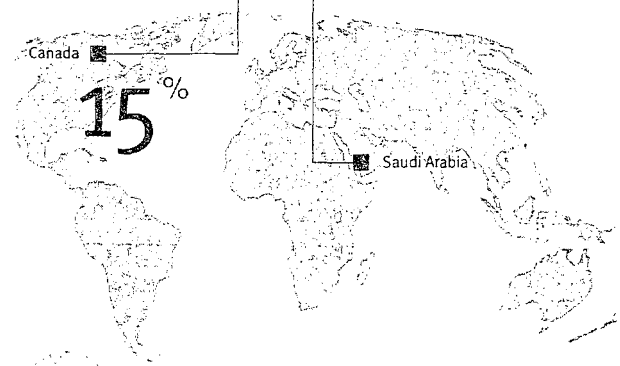
Canadian Oil Sands Trust

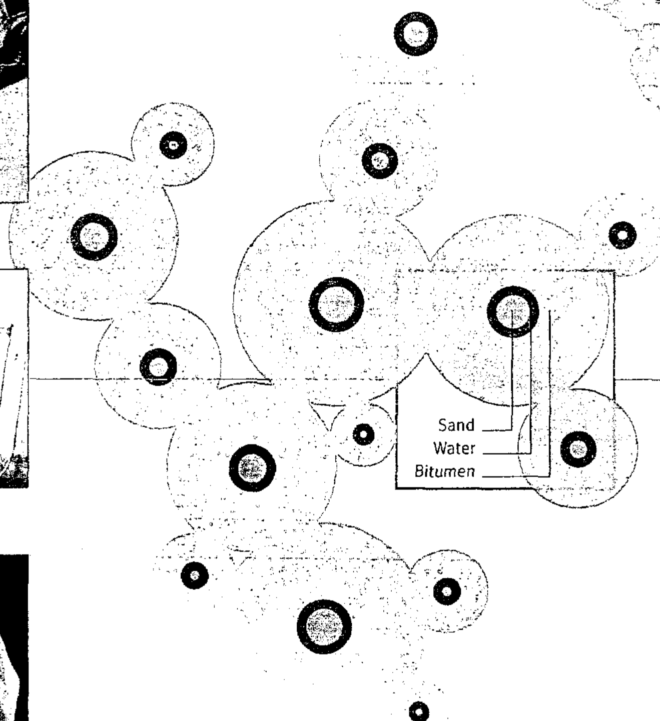


Canada's oil sands resource

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

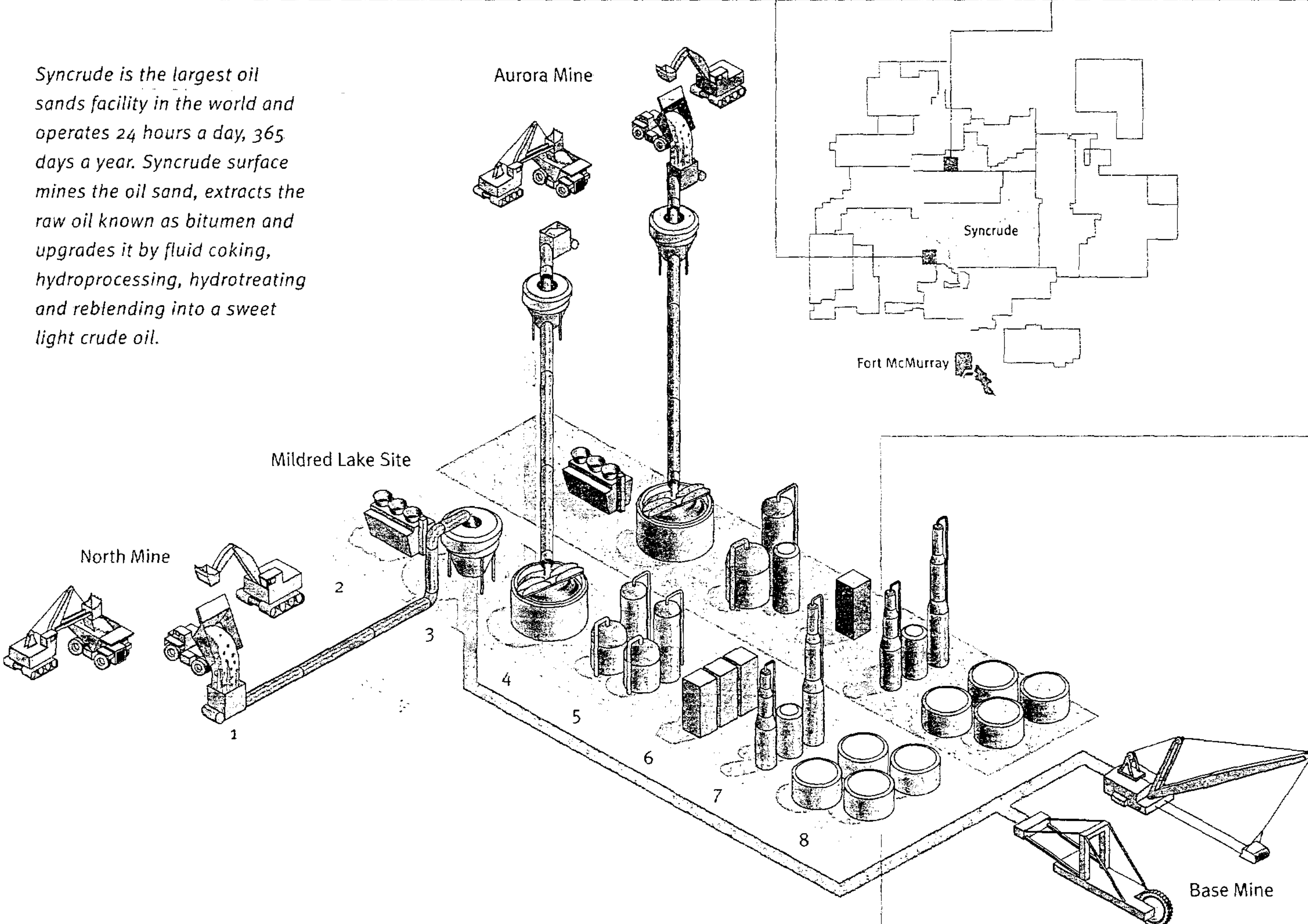
Oil sands production at about 1.4 million barrels per day is expected to exceed conventional production in Canada.

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.

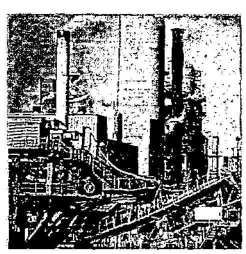
Syncrude's Aurora leases contain a richer ore body with less overburden, and as production from this area grows, operating costs are expected to decline.

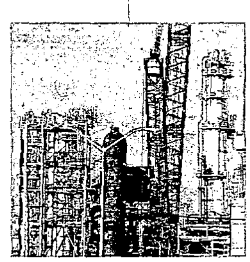
Syncrude is the largest oil sands facility in the world and operates 24 hours a day, 365 days a year. Syncrude surface mines the oil sand, extracts the raw oil known as bitumen and upgrades it by fluid coking, hydroprocessing, hydrotreating and reblending into a sweet light crude oil.



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.

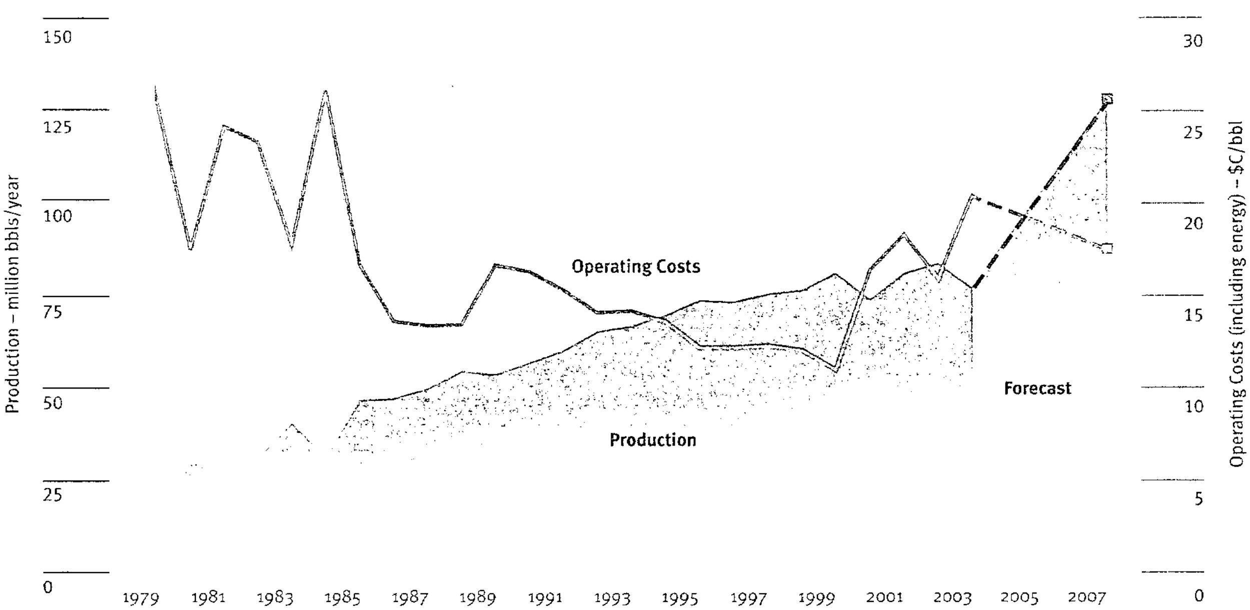
Q: How is Stage 3 expected to lead to lower operating costs?

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.

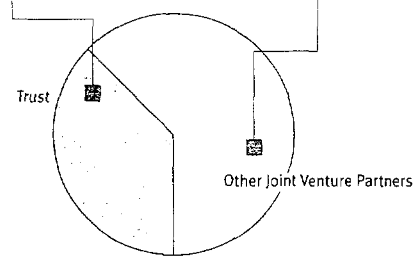
Syncrude Performance

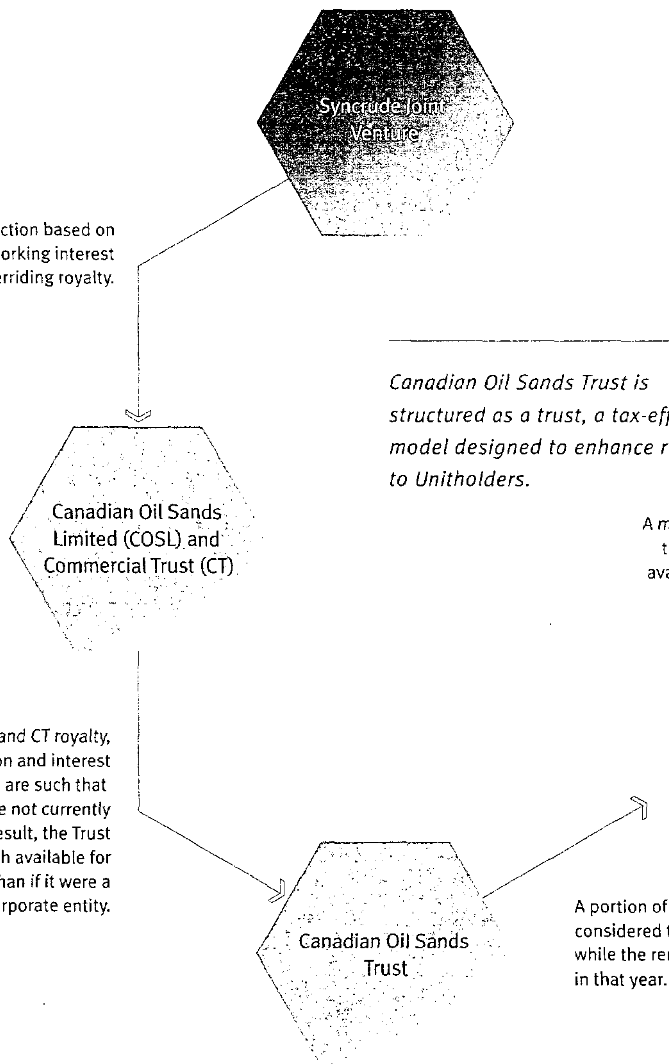


Pure investment

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.





Receives production based on a 35.49% working interest and gross overriding royalty.

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

COSL and CT royalty, distribution and interest payments are such that COSL and CT are not currently taxable. As a result, the Trust has more cash available for distribution than if it were a taxable corporate entity.

A portion of the distributions is considered tax-deferred return while the remainder is taxable in that year.

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?

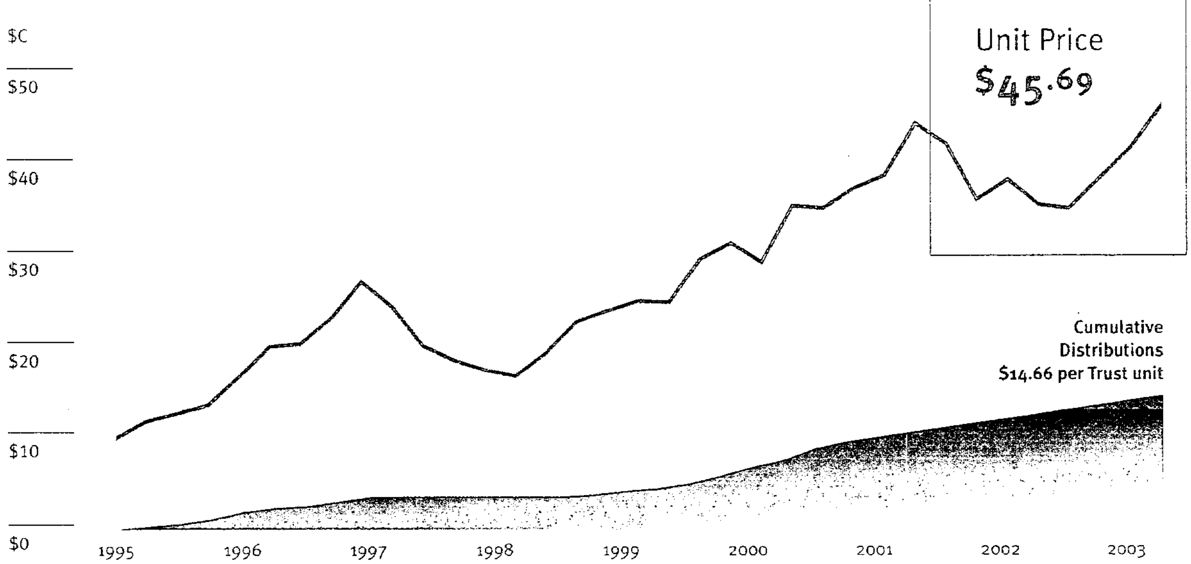
We're financing growth to increase our value and that growth is funded by the same pool of cash available for distributions. Once Stage 3 is complete and production increases, we anticipate being able to sustain some increase in distributions while also financing our growth mandate and strengthening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

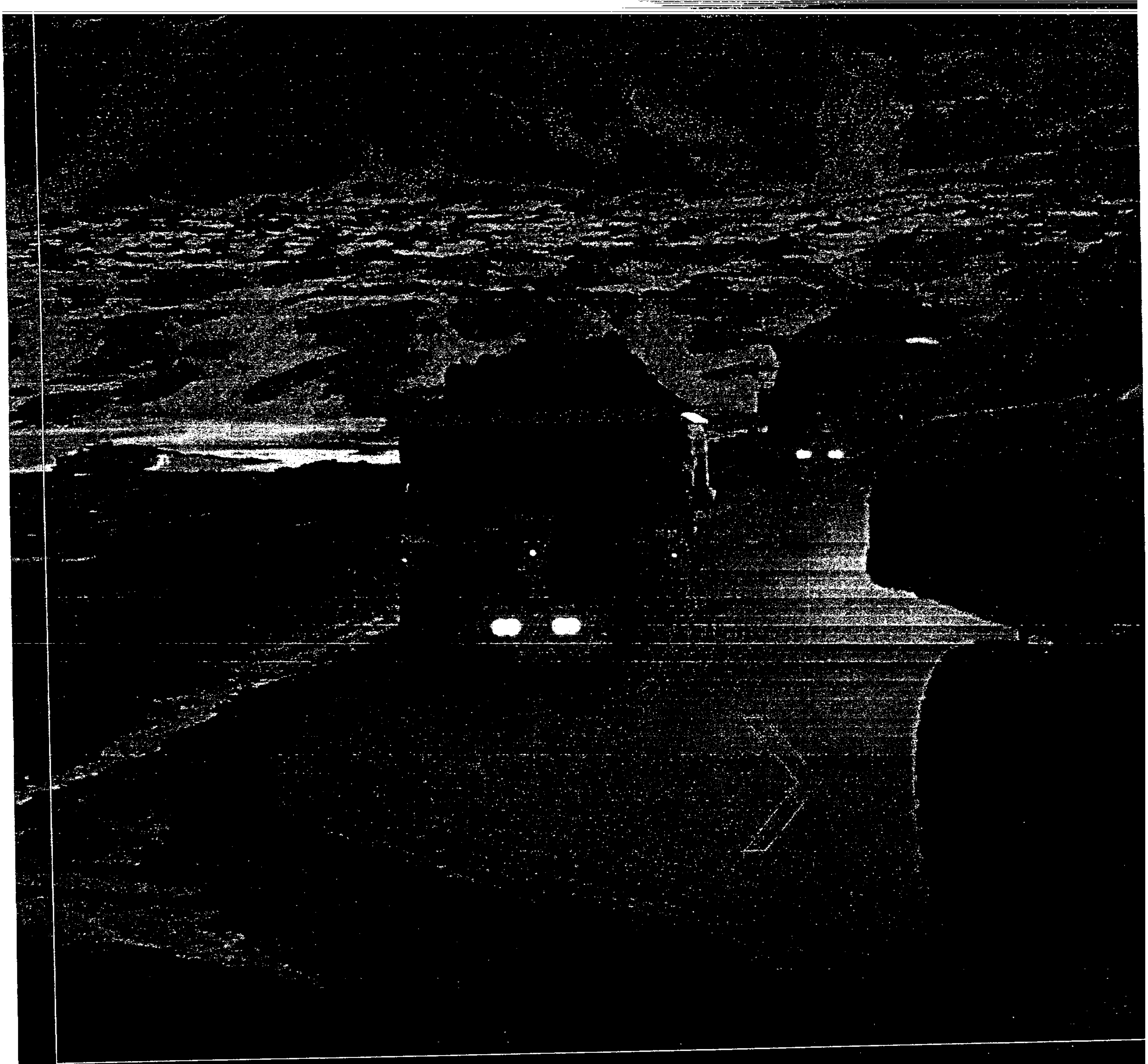
Prudent financial management enables Canadian Oil Sands to manage its growth over the long term. Our Unitholders benefit from a stable distribution and the opportunity to participate in the potential future growth in value of the Syncrude project.

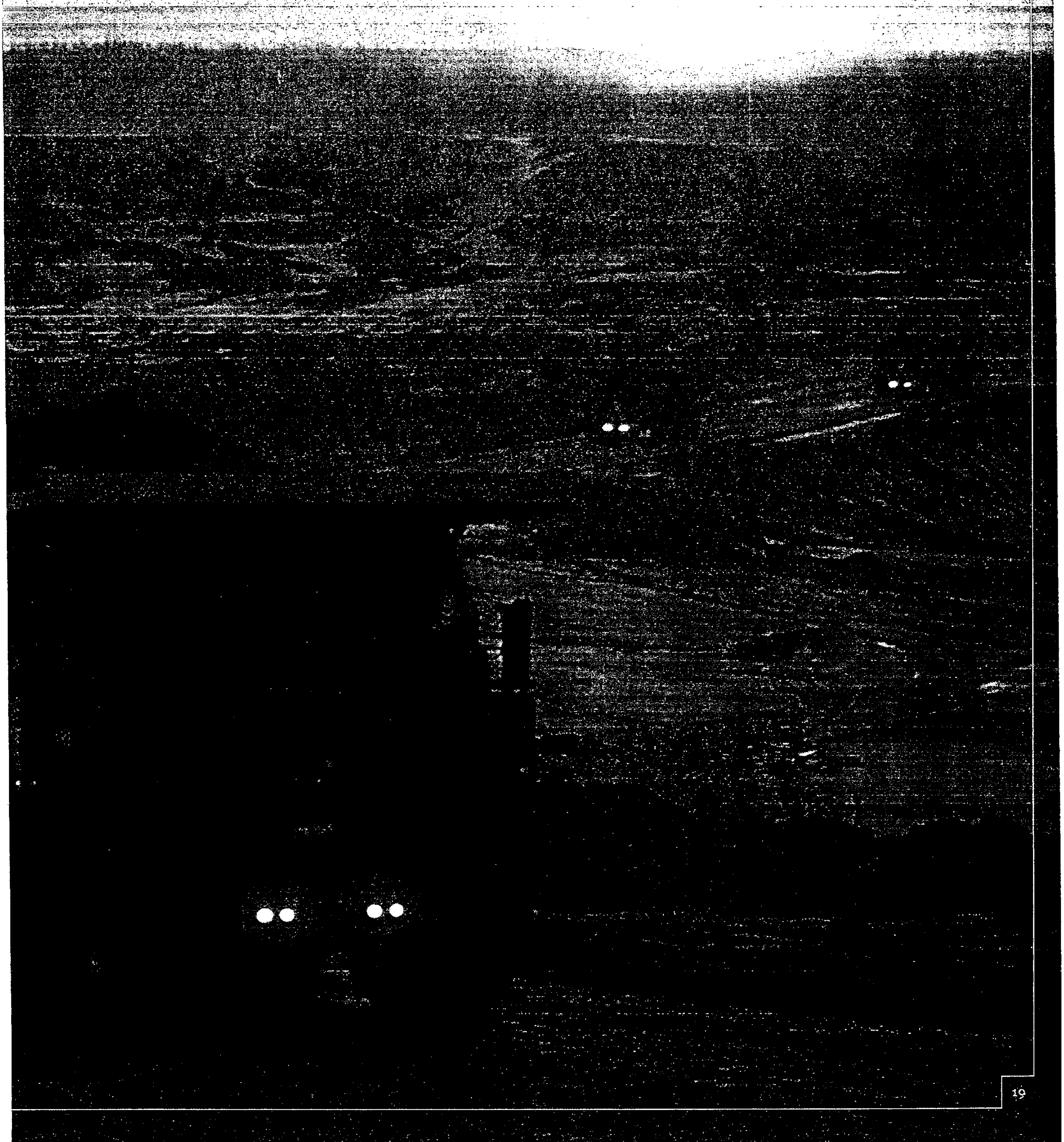
A premium distribution, distribution reinvestment and optional unit purchase plan (DRIP) allows Unitholders to further leverage their investment in the Trust, providing them with the option to reinvest their distribution to receive new units at a 5% discount to the average market price, or for Canadian 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 MD&A 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

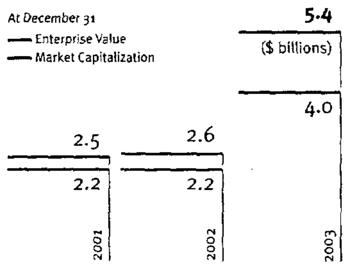
Our working interests in Syncrude are held through two operating subsidiaries: Canadian Oil Sands Limited (COSL) and Canadian Oil Sands Commercial Trust (CT). The only business of these operating subsidiaries is to manage the aggregate 35.49 per cent interest in Syncrude and, in the case of COSL, to 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.

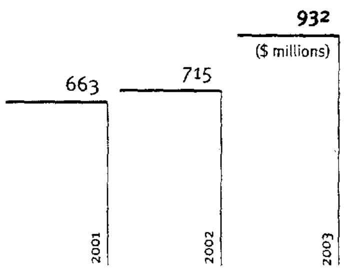
In addition to internal growth through the Stage 3 expansion, we have grown through acquisitions. In 2003, we acquired an additional 13.75 per cent interest in Syncrude from EnCana in two separate transactions. The total purchase price of $1.5 billion was financed through the issuance of additional equity 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.

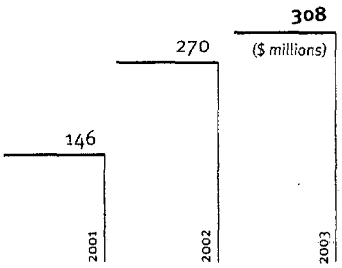
Net revenues increased 30 per cent in 2003 over 2002, reflecting the increased working interest offset by lower Syncrude production volumes in 2003 as a result of an unplanned coker turnaround during the year, which had a negative impact on both sales and operating costs. The net realized sales price 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**

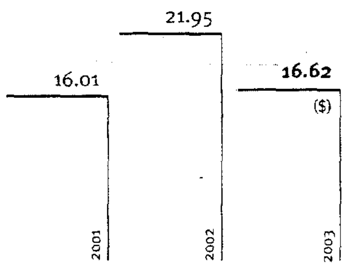
			2002		
	Q1	Q2	Q3	Q4	Annual
Net revenues	156.7	136.4	218.4	203.8	715.3
Net income	50.0	36.8	88.5	94.6	269.9
Net income per Trust unit, Basic and Diluted	0.88	0.65	1.54	1.64	4.72
Funds from operations	64.3	18.0	132.2	111.9	326.4
Funds from operations per Trust unit	1.13	0.32	2.31	1.94	5.71

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)

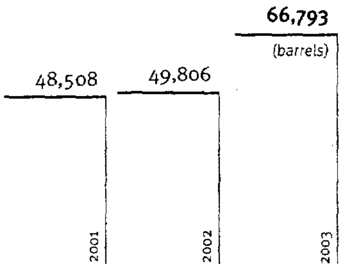
* The earnings reflected in the above table are a non-GAAP measurement, and therefore, are unlikely to be comparable to similar measures presented by other companies or trusts.

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)

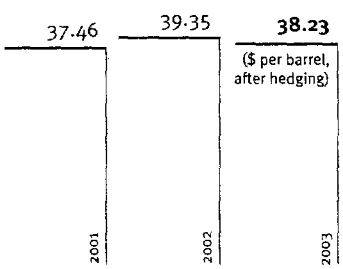
AVERAGE DAILY SALES

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



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.



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)

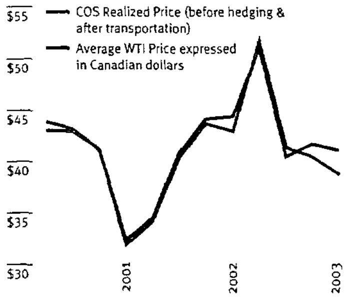
We have expanded our disclosure of production revenues and now are providing additional information on transportation and marketing fees with these costs separated on the Consolidated Statement of Income and Unitholders' Equity. In doing so, we have chosen to adopt new accounting rules established by 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.

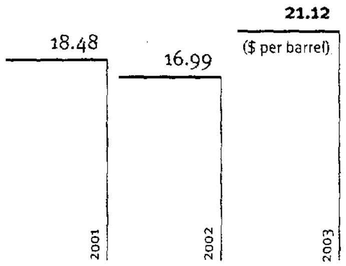
Production revenue was higher in 2003 than 2002 as a result of having acquired from EnCana the additional 10 per cent working interest on February 28, 2003 and another 3.75 per cent working interest on July 10, 2003. Canadian Oil Sands' average Syncrude working interest of approximately 32 per cent in 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.

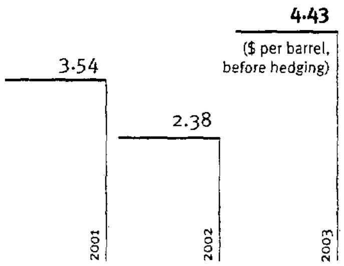
3 Canadian Oil Sands' adjustments primarily relate to pension cost adjustments and the inventory impact of moving from production to sales as Syncrude reports unit costs based on shipment volumes and we report based on sales volumes.

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

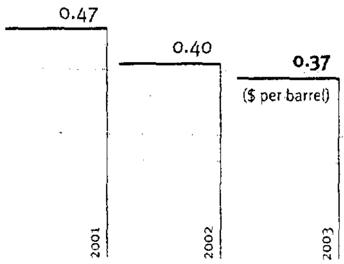
Non-production costs increased in 2003 from 2002 due to the larger working interest and higher levels of development activity associated primarily with UE-1. Non-production expenses relate mainly to Syncrude 21 development expenditures, which include costs incurred to modify, relocate or remove equipment 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.

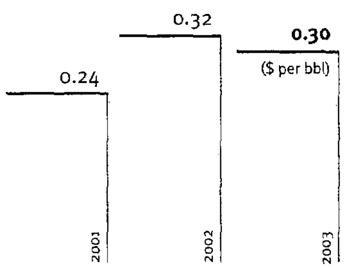
ADMINISTRATION EXPENSE

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

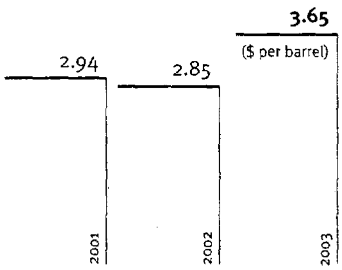
($ millions)	**2003**	2002	$ Change	% Change
Interest expense	**72.0**	48.6	23.4	48
Interest income and other	**(4.2)**	(9.9)	5.7	(58)
Interest expense, net	**67.8**	38.7	29.1	75

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

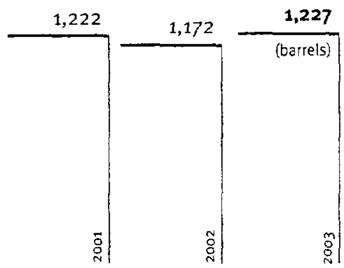
Depreciation and depletion (D&D) expense for 2003 was approximately $40 million higher than in 2002 as a result of the acquisitions of the Syncrude working interests during the year. The effective D&D rate in 2003 was $3.65 per barrel compared to $2.85 per barrel in 2002. We depreciate and deplete our 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

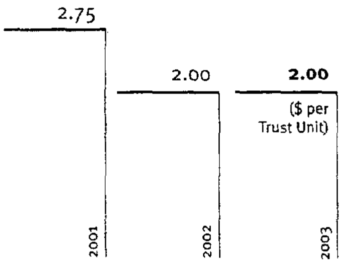
Income and Large Corporations Tax (LCT) expense in 2003 reflects the estimated LCT payable by COSL of approximately $8 million, compared with approximately $3 million in 2002. The increase in LCT expense in 2003 compared to 2002 reflects the significantly larger taxable capital base as a result of the 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.

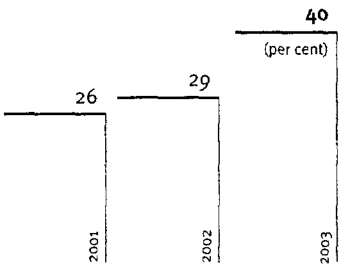
New Accounting Pronouncements

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.

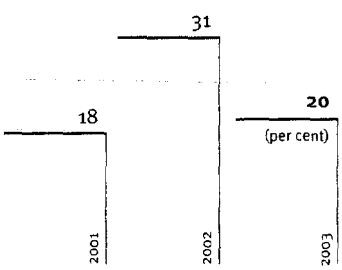
NET DEBT TO TOTAL BOOK CAPITALIZATION

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

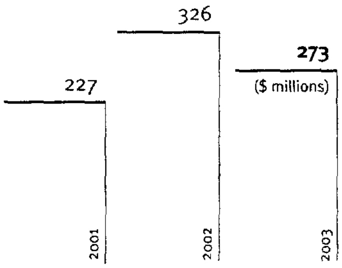
In 2003, the Trust's total capitalization increased significantly as a result of the acquisitions and related financing initiatives the Trust undertook during the year. To finance a significant portion of the 13.75 per cent Syncrude interest acquisitions from EnCana in 2003, which totalled approximately $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

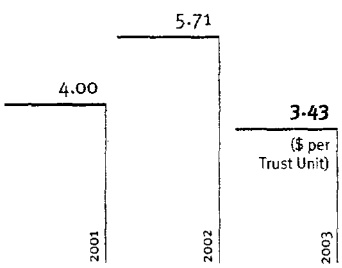
FUNDS FROM OPERATIONS

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

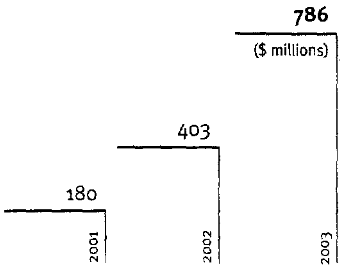
On January 15, 2004, COSL issued $20 million of floating rate and $175 million of 3.95% medium term notes. Both issues were for three year terms and are unsecured. As discussed more fully in the Risk Management section of this MD&A, interest rate swap transactions were undertaken to convert the fixed 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.

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

A. R. Hagerman

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Tabular amounts expressed in thousands of dollars, except where otherwise noted)

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.

CORPORATE INFORMATION

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

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

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Canadian Oil Sands

CANADIAN OIL SANDS TRUST

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2003

March 22, 2004

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GLOSSARY

"Acquisition" means the purchase of an additional 13.75% working interest in the Syncrude Joint Venture which occurred in 2003;

"Alberta Crown Agreement" means the agreement between the Province of Alberta and the Syncrude Participants providing for payments to the Province of Alberta of the Crown Royalty in lieu of Crown Royalties;

"AEP" means Alberta Environmental Protection;

"AEPEA" means Alberta Environmental Protection and Enhancement Act;

"AOSII" means Athabasca Oil Sands Investments Inc.;

"AOST" means Athabasca Oil Sands Trust;

"bitumen" in its raw state, is a black, asphalt-like oil;

"bucketwheel reclaimer" means a very large machine that scoops up mined oil sand and places it on conveyors;

"CCRA" means Canada Customs and Revenue Agency;

"CO" means carbon monoxide;

"CO_2" means carbon dioxide;

"CT" means Canadian Oil Sands Commercial Trust;

"Canadian Oil Sands", "us" or "we" mean collectively the Trust, the Corporation and CT;

"coker" means vessels in which bitumen is cracked into its fractions and coke is withdrawn to start the conversion process of bitumen to upgraded crude oil;

"Corporation" means Canadian Oil Sands Limited, the continuing corporation resulting from the amalgamation of AOSII, COSII and COSL on January 1, 2003;

"COSII" means Canadian Oil Sands Investments Inc.;

"COSL" means Canadian Oil Sands Limited, prior to the amalgamation with AOSII and COSII;

"COST" means the former Canadian Oil Sands Trust, which was merged with the Trust;

"cracking" means a process which breaks large, complex hydrocarbon molecules into smaller, simpler compounds by means of heat;

"Crown Royalty" or "Crown Royalties" means the payments to be made to the Province of Alberta pursuant to the Alberta Crown Agreement or under the generic crown royalty scheme;

"deemed unit price" means, generally, the fair market price received as the result of an arms length basis for the sale of SSB;

"double roll crusher" means a large unit which crushes the oil sands and deposits the crushed oil sands on to a conveyor;

"dragline" means a large machine which digs oil sand from the mine pit and places it into elongated piles;

"ERCB" means the Energy Resources Conservation Board of Alberta, a governmental body that oversees the exploration and development of natural resources in Alberta;

"EUB" means Alberta Energy Utilities Board;

"EnCana" means EnCana Corporation, formerly PanCanadian Energy Corporation;

"extraction" means the process of separating the bitumen from the oil sand;

"fines (fine tailings)" means essentially, muddy water, which is about 85% water and 15% fine clay particles by volume that is produced as a result of extraction;

"First Acquisition" means the acquisition of the 10% interest in Syncrude from EnCana which was completed on February 28, 2003;

"joint venture" means an economic activity resulting from a contractual arrangement whereby two or more venturers jointly control the economic activity;

"Manager" means, prior to January 1, 2003, AOSII and COSII and, on and after January 1, 2003, the Corporation;

"naphtha" means a light fraction of crude oil used to make gasoline;

"oil sand" is comprised of sand, bitumen, mineral rich clays and water;

"Option Acquisition" means the acquisition of the 3.75% interest in Syncrude and the 6% GORR from EnCana which acquisition was completed on July 10, 2003;

"Plan" means the Premium Distribution, Distribution Re-Investment and Optional Unit Purchase Plan;

"residuum" means the fraction of bitumen that remains after the light ends have been distilled;

"SSB" means Syncrude™ Sweet Blend;

"SSP" means Syncrude™ Sweet Premium;

"Syncrude" means, collectively, the Syncrude Joint Venture and the Syncrude Project;

"Syncrude Joint Venture" means the joint venture formed by the Syncrude Participants for the purpose of exploiting the Athabasca oil sands, which includes the Syncrude Plant and leases acquired or developed in connection therewith;

"Syncrude Participants" means Canadian Oil Sands Limited Partnership (5%), the Corporation (31.74%), ConocoPhillips 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 Oil and Gas (12%), the corporations or partnerships that own the undivided interests in the Syncrude Project and their respective successors and assigns in interest from time to time to;

"Syncrude Plant" means the plant and facilities owned by the Syncrude Participants and operated by Syncrude Canada Ltd. located at Mildred Lake, approximately 40 kilometres north of Fort McMurray, Alberta, where the mining, extraction and upgrading of bitumen occurs;

"Syncrude Project" means (a) the scheme for recovery of oil sands, crude bitumen or products derived therefrom originally approved in Approval No. 1920 of the ERCB and currently approved in Approval Nos. 8573 and 8250, as issued by the EUB (as successor of the ERCB), as such scheme may be amended or superseded from time to time, (b) all property now owned or hereafter acquired or developed by the owners participating from time to time in such scheme or by Syncrude Canada Ltd. on their behalf in connection with such scheme, (c) the oil sands leases and (d) any other scheme or schemes implemented for the purpose of recovering oil sands, crude bitumen or products derived from those oil sands leases related to such scheme or schemes and all property acquired or developed in connection with such scheme or schemes;

"Trust" means Canadian Oil Sands Trust, which prior to the merger with COST, was known as Athabasca Oil Sands Trust;

"trust royalty" means the net royalty paid by the Manager on the production of synthetic crude oil and associated products, attributable to each Manager's respective working interest in Syncrude;

"Unitholders" means the holders of the units of the Trust; and

"upgrading" means the conversion of heavy bitumen into a lighter crude oil by increasing the hydrogen to carbon ratio, either through the removal of carbon (coking) or the addition of hydrogen (hydroprocessing).

UNITS

API	a measure of specific gravity
bbl	barrel
bbls/d	barrels per day
C	Celsius
gj or GJ	gigajoule

**NOTE: All figures are provided in Canadian dollars unless otherwise noted.
All information is as at December 31, 2003, unless specified otherwise.**

FORWARD-LOOKING INFORMATION ADVISORY

In the interest of providing Canadian Oil Sands Trust ("Canadian Oil Sands", "we" or "us") Unitholders and potential investors with information regarding Canadian Oil Sands, including the Corporation's assessment of Canadian Oil Sands' future plans and operations, certain statements throughout this Annual Information Form ("AIF") contain "forward-looking statements". Forward-looking statements are typically identified by words such as "anticipate", "expect", "believe", "plan", "intend" or similar words suggesting future outcomes, or statements regarding an outlook with respect to: the expected production level at Syncrude for 2004 and beyond, and the resulting oil production per day for Canadian Oil Sands; the expected level of oil and natural gas prices; the anticipated impact that certain factors such as natural gas and oil prices, foreign exchange and operating costs have on Canadian Oil Sands' cash flow and net income; the aggregate capital cost of the Stage 3 expansion and the completion date for such expansion; the amount of reserves recoverable and the time frame to recover such reserves; the impact of the Kyoto Protocol on Canadian Oil Sands; the estimate of reserves and resources; and the anticipated maintenance work at Syncrude and the impact such maintenance will have on Canadian Oil Sands' financial results. 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 Canadian Oil Sands 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 AIF include, but are not limited to: volatility of crude oil and natural gas prices, product supply and demand, market competition, Canadian Oil Sands' ability to either generate sufficient cash flow from operations to meet its current and future obligations or obtain external sources of debt and equity capital, changes in environmental and other regulations, general economic, business and market conditions, and such other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by Canadian Oil Sands. You are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this AIF are made as of the date of this AIF, and Canadian Oil Sands 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 AIF are expressly qualified by this cautionary statement.

THE TRUST AND ITS STRUCTURE

Name and Formation

The Trust is an open-ended investment trust formed in October 1995 under the laws of the Province of Alberta pursuant to an amended and restated trust indenture created upon the merger of the Athabasca Oil Sands Trust ("AOST") and the former Canadian Oil Sands Trust ("COST"). On July 5, 2001, AOST acquired all the assets of COST and assumed all the liabilities of COST in exchange for AOST units equal to the number of COST units issued and outstanding as of such date. AOST then changed its name to Canadian Oil Sands Trust. As a result of the approval of certain option plans by Unitholders at the Trust's annual and special meeting held on April 25, 2002 and of the approval of certain amendments to the trust indenture terms at the annual and special meeting of unitholders of the Trust held on April 22, 2003, the trust indenture is being further amended and restated to reflect the adoption of such plans along with amendments passed at the 2003 unitholders' meeting which allow for electronic voting and the issuance of convertible securities by the Trust. The current trustee is Computershare Trust Company of Canada (the "Trustee").

The registered and head office of the Trust is located at 2500 First Canadian Centre, 350 – 7th Avenue S.W., Calgary, Alberta, T2P 3N9.

Intercorporate Relationships

The following table provides the name, the percentage of voting securities owned and the jurisdiction of incorporation, continuance or formation of the Trust's subsidiaries and partnership as at March 22, 2004.

	Percentage of Voting Securities (directly or indirectly)	Jurisdiction of Incorporation/ Formation
Canadian Oil Sands Limited (the "Corporation")(1)(2)	100%	Alberta
Canadian Oil Sands Commercial Trust ("CT")(3)	100%	Alberta
Canadian Oil Sands Limited Partnership ("LP")	75%	Alberta
834541 Alberta Ltd. ("834541")(4)	100%	Alberta

Notes:

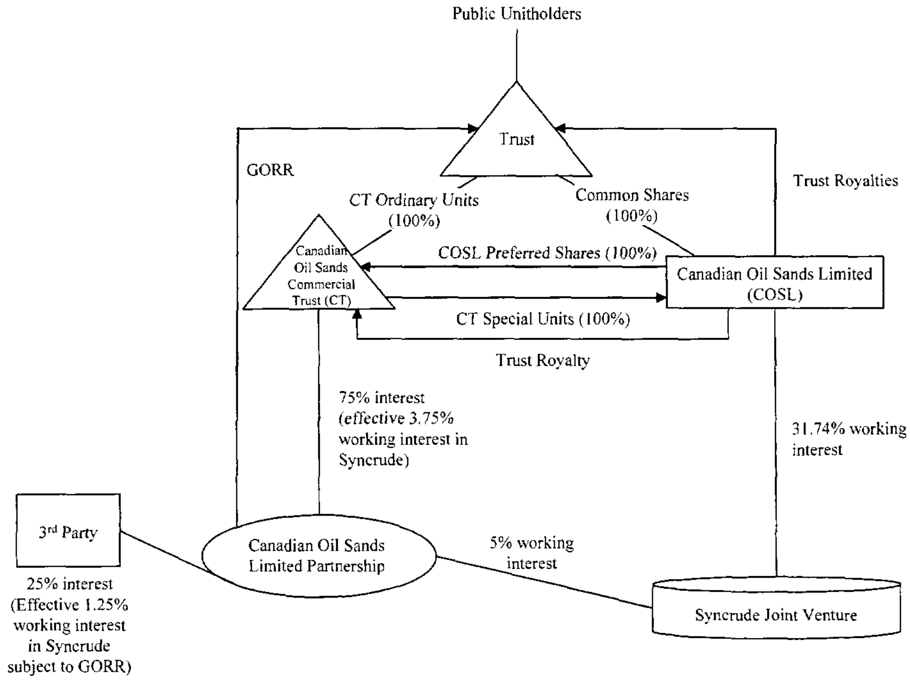
(1) Total assets and total revenues of this entity constituted more than 10% of the consolidated assets and consolidated revenues of the Trust at December 31, 2003.

(2) Holds a 31.74% working interest in Syncrude.

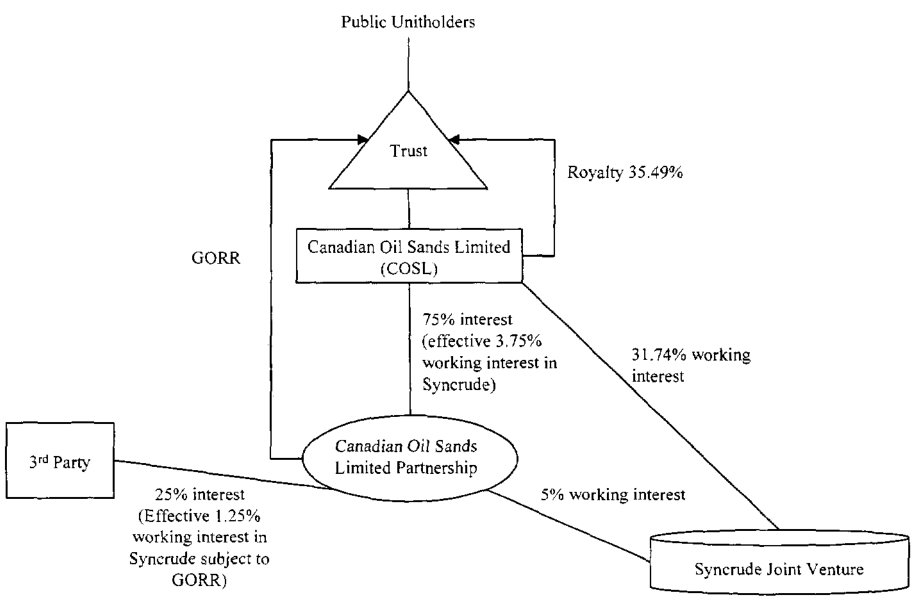
(3) Holds a beneficial 3.75% working interest in Syncrude through its holding of limited partnership units of Canadian Oil Sands Limited Partnership.

(4) Was dissolved effective July 1, 2003 and awaiting final tax clearance before formal dissolution documents filed.

The following diagram outlines the corporate structure of the Trust and its subsidiaries as at December 31, 2003:



If we can obtain satisfactory rulings from Canada Customs and Revenue Agency ("CCRA") that would enable us to simplify our structure such that the Corporation held directly or through the LP all the working interests in Syncrude and paid a single royalty on such interests directly to the Trust in a tax efficient manner, we would effect an internal restructuring to achieve this with the resulting corporate structure:



GENERAL DEVELOPMENT OF THE BUSINESS

Summary

We are the largest energy trust in Canada, based on market capitalization as at March 9, 2004 of approximately $4.0 billion, and the only public investment vehicle that provides a non-diversified ownership in Syncrude, the largest oil sands project in the world. Syncrude is located near Fort McMurray, Alberta, Canada and 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. The Syncrude operation is comprised of four major operating areas: mining, extraction, upgrading and utilities. Syncrude's principal product is a high quality, light, sweet synthetic crude oil blend, referred to as "Syncrude Sweet Blend" ("SSB"), which has an average gravity of about 32° API and low sulphur content of between 0.1% and 0.2%. The Trust's business is its indirect ownership of Syncrude and the marketing and sales of SSB derived from such ownership.

On July 5, 2001, the Trust was created by the merger of AOST and COST, which trusts held an 11.74% and 10% working interest, respectively, in Syncrude. Following the merger, the Trust's indirect 21.74% working interest in Syncrude was administered by PanCanadian Petroleum Limited (now EnCana Corporation) ("EnCana") pursuant to an administrative services agreement. In August 2001, Canadian Oil Sands hired Mr. Coutu as President and Chief Executive Officer to oversee the Trust's working interests and assume a more active management role in relation to the Trust's assets. This internalization of management continued, when in the fall of 2002, the Corporation terminated the administrative services agreement with EnCana and hired its own staff.

As at March 22, 2004, the Trust's indirect 35.49% working interest in Syncrude is held through the Trust's ownership in the Corporation and CT. The Corporation pays a net royalty ("trust royalty") on the production of synthetic crude oil and associated products, attributable to its working interest in Syncrude, to the Trust (as to an aggregate 21.74% working interest) and to CT (as to a 9.5% working interest). CT distributes income net of expenses as distributions on its ordinary units and special units to the Trust and the Corporation, respectively. The Trust in turn receives the trust royalties and distributions and makes distributions to Unitholders. CT also acts as general partner and holds 75% of the limited partnership units in Canadian Oil Sands Limited Partnership (the "LP") which in turn holds a 5% working interest in Syncrude. The other 25% of the limited partnership interests in the LP are held by a third party independent oil and gas company. The LP pays a 6% gross overriding royalty ("GORR") directly to the Trust on revenues from the total 5% working interest in respect of production by Syncrude from leases 17 and 22. When LP distributes the remaining profits after payment of the GORR to the Trust, CT's 75% share is paid to the Trust and the Corporation as distributions on the ordinary and special units respectively. The Corporation uses these funds from CT and earnings on the 0.5% working interest that is not subject to a royalty to meet a portion of its current operating and debt requirements.

The Corporation manages CT's interest in the LP and as such oversees the 35.49% working interest in Syncrude. In addition, the Corporation is responsible for the management of the Trust. Specific responsibilities are as follows: (i) to ensure compliance by the Trust with continuous disclosure obligations under all applicable securities legislation; (ii) to provide investor relations services; (iii) to provide, or cause to be provided to Unitholders, all information to which Unitholders are entitled under the amended and restated trust indenture; (iv) to call, hold and distribute material including notices of meetings and information circulars in respect of all necessary meetings of Unitholders; (v) to determine the amounts payable from time to time to Unitholders and to arrange for distribution to Unitholders of distributable income; and (vi) to determine the timing and terms of future offerings of units, if any.

The Syncrude Joint Venture is owned as various undivided interests by the Syncrude Participants. The assets of the Syncrude Joint Venture are operated and managed by Syncrude Canada Ltd., which is owned by the Syncrude Participants in the same proportions as their interest in the Syncrude Joint Venture. Syncrude Canada Ltd. is a single purpose company with no significant assets. The Syncrude Management Committee governs Syncrude and each Participant nominates a representative to the committee, which is charged with setting the strategic direction for and making decisions regarding the operation of the Syncrude Joint Venture. Our President and Chief Executive Officer is the Chairman of the Syncrude Management Committee and Chairman of the Board of Directors of Syncrude Canada Ltd. He also chairs the CEO Committee of the Board of Syncrude Canada Ltd. Our Chief Financial Officer of the Corporation is the Chairman of the Audit and Pension Committee of the Board of Syncrude Canada Ltd. Each Participant receives its share of production *in kind* and is responsible for the subsequent marketing of such share of the production. Syncrude commenced production in 1978 and has, through capital investment, technological and efficiency improvements, increased production at the Syncrude Plant in 19 out of 25 years of operation.

Funds generated for Canadian Oil Sands from operations at Syncrude 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, 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 U.S.$37.83 per barrel to a low of U.S.$17.45 per barrel.

Production volumes reflect the capacity of the Syncrude facility and reliability of operations. Our proven reserve life index estimated at 35 years 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. Syncrude is currently in the midst of the largest expansion project in its history, known as Stage 3. The expansion is designed to increase annual Syncrude production to 128 million barrels, reduce unit operating costs and enhance the product quality of SSB. Stage 3 is scheduled for completion in mid 2006 and the total project cost currently is estimated at $7.8 billion, or $2.8 billion net to the Trust. See the discussion under Syncrude below.

Significant Acquisitions

On February 28, 2003, we completed the purchase from EnCana of an indirect 10% working interest in the Syncrude Joint Venture for aggregate cash consideration of approximately $1.1 billion (the "First Acquisition"). The First Acquisition was effected pursuant to an acquisition agreement dated February 3, 2003 (the "Acquisition Agreement") under which the Corporation acquired: (i) all of the outstanding trust units and debt obligations of CT, which at the time of closing of the First Acquisition held legally (and beneficially) a 9.5% working interest (10% legal interest) in the Syncrude Joint Venture; and (ii) all of the outstanding shares of 834541 (formerly AEC Oil Sands GP Ltd.), which at the time of closing of the First Acquisition held (beneficially) an additional 0.5% working interest in the Syncrude

Joint Venture. Immediately following the First Acquisition, the Corporation transferred all of the ordinary units of CT to the Trust and transferred all of the shares of 834541 to CT. Following certain regulatory approvals, the Trust effected a restructuring of the 10% Syncrude interest such that the aggregate 31.74% working interest in Syncrude is held directly by the Corporation rather than by three separate legal entities.

Pursuant to the Acquisition Agreement, the Corporation also acquired certain rights in relation to: (i) EnCana's remaining 3.75% working interest in the Syncrude Joint Venture that was held by AEC Oil Sands Limited Partnership, including a 6% gross overriding royalty on such 3.75% working interest in respect of certain of the leases included in the Syncrude Project; and (ii) EnCana's 6% gross overriding royalty on another 1.25% working interest in respect of certain of the leases included in the Syncrude Project (collectively, the "Remaining Interest"). The Corporation exercised this option in May 2003 and completed the purchase of the Remaining Interest, for an aggregate purchase price of approximately $430 million.

The $1.1 billion purchase price for the First Acquisition was financed by means of: (i) a sale by the Trust of 12,322,250 Units by way of subscription receipts at a price of $35.00 for aggregate gross proceeds of approximately $431 million (the "Subscription Offering"); (ii) a sale by the Trust of a further 9,352,518 Units at a price of $34.75 on a private placement basis to certain mutual funds managed by Capital Research and Management Company for aggregate gross proceeds of approximately $325 million (the "Private Placement"); (iii) a draw by the Corporation of approximately $350 million under a credit facility of up to $560 million that had been obtained from affiliates of each of CIBC World Markets Inc. and Merrill Lynch Canada Inc. (the "Original Acquisition Facility"). The Subscription Offering closed on February 27, 2003 and the Private Placement closed on February 28, 2003.

On March 28, 2003, the Original Acquisition Facility was replaced with a $560 million syndicated credit facility (the "Replacement Acquisition Facility") and permitted amounts drawn under that facility to be used to finance additional asset purchases related to the Acquisition and, following repayment of such acquisition amounts, up to $225 million for general corporate purposes. On April 9, 2003, the Corporation issued $150 million of 5.75% unsecured notes (the "Notes") which mature on April 9, 2008. The proceeds from such note issuance were used to pay down the Replacement Acquisition Facility to $200 million, leaving $360 million available for the acquisition of the Remaining Interest.

The $430 million purchase price for the Option Acquisition was financed by means of : (i) a sale by the Trust of 5,500,000 Units (including 1,200,000 pursuant to the exercise of an underwriters' over-allotment option) at a price of $35.15 each for aggregate gross proceeds of approximately $193 million (the "Unit Offering"); (ii) a sale by the Trust of a further 1,000,000 Units at a price of $35.15 each on a private placement basis for gross proceeds of approximately $35 million ("Bought Deal"); and (iii) a draw by the Corporation of approximately $220 million under the Replacement Acquisition Facility. The Unit Offering and Bought Deal closed on July 10, 2003.

Syncrude

Syncrude produces SSB by surface mining certain Athabasca oil sands deposits, extracting the bitumen and upgrading the bitumen to a light, sweet crude oil. Bitumen, in its raw state, is a thick molasses-like, black crude oil that requires upgrading to make it transportable by pipelines and useable by conventional refineries. The upgraded bitumen or SSB produced at the Syncrude Plant is marketed to various refineries throughout Canada and the United States.

Syncrude has, through the introduction of pioneering technologies, improved energy efficiency, reduced atmospheric emissions and increased the amount of oil recovered and produced. Current proprietary technologies, developed over the last 12 years, include low-energy extraction, which reduces the process temperatures to extract bitumen from the oil sands, resulting in energy savings and emission reductions. Another innovation is hydrotransport, where oil sands and water are combined into a slurry and transported via pipeline to the extraction plant. This technology reduces maintenance and operating costs. Syncrude has developed the technology to pipeline bitumen froth (approximately 60% bitumen, 30% water and 10% fine solids) called "natural flow lubricity" without the use of a diluent, which is normally used to pipeline viscous heavy oil. This innovation improves the economies of operating oil sands mines farther from the extraction facilities, such as the Aurora mine. By 2007, all mined oil sands are expected to be moved by pipelines as the older operations are phased out, other than the oil sands from the North Mine auxiliary mining system.

In 2000, Syncrude commenced mining and extraction operations at a third site, the Aurora North Mine, located approximately 35 kilometres from the Mildred Lake plant site. In early 2001, after several years of planning, Syncrude Participants approved the Stage 3 expansion, which is the largest stage of Syncrude's expansion plans in Syncrude's 26 year history. At the end of 2003, engineering and design work on the upgrader expansion ("UE-1") was approximately 84% complete and construction was approximately 35% complete. A separate component of the expansion, the Aurora 2 mining and extraction train ("Aurora 2"), was completed in October 2003 and put into service before year end. The Aurora 2 train was completed within two months of the scheduled completion date and about 4% over budget. To date, the Aurora 2 train has operated as designed and provides additional flexibility in the production and transportation of bitumen from Aurora to the Mildred Lake upgrader.

In November 2002, Canadian Oil Sands confirmed the increase in the total estimated cost to the Syncrude Joint Venture for the Stage 3 expansion from the initial $4.1 billion estimate provided early in 2002 to approximately $5.7 billion. By late 2003, the UE-1 project was over 2 months behind schedule and costs began accruing above plan. As a result, Syncrude commissioned further resources from experts to study the project in more detail and depth. From the end of 2003 to March 2004, Syncrude, assisted by many independent experts sourced worldwide and from the project management ranks of the Syncrude Participants, including experts from ExxonMobil, reassessed the status of Stage 3. As a result of this further analysis and evaluation, on March 4, 2004, Syncrude advised the Syncrude Participants of a new increased cost estimate for the Stage 3 project. Syncrude advised that the majority of the capital cost increases stem from the protracted engineering phase at the beginning of the project and underestimating the complexity of revamping existing facilities and tie-ins, which together have overshadowed the relatively strong productivity on the greenfield components of the construction. In particular, Syncrude currently estimates that it will take 25 million manhours to complete UE-1 rather than the 15 million manhours included in the earlier estimated cost for the project. The net impact on Canadian Oil Sands from the prior estimates is an increase of about $750 million.

Based on such third party analysis, on March 4, 2004, Canadian Oil Sands announced that the cost of completing Stage 3 was expected to further increase to $7.8 billion. After giving effect to this revised estimate, the total estimated cost net to Canadian Oil Sands based on its 35.49% ownership interest is approximately $2.8 billion. The total Stage 3 expansion net to Canadian Oil Sands is comprised of $2.5 billion for UE-1 and $0.26 billion for Aurora 2.

Significant reorganization and forward plans are being implemented as a result of this new information. In particular, many of these project management specialists who participated in the project review, including a number of experts from ExxonMobil, will be introduced into a newly reorganized project management structure to oversee the completion of Stage 3. Syncrude's third-party contractors also have been instructed to strengthen their on-site construction management teams.

Stage 3 expenditures to March 1, 2004 total $4.7 billion, which include the completion of the Aurora 2 mining train and about 37% completion of construction for the upgrader expansion (UE-1) with the purchase of materials, modules and equipment over 90% complete.

Following this project assessment, Syncrude's decision to extend the construction period rather than attempt to dramatically ramp up the workforce is consistent with its original contingency plan, which is founded on recent industry experience that such tactics do not accelerate the completion date, but merely reduce productivity and further increase costs.

Canadian Oil Sands' view is that the current loss in schedule of three months will not be recaptured, and in fact, will continue to trend toward a longer delay of six to eight months to mechanical completion with an additional two to four months to an in-service date, resulting in a mid 2006 full completion date. Similar peak workforce levels of 4,500 to 5,500 people will remain but for an additional duration, contributing largely to the approximate $2 billion increase in the forecast completion cost. As previously announced, the $0.7 billion bitumen production expansion component of Stage 3, known as the Aurora 2 mine, already was completed on time and approximately 4% over budget and is currently operating according to plan.

Canadian Oil Sands expects that the outlook for its 2004 capital program will increase from $750 million to about $1.0 billion, 75% of which will represent Stage 3 investment. Details of the capital program for 2004, 2005 and 2006 are: 2004 – $1.0 billion; 2005 – $0.6 billion; and 2006 – $0.2 billion of which approximately 75%, 65% and 10%, respectively are related to Stage 3 costs.

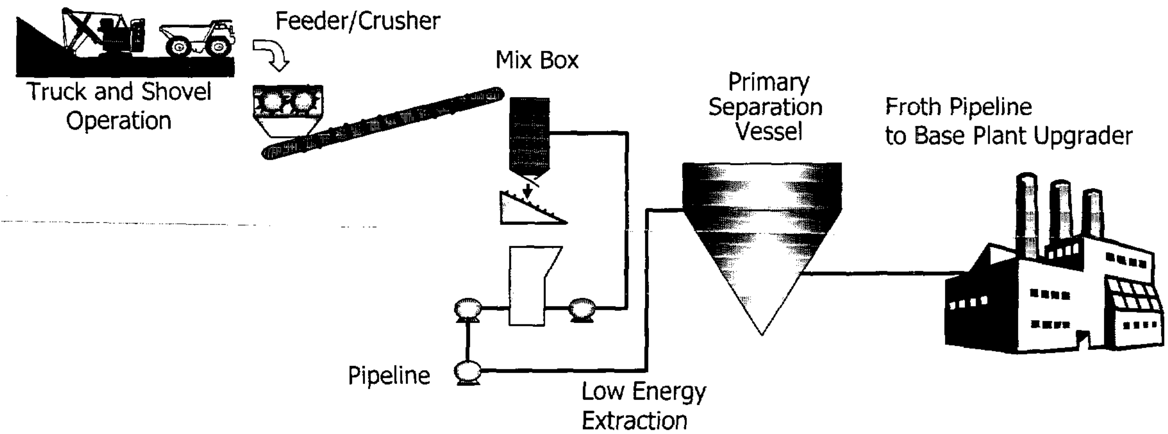
Canadian Oil Sands monitors its financing plan continually, and it does not currently foresee having to take any action regarding its current distributions; however, new equity outside of the Trust's DRIP likely will be required in due course, the amount and timing of which will be highly sensitive to crude oil prices and production performance.

Two additional expansion phases to follow Stage 3 also are in the preliminary design phase and have not been approved nor has the potential timing of any implementation of such expansions been determined. The Stage 4 expansion is expected to be principally a debottlenecking of the facilities and is expected to increase production to 150 million barrels per year. The Stage 5 expansion is conceptually another coker and additional mining trains, similar to Stage 3, and could increase production to approximately 200 million barrels per year. Stages 4 and 5 expansions are preliminary and have not received approval. They would only be considered once Stage 3 is completed and operating satisfactorily.

NARRATIVE DESCRIPTION OF THE BUSINESS

Syncrude is focused on maintaining a strong foundation of operational excellence to provide reliable production of SSB. To help achieve this goal, the following objectives have been identified: improve operational reliability; reduce unit operating costs; increase bitumen productive capacity; improve energy and environmental efficiency; and capture expansion related economies of scale. These objectives apply to immense and complex operations that include oil sand mines, bitumen extraction facilities, upgrading facilities and utility plants. Maintenance work regarding such operations has a key impact on Syncrude's operations and, consequently, on the revenues that Canadian Oil Sands derives. Maintenance work that occurs during the colder winter season may experience more time delays and operational issues due to the impact of workers having to work in extremely cold weather conditions.

The Syncrude Operation



Mining

The Syncrude operations include three separate mines: the Base, North and Aurora Mines. Syncrude's method of mining and extraction is evolving as its operations transition from the Base Mine to the North Mine and Aurora North Mine. As part of the transition away from the Base mine, two mining systems each comprised of a dragline, bucketwheel reclaimer and conveyor system, were retired in 1999. One of the two remaining mining systems was retired in 2002 and the remaining system is expected to be retired in 2005. After dragline mining is complete, oil sands remnants will be recovered by truck/shovel mining prior to the mine being decommissioned. In each of the years 2001, 2002 and 2003 the Base Mine contributed 33%, 25% and 16% respectively, of all bitumen produced from the Syncrude mines.

In the North Mine, which began operations in 1997, Syncrude uses a truck and shovel operation to mine the oil sands instead of dragline and bucketwheels used at the Base Mine. The shovels are very large and can dig approximately 90 tonnes of ore with each scoop. The trucks used to transport the ore to the double roll crusher can transport up to 400 tonnes. The truck and shovel operation is more cost effective than the Base Mine mining system because of lower maintenance costs, greater flexibility and improvement in large trucks and shovels. Current mining and hydrotransporting technology uses bitumen ore mined from the North Mine to replace depleted ore from the east half of the Base Mine. As a result, starting in 2002, the North Mine and Base Mine are treated as one bitumen producing area. In 2002, production from the North Mine and Base Mine accounted for 73% of production with bitumen production from Aurora comprising 27%, as compared to 79% in 2001 from the North Mine and Base Mine and 21% from Aurora. In 2003, 69% of production from bitumen came from the North Mine and Base Mine while 31% came from Aurora.

The Aurora North Mine is comprised of Leases 10, 12 and 34 and the Aurora South Mine will initially be located on Lease 31. Mining operations began at the Aurora North Mine in 2000 and incorporate a new generation of larger 400-tonne trucks and larger shovels. It is anticipated that the Aurora North Mine will continue to increase the amount of bitumen produced compared to the North Mine and Base Mine over the next several years.

Extraction

Historically, all extraction activity occurred at the Mildred Lake plant as the ore was mined exclusively at the Base Mine. As mentioned above, because of the transition from the Base Mine to the

North Mine and Aurora North Mine, the method of extraction and the location of extraction facilities has changed.

The ore from the Base Mine is delivered to the Mildred Lake extraction facilities by conveyor and is then mixed with steam, hot water and caustic soda to produce a slurry at a temperature of approximately 80°C. This mixing process occurs in large horizontal rotating tumblers that condition the mixture for separation. This slurry is discharged from the tumblers onto vibrating screens to remove large rocks and lumps of clay prior to entering the primary separation vessel, the last step of the extraction process.

At the North Mine, once the ore has left the double roll crusher, it is conveyed to a cyclofeeder where it is mixed with warm water and caustic soda to produce a slurry with a temperature of approximately 50°C. The use of warm water in this process as opposed to hot water at Mildred Lake has led to decreases in energy consumption. The resulting slurry is screened, and the oversized material is rejected for further crushing. The slurry is further conditioned as it is transported to the Mildred Lake extraction plant via a hydrotransport pipeline.

The extraction process at the Aurora North Mine is similar to the North Mine, with a few exceptions. After the ore is crushed in the double roll crusher, it is conveyed to a mixbox where it is mixed with cooler water to produce a slurry with a temperature of approximately 25°C to 35°C. Rather than shipping the oil sand slurry to the Mildred Lake extraction plant, the slurry is transported via a hydrotransport pipeline to a primary separation vessel located at the Aurora North Mine (approximately three to five kilometres from the mining area). Here, the sand settles to the bottom of the vessel and is transferred to the Aurora North Mine's tailings pond. The bitumen froth is skimmed from the primary separation vessel and pipelined to the Mildred Lake upgrading facilities. The first shipment of bitumen froth from the Aurora North Mine arrived in Mildred Lake in mid-July 2000.

At the Mildred Lake extraction plant, the Base Mine slurry and the slurry from the North Mine flow into primary separation vessels and are further treated. The resulting froth is then mixed with the froth from the Aurora North Mine and diluted with naphtha prior to further processing. A final stage of separation removes substantially all of the remaining water and clay fines, leaving a clean bitumen as the feedstock for the upgrader.

The material remaining after the bitumen is extracted from the oil sands consists of water, sand, fine clay particles and some residual hydrocarbons. At both the Base and the Aurora North Mines, the coarse sand is accumulated and a dyke is created to separate the water and fine tailings. The water and fine tailings run off to a tailings settling basin where the solids settle to the bottom and the clarified water is recycled for use in the extraction process. The rate at which the fine tailings settle out of the water is extremely slow and is the subject of considerable research and development activity to identify the most cost effective and environmentally acceptable disposal method. A new composite tails technology using the mature fine tailings from the settling basin to create solid, permanent landscapes in mined-out areas became operational at the Mildred Lake site during 2000. The key tailings research and development initiatives proposed for the next few years include optimization of the composite tailings process, reclamation of tailings deposits, managing recycle water chemistry and development of thickened tailings for oil sand application.

Upgrading

Upgrading is the final stage in which the bitumen is converted into SSB. The first step in upgrading is to recover the naphtha for recycling to the froth treatment plant. Next, the bitumen is fed through a vacuum distillation unit where vacuum gas oil (35% by volume) is removed from the bitumen and the remaining bitumen ("vacuum topped bitumen") is processed through two fluid cokers and one LC-Finer hydroprocessor for further upgrading. The vacuum gas oils removed now bypass the coking units. This is significant because the upgrader's capacity to process bitumen with the coker and vacuum distillation unit has now been increased and product yield has been improved.

Fluid coking involves thermal cracking of the bitumen into lighter components and removal of carbon. The by-products from this process are fluid coke, CO gas and refinery off gas. The CO gas is used as fuel in CO boilers to generate steam and power for the facility while the residual coke from the cokers is stored in coke cells. The refinery off gas is used as fuel. As a result of Syncrude's improvements in design and efficiency, each of the cokers can currently process the equivalent of approximately 125,000 barrels of bitumen per day or approximately 105,000 barrels of heavier blend with vacuum topped bitumen. The LC-Finer breaks down bitumen into lighter hydrocarbons by adding hydrogen with the aid of a catalyst. Residuum from the LC-Finer is sent to the fluid cokers where it is mixed with bitumen. The products from the cokers, the LC-Finer and the top ends from the vacuum distillation unit are then processed in hydrotreating units. The hydrotreated components are then blended into SSB. The final upgraded product contains no residuum and is comparable to sweet conventional crude oil and is valued with reference to postings for light sweet crude oil at Edmonton, Alberta and Cushing, Oklahoma.

The next two years will see the integration and start up of the UE-1 expansion process into the existing upgrading complex. Completing all required tie-ins and base plant unit modifications without impacting plant production is a critical focus area.

After upgrading, SSB is transported through a dedicated pipeline to refineries in Edmonton, and from Edmonton via a number of pipelines to other refineries in Canada and the United States where it is processed into products such as gasoline, diesel and jet fuel. SSB can replace light sweet crude oil but is more typically blended with other refinery feedstock to balance a refinery's product slate and manage sulphur levels. Depending on a refinery's configuration and its product slate, synthetic crude oil can generally constitute between 7% to 20% of the refinery's feedstock. If the refinery produces a significant volume of diesel or jet fuel, it may have specialized equipment to consume large quantities of SSB. In 2002, there were three refineries in or near Edmonton which had the capability of taking synthetic crude oil as 25% to 100% of their feedstock. These three refineries consumed approximately 160,000 to 170,000 barrels per day of synthetic crude oil. By the end of 2003, approximately 350,000 barrels per day of synthetic crude oil production was available from Syncrude and other oil sands projects in the Fort McMurray and Edmonton area. This additional supply resulted in increasing proportions of synthetic crude oil being shipped and sold beyond Edmonton. In 2003, Canadian Oil Sands continued selling its SSB to the refineries in Edmonton, but by the fall of 2003, a larger proportion of volumes were being sold to refineries in Eastern Canada and the United States. In the fourth quarter of 2003, approximately 52% of Canadian Oil Sands' current production was sold to refineries downstream from Edmonton. Overall, in 2003, 67% of our volumes were sold to Eastern Canada and the United States compared to 54% in 2002.

In the past, there has been sufficient transportation and refinery capacity to handle the volume of SSB produced by Syncrude. It is anticipated that there will continue to be sufficient transportation from Edmonton and refinery capacity for the increased levels of production that are planned for Syncrude. The projected growth in synthetic crude oil volumes is expected to be partially offset by declines in Western Canadian conventional light crude. The transportation systems are expected to expand and be connected to the broader network of North American refineries.

Utilities

The utilities operation supplies steam, electricity, air, and water, as required, for the three separate mines at Syncrude. The cost of purchased energy, including natural gas, accounted for approximately 21% of Syncrude's operating costs in 2003 and 14% of Syncrude's 2002 operating costs.

Syncrude operates a utility plant at its Mildred Lake site using refinery off gas, produced from the upgrading operation, augmented with natural gas. This utility plant, previously owned by TransAlta Energy Corporation, was purchased by the Syncrude Participants in January 2001 to allow greater flexibility in long-term planning and to remove uncertainty arising from the expiry of operating agreements in 2003. When economically desirable, Syncrude purchases power from or sells power to the Alberta electric power grid.

Syncrude also owns an 80-Megawatt gas turbine power plant at the Aurora North Mine site that provides electrical and thermal energy for the Aurora Mine operations. This plant, commissioned in 1999, provides power for the Aurora North Mine's requirements and is connected with the Mildred Lake facilities.

Natural gas, used by Syncrude to produce hydrogen as well as fuel power plants, is transported to Syncrude through dedicated pipelines connecting the plant with gas production facilities in the area as well as the intra-provincial gas transmission system. Natural gas is purchased from producers using a strategy of long and short-term supply contracts to manage Syncrude's natural gas requirements. Currently, there has been no difficulty in obtaining the necessary supplies of natural gas.

Marketing

Each Syncrude Joint Venture owner is responsible for marketing its own share of SSB and associated by-products, such as sulphur. SSB is transported by pipeline from Fort McMurray to Edmonton at which point, SSB volumes are transferred to EnCana who markets the SSB on behalf of Canadian Oil Sands.

Effective January 1, 2002, EnCana markets our entire share of SSB production pursuant to a marketing agreement and charges a fee to us. Under the terms of the agreement, EnCana is entitled to a marketing fee for each barrel of crude bitumen or other liquid crude products sold subject to a minimum fee of $33,333 per month and a reasonable fee in respect of other oil sands products sold. In addition, EnCana is entitled to be reimbursed for its reasonable out-of-pocket costs and expenses. EnCana had also provided us with an option to sell to EnCana our share of the SSB produced by Syncrude. Effective February 1, 2002, EnCana purchased from us, on a monthly basis, all such SSB at prices equal to a deemed unit price, as determined pursuant to the Alberta Crown Agreement. The term of such sale was for an initial term of one year and ended, at EnCana's election, on February 1, 2003. Commencing February 1, 2003, EnCana marketed all of Canadian Oil Sands' SSB production in return for the marketing fee of $0.05 per barrel sold, subject to the minimum monthly fee of $33,333. The initial term of the marketing agreement ends June 30, 2006, at which time the agreement will automatically renew for successive three-year terms unless terminated by either us or EnCana.

EnCana marketed and sold 100% of our production from January 1, 2002 to January 31, 2002 to a number of major refineries located throughout North America with 56% of such production being sold to Canadian refineries. From February 1, 2002 until the end of 2002, EnCana purchased all of our SSB production, resulting in EnCana purchasing 91% of the total production for the year. From February 1, 2003 to the present, EnCana has been primarily marketing the SSB production of Canadian Oil Sands to several refineries in Canada and the United States. Recently, EnCana has also marketed Canadian Oil Sands' product to other producers for use as a diluent or in making synbit. As additional volumes of synthetic crude oil came into production in late 2003, our sales were made to a broader group of refineries than was historically the case. These refineries were located further from Edmonton, thereby resulting in higher transportation costs. We anticipate that 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 completion of the Stage 3 expansion, we must expand our markets to achieve the premium price we expect for our quality product. When UE-1 is complete, a new aromatics saturation unit will be used to upgrade our entire production into a higher quality product called SSP. We expect this higher quality blend to be more attractive to refineries, which should further enhance the price per barrel that we are able to realize.

Also, the use of light sweet synthetics as a blend stock for bitumen to product "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 oil, is being considered as an alternative.

Synthetic crude oil sales contracts are commonly negotiated directly with refiners throughout North America. Typical contract terms are based on 30, 60 or 90 day arrangements which continue unless terminated and are occasionally made for one year terms. Synthetic crude oils are priced on the basis of Canadian and U.S. market prices, which reflect the market balance between supply and demand for crude oil, the transportation costs and refined product values.

Although the Syncrude Participants have sold sulphur in the past, currently the sulphur produced by Syncrude is stockpiled at the Syncrude Mildred Lake plant site as present market conditions limit the sale of this by-product. Syncrude is exploring the ability to bury sulphur blocks underground. Initial information indicates that this may be a viable and environmentally friendly solution. Syncrude continues to research alternatives for addressing this issue, which affects the entire petroleum industry. Coke produced by Syncrude has never been commercially marketed and is also stored on the site.

Competition

The Canadian and international petroleum industry is highly competitive in all aspects, including the distribution and marketing of petroleum products. Syncrude competes with other producers of crude oil, most of whom have considerably lower operating costs. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

Research and Development

Syncrude Canada Ltd. spent approximately \$16.9 million in 2003 and \$15.2 million in 2002 on research and development related to all aspects of its operations, including the reduction of environmental impact and site reclamation. The Trust's share of such expenditures was approximately \$5.4 million in 2003 and \$3.3 million in 2002. Research and development is an ongoing process for Syncrude. Technologies currently being studied and tested relate to mining, extraction and tailings management including reclamation and closure planning with a view to reducing capital and operating costs as well as reducing long term liabilities associated with all types of disturbances to the environment.

The research department is located in a facility in the Edmonton Research Park, Edmonton, and employs a staff of scientists, technologists and support staff. It is one of the largest industrial research groups in Western Canada. Syncrude Canada Ltd. is a member of Canadian Oil Sands Network for Research and Development, which brings together the scientific resources of industry, government research organizations and universities, and is an active sponsor of various educational and industry research initiatives.

Fluid coker design, which is the basis for the upgrading operations at Syncrude, is licensed from Exxon-Mobil Research and Engineering ("EMRE"). The new Coker 8-3 being constructed for the UE-1 expansion continues to apply these licensed rights. There are no anticipated issues regarding the continuation of such license. Syncrude has been utilizing such technology under the license from EMRE for over 25 years.

During the spring 2003 turnaround, new design stripper sheds were installed on Coker 8-2. This design is now installed on both cokers to enable more effective stripping and enhancing coker run lengths without unit performance degradation. Plans for achieving 36-month coker runs have been incorporated commencing in 2004. There is no coker turnaround scheduled in 2004. However, historically the longest coker run achieved by Syncrude was 29 months from November 2000 to March 2003 and no assurance can be given that current 24-month run length schedules will be exceeded consistently.

Human Resources

At the end of 2003, Syncrude Canada Ltd. employed 4,026 people, all of whom were non-unionized. While it is believed that Syncrude Canada Ltd. will remain non-unionized, no assurance can be given that the work force will not become unionized.

Syncrude Canada Ltd. also uses the services of various outside contractors to provide contract maintenance support for certain areas of the Syncrude Plant. Additional contractors are also required during shutdowns, maintenance work and major capital construction. Most of the workers employed by these contractors are unionized. Labour stability of the unionized contractor work force is maintained through a number of industry and site-wide agreements, which set labour rates and working conditions for unionized trade workers engaged in construction and maintenance activities at various projects in Alberta, including the Syncrude Plant. As part of the Stage 3 expansion, the use of contractors for construction has significantly increased and is expected to remain at high levels until mid 2006 when the final completion and testing phase of Stage 3 is scheduled. Once Stage 3 construction is completed, it is anticipated that Syncrude staffing will increase to a level just below 4,200.

In the fall of 2002, Canadian Oil Sands internalized management and hired its own staff. As at December 31, 2003, the Corporation employed nine full time employees and one consultant. The Trust has no employees.

Government Regulation

The oil and gas industry in Alberta is subject to extensive controls and regulations. The regulatory scheme as it relates to oil sands is somewhat different from that relating to conventional oil and gas production. Outlined below are some of the more significant aspects of the legislation and regulations governing the mining, extraction, upgrading and marketing of oil sands.

Regulation of Operations

In Alberta, the regulation of oil sands operations is undertaken by the EUB, which derives its jurisdiction from the *Oil Sands Conservation Act*. In addition to requiring certain approvals prior to the operation of an oil sands project, the *Oil Sands Conservation Act* allows the EUB to inspect and investigate oil sands operations and, where a practice employed or a facility used in respect of the oil sands operations does not meet regulated recovery targets, to make remedial orders. Certain changes to an oil sands operation also require the approval of the EUB.

Land Tenure

Oil produced from oil sands is produced under oil sands leases granted by the Province of Alberta. Such leases have initial terms which vary in length but generally are for 15 years. Although the terms of future leases may vary, the current Syncrude leases have, for the most part, 15-year terms. If production attributable to a lease exceeds the minimum production thresholds set forth in the lease, it automatically renews at the end of each term. In addition, leases renew automatically if a development plan for a project involving the lease has been approved by the EUB and is being pursued by the lessor. In 1997, the Province of Alberta approved the continuation of the initial four Aurora leases based on the Syncrude Project development plan, including the Aurora project, and so long as such plan and approval is in effect and being followed, the Aurora leases will continue to renew at the end of each term. In 1999, Syncrude Canada Ltd. received confirmation that Leases 29 and 30 are also included for tenure purposes within the Syncrude Project development plan. In 2002, Leases 17 and 22 were continued under section 13 of the Oil Sands Tenure Regulations AR. 50/2000 for an indefinite term with a production status.

The Syncrude Joint Venture currently has the authorization from the Province of Alberta to hold several leases under that Province's 80-year provision for producing and upgrading facilities, which restricts the acquisition of leases that, in the aggregate, contain more bitumen than can be produced in 80 years using current technology and producing at present rates or pursuant to an approved development plan. Under this provision, the Syncrude Joint Venture is entitled to hold leases containing up to 17.8 billion barrels of bitumen. The Trust estimates that approximately 9.1 billion barrels of SSB crude oil resources (3.2 billion barrels net to the Trust) are recoverable from Syncrude leases of which approximately 3.0 are proved reserves (1.1 billion net to the Trust).

Royalties and Taxes

The Province of Alberta imposes royalties of varying rates on the production of crude oil from lands where it owns the mineral rights. The products recovered by Syncrude are subject to a royalty which is payable to the Alberta Government.

In February 1997, the Syncrude Participants and the Province of Alberta amended the royalty agreement to change the profit sharing formula and to cancel the Province of Alberta's option to convert its net profits interest to a gross production royalty. The amended agreement provided for a transition period from 1997 to the earlier of January 1, 2004 and the month after the Syncrude Participants' aggregate capital expenditures from 1996 reached $2.8 billion. The transition period terminated on December 31, 2001 upon reaching the required capital expenditure threshold. During the transition period, the Province of Alberta received the greater of its net profits interest share of the deemed net profits and 1% of the gross revenues attributable to production from (i) the original two leases in excess of 74 million barrels per year, and (ii) leases acquired subsequent to the original leases. With the amended agreement, the amount of the net profits interest was changed from 50% of the Syncrude Participants' deemed net profits to a volume-weighted percentage, based on production from all of the leases. For the original two leases, the net profits interest was 50% of deemed net profits attributable to volumes up to 74 million barrels, and 25% of the deemed net profits from volumes in excess of 74 million barrels. For production from leases acquired subsequent to the original leases, the net profits interest was 25% of the deemed net profits from all volumes. Capital expenditures after January 1, 1997 generated a

43% royalty credit during the transition period. For 2001, payments to the Province of Alberta were approximately 8% of gross revenues after deduction of pipeline tariffs.

In January 2002, following the conclusion of the transition period, the Syncrude Participants commenced paying royalties according to Alberta's generic oil sands royalty legislation. This legislation stipulates that the Province of Alberta will receive the greater of 1% of the gross revenues and 25% of the deemed net revenues. The deemed net revenues for any year is generally equal to the excess of gross revenues over allowed operating costs, deemed interest expense and capital expenditures and any unutilized carry forward deductions from previous years. As of December 31, 2003, Canadian Oil Sands' share of carry forward deductions was $404 million. In 2002 and 2003, due to the large capital expenditures for Stage 3, the minimum payment of 1% gross of revenues was paid to the Alberta government.

Taxation of Syncrude related income follows normal resource industry practices but with a few important differences. As Syncrude is a mining operation, there are certain provisions that are unique, such as the accelerated rate of deduction (100%) for class 41(a) assets which applies to new mines or a major expansion of an existing mine where there is a 25% or greater increase in mine capacity. Effective March 6, 1996, mining and oil sands operations which have made capital expenditures in excess of 5% of gross revenue in a fiscal year will also be eligible for the accelerated rate of deduction (100%) for such expenditures over the 5% threshold under class 41 (a.1). In addition, Syncrude Participants also received the benefit of the Syncrude Remission Order until December 31, 2003. This effectively allowed the deduction of actual Crown royalty payments for Leases 17 and 22 for purposes of federal tax calculations. For purposes of provincial taxation, the greater of actual royalty paid or resource allowance was allowed as a deduction. Generally, in times of high capital expenditures, minimum 1% of gross revenues are payable as a Crown royalty. As a result, we expect to pay only the minimum 1% of gross revenues royalty for the next couple of years while Stage 3 is being completed.

Environmental Regulation and Compliance

Oil sands operations, including Syncrude, are subject to environmental regulation pursuant to provincial and federal legislation. Environmental legislation requires various approvals and provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and gas industry operations. In addition, legislation requires that facilities and operating sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of fines and penalties. In Alberta, environmental compliance is primarily governed by the Alberta Environmental Protection and Enhancement Act ("AEPEA"). The AEPEA imposes certain environmental responsibilities on oil and natural gas operators in Alberta and in certain instances also imposes significant penalties for violations. Syncrude Canada Ltd. has received and presently maintains the requisite environmental approvals necessary to operate the Syncrude Plant.

The December 1999 EUB approval of Syncrude's upgrading expansion application permits production of 173 million barrels of SSB per year using technology identified in the application. This permit expires on December 31, 2035.

The Syncrude Joint Venture must maintain licenses from Alberta Environmental Protection ("AEP") regulating the discharge of substances into the air and water. These licenses generally have 10 year terms. The renewal or modification of licenses generally involves the AEP soliciting views of stakeholders (the local community, native population and other interested persons). Renewal or modification of licenses is often conditional, permitting AEP to review the effect of discharges or the implementation and effectiveness of new technologies. AEP approval for the Aurora Project was received in 1998. Syncrude Canada Ltd. received an environmental approval license required to conduct its Mildred Lake oil sands processing plant, Base Mine and North Mine operations until December 31, 2005, which expiry date has been extended to December 31, 2006 or until a new AEPEA approval is issued, whichever occurs first. The AEP granted Syncrude Canada Ltd. a single comprehensive license approval identifying allowable emissions levels which may affect air, water and land under the new Alberta Environmental Protection and Enhancement Regulations.

Estimates of future reclamation costs are determined approximately every five or six years with the next revision to occur in 2005. In December 1998, based on Syncrude Canada Ltd. revised estimates of future reclamation costs, we anticipated the future reclamation costs for the Syncrude Project to be approximately \$1.3 billion in 1998 dollars, of which our 35.49% share was approximately \$0.5 billion as at December 31, 2003. The 1998 revision took into account the extension of operations onto the Aurora Leases, monitoring requirements and reclamation of the expanded plant site and related infrastructure.

Annually, Syncrude Canada Ltd. is required to and, prior to 2003, posted with the AEP an irrevocable letter of credit equal in amount to \$0.03 per barrel of SSB produced on the Base Mine plus estimated reclamation costs relating to the Aurora Mine since inception of the Syncrude Project to secure the ultimate reclamation obligations of the Syncrude Participants. Each of the Syncrude Participants was required to guarantee its pro-rata share of this letter of credit to the issuing bank or alternatively, to provide its own letter of credit to AEP for such Syncrude Participants' pro-rata share. In 2003, the Syncrude Participants elected to post their own letters of credit rather than having Syncrude Canada Ltd. post such letter of credit. As a result, Canadian Oil Sands 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 Participants. In 2002, site reclamation expenditures for Syncrude Canada Ltd. totaled \$5.3 million and approximately 269 hectares of land were reclaimed. In 2003, site reclamation expenditures for Syncrude Canada Ltd. totaled \$3.5 million and approximately 182 hectares of land were reclaimed. Syncrude's long term plan is to return the land to a stable, biologically self-sustaining condition with a vision of creating an area of forest, parklands and lakes. During the next three years, Syncrude intends to invest approximately \$840 million in environmental mitigation and energy conservation matters. As at December 31, 2003, Syncrude had reclaimed more than 3,500 hectares of the land affected by its operation and planted more than 2.5 million trees in the Athabasca area. A significant portion of the land that had been tracked and mined by Syncrude and which has been reclaimed, is used for a grazing ground for more than 250 wood bison.

In addition to posting a letter of credit for its share of reclamation with the AEP, Canadian Oil Sands currently pays \$0.1322 for each barrel of SSB produced and attributable to our 35.49% working interest to a mining reclamation trust to fund our share of reclamation obligations at the termination of the Syncrude Project. Since 2002, we had the right to adjust the amount deposited in the mining reclamation trust from time to time as estimates of final reclamation costs change. Canadian Oil Sands and each of the other Syncrude Participants are liable for their share of on-going environmental obligations for the ultimate reclamation of the Syncrude Joint Venture on abandonment. We have accumulated (including interest earned on contributions), in the reclamation trust, \$16.6 million towards future reclamation. In 2002, this amount was \$12.9 million. The provisions of \$0.17 per barrel of production for future reclamation and site restoration costs, aggregating to \$4.5 million in 2003 and \$3.1 million in 2002, has been included in our depreciation and depletion expense on our financial statements. Management reviewed the amount per barrel in 2003 and confirmed that \$0.17 per barrel is adequate based on estimated costs, future reclamation and site restoration costs provided by Syncrude.

The current year provision in the financial statements, combined with the liability recorded on the acquisition of the additional 13.75% working interest from EnCana, resulted in a future site reclamation liability on our consolidated balance sheet of $57.6 million at December 31, 2003, which amount is already partially funded by the $16.6 million deposited in the trust reclamation account. Canadian Oil Sands' share of Syncrude cash reclamation expenditures was $1.1 million in 2003 (2002 – $1.2 million) which reduced the liability shown on our balance sheet.

The construction and operation of a large oil sands project such as Syncrude presents many environmental challenges. Responsible environmental management is a priority of the Syncrude Participants. The technical and management challenges to date have been addressed by Syncrude Canada Ltd. through many years of investment in research and the development of advanced management systems. Syncrude Canada Ltd. continues to seek ways to improve and reduce the cost of reclamation. Syncrude Canada Ltd. has never been assessed a significant fine or received any government control order regarding an environmental concern at Syncrude. Syncrude Canada Ltd. believes that it is in compliance with all material environmental requirements.

The Syncrude Participants support the voluntary reduction of greenhouse gas emissions, such as carbon dioxide, in the context of promoting energy efficiency. Syncrude Canada Ltd. participates in the Cumulative Environmental Management Association and other organizations concerned with environmental, aboriginal and community development matters. Syncrude Canada Ltd. is focused on reducing both energy consumption and greenhouse gas emissions per barrel of SSB produced.

Canada and more than 160 other nations are signatories to the 1992 United Nations Framework Convention on Climate Change, which is intended to limit emissions of carbon dioxide and other "greenhouse gases" that may be contributing to the suspected increase in mean global temperature. In December 1997, 39 industrialized nations that signed the Convention, including Canada, established the Kyoto Protocol which contained a binding set of emission targets for developed nations that is intended to result in the reduction of greenhouse gases. The average reduction in greenhouse gas emissions required from all 39 signatories is 5.2% from 1990 emission levels, to be achieved between 2008 and 2012, although specific emission targets vary from country to country. Canada, for example, would be required to reduce emissions by 6% from 1990 levels.

On July 23, 2001, at the Sixth Conference of Parties on Climate Change in Bonn, Germany, a broad political agreement was reached on the operational rulebook for the 1997 Kyoto Protocol. Following this political agreement, the federal government of Canada undertook some consultations with provincial and territorial governments. In late 2002, the federal government ratified the Kyoto Protocol. In response to comments from provincial governments and various stakeholders, the federal government has provided some parameters for implementing the Kyoto Protocol. The targets for emission intensity reductions have been capped at 15% of emissions based on current business plans (which in our case includes the Stage 3 expansion) and the cost of the carbon credit has been limited to $15 per tonne. Based on these parameters, we have estimated the cost impact that the Kyoto Protocol will have on operations is between $0.22 - $0.30 per barrel from 2008 to 2012. However, we note that numerous uncertainties regarding details of the Kyoto Protocol's implementation remain outstanding, thereby making it difficult to ascertain the cost estimate, including third party costs related to the Kyoto Protocol from Syncrude's suppliers of goods and services. We continue to work through industry associations such as the Canadian Association of Petroleum Producers and directly with the Alberta provincial and federal governments to develop a cost effective plan to reduce greenhouse gas emissions.

Exports

Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of light crude oil. Any crude oil export to be made pursuant to a contract of longer duration requires an exporter to obtain an export license from the National Energy Board and the issue of such a license requires approval of the Governor-in-Council. We currently do not have any contracts in excess of the one year duration and do not anticipate having any such contracts in the next year.

Leasehold Interests

Prior to the opening of the Aurora Mine, Syncrude's mining operations were limited to the Base Mine and the North Mine. These operations were conducted on two oil sands leases granted by the Province of Alberta, Leases 17 and 22, which are adjacent to each other and are located on the west bank of the Athabasca River about 40 kilometres north of Fort McMurray.

The Syncrude Joint Venture has also acquired Leases 10, 12 and 34 located approximately 35 kilometres North of Leases 17 and 22 on the east bank of the Athabasca River. On March 26, 1998, the Syncrude Joint Venture received approval from the EUB for the development of the Aurora Mine on Leases 10, 12 and 34. The Syncrude Participants have also acquired Leases 29, 30 and 31 located on the east bank of the Athabasca River near to Leases 17 and 22.

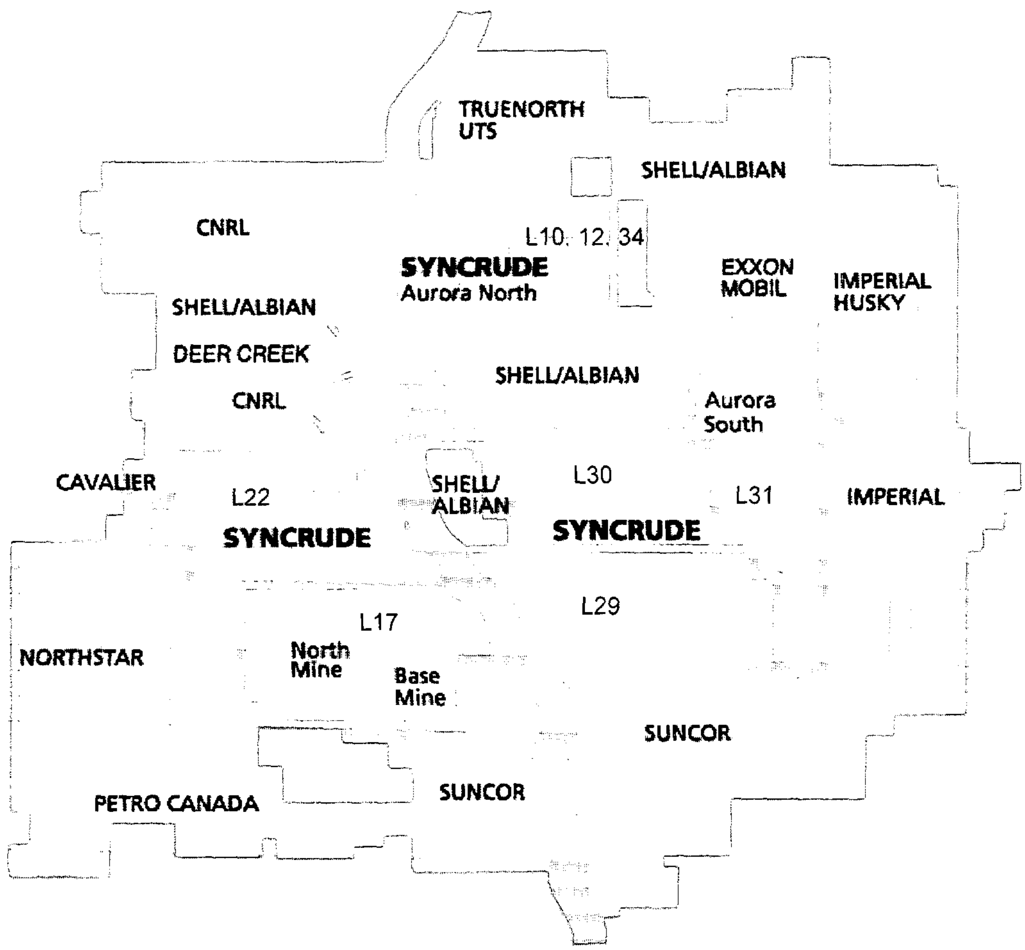
The following summarizes the Syncrude Joint Venture's leasehold interests as at December 31, 2003:

	Number of Acres	
	Gross	**Net**[1]
Producing		
Lease 10	11,092	3,937
Lease 17	49,540	17,582
Lease 22	43,200	15,332
Lease 34	9,019	3,201
	112,851	40,052
Non-Producing		
Lease 12	4,124	1,464
Lease 29	49,125	17,434
Lease 30	37,262	13,224
Lease 31	48,327	17,151
	138,838	49,273
Total	251,689	89,325

Note:

(1) Net acres represents Canadian Oil Sands' 35.49% interest in the lease as at December 31, 2003.

The following map shows the locations of the Syncrude leases.



RISK FACTORS

A substantial and extended decline in oil prices will have an adverse effect on Canadian Oil Sands

The financial condition, operating results and future growth of Canadian Oil Sands are substantially dependent on prevailing prices of oil. Prices for oil are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil, market uncertainty and a variety of additional factors beyond the control of Canadian Oil Sands. These factors include weather conditions in Canada and the United States, the condition of the Canadian, U.S. and global economies, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, war, or the threat of war, in oil producing regions, the foreign supply of oil, the price of foreign imports and the availability of alternate fuel sources. In view of the higher fixed operating costs of Syncrude Canada Ltd., the operating margin is very sensitive to oil prices. Any substantial and extended decline in the price of oil could have an adverse effect on the revenues, profitability and cash flows of Canadian Oil Sands and may affect the ability of Canadian Oil Sands to pay distributions, to finance its Stage 3 expansion and to repay its debt obligations. The Corporation has entered into crude oil forward contracts to manage a portion of this risk.

While the Syncrude Project has not been shut down by the Syncrude Participants since production commenced in 1978, a prolonged period of abnormally low oil prices could result in the

Syncrude Participants deciding to suspend production. Any such suspension of production could expose Canadian Oil Sands to significant additional expense and could negatively impact our ability to finance our share of Syncrude's Stage 3 expansion program and to repay our debt obligations.

Canadian Oil Sands has financial exposure to foreign currency exchange rates

Crude oil prices are generally based on a U.S. dollar market price, while operating and capital costs are primarily in Canadian dollars. In addition, Canadian Oil Sands makes interest payments in U.S. dollars on its U.S.-dollar denominated debt and funds its share of Syncrude's U.S. dollar vendor payments. Fluctuations in exchange rates between the U.S. and Canadian dollar give rise to foreign currency exchange exposure. Consequently, exchange rate movements can have a significant impact on results. To manage its exposure to currency fluctuations, Canadian Oil Sands has, in the past, entered into currency exchange contracts, Canadian dollar denominated crude oil forward contracts and issued debt securities in US dollars. The use of financial instruments involves a degree of credit risk.

To the extent that Canadian Oil Sands issues debt securities denominated in foreign currencies, such an investment may entail significant risks that are not associated with a similar investment in a security denominated in Canadian dollars. Such risks include, without limitation, the possibility of significant changes in rates of exchange between the Canadian dollar and the various foreign currencies and the possibility of the imposition of currency controls by either the Canadian or foreign governments. These risks will vary depending upon the currency or currencies involved.

Canadian Oil Sands may not have capital sufficient to fund all required capital expenditures; capital projects may experience significant cost overruns

Canadian Oil Sands and the other Syncrude Participants will continue to make substantial capital expenditures for the mining of oil sands and production of synthetic crude oil. There is no assurance that capital cost overruns will not occur or that investments will deliver the production increases expected by design or that start-up will occur as expected. Canadian Oil Sands has credit facilities available to it to assist in funding capital expenditures in excess of cash flow. However, it is expected that access to public debt markets will be required.

Canadian Oil Sands will not be economically viable if reserves from the Syncrude Project cannot be economically produced and marketed

Market fluctuations of crude oil prices may render uneconomic the mining, extraction and upgrading of oil sands reserves containing relatively lower grades of bitumen. Moreover, short-term factors relating to the oil sands reserves, such as the need for orderly development of ore bodies or the processing of new or different grades of ore, may impair the profitability of a mine and upgrading facility in any particular accounting period.

Canadian Oil Sands will not be economically viable if reserves from the Syncrude Project cannot be economically produced and marketed.

Marketing and transportation of synthetic crude oil

A significant volume of production from the Syncrude Project is sold beyond Edmonton, Alberta into Eastern Canada and the United States, such that pipeline access, transportation tariffs and price differentials with competing products are all factors which can affect sales volumes for SSB as well as netbacks receivable by the Syncrude Participants for their share of production.

Over the next five years, planned oil sands and heavy oil projects, including the Stage 3 expansion, could result in an additional 240,000 barrels per day of synthetic crude oil entering the market. There can be no assurance that existing transportation systems will be sufficient to handle this additional production or that new transportation systems will be built.

Currently, it is estimated that Edmonton refiners are consuming approximately 40% of Syncrude's production. Most of the remaining production is sold in Eastern Canada and the U.S. Canadian Oil Sands has seen a growing demand for its SSB product in the U.S. Rockies and U.S. Mid-West. Additionally, Canadian Oil Sands continues its efforts to identify new, or expand existing, markets for SSB, including considering the sale of SSB as a diluent for heavy oil producers in Canada.

There are a number of risks particular to the Syncrude operations that could have a material adverse impact on Canadian Oil Sands

The Syncrude Project is a single inter-related and inter-dependent facility. The shutdown of one part of the Syncrude Project could significantly impact the production of synthetic crude oil. Since essentially the sole source of income to Canadian Oil Sands is the sale of synthetic crude oil, a shutdown may reduce, or even eliminate our cash flow. There can be no assurance that the Syncrude Project will produce synthetic crude oil in the quantities or at the cost anticipated, or that it will not cease producing entirely in certain circumstances. Because operating costs to produce synthetic crude oil are substantially higher than operating costs to produce conventional crude oil, an increase in such costs could have a material adverse effect on Canadian Oil Sands and our cash flow.

The Syncrude Project is located in a remote area, and is serviced by one all weather road. In the event that the road is closed due to climatic conditions or other factors, Syncrude Canada Ltd. may encounter difficulties in obtaining materials required for it to continue production.

The production of synthetic crude oil requires high levels of investment and has particular economic risks, such as settling basin dike failures, fires, explosions, gaseous leaks, spills and migration of harmful substances, any of which can cause personal injury, damage to property, equipment and the environment, and result in the interruption of operations. Certain of these risks cannot be insured.

Synthetic crude oil is shipped from the Syncrude Project via a single pipeline. There are limited facilities at the Syncrude site for the storage of synthetic crude oil and, in the event of an interruption in pipeline shipments, the Syncrude Project's operations may be materially adversely affected.

Syncrude Canada Ltd. 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 crude oil.

Canadian Oil Sands could experience significant changes in debt services amounts

The ability of Canadian Oil Sands to meet its debt service obligations will depend on the future operating performance and financial results of Syncrude, which will be primarily subject to factors beyond our control, including, among others, requirements to fund its pro rata share of operating costs and capital expenditures which may exceed revenue received from the sale of its pro rata share of SSB. If we are unable to obtain sufficient cash to service our debt, we may be required to refinance all or a portion of our debt, obtain additional financing, sell certain of our assets or reduce capital expenditures. There can be no assurance that any such refinancing would be possible or that any additional financing could be obtained on acceptable terms, nor can there be any assurance as to the timing of any such asset sales or the proceeds which could be realized therefrom.

Canadian Oil Sands is subject to environmental legislation in all jurisdictions in which it operates and any changes in such legislation could negatively affect its results of operations

Each of the Syncrude Participants is liable for its share of ongoing environmental obligations and for the ultimate reclamation of the Syncrude Project site upon abandonment. Ongoing environmental obligations have been and are expected to continue to be funded out of the Syncrude Project cash flow.

Canadian Oil Sands and the other Syncrude Participants, either directly or through Syncrude, have posted letters of credit with the Province of Alberta since the inception of the Syncrude Project to secure the ultimate reclamation obligations of the Syncrude Participants. Each of the Syncrude Participants is required to guarantee repayment of its pro rata share of the letter of credit posted by Syncrude Canada Ltd. to the issuing bank or to provide its own letter of credit.

The Syncrude Project is a significant producer of sulphur dioxide and carbon dioxide emissions. While the amounts of both sulfur dioxide and carbon dioxide produced has been decreasing on a per barrel basis, the overall amount of sulphur dioxide and carbon dioxide has increased due to generally increasing production volumes. Presently, sulphur dioxide emissions are at or near permitted levels which may require managed coker feed rates. Further, no assurance can be given that existing or future environmental regulations will not adversely impact the ability of the Syncrude Project to operate at present levels or increase production, or that such regulations will not result in higher unit costs of production.

Syncrude Canada Ltd. announced in 2003 that it intends to design and install a sulfur dioxide scrubbing system which would reduce the amount of sulfur dioxide produced on a per barrel basis. These reductions would be in addition to any reductions in sulphur dioxide emissions which are expected to result from implementation of the Stage 3 expansion plan. At the present time, there is no requirement under the AEPEA or the terms of Syncrude Canada Ltd.'s current environmental approvals to install any additional or replacement sulphur dioxide scrubbing system, but Syncrude plans on installing such a system. However, there can be no assurance that requirements for installation of a different system will not come into existence in the future or that any system which may be selected in anticipation of or in response to any such requirements will effectively lower sulphur dioxide emissions to desired or required levels. Current estimates of the total cost of sulphur dioxide redirected scrubbing system range from approximately $300 million to $400 million, with Canadian Oil Sand's share being approximately $106 million to $142 million. If such a system is implemented, there can be no assurance that the total costs associated with it would not exceed current estimates.

Syncrude also produces a significant volume of fine tailings, which are presently held in a settling basin. Upon cessation of production, the settling basin will be required to be reclaimed.

Continued high natural gas prices or increases in natural gas prices could have an adverse effect on Canadian Oil Sands

The financial condition, operating results and future growth of Canadian Oil Sands is substantially affected by the price of natural gas. Natural gas is used in material quantities as a feed stock at the Syncrude Project for the production of hydrogen and as a fuel for the generation of heat, steam and power. The price of natural gas is subject to large variations based on supply and demand for natural gas in North America. Syncrude Canada Ltd. and Canadian Oil Sands have no control over such prices. A prolonged period of high natural gas prices combined with crude oil prices or a material increase in natural gas prices could have an adverse effect on the revenues, profitability and cash flow of Canadian Oil Sands.

On an energy equivalent basis, we are only one tenth as sensitive to natural gas prices as we are to crude oil prices.

The implementation of the Kyoto Protocol could increase Syncrude's operating costs

The Canadian federal government has provided some parameters for implementing the Kyoto Protocol. Total annual emissions for large industrial emitters has been capped at 55 megatonnes, emissions have been targeted to be reduced by 15% from current business as usual levels, and the cost of a carbon credit has been limited to $15 per tonne. Based on these parameters, we provided an initial estimated 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. However, numerous uncertainties regarding details of the Kyoto Protocol's implementation remain that make it difficult to ascertain the cost estimate, including when third party costs related to the Kyoto Protocol factor their way into Syncrude's supply chain of goods and services. There is no assurance that the actual cost impact to Canadian Oil Sands of the Kyoto Protocol will not be significantly higher, which could result in a material adverse effect on our financial condition or our results of operation.

The Syncrude Project's operations are subject to extensive government regulation; the costs of compliance with additional government regulation and the cancellation of government licenses could have an adverse effect on Canadian Oil Sands

The Syncrude Project's mining, extraction and upgrading operations activities are subject to extensive Canadian federal, provincial and local laws and regulations governing exploration, development, transportation, production, exports, labour standards, occupational health, waste disposal, protection and redemption of the environment, safety, hazardous materials, toxic substances and other matters. We believe that Syncrude Canada Ltd. is in substantial compliance with all applicable laws and regulations. Amendments to current laws and regulations governing operations and activities of mining and refining companies and the more stringent implementation thereof are actively considered from time to time and the implementation thereof could have a material adverse impact on the Syncrude Project. There can be no assurance that the various government licenses granted to the Syncrude Project will not be cancelled or will be renewed upon expiry or that income tax laws and government incentive programs relating to the Syncrude Project, and the mining and oil and gas industries generally, will not be changed in a manner which may adversely affect Canadian Oil Sands. The Syncrude Project facility approval granted by the EUB expires on December 31, 2035 unless extended.

Nature of Trust Units

Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in a corporation. Units represent a fractional interest in a trust. As holders of Units, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions. The market price of the Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and the ability of the Trust to develop and produce its reserves. Changes in market conditions may adversely affect the trading price of the Units.

Unitholders May Have Greater Liability than if They held Shares in a Corporation

Canadian Oil Sands' Trust Indenture 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 Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of, the Trust's assets. In addition, the Trust Indenture states that no Unitholder is liable to indemnify the Trustee or any other person for any liabilities incurred by the Trustee, including with respect to taxes payable by the Trust or the Trustee, and all such liabilities will be enforced only against, and will be satisfied only out of, the Trust's assets. The Trust Indenture also provides that all contracts entered into by or on behalf of the Trust shall contain a provision or be subject to an acknowledgement to the effect that the obligations of the Trust thereunder will not be binding upon Unitholders personally and that such provisions and acknowledgement shall be held in trust and enforced by the Trustee for the benefit of the Unitholders.

In conducting its affairs, Canadian Oil Sands has assumed certain existing contractual obligations and may have to do so in the future. Although we will use reasonable efforts to have any contractual obligations modified so as not to have such obligations binding upon any of the Unitholders personally, we may not obtain such modification in all cases. To the extent that any claims under such contracts are not satisfied by Canadian Oil Sands, there is a risk that a Unitholder may be held personally liable for obligations of Canadian Oil Sands where the liability is not disavowed as described above.

Notwithstanding the terms of the Trust Indenture, Unitholders may not be protected from liabilities of Canadian Oil Sands to the same extent as a shareholder is protected from the liabilities of a corporation. Personal liability may also arise in respect of claims against the Trust (to the extent that claims are not satisfied by the Trust assets) that do not arise under contract, including claims in tort, claims for taxes and other possible statutory liabilities. We conduct the Trust's activities in such a way and in such jurisdictions as to avoid, so far as reasonably possible, to the extent we deem practicable any material risk of liability on the Unitholders for claims against the Trust. We will, to the extent we consider possible and reasonable, carry insurance, in such amounts as we consider adequate to cover our operations and in respect of the Unitholders as additional insureds. However, most insurance policies have exclusions for certain environmental or other liabilities. Based on the foregoing and considering the nature of our activities and its intention to comply with all environmental regulations relating to its properties and the insurance policies which it will hold, the possibility of any personal liability of this nature arising is considered remote. The Trust Indenture provides that, in the event that the payment of a Trust obligation is made by a Unitholder, such Unitholder will be entitled to reimbursement from the available assets of the Trust. Notwithstanding the foregoing, because of uncertainties in law relating to trusts such as the Trust, there is a risk that a Unitholder could be held personally liable for the obligations of the Trust to the extent that claims are not satisfied by the Trust. As part of the acquisition of the additional 13.75% working interest from EnCana, a portion of the assets of the Trust were invested in the trust units and debt obligations of CT and as a holder of trust units, the Trustee is subject to potential liability for obligations of CT in circumstances similar to those described above for Unitholders. CT currently owns an effective 3.75% interest in the Syncrude Project through its 75% ownership of Canadian Oil Sands Limited Partnership.

Changes in the fiscal regime between the Province of Alberta and the Syncrude Project could affect Canadian Oil Sands' profitability

Our results of operations are directly affected by the fiscal regime applicable to the Syncrude Project. The generic crown royalty system entitles the Province of Alberta to a royalty payment equivalent to the greater of 1% of gross revenue and 25% of net revenue after deducting applicable operating and capital expenditures. There can be no assurance that the Canadian federal government and the Province of Alberta will continue the regime currently in place in the future.

The petroleum industry and energy sector are highly competitive

The Canadian and international petroleum industry is highly competitive in all aspects, including the distribution and marketing of petroleum products. The Syncrude Project competes with other producers of crude oil, most of whom have considerably lower operating costs. Also, an increasing supply of synthetic crude oil came on stream in 2003 and is expected to increase in 2004 and beyond. It is expected that with such additional supply, we may obtain lower net realized revenues and may need to sell our product further from the source of production. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

Certain decisions regarding the operation of the Syncrude Project require agreement among the other Syncrude Participants

Including the Corporation and the LP, the Syncrude Project is a joint venture currently owned by eight Syncrude Participants. Each Syncrude Participant's voting interest is equal to its pro rata interest in the Syncrude Project. Certain decisions regarding the operations of the Syncrude Project require majority agreement among the Syncrude Participants and some fundamental decisions require unanimity. Canadian Oil Sands, through the Corporation and the LP, has two representatives on the Syncrude Management Committee, which is a committee of the Syncrude Participants that determine the oversight of the Syncrude Joint Venture. Future plans of the Syncrude Project will depend on such agreement and may depend on the financial strength and views of the other Syncrude Participants at the time such decisions are made.

Canadian Oil Sands cannot provide unequivocal assurance that it is not a passive foreign investment corporation for U.S. tax purposes.

While Canadian Oil Sands has obtained independent advice that the better view is that it is not a passive foreign investment corporation for U.S. tax purposes, we cannot provide unequivocal assurance that U.S. tax regulators will not take a different view. The Corporation, as the Trust's operating subsidiary, has employees that are actively engaged in managing the Trust's investment in Syncrude and also market Canadian Oil Sands' SSB though a third party contractor. However, if U.S. authorities view this activity as "passive", then Unitholders resident in the United States may be subject to additional taxes and filings as a result of such determination.

Oil and gas reserve data and future net reserve estimates are uncertain

The reserve figures contained or incorporated by reference into this Annual Information Form are estimates and no assurance can be given that the indicated level of recovery of SSB will be realized. Reserves estimated for properties that have not yet commenced production may require revision based on actual production experience. Such figures have been determined based upon the term of the operating permit, plant processing capacity and estimates of yield and recovery factors as well as estimates of bitumen in place. All such estimates are to some degree uncertain, and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable oil and gas reserves, prepared by different engineers or by the same engineers at different times, may vary. Canadian Oil Sands' actual production, revenues, taxes and development and operating expenditures with respect to its reserves may vary from such estimates.

The proved reserves included in the reserve data are calculated in accordance with Canadian practices. The reserves from the Syncrude Project are not considered proved reserves under applicable SEC regulations. In addition, the procedures used to estimate reserves from the Syncrude Project are not comparable to the procedures used to estimate conventional proved reserves.

RESERVES DATA AND OTHER INFORMATION

Canadian Securities Administrators have implemented new standards of disclosure for reporting issuers engaged in upstream oil and gas activities effective December 31, 2003. The new disclosure standards, referred to as National Instrument ("NI") 51-101, establish a regime of continuous disclosure for oil and gas companies and include specific reporting requirements. In addition, Canadian Oil Sands applied for and received an order from the various securities commissions in Canada allowing Canadian Oil Sands to report, on a consolidated basis, the reserves of the Trust's subsidiaries and to footnote the percent of interest that the Corporation holds of such aggregate amount. The Trust's year-end reserve report summarized in this Annual Information Form is compliant with NI 51-101 and such exemptive relief order.

In conjunction with NI 51-101, the Standing Committee on Reserves Evaluation of the Calgary Chapter of the Society of Petroleum Evaluation Engineers ("SPEE") and the Standing Committee on Reserves Definitions of the Canadian Institute of Mining, Metallurgy and Petroleum ("CIM") (Petroleum Society) developed the Canadian Oil and Gas Evaluation Handbook ("COGEH") to serve as the guidelines for conducting reserve evaluations and reporting the results thereof. Canadian Securities regulators require reporting issuers to comply with COGEH. Volume 1 of the handbook entitled "Reserve Definitions and Evaluation Practices and Procedures" was published in June 2002. Additional clarification of the guidelines is still expected, hence some uncertainty still exists regarding the final form certain mandatory reports will take.

To assist you in understanding the terminology required by NI 51-101, we are providing you with the following definitions:

> **Proved Reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. This definition is materially consistent between NI 51-101 and National Policy (NP) 2-B. However, NI 51-101 further identifies the certainty level for proved reserves as "at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves". No such estimate of probability was included in NP 2-B.
>
> **Proved plus Probable Reserves** are those additional reserves that are less certain to be recovered than proved reserves. NI 51-101 defines the certainty level as "at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves." Therefore, under NI 51-101, the proved plus probable reserves represent a "best estimate" or "expected reserves". Under NP 2-B, a best estimate of reserves was derived by summing proved reserves plus a fraction of the probable reserves which were "reduced for an allowance for the risk that is associated with the probability of obtaining production from such reserves". The risk factors were not generally estimated rigorously and it was common industry practice for companies to report proved plus 50% of probable reserves. Historically, the Trust did not report probable reserves.

Based on an independent engineering evaluation conducted by Gilbert Laustsen Jung Associates Ltd. ("GLJ") effective March 9, 2004 and prepared in accordance with NI 51-101, Canadian Oil Sands had proved plus probable reserves of 1.8 billion barrels. Proved developed producing reserves represent 52% of proved plus probable reserves while total proved reserves account for 58% of proved plus probable reserves.

Our crude oil reserve quantities and future net revenues were determined by GLJ both under a constant price case as of December 31, 2003 and utilizing GLJ's price forecast as of March 1, 2004. The future net revenues shown below are after reflecting our oil hedges and currency contracts but, prior to provision for interest, debt service charges, general and administrative costs, mine reclamation costs and income taxes. It should not be assumed that the discounted future net revenues estimated represents the fair market value of the reserves.

Constant Prices

	Synthetic Crude Oil Reserves		Before Income Tax Discounted Present Value (MM$)[3]					
	Working Interest	Net After Royalty						
Reserves Category[1][2]	MMbbl	MMbbl	0%	5%	10%	12%	15%	20%
Proved Developed Producing	961	840	$14,735	$7,533	$4,669	$4,015	$3,307	$2,555
Proved Developed Non-Producing	0	0	0	0	0	0	0	0
Proved Undeveloped	109	96	1,685	957	334	148	-72	-324
Total Proved	1,070	936	16,420	8,490	5,003	4,163	3,235	2,231
Probable	779	666	13,517	3,424	1,061	706	411	205
Total Proved Plus Probable	1,849	1,602	$29,937	$11,914	$6,064	$4,869	$3,646	$2,436

Notes:

(1) Canadian Oil Sands Limited constitutes 89% of the total reserves shown; the remaining 11% being held by CT through the LP.

(2) Figures may not add correctly due to rounding.

(3) Based on a light sweet crude oil price at Edmonton, Alberta of $40.81 per barrel less an $0.80 per barrel differential.

Total Future Net Revenue (Undiscounted Constant Case)[1]

	Revenue (MM$)	Royalties (MM$)	Operating Costs (MM$)	Capital Development Costs (MM$)	Abandonment[2] Costs (MM$)	Future Net Revenue[3] Before Income Taxes (MM$)
Proved Producing	$38,415	$4,821	$16,542	$2,316	$0	$14,736
Proved Developed Non-producing	0	0	0	0	0	0
Proved Undeveloped	4,374	542	271	1,877	0	1,684
Total Proved	42,789	5,363	16,813	4,193	0	16,420
Total Probable	31,168	4,536	11,193	1,922	0	13,517
Total Proved Plus Probable	$73,957	$9,899	$28,006	$6,115	$0	$29,937

Notes:

(1) Figures may not add correctly due to rounding.

(2) Mining reclamation costs were not included in this calculation. Future mining reclamation costs for proved reserves net of reclamation trust funds are estimated at $210 million, and for proved plus probable reserves, at $350 million.

(3) As the Trust and its subsidiaries do not expect to pay any income taxes other than large corporations tax in the foreseeable future, the calculation of the future net revenues pre and post tax are the same amount.

Forecast Prices and Costs

	Synthetic Crude Oil Reserves							
	Working Interest	Net After Royalty	Before Income Tax Discounted Present Value (MM$)[3]					
Reserves Category[1][2]	MMbbl	MMbbl	0%	5%	10%	12%	15%	20%
Proved Developed Producing	961	875	$9,977	$5,100	$3,233	$2,816	$2,371	$1,902
Proved Developed Non-Producing	0	0	0	0	0	0	0	0
Proved Undeveloped	109	98	1,103	396	-100	-238	-398	-573
Total Proved	1,070	973	11,080	5,496	3,133	2,578	1,973	1,329
Probable	779	682	13,231	3,037	815	502	256	103
Total Proved Plus Probable	1,849	1,655	$24,311	$8,533	$3,948	$3,080	$2,229	$1,432

Notes:

(1) Canadian Oil Sands Limited constitutes 89% of the total reserves shown; the remaining 11% being held by CT through the LP.

(2) Figures may not add correctly due to rounding.

(3) Based on a light sweet crude oil price at Edmonton, Alberta less an $0.80 differential. Projected Edmonton light sweet crude oil prices are as follows:

2004	$44.75 per barrel
2005	$37.75 per barrel
2006	$34.25 per barrel
2007-2009	$32.50 per barrel
2010	$33.00 per barrel

Thereafter increased by 1.5% per annum

Total Future Net Revenue (Undiscounted Forecast Prices and Costs)[1]

	Revenue (MM$)	Royalties (MM$)	Operating Costs (MM$)	Capital Development Costs (MM$)	Abandonment[2] Costs (MM$)	Future Net Revenue[3] Before Income Taxes (MM$)
Proved Producing	$36,528	$3,248	$20,329	$2,974	$0	$9,977
Proved Developed Non-producing	0	0	0	0	0	0
Proved Undeveloped	2,834	340	-475	1,866	0	1,103
Total Proved	39,362	3,588	19,854	4,840	0	11,080
Total Probable	35,194	4,483	14,790	2,690	0	13,231
Total Proved Plus Probable	$74,556	$8,071	$34,644	$7,530	$0	$24,311

Notes:

(1) Figures may not add correctly due to rounding.

(2) Mining reclamation costs were not included in this calculation. Future mining reclamation costs for proved reserves net of reclamation trust funds are estimated at $210 million, and for proved plus probable reserves, at $350 million.

(3) As the Trust and its subsidiaries do not expect to pay any income taxes other than large corporations tax in the foreseeable future, the calculation of the future net revenues pre and post tax are the same amount.

The proved developed producing reserves and production forecast reflect the current upgrading capacity available at Syncrude and limit the reserves to those forecast to be recovered within the remaining 32 years of the Alberta Energy and Utilities Board (EUB) approval. Although the center and west pits of Aurora North are not yet on production, reserves from these pits are classified as proved developed producing since their recovery does not require a material amount of additional capital.

The proved undeveloped scenario includes capital relating to the upgrader expansion that is currently in progress (UE-1) and the base mine replacement (SWQR) and the sulphur emissions reduction (SER) projects. These investments will accelerate production, improve the yield on bitumen and enable all of the reserves associated with Aurora North to be recovered within the current approval period. Proved reserves were constrained to areas where Syncrude currently has approvals to mine.

The probable undeveloped reserves are primarily associated with the development of Aurora South and improvements to both extraction recovery and upgrading yield. Although Aurora South development plans are continuing to progress, the independent evaluator has classified recovery from this ore body as probable, given both the lack of a firm commitment by the owners to proceed beyond a Stage 3 off-ramp scenario and current expectations of production not occurring until after 2010.

Reserve Life

Canadian Oil Sands' estimated reserve life index using reserves prepared by GLJ based on 2004 production guidance of 30.5 million barrels provided by Canadian Oil Sands is as follows:

	Reserves (Millions of barrels)	Reserve Life Index
Proved Reserves	1,070	35 years
Proved plus Probable	1,849	60 years

Please refer to our Form 51-101F1 which is available at www.sedar.com for further information on Canadian Oil Sands' reserves.

HISTORICAL QUARTERLY INFORMATION

The following tables set out the Trust's average daily sales of synthetic crude oil (before deduction of royalties), the average realized selling price received per barrel, netback price per barrel and capital expenditures for each quarter of 2003 and 2002. Netback is defined as the averaged realized selling price after giving effect to hedging, less operating costs and Crown royalties.

Quarterly Information – 2003	First	Second	Third	Fourth
Average daily sales bbls/d	46,752	64,777	86,196	68,990
Netback ($/bbl)				
Realized selling price before hedging	51.71	41.41	40.46	38.73
Hedging gains (losses)	(9.81)	(1.90)	(2.59)	(3.69)
Total realized selling price	41.90	39.51	37.87	35.04
Operating costs	(24.21)	(24.05)	(15.86)	(22.93)
Crown Royalties	(0.42)	(0.49)	(0.59)	(0.41)
Netback	17.27	14.97	21.42	11.70
Capital Spending ($ thousands)	132,937	189,438	205,766	257,446

Quarterly Information – 2002	First	Second	Third	Fourth
Average daily sales bbls/d	49,441	38,761	56,757	54,135
Netback ($/bbl)				
Realized selling price before hedging	34.18	40.43	43.73	42.95
Hedging gains (losses)	1.03	(1.74)	(1.91)	(2.03)
Total realized selling price	35.21	38.69	41.82	40.92
Operating costs	(16.25)	(27.35)	(12.78)	(14.73)
Crown Royalties	(0.34)	(0.41)	(0.44)	(0.43)
Netback	18.62	10.93	28.60	25.76
Capital Spending ($ thousands)	60,622	92,541	105,891	144,149

FUTURE COMMITMENTS

Our future commitments and contractual obligations are outlined on pages 38 and 39 of the Management's Discussion and Analysis of our Annual Report for the year ended December 31, 2003 which pages are incorporated herein by reference.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

The provisions relating to selected consolidated financial information that are contained on pages 23 to 25 of our Management's Discussion and Analysis of the Annual Report are incorporated herein by reference.

DISTRIBUTABLE INCOME

Unitholders of record on or about the last business day of each of January, April, July and October are entitled to receive cash distributions on the last working day of the following month in respect of the Unitholder distributions of the immediately preceding calendar quarter. For example, distributions for the fourth quarter, 2003 are paid on the last business day of February, 2004; distributions for the first quarter, 2004 will be paid on the last business day of May; for the second quarter, 2004, the last business day of August and for the third quarter, 2004, the last business day of November. Unitholder distributions are comprised of the trust royalty payments, revenues from the GORR, interest income earned, distribution on CT's ordinary units, and debt repayments received by the Trust for that quarter less the direct expenses of the Trust paid during that quarter. Cash distributions paid to Unitholders are determined by the Corporation's Board of Directors, in their sole discretion, and will only be declared and paid if deemed prudent to do so. Covenants in our bank credit agreements could limit cash distributions to the Unitholders in certain circumstances, including where the credit rating of the Corporation falls below investment grade.

At the discretion of the Corporation's Board of Directors, the Trust may also make cash distributions of the Trust's capital provided that such distributions are made out of funds that are in excess of amounts reasonably required to satisfy obligations of Canadian Oil Sands.

The actual amount of the trust royalty received by the Trust from the Corporation depends on the quantity of oil produced, prices received, hedging contract receipts and payments, capital, operating and administrative expenses, debt service charges, and changes to the utilization of expansion financing determined to be prudent by the Corporation.

During normal operations, the production of SSB is generally consistent from month to month, but capital and other expenditures will generally occur in a less consistent manner. As a result, the Corporation has the right to hold back certain funds in the calculation of the trust royalty as a utilization of expansion financing to allow it to meet cash requirements attributable to the working interest and to meet its ongoing obligations as a Participant. Thereafter, the Corporation has the right to maintain, add to or reduce this utilization fund, as it believes necessary or prudent in the management of the working interest, provided that amounts drawn from such utilization fund must be applied to pay production costs.

In addition to the trust royalty payments received from the Corporation, commencing in March 2003, the Trust also received distribution income from its subsidiary, CT. CT makes distributions from available cash flow on the ordinary units of CT that are held by the Trust on a quarterly basis.

DESCRIPTION OF CAPITAL STRUCTURE

General Description Structure

The Trust is authorized to issue up to 500,000,000 Units. Each Unit represents a beneficial interest in the Trust and entitles the holder to one vote per Unit and participates in any distributions or liquidation made by the Trust. At the annual general and special meeting held in April 2003, Unitholders approved the issuance by the Trust of convertible securities. As of March 22, 2004, there were no securities of the Trust created and issued other than Units. All Unitholders share equally in all distributions of the Trust. No conversion, retroaction 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% of the average closing price of the Units on the principal trading market for the previous 10 days and the closing market price on the date of tender for redemption. There is a limit of $250,000 per quarter for such redemptions.

Foreign Ownership

The trust indenture, under which the Trust was created, provides that no more than 49% 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 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% 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 that 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 March 22, 2004, based on account data at March 12, 2004, Canadian Oil Sands estimates that approximately 45% of our Units are held by non-Canadian residents with the remaining 55% being held by Canadian residents. We will continue to monitor the non-resident ownership levels. If at any time the Trustee of the Trust becomes aware that the 49% 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%, the Trustee may send a notice to Unitholders and require any non-Canadian resident Unitholder to sell their 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.

Ratings

As at March 22, 2004, the Units of the Trust were not separately rated. The debt securities of the Corporation, the main operating subsidiary of the Trust, were rated BBB+ with a negative outlook from Standard and Poor's and Baa2 with a negative outlook from Moody's Investor Service.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Reference is made to the Management's Discussion and Analysis section on pages 20 through 48 of our Annual Report for the year ended December 31, 2003, which is incorporated by reference in this Annual Information Form.

MARKET FOR SECURITIES

The Units are listed for trading on the Toronto Stock Exchange ("TSX") and trade under the symbol COS.UN. The table below sets out the price ranges and volumes traded on the TSX during 2003.

Month	High ($/Units)	Low ($/Units)	Close ($/Units)	Volume Traded (thousands)
January	39.00	36.55	38.90	2,258
February	39.00	34.93	36.20	4,443
March	36.23	34.55	35.35	2,619
April	35.70	33.90	34.26	3,674
May	35.45	32.26	35.25	4,927
June	36.00	34.84	34.93	3,278
July	37.65	34.40	37.08	5,221
August	38.35	36.90	38.20	5,736
September	40.10	37.80	39.20	3,781
October	39.95	38.50	38.72	2,800
November	41.55	38.05	41.50	3,414
December	45.70	40.80	45.69	3,266

DIRECTORS AND OFFICERS

The Trust has no directors, officers or employees. The following information pertains to the board of directors and officers of the Corporation as at March 22, 2004.

Directors

The following are the names and municipalities of residence of the directors of the Corporation, their positions with the Corporation and principal occupations within the past five years and the year in which each first became a director of the Corporation.

Name and Municipality of Residence	Position Held and Principal Occupation	Year First Became a Director
Marcel R. Coutu Calgary, Alberta	President and Chief Executive Officer	2001
E. Susan Evans, Q.C.(1)(2) Calgary, Alberta	Corporate Director	1997
The Right Honourable Donald F. Mazankowski(1) Vegreville, Alberta	Corporate Director and Business Consultant	2002
Wayne M. Newhouse(1) Calgary, Alberta	President, Morgas Ltd. (oil and gas production)	1996
Walter B. O'Donoghue, Q.C.(2) Calgary, Alberta	Counsel, Bennett Jones LLP (law firm)	1995
C.E. (Chuck) Shultz Calgary, Alberta	Chairman, Canadian Oil Sands Limited, Chairman and Chief Executive Officer, Dauntless Energy Inc. (private oil and gas corporation)	1996
Wesley R. Twiss(1) Calgary, Alberta	Corporate Director	2001
John B. Zaozirny, Q.C.(2) Calgary, Alberta	Counsel, McCarthy Tétrault LLP (law firm)	1996

Notes:

(1) Member of the Audit Committee.

(2) Member of the Corporate Governance and Compensation Committee.

Each of the Nominees has been engaged in the occupation set forth in the above table or similar occupations with the same employer for the last five years except: Mr. Coutu (who was Senior Vice President and Chief Financial Officer of Gulf Canada Resources Limited from May 1999 to July 2001, and prior to that was Director, Finance, Vice President, Finance and, subsequently, Senior Vice President, International of TransCanada Pipelines Limited); Mr. Twiss (who was Executive Vice President and Chief Financial Officer of PanCanadian Energy Corporation from January 2000 to April 2002, and prior to that was Executive Vice President and Chief Financial Officer of Petro-Canada from 1998 to January 2000); and Mr. Newhouse (who was President of Newhouse Resource Management Limited from February 1995 to June 2001).

Mr. O'Donoghue is counsel to Bennett Jones LLP and Mr. Zaozirny is counsel to McCarthy Tétrault LLP, both of which firms provide legal services to Canadian Oil Sands from time to time.

Computershare Trust Company of Canada, the successor in interest to Montreal Trust Company of Canada, is the Trustee of the Trust. The Corporation does not have an executive committee. The Corporate Governance and Compensation Committee was formed in early 2002. Commencing in the fall of 2003, the Audit Committee also acts as the reserves committee of the Board.

The Audit Committee is comprised of the members listed below. The Board has determined that each member is an "independent" director and is financially literate. Beside each member's name is such person's education and experience relevant to such member's performance as an audit committee member.

Name	**Relevant Education and Experience**
Wesley R. Twiss (Chair)	Mr. Twiss has over 30 years experience in the oil and gas industry, including more than 10 years of which were in the position as chief financial officer of large public oil and gas companies which held or managed an interest in the Syncrude Joint Venture. Mr. Twiss is a member of the Audit Committee of Hydrogenics Corporation and of the managing company of which KeySpan Facilities Income Fund owns 75%. He is also a trustee of Enbridge Income Fund and is also a member of the Audit Committee of a subsidiary of such fund. Given this background, Mr. Twiss has experience on both trust and financial issues. Mr. Twiss has an MBA from the University of Western Ontario and is a member of the Institute of Corporate Directors.
E. Susan Evans, Q.C.	Ms. Evans has acted as a director on numerous boards of public and private entities which operated in the areas of oil and gas, utility, banking, government and charities. Ms. Evans was a former Chair of the Audit Committee for the Province of Alberta, is a member of the Audit, Risk and Finance Committee of Enbridge Inc. and was a member of the Audit Committee of Anderson Exploration Ltd. and the Chair of the Audit Committee of Canadian Oil Sands prior to and immediately following the merger with Canadian Oil Sands Trust and Athabasca Oil Sands Trust in 2001. She was also a Commissioner of the Alberta Financial Review Commission. Ms. Evans has completed an MBA level accounting course at Edinburgh Business School, Heriot-Watt University, and has completed the Ivey League Executive Program at the Richard Ivey School of Business.

Name	Relevant Education and Experience
The Right Honourable Donald F. Mazankowski	Mr. Mazankowski was the former Minister of Finance, Government of Canada and has acted as a member of the audit committee on several public entities, including his current position on the audit committees of Investors Group and Weyerhaeuser Company.
Wayne M. Newhouse	Mr. Newhouse has acted in various director and executive capacities for a number of private and public entities, primarily in the oil and gas sector. In particular, he was the former Chair of the Audit Committee of Progas Ltd. and currently is a director and Chair of the Reserves Audit Committee of Petrofund Energy Trust. Mr. Newhouse has also completed an Alexander Hamilton Institute two year business program and Investment Dealer Association courses.

The terms of reference for the Audit Committee are set out in Schedule A to this Annual Information Form. In addition to the terms of reference, the Audit Committee has adopted procedures relating to the engagement of non-audit services.

The Audit Committee has restricted the auditors from providing any services that could reasonably be seen as functioning in the role of management, auditing their own work or acting as an advocate role for Canadian Oil Sands. In particular, the external auditor is not to provide bookkeeping functions, actuarial or appraisal services (other than related to tax services), internal audit, human resources, or legal services (other than for French translation services). The Audit Committee has defined what constitutes audit services, audit related services, tax services and other services. Except in relation to audit services, amounts over $25,000 require the pre-approval of the Audit Committee. However, all of the services provided and the amounts paid, regardless of their magnitude, must be disclosed to the Audit Committee at the Audit Committee meeting immediately following such engagement. If any of the services (other than audit services) are over $25,000, such services must be pre-approved by the Audit Committee or the Chair of the Audit Committee.

The following fees (exclusive of GST) were paid to PricewaterhouseCoopers LLP in 2002 and 2003:

Fee Descriptions	2002	2003
Audit	$ 70,630	$ 123,500
Audit Related	$ 10,655	$ 214,300
Tax	$ 17,650	$ 354,000
All Other	Nil	Nil

Officers

There are no direct officers of the Trust. Instead, management of the Trust is exercised by the Corporation and its directors and officers. The following table identifies each of the officers of the

Corporation, as at March 22, 2004, their municipalities of residence, their current office, and their principal occupations for the five-year period preceding December 31, 2003.

Name and Municipality of Residence	Current Office	Five Year History of Principal Occupations
C.E. (CHUCK) SHULTZ Calgary, Alberta	Chairman of the Board of Directors	Chairman and Chief Executive Officer, Dauntless Energy Inc. (private oil and gas corporation)
MARCEL R. COUTU Calgary, Alberta	President and Chief Executive Officer	President and Chief Executive Officer, the Corporation; prior thereto, Senior Vice President and Chief Financial Officer of Gulf Canada Resources Limited from May 1999 to July 2001; prior thereto, Director, Finance, Vice President, Finance and, subsequently, Senior Vice President, International of TransCanada PipeLines Limited
ALLEN R. HAGERMAN, F.C.A. Cochrane, Alberta	Chief Financial Officer	Vice President and Chief Financial Officer of Fording Canadian Coal Trust from March 2003 to May 2003; Vice President and Chief Financial Officer of Fording Inc. from June 2001 to March 2003 and Vice President, Finance and Accounting and Secretary of Fording Inc. from 1996 to 2001
TRUDY M. CURRAN Calgary, Alberta	General Counsel and Corporate Secretary	Corporate Secretary of the Corporation from November 2001 to May 2002; Senior Counsel and Assistant Corporate Secretary, EnCana Corporation from April 2002 to September 2002; Staff Legal Counsel, PanCanadian Energy Corporation from November 2001 to March 2002; Senior Counsel, Canadian Pacific Limited from March 1999 to October 2001; and prior thereto, Associate General Counsel and Assistant Corporate Secretary, Canadian Airlines Corporation
RYAN M. KUBIK Calgary, Alberta	Treasurer	Advisor, Corporate Finance, EnCana Corporation from April 2002 to August 2002 and prior thereto, Associate Director, Treasury, PanCanadian Energy Corporation
LAUREEN C. DUBOIS Calgary, Alberta	Controller	Manager, Accounting of the Corporation from November 2002 to January 2004; Senior Accountant, EnCana Corporation November 2001 to October 2002; Assistant Manager, Group Accounting, Canadian Pacific Limited from January 2000 to October 2001 and prior thereto, Senior Associate, Deloitte and Touche

As of March 12, 2004, the Directors and Officers of Canadian Oils Sands, as a group, beneficially own, directly or indirectly, or exercise control or direction over 102,891 Units of the Trust, representing less than 1% of the issued and outstanding units of the Trust.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as disclosed in this Circular or in a prior information circular, no "informed person" (as defined in National Instrument 51-102), nor any insider of the Trust or the Corporation, nor the Trustee, nor any person nominated for election as a director of the Corporation, nor any associate or affiliate of such persons, has had any material interest, direct or indirect, in any transaction of the Trust since the commencement of the Trust's last financial year or in any proposed transaction which has materially affected or would materially affect the Trust or any of its subsidiaries. Copies of prior information circulars of the Trust may be accessed at the website for the "System for Electronic Data Analysis and Retrieval" maintained by the Canadian Securities Administrators at www.sedar.com.

Computershare Trust Company of Canada acts as both Trustee and the transfer agent for the Units, and receives fees for its services in both capacities. In its capacity as Trustee of the Trust, the Trustee is paid a reasonable fee in connection with the administration and management of the Trust and is also reimbursed for all expenses properly incurred, as agreed by the Trustee and the Corporation.

The Trustee, on behalf of the Trust, holds all of the issued and outstanding COSL Shares.

TRANSFER AGENT AND REGISTRARS

Computershare is our trustee, transfer agent and registrar. They may be contacted at 710, 530 – 8th Avenue S.W., Calgary, Alberta T2P 3S8; phone (403) 267-6800; facsimile (403) 267-6598 and have offices in Vancouver, Calgary, Toronto, Montreal, and Halifax. In 2003, we paid Computershare $35,845 in fees plus an additional $103,360 as reimbursement for expenses and ancillary charges for the year in relation to them acting as trustee and as transfer agent and registrar of the Units.

INTEREST OF EXPERTS

Gilbert Laustsen Jung Associates Ltd.

In October, 2003, the Board appointed GLJ as the independent reserves evaluator for Canadian Oil Sands. The partners and associates of GLJ, as a group, own, directly or indirectly, less than 1% of the outstanding Units.

ADDITIONAL INFORMATION

Additional information, including Directors' and Officers' remuneration and indebtedness, principal holders of the Trust's securities, options to purchase securities and interest of insiders in material transactions, where applicable, is contained in the Trust's Management Proxy Circular dated March 12, 2004, which relates to the Annual and Special Meeting of Unitholders held on April 26, 2004. Additional financial information is provided in the Trust's consolidated comparative audited financial statements and notes thereto for the year ended December 31, 2003.

When securities of the Trust are in the course of a distribution pursuant to a short form prospectus or a preliminary short form prospectus has been filed in respect of a distribution of its securities, copies of the following documents may be obtained by contacting:

Canadian Oil Sands Trust
c/o Canadian Oil Sands Limited
2500 First Canadian Centre
350 – 7th Avenue S.W.
Calgary, Alberta T2P 3N9

Telephone (403) 218-6240
Facsimile (403) 218-6210

Attention: General Counsel and Corporate Secretary

1) one copy of the Trust's Annual Information Form, together with one copy of any document, or the pertinent pages of any document, incorporated by reference in the Annual Information Form;

2) one copy of the Trust's comparative consolidated financial statements for its most recently completed financial year, together with the accompanying auditors' report and one copy of any interim consolidated financial statements of the Trust filed subsequent to its most recently completed financial year;

3) one copy of the Trust's most recent Management Proxy Circular; and

4) one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or short form prospectus and are not required to be provided under paragraphs (1), (2) or (3) above.

At any time, copies of the documents referred to in paragraphs (1) to (4) above may be obtained upon request from the General Counsel and Corporate Secretary, provided that, if the request is made by a person who is not a Unitholder of the Trust, payment of a reasonable charge for such copies may be required.

Exemption under Rule 12g3-2(b)

Canadian Oil Sands

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FORM OF PROXY

THIS PROXY IS SOLICITED BY THE MANAGER OF CANADIAN OIL SANDS TRUST AND WILL BE USED AT THE ANNUAL AND SPECIAL MEETING OF UNITHOLDERS TO BE HELD ON MONDAY, APRIL 26, 2004

The undersigned holder of trust units ("Units") of Canadian Oil Sands Trust (the "Trust") hereby appoints C.E. (Chuck) Shultz, Chairman of the Board of Canadian Oil Sands Limited ("COSL"), or Marcel R. Coutu, President and Chief Executive Officer of COSL, or instead of either of them, ______________________________, as the nominee of the undersigned, to attend and act for and on behalf of the undersigned at the annual and special meeting (the "Meeting") of the Unitholders of the Trust to be held on Monday, April 26, 2004 at 2:00 p.m. (Calgary time) in the Glenview Room, TELUS Convention Centre, 120 - 9th Avenue S.E., Calgary, Alberta, and at any adjournment thereof, and at every poll which may be taken in consequence thereof, and to vote the Units registered in the name of the undersigned, with the same powers that the undersigned would have if the undersigned was personally present at the Meeting or such adjournment thereof. Without limiting the generality of the authorization and power hereby given, the undersigned hereby revokes any proxy previously given and directs the nominee appointed hereunder to vote the Units as follows, and the trustee of the Trust (the "Trustee") shall, where applicable, in turn vote the common shares of COSL in accordance with the decision of the Unitholders:

1. Directing the Trustee to vote the common shares of COSL so as to appoint PricewaterhouseCoopers LLP as the auditor of COSL for the ensuing year at a remuneration to be fixed by COSL and approved by the directors thereof;

   ☐ FOR

   ☐ WITHHOLD FROM VOTING

2. Appointing PricewaterhouseCoopers LLP as the auditor of the Trust for the ensuing year at a remuneration to be fixed by COSL and approved by the directors thereof;

   ☐ FOR

   ☐ WITHHOLD FROM VOTING

3. Directing the Trustee to vote the common shares of COSL so as to elect as directors of COSL all of the nominees of the Trust, as described and set forth in the Management Proxy Circular of the Trust dated March 12, 2004, and to fill any vacancies among the directors of COSL that may arise between the Meeting and the first meeting of the Unitholders thereafter that considers the election of directors, by appointing to any such vacancy a person selected by COSL;

   ☐ FOR

   ☐ WITHHOLD FROM VOTING

4. Approving the special resolution regarding the approval of an amended Unitholder Rights Plan, as described and set forth in the Management Proxy Circular of the Trust dated March 12, 2004; and

   ☐ FOR

   ☐ AGAINST

5. On any other business that may properly come before the Meeting or any adjournment or adjournments thereof, in such manner as the proxyholder may determine in his or her discretion.

This form of proxy confers on the nominees named herein discretionary authority with respect to amendments or variations of those matters identified in the accompanying Notice of Annual and Special Meeting of Unitholders (the "Notice of Meeting") dated March 12, 2004 or any other matters that may properly come before the Meeting or any adjournments thereof. This proxy also authorizes the Trustee to replace any nominee identified above for election as a director of COSL if such nominee is unable or not willing to serve as a director. As at March 12, 2004, neither the Trustee nor COSL knows of any such amendments, other matters or anticipated replacements.

The Units represented by this proxy will be voted on the matters listed above and identified in the Notice of Meeting in such manner as the Unitholder giving this proxy may have specified by marking an "X" in the spaces provided above for that purpose. If no choice is specified hereon as to the manner in which the Units represented by this proxy are to be voted with respect to any matter listed above and identified in the Notice of Meeting, then all such Units will be voted "FOR" each such matter.

A Unitholder entitled to vote at the Meeting has the right to appoint a person (who need not be a Unitholder) to attend and act for and on behalf of such Unitholder at the Meeting other than the persons designated as nominees in this form of proxy. To exercise this right, the Unitholder should insert in the name of such person in the blank space provided above.

This proxy is solicited on behalf of the Trustee by the management of COSL pursuant to the terms of the Management Agreement dated July 5, 2001 between the Trust and COSL.

To be effective, proxies must be received by Computershare Trust Company of Canada, 100 University Avenue, Toronto, Ontario, M5J 2Y1 (Attention: Proxy Department) not less than twenty-four (24) hours before the time set for the holding of the Meeting or any adjournment thereof. Proxies may be revoked at any time prior to their use.

DATED this _____ day of ____________________, 2004.

____

Name of Unitholder (please print)

____

Signature of Unitholder (or duly authorized person)

NOTES:

1. This proxy must be executed by the Unitholder or by his or her attorney duly authorized in writing or, if the Unitholder is a corporation, under its corporate seal by a duly authorized officer or attorney thereof indicating the capacity under which such officer or attorney is signing.
2. Proxies not dated in the space provided will be deemed to bear the date on which the accompanying Management Proxy Circular was mailed to Unitholders.
3. The name of the Unitholder must appear exactly as it is shown on the affixed label. If Units are held jointly, any one of the joint owners may sign.
4. If Units are registered in the name of an executor, administrator, trustee or similar holder, such holder must set out his or her full title and sign the proxy exactly as registered. If Units are registered in the name of a deceased or other Unitholder, the Unitholder's name must be printed in the space provided, the proxy must sign below the Unitholder signature and evidence of authority to sign on behalf of the Unitholder must be attached to the proxy.

Exemption under Rule 12g3-2(b)

Canadian Oil Sands

March 22, 2004

To: Alberta Securities Commission
British Columbia Securities Commission
Saskatchewan Securities Commission
Manitoba Securities Commission
Ontario Securities Commission
Commission des valeurs mobilières du Québec
New Brunswick Officer of the Administrator of Securities
Nova Scotia Securities Commission
Registrar of Securities, Prince Edward Island
Newfoundland Department of Government Services and Lands, Securities Division

Dear Sirs:

We confirm that the following material was sent by pre-paid mail on March 22, 2004, to all registered holders of units of Canadian Oil Sands Trust:

1. 2003 Annual Report, including Management's Discussion and Analysis and Annual Financial Statements for the year ended December 31, 2003;
2. Notice of Annual and Special Meeting of Unitholders;
3. Management Proxy Circular;
4. Form of Proxy;
5. Postage-paid proxy return envelope; and
6. Interim Financial Statements mailing list card.

We further confirm that copies of the above-mentioned materials will be sent to each intermediary holding units of Canadian Oil Sands Trust who responded to the search procedures pursuant to National Instrument 54-101 regarding shareholder communication.

Yours very truly,

CANADIAN OIL SANDS TRUST
by its manager,
CANADIAN OIL SANDS LIMITED

(signed) Trudy M. Curran

Trudy M. Curran
General Counsel and Corporate Secretary

FORM 51-101F1
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION OF CANADIAN OIL SANDS TRUST

PART 1 RELEVANT DATES

Item 1.1 Effective Date:

The effective date of the reserves estimates and revenue projection in this report is December 31, 2003.

Item 1.2 Data Date:

Estimates of reserves and projections of production were generally prepared using data to March 5, 2004. Canadian Oil Sands Limited (the "Corporation") on behalf of Canadian Oil Sands Trust (the "Trust") and its subsidiaries have provided Gilbert Laustsen Jung Associates ("GLJ") with a representation letter confirming that complete and correct information has been provided to GLJ.

Item 1.3 Preparation Date:

The preparation date of this report is March 9, 2004. As of the preparation date, the Trust and its independent reserves evaluator, GLJ are not aware of any new information (other than commodity pricing assumptions which may differ from those used in this analysis) which could materially impact this evaluation.

PART 2 DISCLOSURE OF RESERVES *DATA*

Item 2.1 Reserves Data (Constant Prices and Costs)

Summary of Oil Reserves and Net Present Values of Future Net Revenue (Constant Case)

	Synthetic Crude Oil Reserves		Before Income Tax Discounted Present Value (MM$)					
Reserves Category	Working Interest MMbbl	Net After Royalty MMbbl	0%	5%	10%	12%	15%	20%
Proved Developed Producing	961	840	$14,735	$7,533	$4,669	$4,015	$3,307	$2,555
Proved Developed Non-Producing	0	0	0	0	0	0	0	0
Proved Undeveloped	109	96	1,685	957	334	148	-72	-324
Total Proved	1,070	936	16,420	8,490	5,003	4,163	3,235	2,231
Probable	779	666	13,517	3,424	1,061	706	411	205
Total Proved Plus Probable	1,849	1,602	$29,937	$11,914	$6,064	$4,869	$3,646	$2,436

Additional Information Concerning Future Net Revenue (Constant Case)

Total Future Net Revenue (Undiscounted Constant Case)

	Revenue (MM$)	Royalties (MM$)	Operating Costs (MM$)	Capital Development Costs (MM$)	Abandonment[1] Costs (MM$)	Future Net Revenue[2] Before Income Taxes (MM$)
Proved Producing	$38,415	$4,821	$16,542	$2,316	$0	$14,736
Proved Developed Nonproducing	0	0	0	0	0	0
Proved Undeveloped	4,374	542	271	1,877	0	1,684
Total Proved	42,789	5,363	16,813	4,193	0	16,420
Total Probable	31,168	4,536	11,193	1,922	0	13,517
Total Proved Plus Probable	$73,957	$9,899	$28,006	$6,115	$0	$29,937

Notes:

(1) Mining reclamation costs were not included in this calculation. Future mining reclamation costs for proved reserves net of reclamation trust funds are estimated at $210 million and for proved plus probable reserves, at $350 million.

(2) As the Trust and its subsidiaries do not expect to pay any income taxes other than large corporations tax in the foreseeable future, the calculation of the future net revenues pre and post tax are the same amount.

The Trust produces only one product type group, namely synthetic crude oil which is produced by the Syncrude Joint Venture ("Syncrude") that is operated by Syncrude Canada Ltd. The Syncrude operations are located near Fort McMurray, Alberta, Canada.

Item 2.2 Reserves Data (Forecast Prices and Costs)

Summary of Oil Reserves and Net Present Value of Future Revenue (Forecast Prices and Costs)

	Synthetic Crude Oil Reserves		Before Income Tax Discounted Present Value (MM$)					
Reserves Category	Working Interest MMbbl	Net After Royalty MMbbl	0%	5%	10%	12%	15%	20%
Proved Developed Producing	961	875	$9,977	$5,100	$3,233	$2,816	$2,371	$1,902
Proved Developed Non-Producing	0	0	0	0	0	0	0	0
Proved Undeveloped	109	98	1,103	396	-100	-238	-398	-573
Total Proved	1,070	973	11,080	5,496	3,133	2,578	1,973	1,329
Probable	779	682	13,231	3,037	815	502	256	103
Total Proved Plus Probable	1,849	1,655	$24,311	$8,533	$3,948	$3,080	$2,229	$1,432

Total Future Net Revenue (Undiscounted Forecast Prices and Costs)

	Revenue (MM$)	Royalties (MM$)	Operating Costs (MM$)	Capital Development Costs (MM$)	Abandonment[1] Costs (MM$)	Future Net Revenue[2] Before Income Taxes (MM$)
Proved Producing	$36,528	$3,248	$20,329	$2,974	$0	$9,977
Proved Developed Nonproducing	0	0	0	0	0	0
Proved Undeveloped	2,834	340	-475	1,866	0	1,103
Total Proved	39,362	3,588	19,854	4,840	0	11,080
Total Probable	35,194	4,483	14,790	2,690	0	13,231
Total Proved Plus Probable	$74,556	$8,071	$34,644	$7,530	$0	$24,311

Notes:

(1) Mining reclamation costs were not included in this calculation. Future mining reclamation costs for proved reserves net of reclamation trust funds are estimated at $210 million and for proved plus probable reserves, at $350 million.

(2) As the Trust and its subsidiaries do not expect to pay any income taxes other than large corporations tax in the foreseeable future, the calculation of the future net revenues pre and post tax are the same amount.

The Trust's produces only one product type group, namely synthetic crude oil which is produced by Syncrude and operated by Syncrude Canada Ltd. The Syncrude operation is located near Fort McMurray, Alberta, Canada.

Item 2.3 Disclosure re: Subsidiary Ownership

Pursuant to an order of the Canadian Securities Administrators, the Trust has disclosed its reserves based on the aggregate 35.49% working interest of its subsidiaries in the Syncrude. As of the date hereof, the Corporation a 31.74% working interest (or 89.4% of the total reserves reported) and Canadian Oil Sands Commercial Trust, through its 75% ownership of Canadian Oil Sands Limited Partnership, holds 3.75% working interest (or 10.6% of the total reserves reported).

The Corporation has been granted an exemption from the annual filing obligation stipulated by National Instrument 51-101, separately from the Trust. The Corporation is exempted from its annual filing obligation pursuant to National Instrument 51-101, separately from the Trust.

PART 3 PRICING ASSUMPTIONS

Item 3.1 Constant Prices Used in Estimates

The benchmark reference prices (reflecting the posted prices corresponding to the last day of the Trust's most recent financial year) used in the Constant price analysis are provided in the table below. The Syncrude plant gate price is expected to correspond to "Light Sweet Crude Oil at Edmonton" less $0.80 per barrel (e.g. $40.01 per barrel).

DECEMBER 31, 2003 CONSTANT PRICES

Crude Oil and Natural Gas Prices

Year	Inflation %	Exchange Rate $US/$Cdn	West Texas Intermediate Crude Oil at Cushing Oklahoma Then Current $US/bbl	Brent Blend Crude Oil FOB North Sea Then Current $US/bbl	Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton Then Current $Cdn/bbl	Bow River Crude Oil Stream Quality at Hardisty Then Current $Cdn/bbl	Heavy Crude Oil Proxy (12 API) at Hardisty Then Current $Cdn/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Then Current $Cdn/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Spec Ethane $Cdn/bbl	Edmonton Propane $Cdn/bbl	Edmonton Butane $Cdn/bbl	Edmonton Pentanes Plus $Cdn/bbl
1993	1.8	0.7750	18.46	17.03	21.94	16.73	13.26	17.59	n/a	14.10	13.64	21.17
1994	0.2	0.7300	17.18	15.82	22.22	18.47	15.02	19.30	n/a	12.53	13.45	21.69
1995	2.2	0.7290	18.39	17.04	24.23	20.80	17.28	21.69	n/a	13.90	13.79	24.11
1996	1.6	0.7334	21.99	20.43	29.39	25.13	20.06	26.10	n/a	22.31	17.15	30.06
1997	1.6	0.7224	20.61	19.18	27.85	21.17	14.41	23.72	n/a	18.62	18.73	30.91
1998	0.9	0.6723	14.42	12.83	20.38	14.64	9.45	16.95	n/a	11.15	12.44	21.83
1999	1.7	0.6750	19.29	17.81	27.69	23.84	19.67	25.42	n/a	15.89	18.70	27.71
2000	2.7	0.6740	30.22	28.35	44.56	35.25	27.34	39.91	n/a	32.18	35.60	46.31
2001	2.6	0.6448	25.97	24.37	39.40	27.70	16.94	31.56	n/a	31.85	31.17	42.48
2002	2.2	0.6376	26.08	24.99	40.33	31.63	26.57	35.48	n/a	21.39	27.08	40.73
2003 (e)	2.8	0.7213	30.96	29.00	43.51	32.01	26.01	37.26	n/a	32.01	34.01	44.01
2004	**0.0**	**0.7738**	**32.52**	**31.02**	**40.81**	**29.81**	**23.31**	**34.81**	**19.50**	**29.81**	**31.81**	**41.31**

Constant Thereafter

Natural Gas and Sulphur

Year	US Gulf Coast Gas Price @ Henry Hub Then Current $US/mmbtu	Midwest Price @ Chicago Then Current $US/mmbtu	AECO-C Spot Then Current $Cdn/mmbtu	Alberta Plant Gate: Spot Then Current $/mmbtu	Alberta Plant Gate: ARP $/mmbtu	Alberta Plant Gate: Aggregator $/mmbtu	Alberta Plant Gate: Alliance $/mmbtu	Saskatchewan Plant Gate: SaskEnergy $/mmbtu	Saskatchewan Plant Gate: Spot $/mmbtu	Saskatchewan Plant Gate: Sumas Spot $US/mmbtu	British Columbia: CanWest Plant Gate $/mmbtu	British Columbia: Spot Plant Gate $/mmbtu	Sulphur FOB Vancouver $US/LT	Alberta Sulphur at Plant Gate $Cdn/LT
1993	2.11	2.31	2.26	2.16	1.71	n/a	n/a	1.48	2.07	1.89	1.73	2.10	30.22	-9.68
1994	1.94	2.11	1.98	1.88	1.81	n/a	n/a	1.88	1.87	1.59	1.81	1.87	44.96	16.57
1995	1.70	1.69	1.15	1.02	1.31	n/a	n/a	1.35	0.98	1.03	1.29	1.12	54.99	30.07
1996	2.52	2.73	1.39	1.26	1.63	n/a	n/a	1.52	1.28	1.32	1.50	1.47	36.28	14.44
1997	2.47	2.75	1.84	1.69	1.96	n/a	n/a	1.84	1.74	1.70	1.80	1.98	34.75	11:50
1998	2.16	2.20	2.03	1.88	1.94	n/a	n/a	2.05	2.13	1.60	1.94	2.00	24.59	-6.51
1999	2.32	2.34	2.92	2.75	2.48	n/a	n/a	2.83	2.97	2.15	2.51	2.78	33.74	6.93
2000	4.33	4.38	5.08	4.82	4.50	4.60	n/a	4.79	5.16	4.17	5.27	4.88	38.14	13.59
2001	4.05	4.17	6.21	6.07	5.41	5.30	5.61	5.71	6.20	4.56	6.76	6.29	18.29	-14.66
2002	3.36	3.30	4.04	3.88	3.88	3.83	3.82	4.04	4.08	2.68	3.64	3.93	29.38	3.04
2003 (e)	5.43	5.46	6.66	6.49	6.33	5.85	6.83	6.60	6.68	4.66	5.69	6.32	59.81	40.01
2004	**5.77**	**5.86**	**6.09**	**5.83**	**5.73**	**5.43**	**5.83**	**5.88**	**5.98**	**5.49**	**5.43**	**5.78**	**59.50**	**35.00**

Constant Thereafter

Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate.
The plant gate price represents the price before raw gas gathering and processing charges are deducted.
Spot refers to weighted average one month price.

Note: These prices are actual posted prices at the referenced date; other reference prices are derived based on estimated price offsets.

Item 3.2 Forecast Prices Used in Estimates

The forecast reference prices used in preparing Canadian Oil Sands' reserves data are provided in the below table. The Syncrude plant gate price is expected to correspond to "Light Sweet Crude Oil at Edmonton" less $0.80 per barrel (e.g. $43.95 in 2004).

Crude Oil and Natural Gas Liquids

Year	Inflation %	Bank of Canada Average Noon Exchange Rate $US/$Cdn	West Texas Intermediate Crude Oil at Cushing Oklahoma Constant 2004 $ $US/bbl	West Texas Intermediate Crude Oil at Cushing Oklahoma Then Current $US/bbl	Brent Blend Crude Oil FOB North Sea Constant 2004 $ $US/bbl	Brent Blend Crude Oil FOB North Sea Then Current $US/bbl	Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton Constant 2004 $ $Cdn/bbl	Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton Then Current $Cdn/bbl	Bow River Crude Oil Stream Quality at Hardisty Constant 2004 $ $Cdn/bbl	Bow River Crude Oil Stream Quality at Hardisty Then Current $Cdn/bbl	Heavy Crude Oil Proxy (12 API) at Hardisty Constant 2004 $ $Cdn/bbl	Heavy Crude Oil Proxy (12 API) at Hardisty Then Current $Cdn/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Constant 2004 $ $Cdn/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Then Current $Cdn/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Spec Ethane $Cdn/bbl	Edmonton Propane $Cdn/bbl	Edmonton Butane $Cdn/bbl	Edmonton Pentanes Plus $Cdn/bbl
1993	1.8	0.775	22.56	18.46	20.81	17.03	26.81	21.94	20.44	16.73	16.20	13.26	21.49	17.59	n/a	14.10	13.64	21.17
1994	0.2	0.732	20.62	17.18	18.99	15.82	26.67	22.22	22.17	18.47	18.03	15.02	23.17	19.30	n/a	12.53	13.45	21.69
1995	2.2	0.729	22.03	18.39	20.41	17.04	29.03	24.23	24.92	20.80	20.70	17.28	25.98	21.69	n/a	13.90	13.79	24.11
1996	1.6	0.733	25.78	21.99	23.95	20.43	34.46	29.39	29.47	25.13	23.52	20.06	30.60	26.10	n/a	22.31	17.15	30.06
1997	1.6	0.722	23.79	20.61	22.14	19.18	32.14	27.85	24.43	21.17	16.63	14.41	27.37	23.72	n/a	18.62	18.73	30.91
1998	0.9	0.675	16.38	14.42	14.57	12.83	23.13	20.36	16.63	14.64	10.73	9.45	19.25	16.95	n/a	11.15	12.44	21.83
1999	1.7	0.673	21.72	19.29	20.05	17.81	31.17	27.69	26.84	23.84	22.14	19.67	28.62	25.42	n/a	15.89	18.70	27.71
2000	2.7	0.673	33.45	30.22	31.38	28.35	49.33	44.56	39.02	35.25	30.26	27.34	44.18	39.91	n/a	32.18	35.60	46.31
2001	2.6	0.646	27.99	25.97	26.27	24.37	42.47	39.40	29.86	27.70	18.26	16.94	34.02	31.56	n/a	31.85	31.17	42.48
2002	2.2	0.637	27.40	26.06	26.25	24.99	42.37	40.33	33.44	31.83	27.91	26.57	37.27	35.48	n/a	21.39	27.08	40.73
2003	2.8	0.721	31.93	31.07	29.74	28.93	44.88	43.66	33.01	32.11	26.99	26.26	38.60	37.55	n/a	32.14	34.36	44.23
2004 Q1 (e)	1.5	0.757	34.50	34.50	33.00	33.00	44.50	44.50	34.25	34.25	28.00	28.00	40.50	40.50	n/a	33.50	36.50	45.00
2004 Q2	1.5	0.750	36.00	36.00	34.50	34.50	47.25	47.25	37.75	37.75	31.75	31.75	43.75	43.75	22.00	36.25	39.25	47.75
2004 Q3	1.5	0.750	34.00	34.00	32.50	32.50	44.50	44.50	35.25	35.25	29.50	29.50	41.00	41.00	22.25	33.50	36.50	45.00
2004 Q4	1.5	0.750	32.75	32.75	31.25	31.25	43.00	43.00	32.50	32.50	26.25	26.25	39.00	39.00	23.25	32.00	35.00	43.50
2004 Full Year	1.5	0.750	34.25	34.25	32.75	32.75	44.75	44.75	35.00	35.00	29.00	29.00	41.00	41.00	22.50	33.75	36.75	45.25
2004 Q2-Q4	0.0	0.750	34.25	34.25	32.75	32.75	44.75	44.75	35.00	35.00	29.00	29.00	41.00	41.00	22.50	33.75	36.75	45.25
2005	1.5	0.750	28.50	29.00	27.00	27.50	37.25	37.75	29.75	30.25	24.75	25.00	33.25	33.75	18.50	25.75	28.75	38.25
2006	1.5	0.750	26.25	27.00	24.75	25.50	34.25	35.25	28.00	28.75	23.00	23.75	30.25	31.25	17.25	23.25	25.25	35.75
2007	1.5	0.750	24.00	25.00	22.50	23.50	31.00	32.50	24.75	26.00	20.00	21.00	27.25	28.50	16.50	20.50	22.50	33.00
2008	1.5	0.750	23.50	25.00	22.25	23.50	30.50	32.50	24.50	26.00	19.75	21.00	26.75	28.50	16.50	20.50	22.50	33.00
2009	1.5	0.750	23.25	25.00	21.75	23.50	30.25	32.50	24.25	26.00	19.50	21.00	26.50	28.50	16.50	20.50	22.50	33.00
2010	1.5	0.750	23.25	25.50	22.00	24.00	30.25	33.00	24.25	26.50	19.75	21.50	26.50	29.00	17.00	21.00	23.00	33.50
2011	1.5	0.750	23.25	25.75	21.75	24.25	30.25	33.50	24.25	27.00	19.75	22.00	26.50	29.50	17.25	21.50	23.50	34.00
2012	1.5	0.750	23.25	26.25	22.00	24.75	30.25	34.00	24.50	27.50	20.00	22.50	26.75	30.00	17.50	21.75	24.00	34.50
2013	1.5	0.750	23.25	26.50	21.75	25.00	30.25	34.50	24.50	28.00	20.00	23.00	26.75	30.50	18.00	22.00	24.50	35.00
2014	1.5	0.750	23.25	27.00	22.00	25.50	30.25	35.00	24.50	28.50	20.25	23.50	26.75	31.00	18.00	22.50	24.75	35.50
2015+	1.5	0.750	23.25	+1.5%/yr	22.00	+1.5%/yr	30.25	+1.5%/yr	24.50	+1.5%/yr	20.25	+1.5%/yr	26.75	+1.5%/yr		Escalate at 1.5 % per year		

Natural Gas and Sulphur

Year	US Gulf Coast Gas Price @ Henry Hub Constant 2004 $ $US/mmbtu	US Gulf Coast Gas Price @ Henry Hub Then Current $US/mmbtu	Midwest Price @ Chicago Then Current $US/mmbtu	AECO-C Spot Then Current $Cdn/mmbtu	Alberta Plant Gate Spot Constant 2004 $ $/mmbtu	Alberta Plant Gate Spot Then Current $/mmbtu	Alberta Plant Gate ARP $/mmbtu	Alberta Plant Gate Aggregator $/mmbtu	Alberta Plant Gate Alliance $/mmbtu	Saskatchewan Plant Gate SaskEnergy $/mmbtu	Saskatchewan Plant Gate Spot $/mmbtu	Sumas Spot $US/mmbtu	British Columbia CanWest Plant Gate $/mmbtu	British Columbia Spot Plant Gate $/mmbtu	Sulphur FOB Vancouver $US/LT	Alberta Sulphur at Plant Gate $Cdn/LT
1993	2.58	2.11	2.31	2.26	2.64	2.16	1.71	n/a	n/a	1.48	2.07	1.89	1.73	2.10	30.22	-9.68
1994	2.33	1.94	2.11	1.98	2.23	1.86	1.81	n/a	n/a	1.88	1.87	1.59	1.81	1.87	44.96	16.57
1995	2.04	1.70	1.69	1.15	1.22	1.02	1.31	n/a	n/a	1.35	0.98	1.03	1.29	1.12	54.99	30.07
1996	2.95	2.52	2.73	1.39	1.48	1.26	1.63	n/a	n/a	1.52	1.28	1.32	1.50	1.47	36.28	14.44
1997	2.85	2.47	2.75	1.84	1.95	1.69	1.96	n/a	n/a	1.84	1.74	1.70	1.80	1.98	34.75	11.50
1998	2.45	2.16	2.20	2.03	2.14	1.88	1.94	n/a	n/a	2.05	2.13	1.60	1.94	2.00	24.59	-6.51
1999	2.61	2.32	2.34	2.92	3.10	2.75	2.48	n/a	n/a	2.83	2.97	2.15	2.51	2.78	33.74	6.93
2000	4.79	4.33	4.38	5.08	5.45	4.92	4.50	4.60	n/a	4.79	5.16	4.17	5.27	4.88	38.14	13.59
2001	4.37	4.05	4.17	6.21	6.54	6.07	5.41	5.30	5.61	5.71	6.20	4.56	6.76	6.29	18.29	-14.66
2002	3.53	3.36	3.30	4.04	4.08	3.86	3.88	3.83	3.82	4.04	4.08	2.68	3.64	3.93	29.38	3.04
2003	5.65	5.50	5.60	6.66	6.67	6.49	6.13	5.89	6.69	6.40	6.68	4.66	5.71	6.32	59.81	39.63
2004 Q1 (e)	5.70	5.70	5.85	6.65	6.30	6.30	6.20	5.90	6.30	6.35	6.45	5.10	5.55	6.25	60.00	35.50
2004 Q2	5.60	5.60	5.65	6.55	6.30	6.30	6.20	5.90	6.15	6.35	6.45	4.95	5.60	6.15	67.00	46.00
2004 Q3	5.70	5.70	5.75	6.65	6.40	6.40	6.30	6.00	6.20	6.45	6.55	5.05	5.65	6.25	65.00	43.00
2004 Q4	5.85	5.85	6.00	6.90	6.65	6.65	6.55	6.20	6.55	6.70	6.80	5.35	5.85	6.65	60.00	36.50
2004 Full Year	5.70	5.70	5.80	6.65	6.40	6.40	6.30	6.00	6.30	6.45	6.55	5.10	5.65	6.35	63.00	40.50
2004 Q2-Q4	5.70	5.70	5.80	6.70	6.45	6.45	6.35	6.05	6.30	6.50	6.60	5.10	5.70	6.35	64.00	42.00
2005	4.75	4.80	5.00	5.55	5.20	5.30	5.25	5.15	5.30	5.40	5.45	4.30	5.15	5.30	45.00	16.50
2006	4.35	4.50	4.75	5.20	4.60	4.95	4.95	4.95	4.95	5.10	5.10	4.05	4.95	4.95	45.00	16.50
2007	4.15	4.35	4.60	5.00	4.55	4.75	4.75	4.75	4.75	4.90	4.90	3.90	4.75	4.75	45.00	16.50
2008	4.10	4.35	4.60	5.00	4.50	4.75	4.75	4.75	4.75	4.90	4.90	3.90	4.75	4.75	45.00	16.50
2009	4.05	4.35	4.60	5.00	4.45	4.75	4.75	4.75	4.75	4.90	4.90	3.90	4.75	4.75	46.00	18.00
2010	4.05	4.40	4.65	5.10	4.45	4.85	4.85	4.85	4.85	5.00	5.00	3.95	4.85	4.85	47.00	19.00
2011	4.05	4.50	4.75	5.20	4.45	4.95	4.95	4.95	4.95	5.10	5.10	4.05	4.95	4.95	48.00	20.50
2012	4.05	4.55	4.80	5.25	4.45	5.05	5.05	5.05	5.05	5.20	5.15	4.10	5.05	5.05	49.00	22.00
2013	4.05	4.60	4.90	5.35	4.50	5.15	5.15	5.15	5.15	5.30	5.25	4.20	5.15	5.15	50.00	23.50
2014	4.05	4.70	4.95	5.45	4.50	5.20	5.20	5.20	5.20	5.35	5.35	4.25	5.20	5.20	51.00	25.00
2015+	4.05	+1.5%/yr	+1.5%/yr	+1.5%/yr	4.50	+1.6%/yr				Escalate at 1.5 % per year					+1.5%/yr	

Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate.
The plant gate price represents the price before raw gas gathering and processing charges are deducted.
Spot refers to weighted average one month price.

This price forecast is the independent evaluator's standard price forecast effective March 5, 2004.

In 2003, Canadian Oil Sands received a weighted average price fo $43.65 per barrel (before transportation, marketing fees and hedging) for its synthetic crude oil.

PART 4 RECONCILIATIONS OF CHANGES IN RESERVES AND FUTURE NET REVENUE

Item 4.1 Reserves Reconciliation

The following table provides a reconciliation of Canadian Oil Sands' net reserves based on forecast prices and costs between this analysis and Canadian Oil Sands' prior year-end evaluation:

	Synthetic Crude Oil		
FACTORS	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)
January 1, 2003	614	374	988
Technical Revisions	-1	44	43
Acquisitions	384	264	648
Production	-24	0	-24
January 1, 2004	973	682	1,655

Reconciliations of reserves in Canada on a company net reserves basis are more complex than on a company gross reserves basis due to price and rate-sensitive royalties, which can cause the net company reserves to change without a change in the gross company reserves. In considering the above reconciliation table, it should be noted that:

(a) the net reserves associated with the opening balance were estimated as the Trust's prior disclosure only presented working interest reserves for the total proved reserves category;

(b) the acquisitions of the additional 13.75% interest from EnCana Corporation were approximated using the December 31, 2003 estimates; and

(c) the technical revisions are primarily related to the average royalty rate.

Item 4.2 Future Net Revenue Reconciliation

There is no reconciliation provided since Canadian Oil Sands did not provide future net revenue calculations last year.

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 Undeveloped Reserves

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook.

The proved developed producing reserves and production forecast reflect the current upgrading capacity situation at the Syncrude and limit the reserves to those forecast to be recovered within the remaining 32 years of the Alberta Energy and Utilities Board (EUB) approval. Although the center and west pits of Aurora North are not yet on production, reserves from these pits are classified as proved developed producing since their recovery does not require a material amount of additional capital.

The proved undeveloped scenario includes capital relating to the upgrader expansion that is currently in progress (UE1) and the base mine replacement (SWQR) and the sulphur emissions reduction (SER) projects. These investments will accelerate production, improve the yield on bitumen and enable all of the reserves associated with Aurora North to be recovered within the current approval period. Proved reserves were constrained to areas where Syncrude currently has approvals to mine.

The probable undeveloped reserves are primarily associated with the development of Aurora South and improvements to both extraction recovery and upgrading yield. Although Aurora South development plans are continuing to progress, the independent evaluator has classified recovery from this ore body as probable, given both the lack of a firm commitment by the Syncrude owners to proceed beyond a Stage 3 off-ramp scenario and current expectations of production not occurring until after 2010.

Item 5.3 Future Development Costs

See the table below which summarizes capital development costs related to the recovery of Canadian Oil Sands' reserves:

Annual Capital Expenditures (MM$) (Constant Prices and Costs)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Subtotal	Remainder	Total	10% Discounted
Proved Producing	$110	$110	$75	$75	$75	$75	$75	$75	$75	$75	$75	$75	$970	$1,347	$2,316	$805
Total Proved	1,047	650	214	158	112	103	103	103	103	103	103	103	2,901	1,292	4,193	2,475
Total Proved Plus Probable	$1,029	$632	$173	$140	$147	$302	$422	$422	$250	$255	$154	$80	$4,003	$2,112	$6,115	$3,015

Annual Capital Expenditures (MM$) (Forecast Prices and Costs)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Subtotal	Remainder	Total	10% Discounted
Proved Producing	$110	$114	$79	$81	$82	$84	$85	$86	$87	$89	$90	$91	$1,078	$1,896	$2,974	$932
Total Proved	1,047	670	227	171	123	115	116	118	120	122	124	125	3,077	1,763	4,840	2,647
Total Proved Plus Probable	$1,029	$651	$183	$151	$161	$337	$477	$484	$291	$301	$184	$98	$4,347	$3,183	$7,530	$3,289

PART 6 OTHER OIL AND GAS INFORMATION

Item 6.3 Forward Contracts

Hedging Activity – The impact of Canadian Oil Sands' hedging activity was applied as a corporate level adjustment based on actual hedged volumes and prices instead of the independent evaluator's price forecasts used in property evaluations. The tables below summarize hedging activity and the resulting gains and losses

Summary of Company Hedging Activity – Constant Pricing

		Terms				Constant Price			
		2004	2005	2006	2007	2004	2005	2006	2007
US$ Sold Forward	Million US$	92	100	60	20	92	100	60	20
	Exchange Rate (US$/C$)	0.6650	0.6640	0.6690	0.6920	0.7738	0.7738	0.7738	0.7738
	Thousand C$	138,346	150,602	89,686	28,902	118,894	129,232	77,539	25,846
US$ Sold Forward Hedge impact	('000$ C$)					19,452	21,370	12,147	3,056
US$ WTI hedge	Volume (Mbbl)	9,125	0	0	0	9,125	0	0	0
	Price (US$/bbl)	24.74				32.52			
	Exchange Rate (US$/C$)	N/A				0.7738			
Crude Oil (US$ WTI) Hedge impact	('000$ C$)					(91,745)	0	0	0
C$ WTI hedge	Volume (Mbbl)	5,110	0	0	0	5,110	0	0	0
	Price (C$/bbl)	38.65				42.03			
Crude Oil (C$ WTI) Hedge impact	('000$ C$)					(17,272)	0	0	0
Total Hedging	**('000$ C$)**					**(89,565)**	**21,370**	**12,147**	**3,056**

Item 6.4 Additional Information Concerning Abandonment and Reclamation Costs

No aspects of Canadian Oil Sands' future abandonment and reclamation costs have been included in the economic forecasts. See note (1) of Sections 2.1 and 2.2.

Item 6.5 Tax Horizon

There is no after income tax economic analysis of Canadian Oil Sands since as a royalty trust, Canadian Oil Sands' income tax liability is transferred to individual trust unit holders and therefore no tax is anticipated to be incurred or paid by Canadian Oil Sands other than Large Corporations Tax.

Item 6.8 **Production Estimates**

A forecast of Canadian Oil Sands' production in the first year of forecast is presented below:

	Synthetic Crude Oil (million barrels)	
Reserves Category	Working Interest	After Royalty
Proved developed producing	31	30
Total proved	31	30
Total proved plus probable	32	31

CANADIAN OIL SANDS LIMITED, on its behalf and as Manager of **CANADIAN OIL SANDS TRUST**

Marcel R. Coutu
President and Chief Executive Officer

Allen R. Hagerman
Chief Financial Officer

Wayne M. Newhouse
Director

Wesley R. Twiss
Director

March 12, 2004

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the board of directors of Canadian Oil Sands Limited (the "Corporation"):

1. We have prepared an evaluation of the subsidiary interests of Canadian Oil Sands Trust (the "Trust") as at December 31, 2003. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2003, using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved oil and gas reserves estimated as at December 31, 2003, using constant prices and costs; and

   (ii) the related estimated future net revenue.

2. The reserves data are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Trust evaluated by us for the year ended December 31, 2003, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Corporation's board of directors:

Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate, million dollars)			
		Audited	Evaluated	Reviewed	Total
March 9, 2004	Canada	0	$3,948	0	$3,948

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.
6. We have no responsibility to update this evaluation for events and circumstances occurring after the preparation dates.
7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Gilbert Laustsen Jung Associates Ltd., Calgary, Alberta, Canada Dated: March 9, 2004

ORIGINALLY SIGNED BY

James H. Willmon, P. Eng.
Vice-President

FORM 51-101F3
REPORT OF
MANAGEMENT AND DIRECTORS
ON RESERVES DATA AND OTHER INFORMATION

04 MAR 30 AM 7:21

1. Terms to which a meaning is ascribed in *NI 51-101* have the same meaning in this form. This report is also made in accordance with the terms of an order dated March 12, 2004 issued under the Mutual Reliance Review System.

2. Management of Canadian Oil Sands Limited ("COSL"), as manager of Canadian Oil Sands Trust (the "Trust") is responsible for the preparation and disclosure of information with respect to the oil and gas activities in accordance with securities regulatory requirements of the Trust and of COSL. This information includes reserves data, which consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2003 using forecast prices and costs; and

   (ii) the related estimated future net revenues; and

   (b) (i) proved oil and gas reserves estimated as at December 31, 2003 using constant prices and costs; and

   (ii) the related estimated future net revenues.

   An independent qualified reserves evaluator evaluated and reviewed the Trust's reserves data. The report of the independent qualified reserves evaluator is presented will be filed with securities regulatory authorities concurrently with this report.

   The Audit Committee of the Board of directors of COSL, acting as the reserves committee of the Board of Directors has:

   (a) reviewed the procedures for providing information to the independent qualified reserves evaluator;

   (b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation on the reserves; and

   (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

   The Audit Committee of the Board of directors has reviewed the procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with the management. The Board of directors has, on the recommendation of the Audit Committee, approved:

   (a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

CANADIAN OIL SANDS LIMITED, on its behalf and as Manager of **CANADIAN OIL SANDS TRUST**

Marcel R. Coutu President and Chief Executive Officer	Allen R. Hagerman Chief Financial Officer
Wayne M. Newhouse Director	Wesley R. Twiss Director

March 12, 2004

Canadian Oil Sands

NEWS RELEASE
For immediate release

Canadian Oil Sands Trust releases 2003 year-end reserves information

Calgary, March 23, 2004 (TSX -- COS.UN) — Canadian Oil Sands Trust ("Canadian Oil Sands" or the "Trust") today announces that it filed its 2003 year-end reserves information, which show no significant revisions from prior disclosure.

Based on an independent reserves evaluation by Gilbert Laustsen Jung Associates Ltd. effective December 31, 2003 and prepared in accordance with National Instrument ("NI") 51-101, Canadian Oil Sands has proved reserves of 1,070 million barrels of Syncrude Sweet Blend and total proved plus probable reserves of 1,849 million barrels of Syncrude Sweet Blend. A copy of the reserve report filed by the Trust is available on SEDAR at www.sedar.com under the company profile for the Trust.

The Trust's proved reserves represent a reserve life of approximately 35 years based on the Trust's 2004 annual production outlook of 30.5 million barrels. This reserve life extends to almost 60 years when the probable reserves are included. Proved developed producing reserves represent 52 per cent of proved plus probable reserves while total proved reserves account for 58 per cent of proved plus probable reserves. The proved reserves include the Aurora North mine, which is also inclusive of the Stage 3 expansion.

The Trust, through its two wholly-owned subsidiaries, holds a 35.49 per cent interest in the Syncrude Project, of which 89.4 per cent of the interest is held by its main subsidiary, Canadian Oil Sands Limited, and 10.6 per cent is held through another subsidiary. These subsidiaries have an exemption from the requirement to file information annually under NI 51-101 separately from the Trust.

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 is one of the largest participants in the expanding development of Alberta's oil sands, a vast resource that rivals the crude oil reserves of Saudi Arabia. The Trust's approximately 87.5 million units outstanding trade on the Toronto Stock Exchange under the symbol COS.UN. The Trust is managed by Canadian Oil Sands Limited.

Advisory: in the interest of providing Canadian Oil Sands Trust ("Canadian Oil Sands" or the "Trust") unitholders and potential investors with information regarding the Trust, including management's assessment of the Trust's future plans and operations, certain statements throughout this release contain "forward-looking statements" under applicable securities law. Forward-looking statements in this release include, but are not limited to, statements with respect to: the expected annual production rate; the amount of reserves and the reserve life. 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 release include, but are not limited to: general economic, business and market conditions; commodity prices; the ability for Syncrude to complete the Stage 3 expansion within the anticipated cost range; 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 release are made as of the date of this release, 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 release are expressly qualified by this cautionary statement.

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Canadian Oil Sands Limited
Marcel Coutu
President & Chief Executive Officer

Units Listed – Symbol: COS.UN
Toronto Stock Exchange

For further information:

Siren Fisekci
Director, Investor Relations:
(403) 218-6228
investor_relations@cos-trust.com

Web site: www.cos-trust.com