UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

04026643

PE
4-1-04

# FORM 6-K

REPORT OF FOREIGN PRIVATE ISSUER
PURSUANT TO RULE 13a-16 OR 15d-16
UNDER THE SECURITIES EXCHANGE ACT OF 1934



For the month of April, 2004

**WESTERN OIL SANDS INC.**
(Exact name of registrant as specified in its charter)

**Suite 2400, Ernst & Young Tower**
**440 Second Avenue S.W.**
**Calgary, Alberta, Canada T2P 5E9**
**(403) 223-1700**
(Address of principal executive offices)



Indicate by check mark whether the registrant files or will file annual reports under cover Form 20-F or Form 40-F.

Form 20-F ____ Form 40-F _X_

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1): _X_

Note: Regulation S-T Rule 101(b)(1) only permits the submission in paper of a Form 6-K if submitted solely to provide an attached annual report to security holders.

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7): _____

Note: Regulation S-T Rule 101(b)(7) only permits the submission in paper of a Form 6-K if submitted to furnish a report or other document that the registrant foreign private issuer must furnish and make public under the laws of the jurisdiction in which the registrant is incorporated, domiciled or legally organized (the registrant's "home country"), or under the rules of the home country exchange on which the registrant's securities are traded, as long as the report or other document is not a press release, is not required to be and has not been distributed to the registrant's security holders, and, if discussing a material event, has already been the subject of a Form 6-K submission or other Commission filing on EDGAR.

Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes ____ No _X_

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): 82-__________

| Exhibit No. | Description |
|---|---|
| 99.1 | 2003 Annual Report of Western Oil Sands Inc. |

## SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

**WESTERN OIL SANDS INC.**

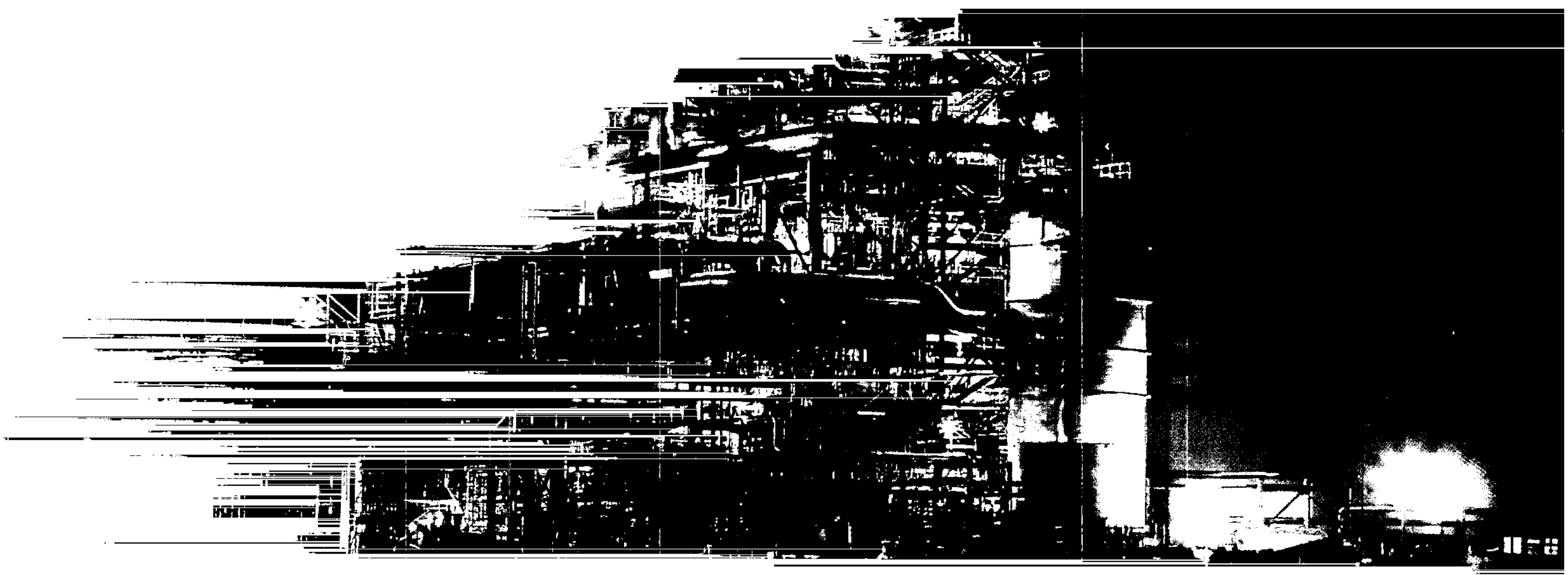
Date: April 15, 2004

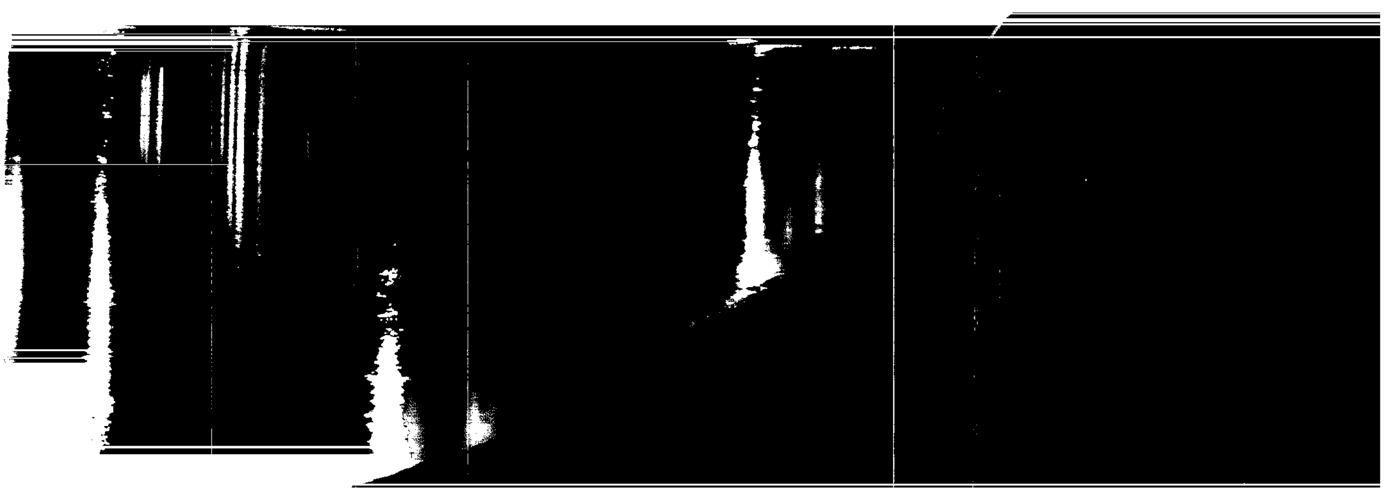
By: ______________________

Name: David A. Dyck
Title: Vice President, Finance and Chief Financial Officer

WesternOilSands

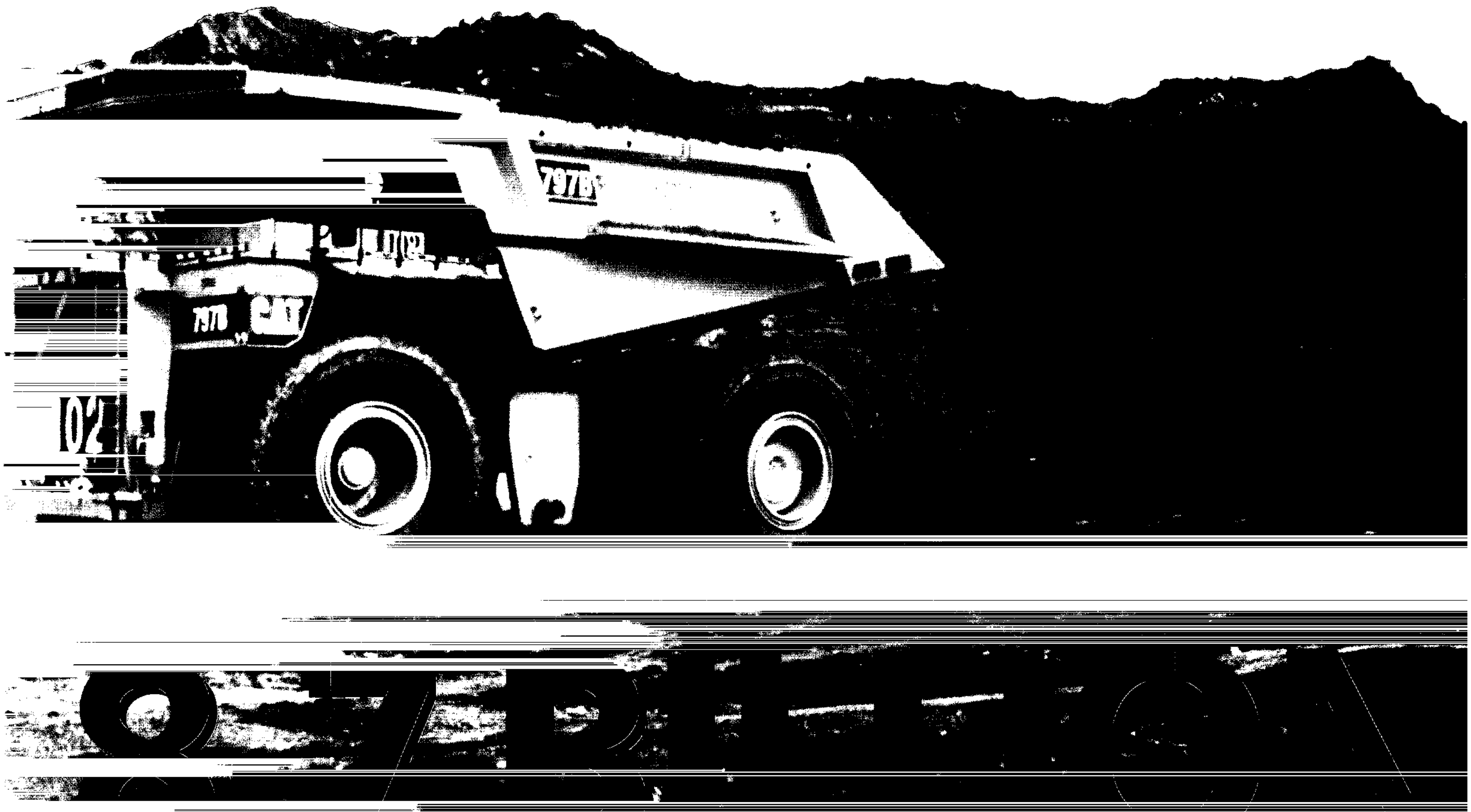
2003 Annual Report

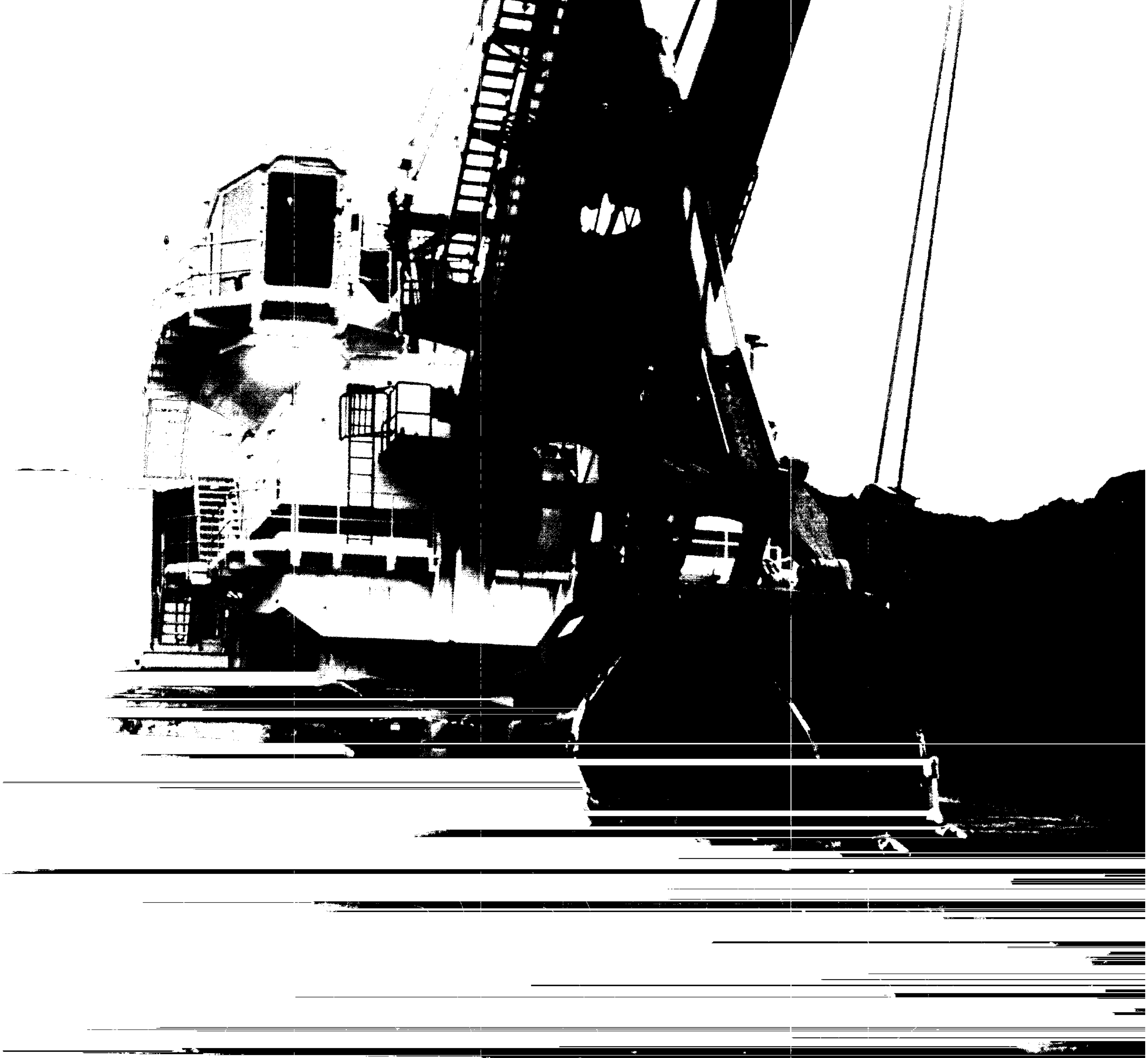




A Year in Perspective

Western Oil Sands' Annual General Meeting of Shareholders will be held at the Metropolitan Centre, 333 - 4th Avenue S.W., Calgary, Alberta on Wednesday, May 12, 2004 at 3:30 pm. All shareholders are invited to attend, and those unable to do so are requested to sign and return the form of proxy mailed with the report to ensure representation at the meeting.





IN 2003, WESTERN OIL SANDS AND ITS JOINT VENTURE PARTNERS BEGAN TO TAP INTO THIS ENORMOUS RESOURCE BASE THAT LIES BENEATH THEIR ATHABASCA OIL SANDS PROJECT LEASES NEAR FORT MCMURRAY. WITH PRODUCTION NOW UNDERWAY, ALL ASPECTS OF THIS MASSIVE $5.7 BILLION PROJECT ARE OPERATIONAL: BITUMEN SAND IS BEING MINED AT THE MUSKEG RIVER MINE, PROCESSED AND PIPED THROUGH THE CORRIDOR PIPELINE TO THE SCOTFORD UPGRADER FOR REFINING INTO SYNTHETIC CRUDE. SYNTHETIC CRUDE IS BEING MARKETED AND SHIPPED THROUGH THE NORTH AMERICAN PIPELINE SYSTEM TO CUSTOMERS. THE DREAM HAS BECOME A REALITY.

STARTING UP A PROJECT OF THIS SCALE IS AN ENORMOUS UNDERTAKING AND THE SUCCESS ACHIEVED BY OUR PROJECT TEAM IS OUTSTANDING. IN ONLY NINE MONTHS, THE PROJECT WAS OPERATING AT 84 PER CENT OF DESIGN CAPACITY AND HAS FREQUENTLY EXCEEDED DESIGN CAPACITY FOR SHORT PERIODS. THE FINE-TUNING AND DE-BOTTLENECKING PROCESS WILL PROCEED FOR SOME TIME AND WE HAVE NO DOUBT THAT BITUMEN PRODUCTION LEVELS AND SYNTHETIC CRUDE OIL SALES VOLUMES WILL CONTINUE TO CLIMB. OUR PROJECT TEAM HAS LEARNED A GREAT DEAL FROM THE SUCCESSES AND THE CHALLENGES AND WE ARE NOW LOOKING FORWARD TO EXPANDING THE PROJECT CAPACITY AND FURTHER DEVELOPING OUR BITUMEN RESOURCES.

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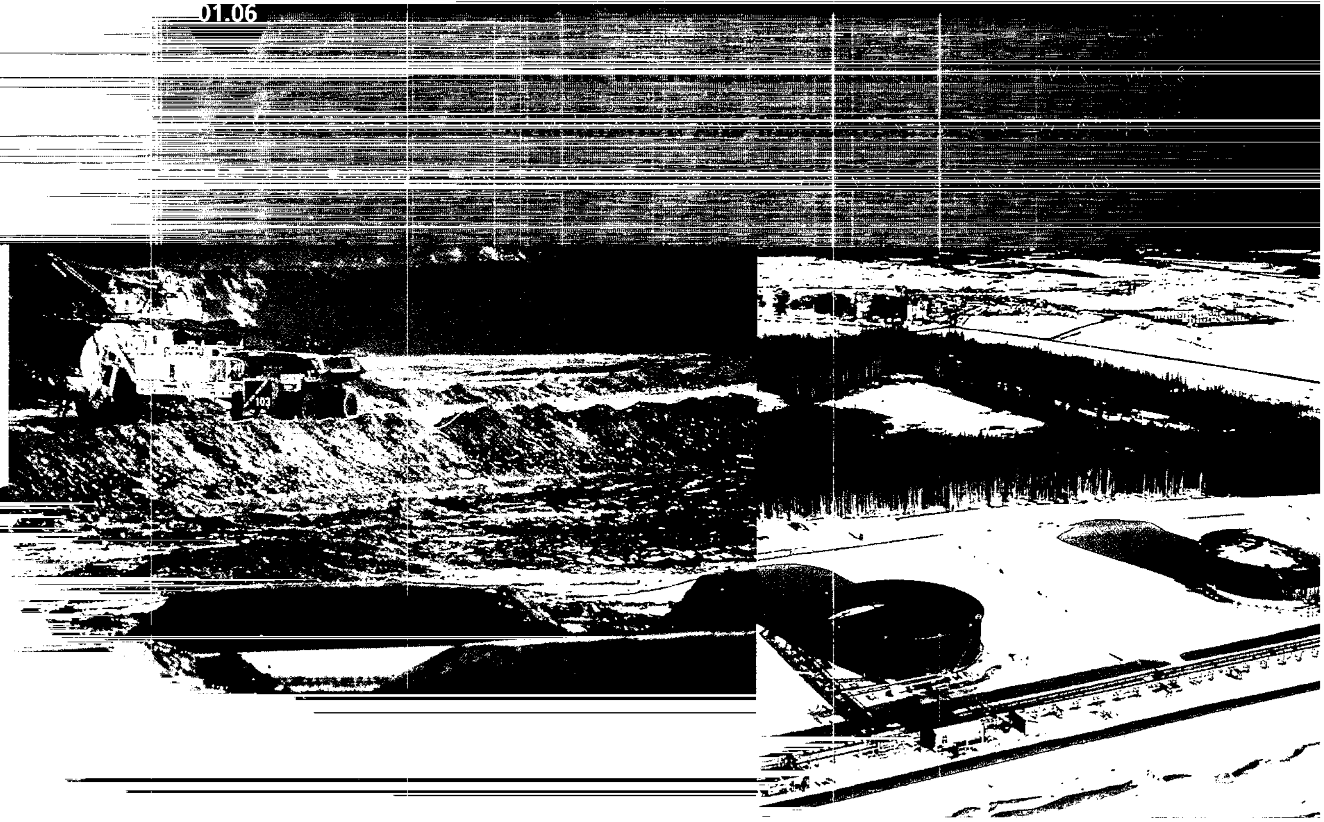

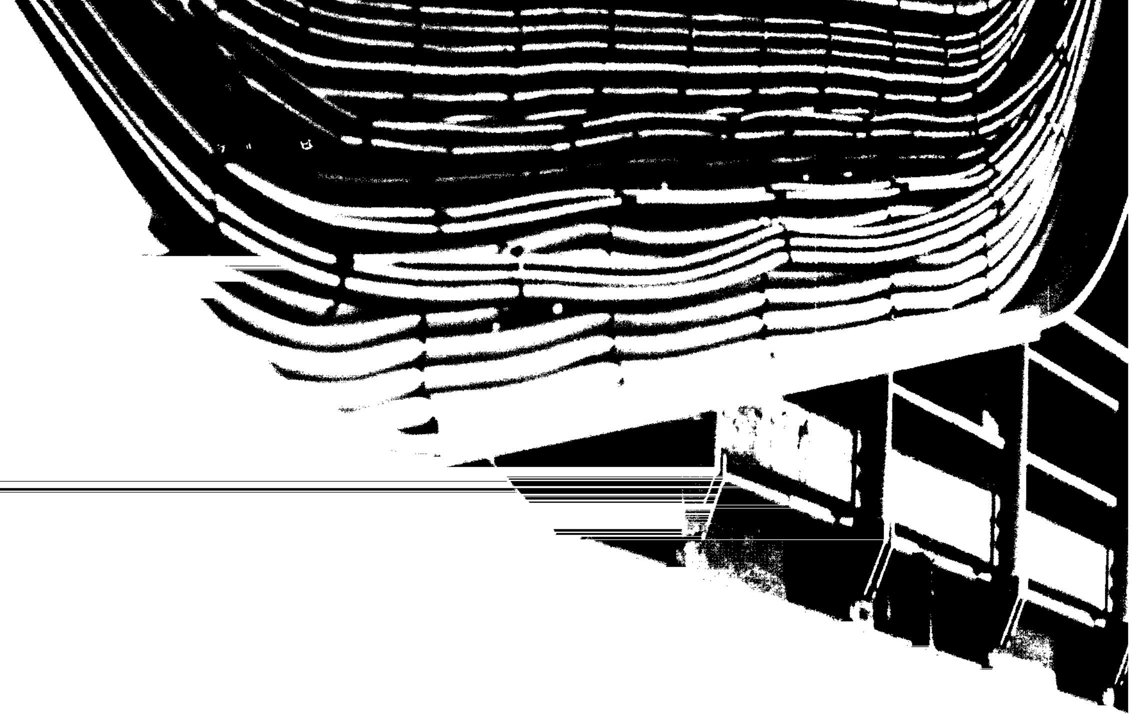


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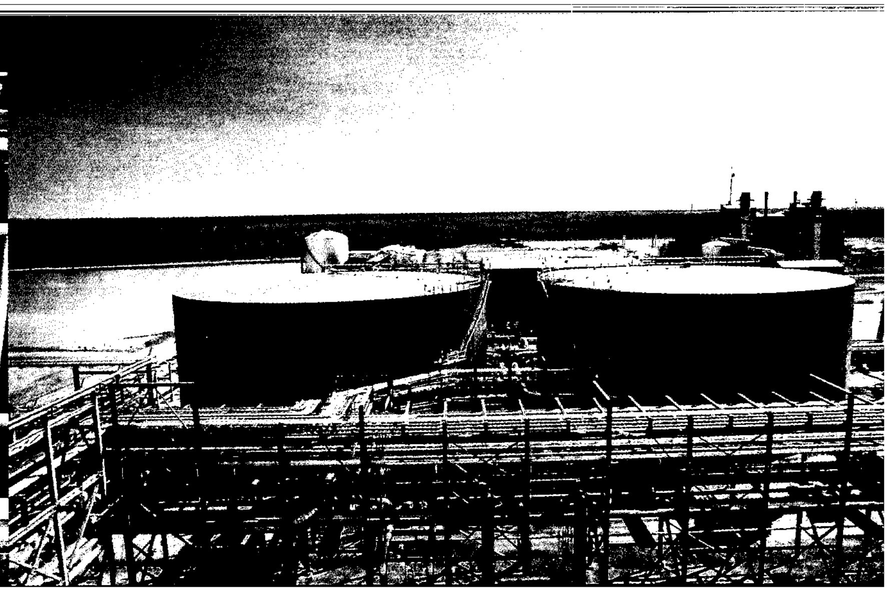

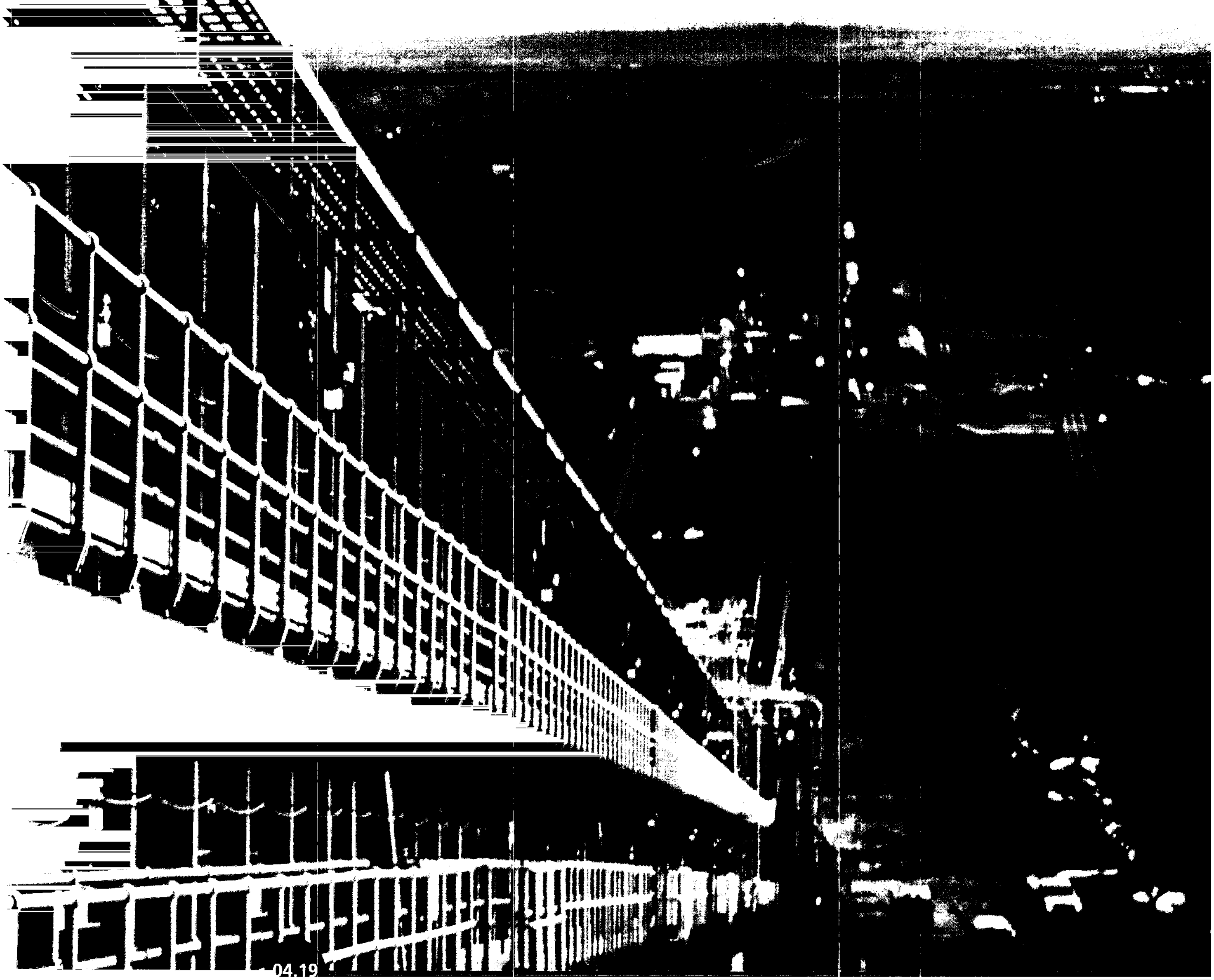

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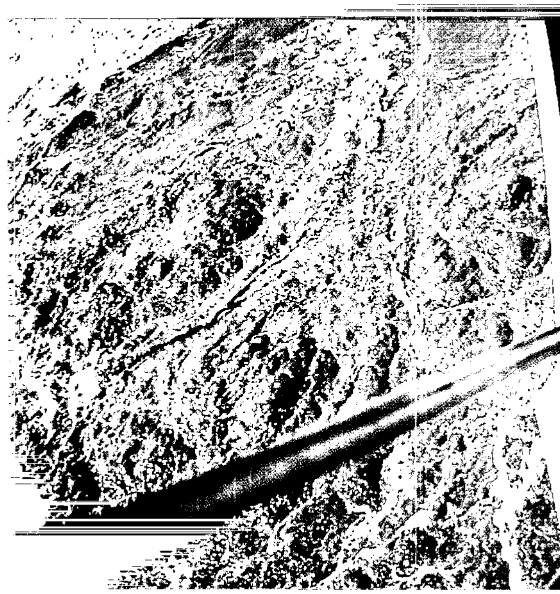

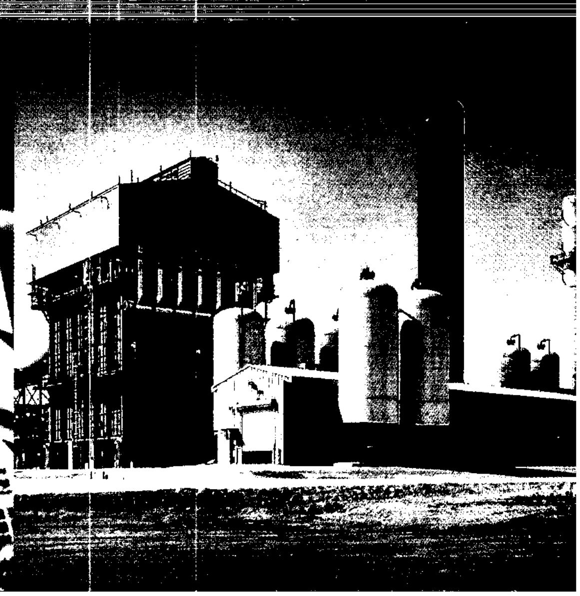

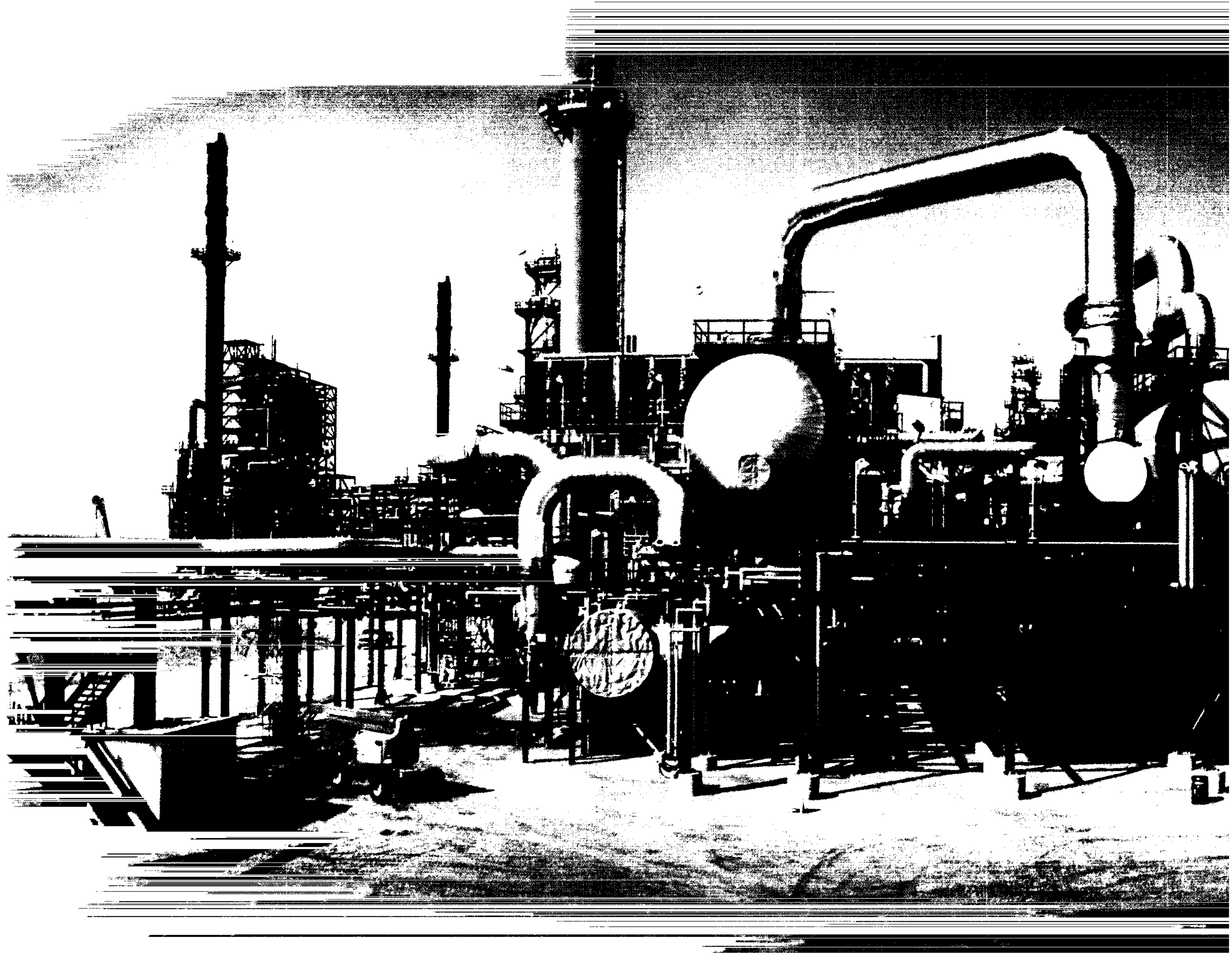

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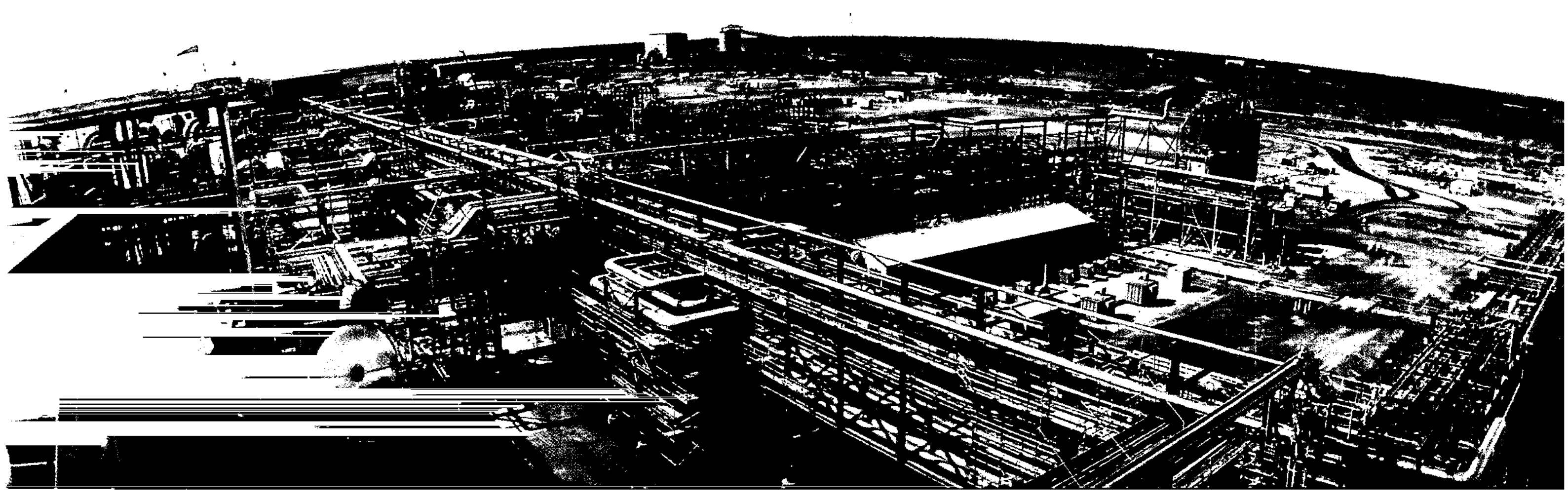

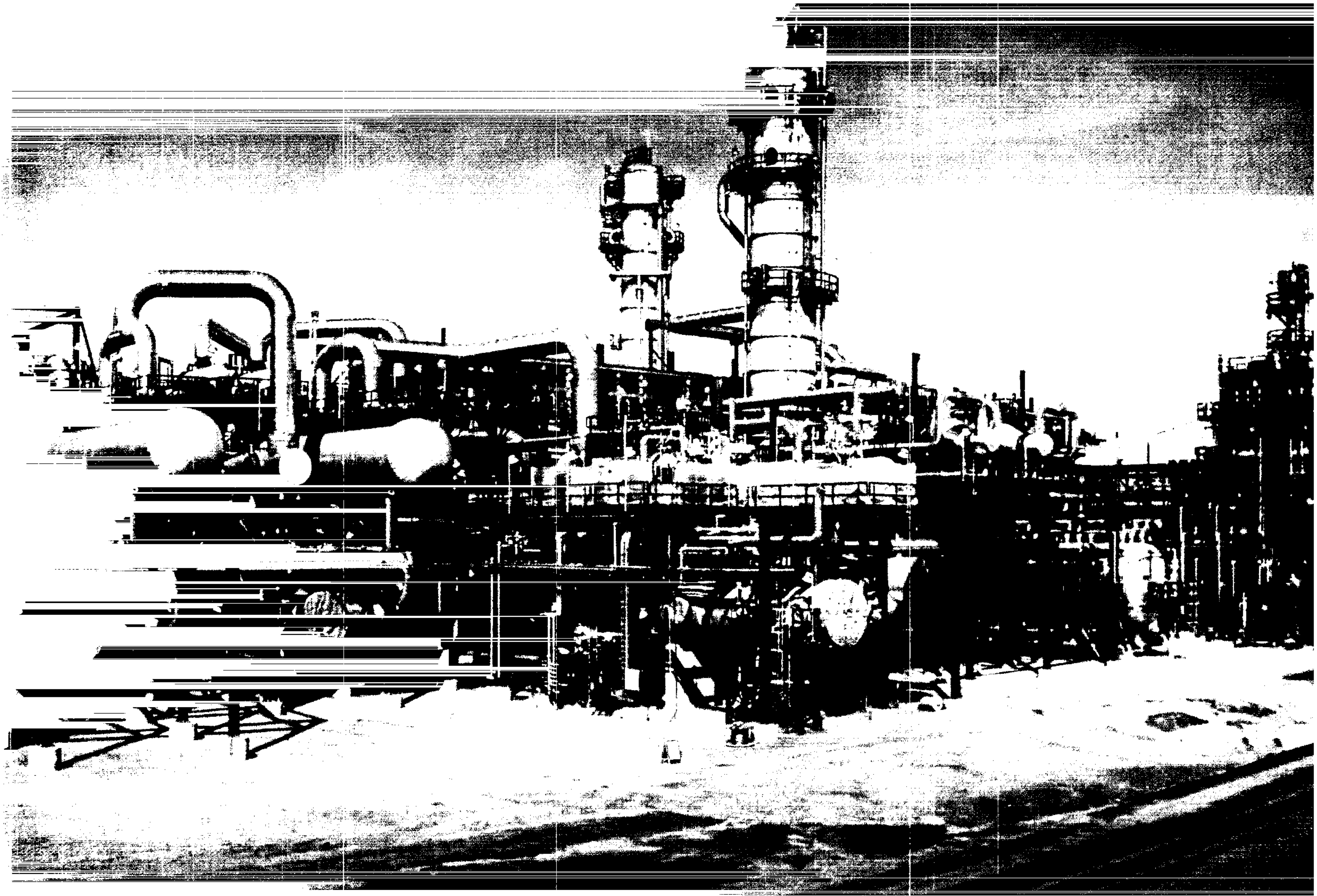

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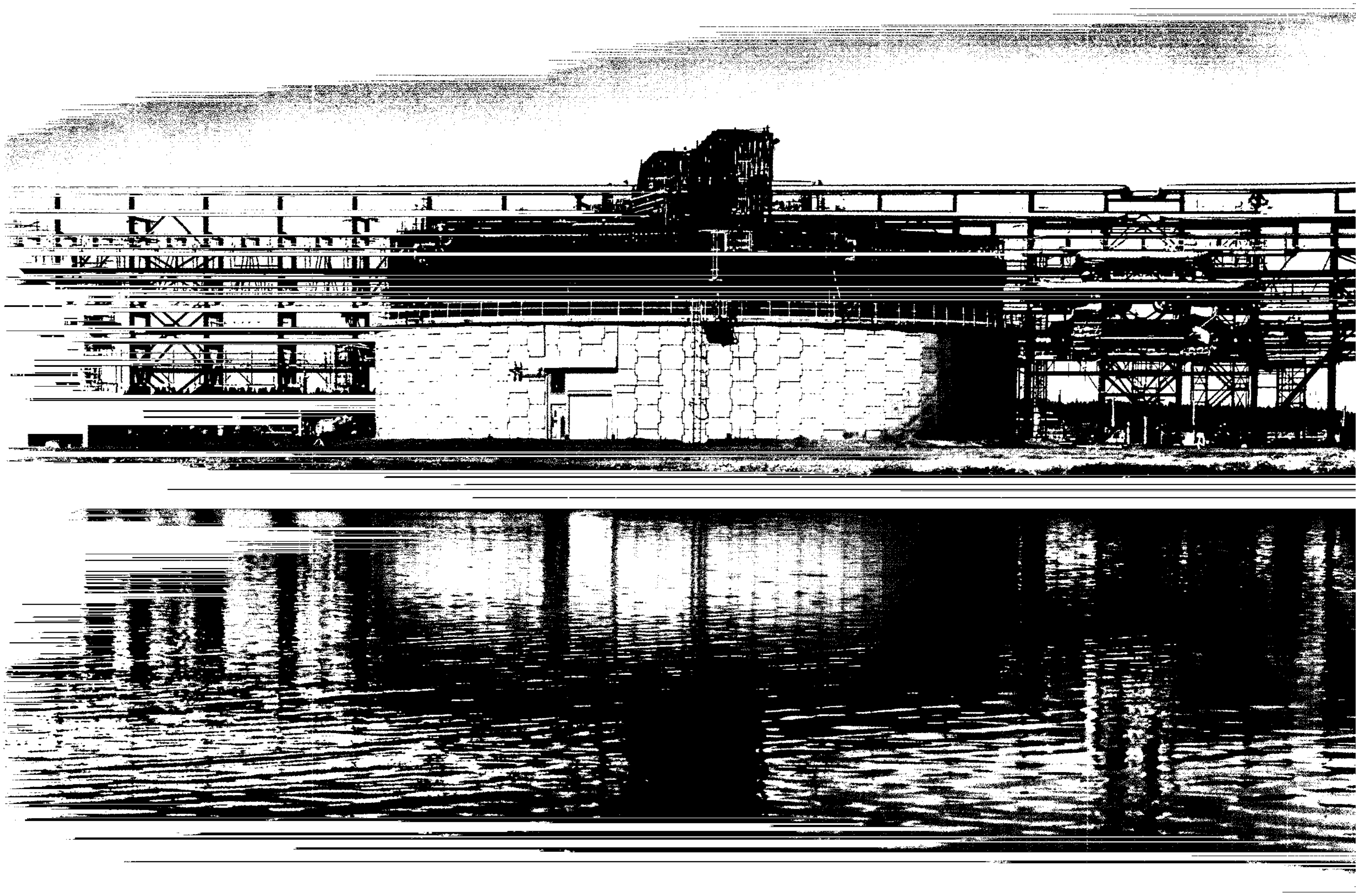


**FIRST PHASE**

**NOW ON**

**STREAM**

**FULL PRODUCTION AND EXPANSION.**

Geoffrey A. Cumming
Chairman

2003 has been both a challenging and successful year for your company. The first phase of the Athabasca Oil Sands Project is now on-stream and producing at rates approaching design capacity. Management is working diligently to achieve full production, control costs and further optimize operations. While Western benefited from strong global oil prices in 2003, we are striving to drive costs down to ensure that your company is fully competitive on a global basis and that even in a much lower oil price environment, Western can achieve attractive after-tax returns on capital.

From a broader perspective, the Company has now closed the first few chapters in its history — these being the creation of Western, the long and arduous building process and the start-up phase. Over the last five years, we have seen this project evolve from a remote location with only the promise of resource production to a $5.7 billion, dual-site facility. The Board is pleased with the results achieved to date and we believe shareholders have been well rewarded.

We have now opened the next set of chapters, which include the optimization and fulfillment of the ultimate potential of this legacy asset. We have received the preliminary regulatory approvals for Phase I of the Jackpine Mine Expansion. This expansion project is part of our long-term plan for steadily and progressively tapping the full potential of our oil sands leases. Our goal is to achieve production of 525,000 barrels per day of bitumen, 105,000 net to Western, within ten years. We should never lose sight of the fact that Western owns 20% of one of the world's largest oil deposits and that, together with our Joint Venture partners, we have the capability to fully develop this endowment to the benefit of all parties. This will be our primary task over the next decade.

In terms of corporate governance, your Board has worked hard to ensure that the best practices are in place. In the first instance, most of the Board members and management are significant and direct personal investors in Western and have been so for some time. Secondly, we have been very fortunate to have excellent directors with a depth and breadth of expertise in all areas of Board operations, who have provided true guidance and valuable insights that have aided management over the past five years. Your Board now consists of ten directors, of which all but one, the Chief Executive Officer, are independent. All four of the committees — Audit, Compensation, Corporate Governance and Health, Safety and Environment — consist of independent directors. In-camera sessions without management form part of every Board meeting.

I would especially like to welcome Mr. Oyvind Hushovd and Mr. John Lill to the Board. Both are highly experienced mining executives with global experience. I would personally like to thank all of my fellow directors for their hard work, frankness, insights and consistent pursuit of Western's best long-term interests.

And the Board would like to thank Mr. Guy Turcotte, our Chief Executive Officer, and all members of the Western team for their commitment and for striving on behalf of Western. We are very proud of, and thankful for, your efforts.

We look forward to the next five years as Western Oil Sands moves into the optimization and expansion phase.

On behalf of the Board of Directors,

G.A. Cumming

Geoffrey A. Cumming
*Chairman*
February 18, 2004

Outstanding team performance. That is how I would characterize the accomplishments that we realized in 2003. After four years of tremendous effort by thousands of people, this Project came to realization. By the fourth quarter we were mining 250,000 tonnes per day of oil sands, pipelining 190,000 barrels per day of diluted bitumen through the Corridor pipeline system to Scotford, upgrading 130,000 barrels per day of bitumen into synthetic crude oil and selling the full production into the marketplace. More recently the Project has reached, and sustained for increasing periods, the design capacity production rate of 155,000 barrels per day. This represents an outstanding success for a greenfield project of mammoth proportions.

Perspective is an appropriate theme for this report. Because it is important to keep in perspective the scale of this Project and the significance of what has been accomplished. We began as a team of three companies with only the oil sands underlying our leases and documents detailing a plan to exploit these assets using a known technology to which we made improvements and then tested in our pilot plant. In only four years we, and our Joint Venture partners, together raised close to $6 billion in financing and built the entire project from the ground up. This is a testimony to the skills of the hundreds of scientists and engineers who planned every detail of this project and to the dedication of the thousands of people who followed those plans in executing the project. Other oil sands pioneers, companies with similarly enormous projects, took years to realize the level of success they anticipated at the outset. We have been fortunate to benefit from their experience.

But it would be inaccurate to suggest that we can pause and rest on this success. The focus of the team has seamlessly shifted to continuous improvement and consistent progress as we have entered the operating phase of the Project. We have identified the challenges ahead and are moving steadily towards overcoming them.

One of the governing principles of this Project is the significant economies of scale that can be achieved when any reduction in cost or improvement in performance is multiplied by the remaining barrels yet to be produced. For Western the equation is clear: for every dollar per barrel of cost we can eliminate, the gain in net earnings is approximately $1.3 billion over the life of the Project. We are working today to reach our target $12 to $14 per barrel cost of producing synthetic crude assuming natural gas prices similar to those experienced in 2003. We will achieve that target through a combination of aggressive cost management, continuous stable output of bitumen production and steady, reliable plant operation. The progress is being made through a series of adjustments to the existing process that forms a continuous flow of refinements known as de-bottlenecking.

In much the same way that the costs are falling, production volumes will steadily increase. At points in time during 2003 we achieved the design capacity of 155,000 barrels per day of bitumen production. In fact, there were days when we were producing well in excess of this level and other days when production dipped below this target as we continued to adjust and fine-tune the processes. Our target production level that we believe is achievable through the de-bottlenecking stage is approximately 180,000 barrels per day and we are confident

**THE GAIN IN NET EARNINGS IS APPROXIMATELY $1.3 BILLION**

Guy J. Turcotte
*President and Chief Executive Officer*

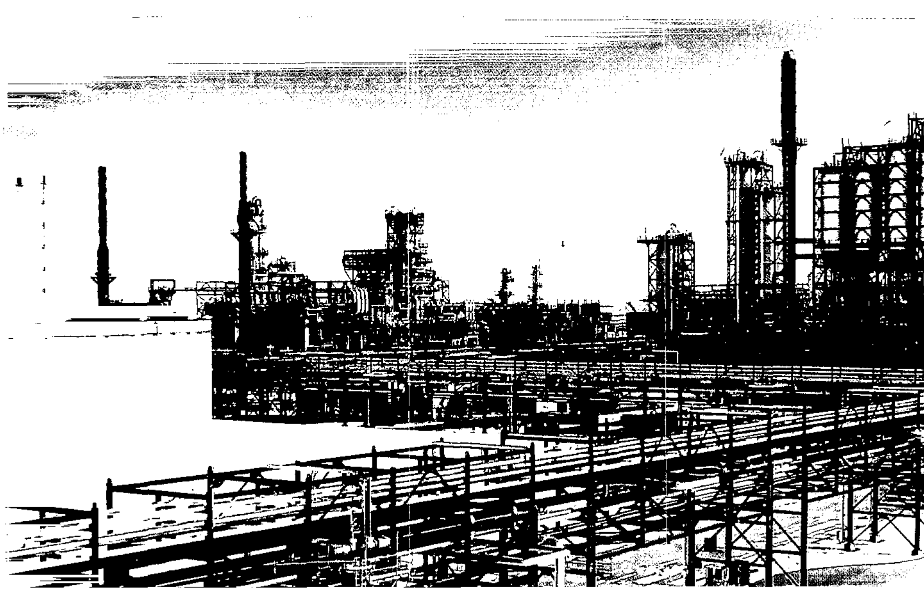
that level will be realized. We will also be looking at an additional investment in the Upgrader over the next two to three years that will result in a higher proportion of lighter synthetic crude in the refined output streams.

The Joint Venture group — Shell, ChevronTexaco and Western — is turning its attention to the expansion phase of the Project. Given the success of the first phase, our collaboration is even stronger and we are aligned in our commitment to build upon what we have learned. The fact that we are in the oil sands production business now gives us a very different starting point for an expansion phase. The risk for the expansion projects is clearly much reduced by our knowledge of the operations and proven status of the technology. We recently received preliminary approval of our application for the Jackpine Mine Expansion — Phase 1 development of the eastern portion of Lease 13. The application is subject to certain conditions and must now be approved by the Cabinets of both the Provincial and Federal governments. Once approvals are received, we will move ahead with the project development phase, which includes feasibility studies and continued community dialogue. This expansion project has the potential to add 200,000 barrels per day (40,000 barrels per day net to Western) of bitumen production. A potential expansion to include Phase 2 of the Jackpine Mine Expansion could contribute a further 100,000 barrels per day (20,000 barrels per day net to Western).

For Western the future is both clear and exciting. We will continue to participate in the development of the Athabasca Oil Sands Project and exploit the full potential of our portion of this massive oil sands resource. At the same time, we are investigating the potential for additional, incremental opportunities. For example, we are considering the acquisition of additional oil sands leases that are or may become available in the Athabasca oil sands area. We are also following with interest the work being done to identify the titanium content in the tailings in the Athabasca oil sands region. To this end, we have formed a joint venture with a highly specialized research team whose expertise is oil sands process technology. Western will invest a modest amount in 2004 with this group to examine opportunities with the potential to add value to our existing investment in oil sands.

In closing, I want to salute our staff and the entire joint venture team for an exceptional job over the past year. We were faced with many challenges and we met them with the same diligent effort and focused expertise that has made this Project such a success. I look forward to 2004 as a year of continuous improvements and steady progress for Western and its Joint Venture partners.

Guy J. Turcotte
*President and Chief Executive Officer*
*February 18, 2004*

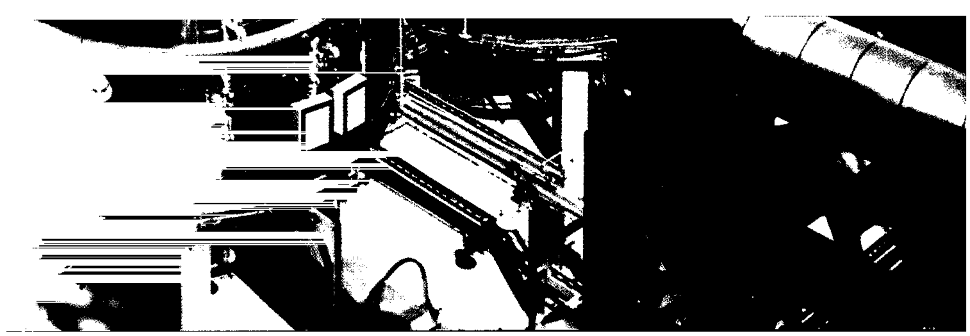


**WE RECENTLY RECEIVED PRELIMINARY APPROVAL OF OUR APPLICATION FOR THE JACKPINE MINE EXPANSION – PHASE 1 DEVELOPMENT OF THE EASTERN PORTION OF LEASE 13.**

HOLDS A 20 PER CENT UNDIVIDED

OWNERSHIP INTEREST IN A MULTI-BILLION DOLLAR JOINT VENTURE THAT IS EXPLOITING THE RECOVERABLE

RESOURCES FOUND IN OIL SANDS DEPOSITS IN THE ATHABASCA REGION.



*The following discussion of financial condition and results of operations was prepared as of February 18, 2004 and should be read in conjunction with the Consolidated Financial Statements and Notes thereto. It offers Management's analysis of our financial and operating results and contains certain forward-looking statements relating but not limited to our operations, anticipated financial performance, business prospects and strategies. Forward-looking information typically contains statements with words such as "anticipate", "estimate", "expect", "potential", "could" or similar words suggesting future outcomes. We caution readers to not place undue reliance on forward-looking information because it is possible that predictions, forecasts, projections and other forms of forward-looking information will not be achieved by Western.*

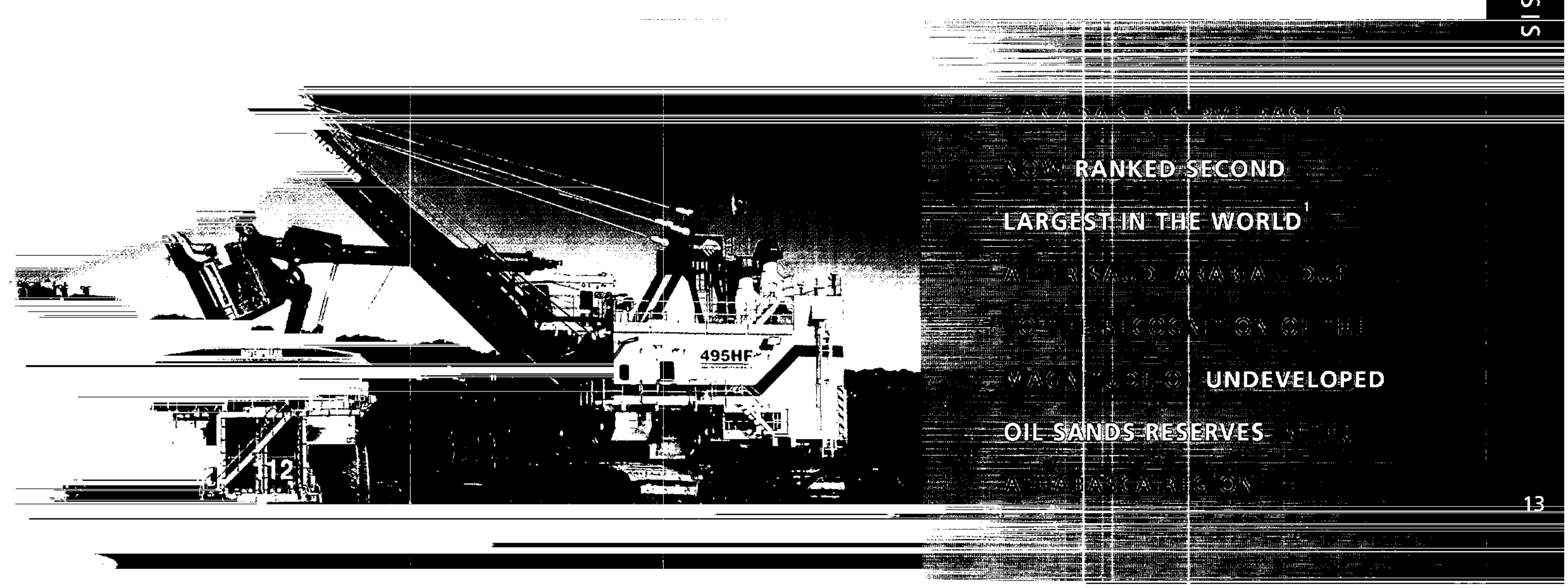
*By its nature, our forward-looking information involves numerous assumptions, inherent risks and uncertainties. A change in any one of these factors could cause actual events or results to differ materially from those projected in the forward-looking information. These factors include, but are not limited to, the following: market conditions, law or government policy, operating conditions and costs, project schedules, operating performance, demand for oil, gas and related products, price and exchange rate fluctuations, commercial negotiations or other technical and economic factors. For additional information relating to risk factors please refer to the discussion on page 34 entitled Risk and Success Factors Relating to Oil Sands.*

*Additional Information relating to Western, including Western's 2003 Annual Information Form, is available at www.sedar.com.*

## OVERVIEW

Interest in non-conventional resources including the oil sands has been growing, particularly with the continued decline in conventional crude oil reserves and production. The investment community, governments and other stakeholders increasingly recognize the important role oil sands will play in the future of the energy industry and of our economy. Canada's reserve base is now ranked second largest in the world [1] — after Saudi Arabia — due to the recognition of the magnitude of undeveloped oil sands reserves in the Athabasca region of northeastern Alberta.

[1] IEA International Energy Outlook




MANAGEMENT'S DISCUSSION & ANALYSIS

Western Oil Sands Inc. is a Canadian oil sands corporation that holds a 20 per cent undivided ownership interest in a multi-billion dollar Joint Venture that is exploiting the recoverable bitumen reserves and resources found in oil sands deposits in the Athabasca region of Alberta, Canada. Shell Canada Limited ("Shell") and Chevron Canada Limited ("ChevronTexaco") hold the remaining 60 per cent and 20 per cent undivided ownership interests in the Joint Venture, respectively. The Athabasca Oil Sands Project (the "AOSP" or the "Project"), which includes facilities owned by the Joint Venture and third parties, uses established processes to mine oil sands deposits, extract, and upgrade the bitumen into synthetic crude oil and vacuum gas oil. Currently, apart from our interest in the Project, we have no other material assets nor do we have any other ongoing operations. Western is, however, actively pursuing other oil sands and related business opportunities.

The Joint Venture is currently developing and producing from the western portion of Lease 13, a large oil sands lease in the Athabasca region held by the Joint Venture. Once bitumen has been extracted at the Mine it is shipped through the Corridor Pipeline to the Scotford Upgrader where it is processed and combined with feedstock, and at design capacity will produce approximately 190,000 barrels per day (38,000 barrels per day net to Western) of vacuum gas oil and synthetic crude oil. The western portion of Lease 13 contains approximately 1.6 billion barrels of proved and probable reserves and is sufficient for 27 years of non-declining bitumen production at a rate of 155,000 barrels per day (31,000 barrels per day net to Western). De-bottlenecking activities being initiated in 2004 are expected to further increase production capacity at the Muskeg River Mine ("MRM" or the "Mine") to 180,000 barrels per day over the next two years.

Western is entitled to participate in future expansion opportunities, including the undeveloped eastern portion of Lease 13 and three other nearby oil sands leases owned by Shell, referred to as Leases 88, 89 and 90. We have commenced work on permitting the expansion of our existing operations at the Muskeg River Mine. Once approvals for the MRM Expansion are received, we expect to move ahead with the project development phase, which will include feasibility studies and continued community dialogue. Western anticipates that the MRM Expansion may increase the productive capacity of our existing facilities by up to 50 per cent. In addition, we recently received conditional approval from the joint review panel established by the Alberta Energy and Utilities Board and the Government of Canada to develop the eastern portion of Lease 13, known as the Jackpine Mine — Phase 1. The application is subject to certain conditions and must now be approved by the Cabinets of both the Provincial and Federal governments. This expansion project has the potential to add 200,000 barrels per day (40,000 barrels per day net to Western) of bitumen production. Phase 2 of the Jackpine Mine Expansion could contribute a further 100,000 barrels per day (20,000 barrels per day net to Western). The timing and details of any expansion will be subject to the outcome of future evaluations of economics, market needs, regulatory requirements and to sustainable development considerations.

BY THE FOURTH QUARTER, THE PROJECT WAS OPERATING AT **84 PER CENT OF DESIGN CAPACITY.** THIS IS VERY CLOSE TO THE ORIGINAL FEASIBILITY STUDY RAMP UP CURVE FOR PRODUCTION WHICH IS **SUBSTANTIALLY BETTER THAN WHAT IS TYPICAL** FOR PLANTS OF THIS NATURE.

John Frangos
*Executive Vice-President and Chief Operating Officer*

## 2003 HIGHLIGHTS

- In 2003, following three years of construction, the Project moved into its operational phase.
- Fully integrated operations between the Muskeg River Mine site and the Scotford Upgrader were achieved on April 19, 2003.
- Western's threshold for commercial bitumen production from the Project of 77,500 barrels per day (15,000 barrels per day net to Western) was exceeded on June 1. Production ramped up over the next seven months of 2003 to average approximately 118,000 barrels per day (23,600 barrels per day net to Western).
- Western successfully established itself as an independent full-service marketer of crude oil.
- Market acceptance for the AOSP's two new synthetic crude products – Premium Albian Synthetic (PAS) and Albian Heavy Synthetic (AHS) was strong and as the Project nears full capacity on a sustained basis, we will manage the mix of our synthetic crude oil products.
- The financial impact on Western of the increase in WTI pricing, to which our products are benchmarked, has been tempered by a strengthened Canadian/US dollar exchange rate.
- Western established a $240 million Revolving Credit Facility, replacing the existing $110 million Revolving Facility and repaying $88 million in Convertible Notes. We also raised $50.2 million in equity.
- Western filed claims totaling $200 million against our Cost Overrun and Project Delay Insurance Policy and subsequently initiated arbitration proceedings to resolve the outstanding claims.
- Western has recovered $9.7 million on insurance claims during the year for costs to repair fire and freeze damages under the Project's Joint Venture construction insurance policies.
- With the commencement of operations, Western established ongoing insurance policies including US$500 million of Property and Business Interruption Insurance and US$100 million of Liability Insurance.
- Preliminary approval has been received for the first phase of the Jackpine Mine Expansion situated on the eastern portion of Lease 13. This expansion has the potential to add up to 200,000 barrels per day of incremental production (40,000 barrels per day net to Western).
- Western's share of proved plus probable reserves at December 31, 2003, totaled 311 million barrels. Total remaining resources for the AOSP, including adjoining leases for potential expansion, are 8.7 billion barrels of which Western's share is 1.7 billion barrels.
- The Project's safety performance record, environmental protection and stakeholder relations, were major successes and are seen as key to sustainable development.

## 2003 HIGHLIGHTS (continued)

Financial results for the year ended December 31, 2003 include operating revenues and expenses from June 1, 2003, the date Western commenced commercial production.

| | 2003 | 2002 | 2001 |
|---|---|---|---|
| **Operating Data** (bbls/d) | | | |
| Bitumen Production | **23,596** | – | – |
| Synthetic Crude Sales | **32,207** | – | – |
| **Financial Data** ($ thousands, except as indicated) | | | |
| Revenues | **281,093** | – | – |
| Realized Crude Oil Sales Price – Oil Sands ($/bbl) [(1)] [(2)] | **32.81** | – | – |
| Cash Flow from Operations [(3)] | **5,803** | (8,603) | (6,845) |
| Cash Flow per Share – Basic ($/Share) [(1)] [(4)] | **0.12** | (0.18) | (0.17) |
| Net Earnings (Loss) Attributable to | | | |
| Common Shareholders [(7)] | **15,003** | (10,286) | (7,015) |
| Net Earnings (Loss) per Share ($/Share) | | | |
| Basic | **0.30** | (0.21) | (0.17) |
| Diluted | **0.29** | (0.21) | (0.17) |
| EBITDA [(1)] [(5)] | **47,337** | (5,698) | (5,310) |
| EBITDA ($/bbl) [(1)] [(6)] | **9.37** | – | – |
| Net Capital Expenditures | **148,473** | 527,541 | 433,604 |
| Total Assets | **1,458,424** | 1,359,638 | 854,394 |
| Long-Term Liabilities | **921,910** | 827,133 | 368,306 |
| Weighted Average Shares Outstanding – Basic (Shares) | **50,344,332** | 48,330,320 | 41,404,904 |

(1) *Please refer to page 38 for a discussion of Non-GAAP financial measures.*

(2) *The realized crude oil sales price is the revenue derived from the sale of Western's share of the Project's synthetic crude oil divided by the corresponding volume. Please refer to page 21 for calculation.*

(3) *Cash flow from operations is expressed before changes in non-cash working capital.*

(4) *Cash flow per share is calculated as cash flow from operations divided by weighted average common shares outstanding, basic.*

(5) *Earnings before interest, taxes, depreciation, depletion, amortization and foreign exchange as calculated on page 26.*

(6) *EBITDA ($/bbl) is EBITDA divided by total bitumen production for the year.*

(7) *Western has not paid cash dividends in any of the above referenced fiscal years.*

## OPERATING RESULTS

On June 1, 2003, Western commenced commercial operations, which was defined by management as attaining 50 per cent of the Project's production design capacity of 155,000 barrels per day, with all aspects of the facilities fully operational. Accordingly, Western has recorded revenues and expenses for our share of operations from the Project beginning on that date. Prior to June 1, 2003 all revenues, operating costs and interest were capitalized as part of the costs of the Project, and no depreciation, depletion or amortization were expensed. Comparisons to prior year, pre-operating information are provided in the following discussion where appropriate.

## Production

In 2003, the Project successfully ramped up production to an average rate of 130,000 barrels per day in the fourth quarter. As expected, we encountered various operational challenges associated with start-up throughout the year; however, each challenge became an opportunity for learning and improving the performance of the systems, equipment and operational teams.

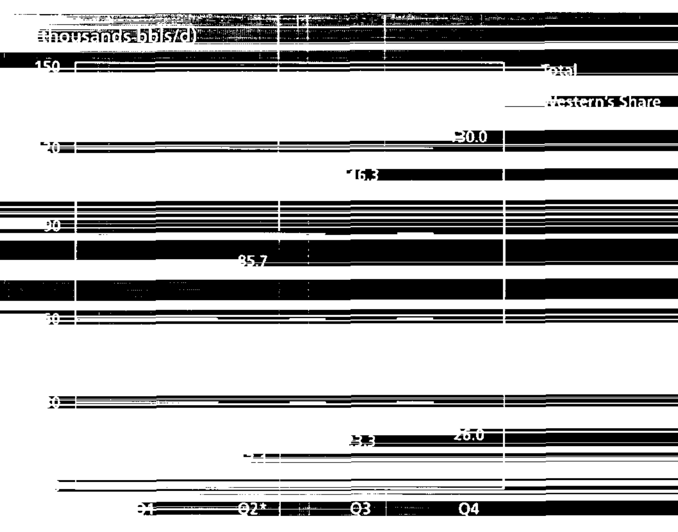
The year began with great anticipation following three intense years of construction and commissioning. On December 29, 2002, operations began at the Muskeg River Mine when Train 1, the first of two extraction units, officially started producing bitumen for transportation through the Corridor Pipeline system to the Scotford Upgrader at Fort Saskatchewan. The production process at the Mine includes the following stages:

- Ore is mined with electric shovels which load the sand/bitumen mixture into 400-ton haul trucks for transport to one of two primary roll crushers. The mixture is then taken by a conveyor system to rotary breakers that further reduce the particle size. Warm water is introduced, waste rock is rejected and the resulting slurry is pumped to the Extraction Plant.
- At the Extraction Plant the bitumen is separated from much of the sand, clay and other materials. The extraction process adds air to the pumped slurry, which is then discharged into two primary separation vessels where the bitumen attaches to air bubbles and rises to the top forming a froth. A steam stripper removes the air bubbles and the bitumen flows to two large froth storage tanks.
- In the final stage, called froth treatment, a solvent is added that separates out the remaining solids, water and heavy asphaltenes, leaving clean diluted bitumen.

On January 6, 2003, we experienced a fire in the froth cleaning circuit at the Mine resulting in damage to electrical and control cables, instrumentation and insulation. Severe weather conditions caused broader freeze damage and impeded progress in making repairs. Operations recommenced on April 4 at the Mine and on April 19 fully integrated operations were achieved when the Scotford Upgrader started receiving and processing bitumen from the Mine. Ramp-up of oil sands throughput and bitumen production has continued uninterrupted and with steady progress and increasing volumes throughout the year.

**2003 PRODUCTION**

| | |
|---|---|
| Production (bbls) | 5,049,595 |
| Daily Average Commercial Production (bbls/d) | 23,596 |



Mining and extraction processes were initiated successfully given the variables expected in this type of operation. The Mine was able to achieve a ramp-up of throughput and production approaching design levels by year-end, with production of bitumen averaging approximately 130,000 barrels per day in the fourth quarter. Issues such as ore variability, equipment reliability and robustness, flow velocities, wear, and measurement and control were encountered; these issues are normal to mine and extraction plant start-ups and are being addressed and resolved systematically.

By the fourth quarter, the Project was operating at 84 per cent of design capacity. This is very close to the original feasibility study ramp-up curve for production at the Mine that was considered by many to be aggressive, and is substantially better than what is typical for plants of this nature where step-out technology[2] has been incorporated. Management believes that this also represents the best start-up performance for large scale projects that the mineable oil sands industry has experienced to date, a credit to the entire team involved in the project.

Other challenges encountered at the Muskeg River Mine were not unusual for mining operations in northern Alberta, where temperatures typically range from +40°C to -50°C. In 2003, the Mine and Extraction Plant experienced no lost time for weather related events which confirms the robustness of our plant and equipment and provides the confidence needed to de-bottleneck and expand these operations in the earliest time frame. In the early part of 2004, however, operations were severely tested with lower than normal temperatures, and this experience gives us confidence that continued improvements can be achieved in terms of increased production and reduced costs. Operators must learn to work within these extremes, given the physical limitations of the mining equipment, the nature of the ore, and the ground conditions of the ore body, to optimize production levels and cost. At the Muskeg River Mine we are nearing the top of this learning curve; we have had considerable success but some challenges may remain for future seasonal cycles.

The Upgrader is among the largest of its type in the world and experienced a world class start-up with production capacity and conversion rates moving consistently towards design targets. Hydro-conversion and integrated hydro-treating technologies performed exceptionally well, meeting design levels and enabling the production of high quality on-spec vacuum gas oil and synthetic crude oil. Management's evaluation of the Solomon Survey of upgraders of similar size and complexity indicates that this unit already ranks among the "best-in-class" but additional improvements are possible as we address deficiencies and gain more operating experience and familiarity with the plant. Currently, the primary areas of focus for the Upgrader management are hydrocarbon management processes that are targeting higher conversion levels, and various other initiatives to increase profitability through improved energy efficiency and reliability, increased production rates and lower operating costs. These initiatives began in 2003 and will continue in earnest in 2004 as higher bitumen feed rates are received from the Mine.

Our third party partners provided pipeline and cogeneration operations that fully met our requirements and contributed to our successful start-up. Minor equipment issues with pump station valves and a heat recovery steam generator were resolved effectively.

Overall, 2003 was a year of significant achievements in starting up a world-class project, aggressively increasing production towards design targets, and establishing a base for continued improvements, de-bottlenecking and expansion opportunities.

[2] *Application of counter-current decantation technology to bitumen froth cleaning circuit at the extraction plant.*

## Marketing

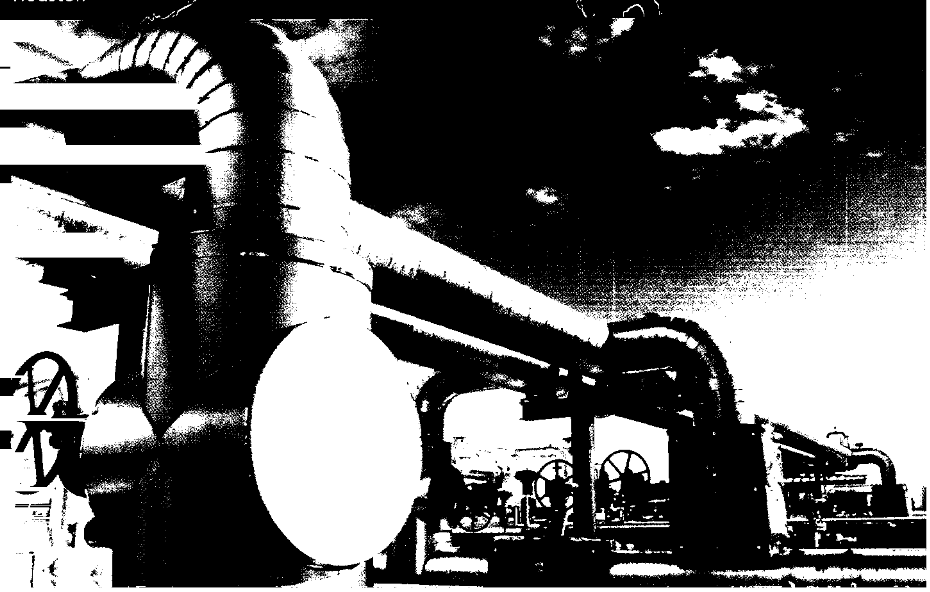
Western has established a marketing department comprised of four individuals who are responsible for marketing Western's share of synthetic crude oil products. Two-thirds of our bitumen products, together with feedstocks and blendstocks are upgraded into synthetic crude oil — our Premium Albian Synthetic (PAS) and Albian Heavy Synthetic (AHS) crude products. We take our 20% share of these products in kind and market them directly to refineries within North America. In addition to marketing our proprietary crude oil products, we have also been actively marketing and brokering displaced and third party volumes. The remaining one-third of our production is comprised of LMHVGO (light, medium and heavy vacuum gas oil) which is sold under a long-term supply agreement.

Our primary marketing objective in 2003 was to establish market outlets and transportation avenues to ensure that we never curtailed production. Other key objectives were to establish Western's profile as an independent full-service marketer of crude oil and to gain market acceptance for two new crude oil products; PAS and AHS. In 2003 we achieved all of these objectives.

We adopted an aggressive strategy to introduce our two new synthetic crude products to customers. In certain circumstances this included marketing and brokering displaced volumes from these customers to other third parties. This innovative approach allowed refiners to assess these new crude types without having to disrupt their normal supply arrangements. It also allowed us to honour our commitments throughout the ramp-up period. Through these third party opportunities and our ongoing marketing efforts, we have become an active shipper on most major crude oil trunkline systems, further enhancing Western's status as a reliable full-service marketer of crude. As a result, we succeeded in moving all of our production volumes into the traditional North American markets.

As customers processed and evaluated our PAS and AHS, they recognized the inherent value in Western's crude streams. While our upgrading provides synthetic crude oil with superior qualities for processing, our products also lend themselves to blending and customizing and this flexibility may lead to significant improvements in refinery efficiencies for our customers. This is the next step in meeting and exceeding continual changes in customer requirements.

As we move into 2004 we continue to forge new customer relationships and build on the competitive advantages that have set us apart from other marketers. Western's role as we continue to grow will be to respond to the continuing changes in our customers' long-term crude oil requirements. Through our existing and expanded infrastructure, we will support our customers by producing and blending customized crude streams that are uniquely tailored to their operations. These streams will be shipped via a dedicated pipeline to the Edmonton terminals and to the customer in segregated batches to maintain quality and ensure the integrity of our product.

AN ACTIVE SHIPPER

ON MOST MAJOR CRUDE OIL TRUNKLINE

WE SUCCEEDED IN MOVING ALL

OF OUR PRODUCTION VOLUMES

The broad market penetration achieved this year has given us a wide customer base to position ourselves for the next phases of our growth, from Western's current year average production of approximately 23,600 barrels per day to the projected 105,000 barrels per day of bitumen to be produced at the Mine in the next decade. Our de-bottlenecking initiatives commencing in 2004 will give our customers access to increasing production volumes in the near-term, while proposed expansion projects will provide access to secure long-term supplies and may yield new and different types of crude.

## Revenue

Western earned $281.1 million in crude oil sales revenue in 2003, including $226.2 million from our share of synthetic crude oil from the Upgrader, at an average realized price of $32.81 per barrel. This includes our risk management activities which reduced revenue by $8.2 million and reduced the average realized price by $1.20 per barrel. The Edmonton PAR benchmark averaged $40.92 per barrel over the seven months of commercial operations, resulting in an average synthetic crude oil quality differential of $6.91 per barrel for Western. This reflects a greater discount from Edmonton PAR than our long-term target of $1.75 to $2.75 per barrel, mainly due to wider than anticipated heavy oil price differentials and higher ratios of heavy synthetic product in the overall sales mix during start-up. Our price realizations relative to Edmonton PAR are expected to improve as our operations stabilize, our products become more established in the marketplace and various Upgrader optimization initiatives are undertaken. Differentials in 2004 should improve compared with 2003 but are still expected to be wider than our long-term target.

Western generated net revenue of $163.5 million, after considering the impact of purchased feedstocks and transportation costs downstream of Edmonton. Feedstocks are crude products introduced at the Upgrader. Some are introduced into the hydrocracking/hydrotreating process and some are used as blendstock to create various qualities of synthetic crude oil products. The cost of these feedstocks is dependent upon world oil markets and the spread between heavy and light crude oil prices.

NET REVENUE

| (thousands, except as indicated) | 2003 |
|---|---|
| **Revenue** | |
| Oil Sands | **$ 226,154** |
| Marketing | **54,512** |
| Transportation | **427** |
| Total Revenue | **281,093** |
| **Purchased Feedstocks and Transportation** | |
| Oil Sands | **62,437** |
| Marketing | **54,412** |
| Transportation | **731** |
| Total Purchased Feedstocks and Transportation | **117,580** |
| **Net Revenue** | |
| Oil Sands | **163,717** |
| Marketing | **100** |
| Transportation | **(304)** |
| Total Net Revenue | **$ 163,513** |
| Synthetic Crude Sales (bbls/d) | **32,207** |
| Crude Oil Sales Price ($/bbl) | **$ 32.81** |

## Operating Costs

Our share of Project operating costs totaled $106.8 million for the seven month period in 2003. Included are the costs associated with removing overburden at the Mine and the costs of transporting bitumen from the Mine to the Upgrader. This equates to unit operating costs of $21.16 per barrel for the seven month operating period based on an average production rate of approximately 118,000 barrels per day (23,600 barrels per day net to Western). We expect to see a significant decline in these unit costs as production volumes grow and stabilize and as the various equipment and operational challenges associated with ramp-up are resolved. Cost reduction initiatives for 2004 are focusing on heat exchanger performance, settler mechanical reliability, ore preparation plant issues, energy efficiency improvements, wear and solvent recovery.

### OPERATING COSTS

| | 2003 |
|---|---|
| $ Millions | **106.8** |
| $/bbl | **21.16** |

The cost of producing synthetic crude oil from oil sands is perceived as being higher than the cost to produce oil from conventional sources. However, when one considers the total cost of production, including finding and development costs, operating costs, royalties, depletion and taxation, oil sands are very competitive. Operating costs for oil sands operations typically decline over time as the technological and engineering challenges are addressed and resolved. This is already occurring for our Project and we expect to see a continued reduction in operating costs over the next couple of years. Given our state of the art technology and what we assess as a superior ore body, we believe we can be one of the lowest cost producers of synthetic crude.

All greenfield resource projects are unique. Unlike expansions that draw from operating experience, the AOSP is a technological extension of the past 30 years of industry's oil sands operating experience and development. As such, many assumptions were made relating to ore grade, grain structure and distribution, wear, flow velocities, settling rates, and heating and cooling rates in the detailed design stages of the project. As operations began, these assumptions were tested and modified and will have an impact on costs until corrected. Modification and optimization will be the focus in 2004 as we move toward our objective of being one of the lowest cost operators in the sector. Part of our cost improvement will come from the benefits inherent in increased throughput above design levels that we expect to achieve through our de-bottlenecking program, now underway. Other improvements in cost will come from energy efficiencies, which were recognized opportunities in 2003 and are now being pursued in earnest in 2004.

## Royalties

Royalties were triggered with the start of production and totaled $1.2 million or $0.23 per barrel of bitumen produced in 2003. Initially, royalties are calculated at one per cent of the gross revenue from the bitumen produced (based on its deemed value prior to upgrading) until we recover all capital costs associated with the Muskeg River Mine and Extraction Plant, together with a return on capital equal to the Government of Canada federal long-term bond rate. After full capital cost recovery, the royalty is calculated as the greater of one per cent of the gross revenue on the bitumen produced and 25 per cent of the net revenue on the bitumen produced. We estimate that payout will not be achieved for several years, after which we will be paying royalties at the higher rates. The timing of this will depend in part on the prices we receive for our production as well any additional capital costs incurred through expansion activities, which would have the effect of deferring this royalty horizon.

## Reserves

Gilbert Laustsen Jung Associates Ltd. (GLJ), an independent engineering firm located in Calgary, evaluates our reserves. The following table summarizes the Project reserves and our share of those reserves as at December 31, 2003, based on GLJ's forecast of escalating prices and costs:

### RESERVES SUMMARY

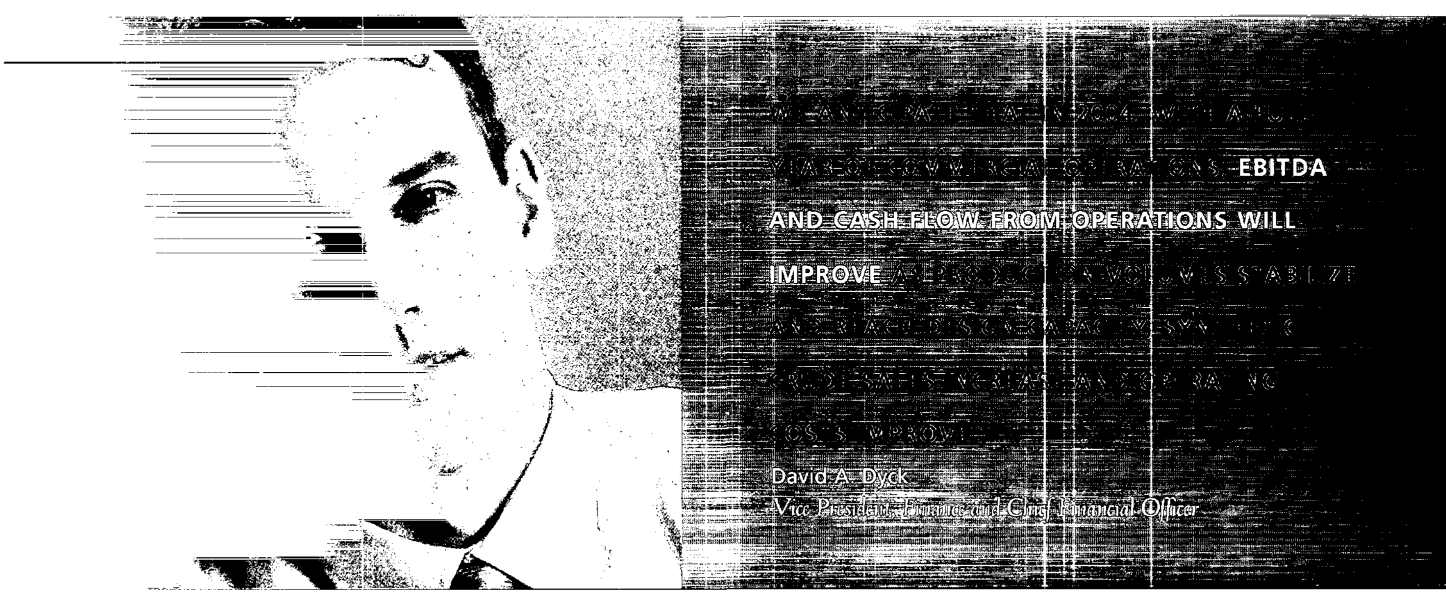
| | Gross Project Reserves (MMbbls) | Ownership Interest Reserves (MMbbls) | Net After Royalty (MMbbls) | Present Values of Estimated Future Net Cash Flow Before Income Taxes | | | |
|---|---|---|---|---|---|---|---|
| | | | | 0% | 10% | 15% | 20% |
| | | | | ($ millions) | | | |
| Proved | 1,071 | 214 | 196 | 2,522 | 1,242 | 971 | 798 |
| Probable | 485 | 97 | 83 | 1,518 | 363 | 221 | 151 |
| Proved Plus Probable | 1,556 | 311 | 279 | 4,040 | 1,605 | 1,192 | 949 |

### RESERVES RECONCILIATION

| | Proved (MMbbls) | Proved Plus Probable (MMbbls) |
|---|---|---|
| December 31, 2002 | 222.0 | 336.0 |
| Production [1] | (5.2) | (5.2) |
| Revisions | (2.8) | (19.8) |
| December 31, 2003 | 214.0 | 311.0 |

[1] *Upgraded bitumen production, which is dry bitumen, uplifted by 3.0 per cent for hydrocracking/hydrotreating.*

This analysis by GLJ includes only those reserves to the west of the Muskeg River on Lease 13 to be mined by the Joint Venture. These reserves will provide a reserve life of approximately 27 years based on anticipated bitumen production rates of 155,000 barrels per day (our share is 31,000 barrels per day).



The following table outlines the potential undeveloped resources available on the remainder of Lease 13 and on three nearby oil sands leases owned by Shell, namely Leases 88, 89 and 90. In so far as we undertake to participate in the expansion opportunities, development of these resources will provide for substantial growth in our proved and probable reserve base at that time.

POTENTIAL RESOURCES

| | Total Resources (MMbbls) | Western's Share (MMbbls) |
|---|---|---|
| Remainder of Lease 13 and Lease 90 | 3,200 | 640 |
| Leases 88 and 89 | 3,900 | 780 |
| Total | 7,100 | 1,420 |

## CORPORATE RESULTS

### General and Administrative Expenses

General and administrative expenses were $6.5 million in 2003 or $1.29 per barrel (2002 — $5.7 million). This year-over-year increase reflects additional personnel as the Project entered the operating phase. As well, our early adoption of the policy to expense stock options as a compensation expense in 2003 added $0.3 million to administrative expenses.

### Insurance Expenses

Insurance expenses were $1.7 million in 2003 (2002 — $0.01 million). During the fourth quarter of 2003, Western established US$500 million of Property and Business Interruption Insurance coverage and Liability Insurance coverage of US$100 million. The annual premium for these policies is approximately $9.0 million. At December 31, 2003, we had incurred $7.7 million in respect of these policies, of which $1.4 million had been expensed in the year and $6.3 million remained in prepaid expenses. The remainder of the insurance expense for 2003 represents director and officer liability insurance and other general office insurance.

### Interest Expense

During 2003 we incurred $60.5 million in interest charges on our debt obligations (2002 — $48.1 million) and $1.4 million on the capital lease obligations. These obligations included US$450 million in Senior Secured Notes, a $100 million Senior Credit Facility and a $240 million Revolving Credit Facility. Interest charges in the amount of $23.5 million incurred prior to commercial production on June 1, were capitalized and will be amortized over the life of the Project's reserves. Interest costs of $38.4 million were expensed over the seven month operating period. The following table summarizes our interest expense and average cost of debt for the past two fiscal years.

**INTEREST AND LONG-TERM DEBT FINANCING**

| (thousands, except as indicated) | 2003 | 2002 |
|---|---|---|
| **Interest Expense** | | |
| Interest Expense on Long-term Debt [1] | $ 60,522 | $ 48,126 |
| Less: Capitalized Interest | (23,479) | (48,126) |
| Net Interest Expense on Long-term Debt | 37,043 | – |
| Interest on Obligations under Capital Lease | 1,386 | – |
| Net Interest Expense | $ 38,429 | $ – |
| **Long-term Debt Financing** | | |
| US$450 Million Senior Secured Notes [2] | $ 581,580 | $ 710,820 |
| Revolving and Senior Credit Facilities [1] | 279,000 | 65,000 |
| Total Long-term Debt | $ 860,580 | $ 775,820 |
| Average Long-term Debt Level | $ 818,200 | $ 527,651 |
| Average Cost of Long-term Debt | 7.40% | 9.12% |

[1] *Includes $88 million in Convertible Notes that were repaid and refinanced October 24, 2003 with the $240 million Revolving Credit Facility, described in Note 7(c) of the Consolidated Financial Statements. Accordingly interest has only been included since October 24, 2003 in respect of this amount, as interest on the Convertible Notes was previously charged directly to the deficit as described in Note 2(i) of the Consolidated Financial Statements.*

[2] *Under Canadian GAAP, the Senior Secured Notes are recorded in Canadian dollars at exchange rates in effect at each balance sheet date. Unrealized foreign exchange gains or losses are then included on the Consolidated Statement of Operations. Prior to June 1, 2003 all foreign exchange gains or losses were capitalized as part of the financing costs of the Project.*

## Depreciation, Depletion & Amortization

In 2003, we recorded $27.5 million as depreciation, depletion and amortization expense. Depletion is calculated on a unit of production basis for our share of Project capital costs while previously deferred financing charges are amortized on a straight-line basis over the remaining life of the debt facilities. Depletion and amortization have only been recorded since June 1, 2003, the date commercial operations commenced.

**DEPRECIATION, DEPLETION & AMORTIZATION**

| | (thousands) | $/bbl |
|---|---|---|
| Depreciation and Depletion | $ 19,994 | $ 3.96 |
| Amortization | 7,537 | 1.49 |
| Total Depreciation, Depletion and Amortization | $ 27,531 | $ 5.45 |

## Foreign Exchange

While the oil and gas industry benefited in 2003 from sustained high commodity prices, this was tempered by a strengthening Canadian dollar that moved from US$0.63 to US$0.77 during the year. For Western, the foreign exchange impact on revenues was somewhat offset by lower interest costs on our US dollar denominated Senior Secured Notes and a reduced liability (as measured in Canadian dollars) associated with this debt. In 2003 we recorded an unrealized foreign exchange gain of $129.3 million relating to the conversion of the US denominated Senior Secured Notes into Canadian dollars. We capitalized $94.0 million of this foreign exchange gain and the remaining $35.3 million was recognized as income for the period, in accordance with Canadian Generally Accepted Accounting Principles ("GAAP").

## Income Taxes

Western has sizeable tax pools totaling $1.5 billion that have been accumulated over the past three years mainly through our 20 per cent share of construction costs for the Muskeg River Mine and Extraction Plant and the Scotford Upgrader. These tax pools will be used to offset future taxable income and extend the time horizon until we must pay cash taxes.

For the year ended December 31, 2003 we recognized a future income tax asset of $6.3 million compared to a future income tax liability at December 31, 2002 of $0.5 million. This asset is comprised mainly of non-capital loss carry forwards, net of the future income tax effect of the book values of assets in excess of tax values and of the unrealized foreign exchange gains on the US$450 million Senior Secured Notes. During 2003 we expensed $3.1 million (2002 — $2.9 million) with respect to the Large Corporations Tax. This was offset by a future income tax recovery of $4.3 million arising from the potential future benefit of the loss carry forwards.

TAX POOLS

| December 31 (thousands) | 2003 | 2002 |
|---|---|---|
| Canadian Exploration Expense | **$ 123,178** | $ 45,214 |
| Canadian Development Expense | **15,993** | 15,993 |
| Canadian Exploration and Development Overhead Expense | **2,677** | 2,704 |
| Cumulative Eligible Capital | **4,114** | 4,039 |
| Capital Cost Allowance | **25,661** | 25,632 |
| Accelerated Capital Cost Allowance | **1,180,940** | 1,031,616 |
| Total Depreciable Tax Pools | **$ 1,352,563** | $ 1,125,198 |
| Loss Carry Forwards | **129,340** | 45,274 |
| Financing and Share Issue Costs | **25,239** | 34,875 |
| Total Tax Pools | **$ 1,507,142** | $ 1,205,347 |

## Net Earnings

The following table provides the reconciliation between Net Earnings (Loss) Attributable to Common Shareholders, Cash Flow from Operations (before changes in non-cash working capital) and EBITDA:

| December 31 (thousands) | 2003 | 2002 | 2001 |
|---|---|---|---|
| **Net Earnings (Loss) Attributable to Common Shareholders** | **$ 15,003** | $ (10,286) | $ (7,015) |
| Add (Deduct): | | | |
| Depreciation, Depletion and Amortization | **27,531** | 192 | 170 |
| Accretion on Asset Retirement Obligation | **471** | – | – |
| Stock-based Compensation | **278** | – | – |
| Write-off of Deferred Charges | **–** | 22,759 | – |
| Foreign Exchange Gain | **(35,280)** | – | – |
| Future Income Tax Recovery | **(4,330)** | (22,551) | – |
| Charge for Convertible Notes | **2,130** | 1,283 | – |
| **Cash Flow From Operations, Before Changes in Non-Cash Working Capital** | **$ 5,803** | $ (8,603) | $ (6,845) |
| Add (Deduct): | | | |
| Interest | **38,429** | – | – |
| Stock Based Compensation | **(278)** | – | – |
| Realized Foreign Exchange Loss | **304** | – | – |
| Large Corporations Tax | **3,079** | 2,905 | 1,535 |
| EBITDA | **$ 47,337** | $ (5,698) | $ (5,310) |



*Please refer to page 38 for a discussion of Non-GAAP financial measures.*

Our net earnings attributable to common shareholders totaled $15.0 million ($0.30 per share) in 2003 including the seven months of commercial operations. This compares to a net loss attributable to common shareholders of $10.3 million ($0.21 per share) in 2002 prior to operational start-up. Earnings for the 2003 period reflect $35.3 million ($29.1 million net of tax) of unrealized foreign exchange gains on our US$450 million Senior Secured Notes and a future income tax recovery of $4.3 million. Earnings before interest, taxes, depreciation, depletion and amortization, and foreign exchange gains were $47.3 million, again including only seven months of commercial operations. Cash flow from operations for 2003 before changes in non-cash working capital was $5.8 million ($0.12 per share) after $38.4 million in interest charges and $3.1 million in Canadian Large Corporations Tax. We anticipate that in 2004, with a full year of commercial operations, EBITDA and cash flow from operations will improve as production volumes stabilize and reach design capacity, synthetic crude sales increase and operating costs improve.

## Quarterly Information

The following table summarizes key financial information on a quarterly basis for the last two fiscal years.

**QUARTERLY INFORMATION**

| (millions, except per share amounts) | Q1 | Q2 | Q3 | Q4 | Total |
|---|---|---|---|---|---|
| **2003** | | | | | |
| Revenue | $ – | $ 24.9 | $ 122.5 | $ 133.7 | $ 281.1 |
| Capital Expenditures, Net | 112.2 | 25.3 | 3.3 | 7.7 | 148.5 |
| Long-term Debt | 757.2 | 780.9 | 852.7 | 860.6 | 860.6 |
| Cash Flow from Operations [1] | (2.2) | (5.0) | 9.6 | 3.4 | 5.8 |
| Cash Flow per Share [2] [5] | (0.04) | (0.10) | 0.19 | 0.07 | 0.12 |
| Earnings (Loss) Attributable | | | | | |
| to Common Shareholders [3] [4] | (2.4) | 1.3 | (1.5) | 17.6 | 15.0 |
| Earnings (Loss) per Share | | | | | |
| Basic [3] | (0.05) | 0.03 | (0.03) | 0.35 | 0.30 |
| Diluted [3] | (0.05) | 0.02 | (0.03) | 0.35 | 0.29 |
| **2002** | | | | | |
| Revenue | $ – | $ – | $ – | $ – | $ – |
| Capital Expenditures, Net | 110.0 | 133.2 | 145.3 | 139.0 | 527.5 |
| Long-term Debt | 418.5 | 683.4 | 713.6 | 775.8 | 775.8 |
| Cash Flow from Operations [1] | (1.7) | (1.9) | (1.8) | (3.2) | (8.6) |
| Cash Flow per Share [2] [5] | (0.03) | (0.04) | (0.04) | (0.07) | (0.18) |
| Earnings (Loss) Attributable | | | | | |
| to Common Shareholders | (1.8) | (24.7) | (1.8) | 18.0 | (10.3) |
| Earnings (Loss) per Share, | | | | | |
| Basic and Diluted | 0.04 | (0.51) | (0.04) | 0.38 | (0.21) |

(1) *Cash flow from operations is expressed before changes in non-cash working capital.*

(2) *Cash flow per share is calculated as cash flow from operations divided by weighted average common shares outstanding, basic.*

(3) *Restated from quarterly releases to reflect changes in accounting policies regarding asset retirement obligations and stock-based compensation adopted in the fourth quarter.*

(4) *Includes unrealized foreign exchange gains on US$450 million Senior Secured Notes (Q2 – $7.0 million, Q3 – $2.0 million, Q4 – $26.3 million).*

(5) *Please refer to page 38 for a discussion of Non-GAAP financial measures.*

## FINANCIAL POSITION

Over the past three years, one of our primary objectives has been to fund our share of construction costs and to ensure that the timing of proceeds from financings coincides with the funding requirements for the Project. We have consciously structured our financing activities to maximize the value for our shareholders by minimizing the amount of equity issued and to issue equity at successively higher prices. Now that we have achieved start-up, our primary objective is to ensure sufficient working capital exists to fund our operations and looking forward, to ensure we have sufficient resources to enable Western to participate in expansion projects or other investment opportunities that may arise.

### Debt Financing

In 2003, we maintained our US$450 million of Senior Secured Notes along with a $100 million senior credit facility held with a syndicate of chartered banks; $75 million of which was to be used primarily to fund the first year's debt service of the Senior Secured Notes as well as construction completion costs, while the remaining $25 million was for working capital and letter of credit requirements. At December 31, 2003, $91.0 million (2002 — $45.0 million) had been drawn under this facility, with letters of credit issued in the amount of $7.1 million (2002 — $15.4 million).

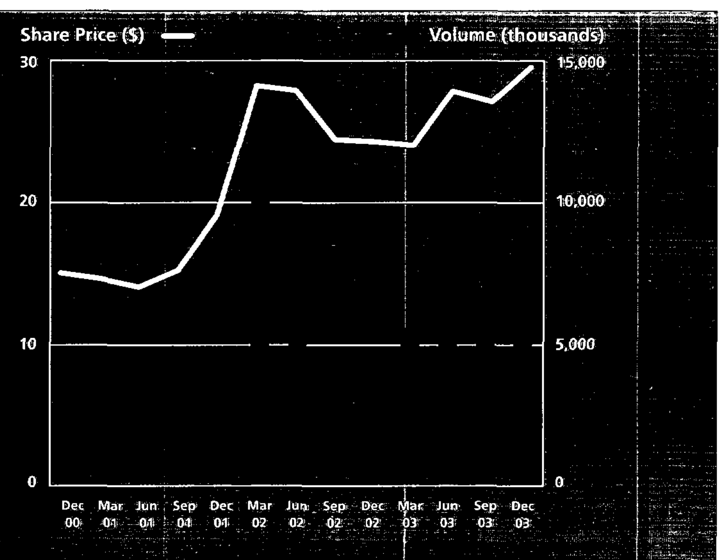
The main change in debt financing in 2003 was establishing a long-term working capital facility to sustain us through operations. To this end, a $50 million Revolving Facility established in November of 2002 was increased in tranches over the year. In January, the facility expanded to $75 million with the addition of another bank to the syndicate, followed by a further increase in May to $110 million with the same banking syndicate. In October, a new $240 million Revolving Credit Facility was established, refinancing the Revolving Facility and providing for the repayment of the $88 million in Convertible Notes. At year-end, $188 million was drawn and outstanding against the new Revolving Credit Facility compared with $20 million drawn on the Revolving Facility at December 31, 2002.

### Equity Financing

In February 2003, we issued 2,050,000 Common Shares at a price of $24.50 per share for gross proceeds of approximately $50.2 million. The Common Shares were offered to the public on a bought-deal basis through a syndicate of Canadian underwriters. This offering was required as a direct result of not having received any of the insurance proceeds from our $200 million Cost Overrun Insurance Policy. Net proceeds from the issue were used to fund remaining costs for the Project and related expenses, for general corporate purposes and to reduce some of our short-term borrowings.

**SHARE TRADING HISTORY**

**FROM WESTERN'S INITIAL OFFERING AT $15.00 PER SHARE IN DECEMBER OF 2000, OUR SHARE PRICE HAS INCREASED 97 PER CENT TO CLOSE AT $29.50 ON DECEMBER 31, 2003. THIS EQUATES TO AN ANNUALIZED RETURN OF APPROXIMATELY 25 PER CENT.**



## EQUITY CAPITAL

| At December 31 | 2003 |
|---|---|
| Issued and Outstanding: | |
| Common Shares | **49,956,271** |
| Class D Preferred Shares, Series A | **666,667** |
| | **50,622,938** |
| Outstanding: | |
| Class A Warrants | **494,224** |
| Stock Options | **1,344,700** |
| Fully Diluted Number of Shares | **52,461,862** |

The share performance graph (shown below) compares the yearly change in the cumulative total shareholder return of a $100 investment made on December 31, 2000 in the Corporation's Common Shares with the cumulative total return of the S&P/TSX Composite Total Return Index and the TSX Oil and Gas Producers Total Return Index assuming the reinvestment of dividends, where applicable, for the comparable period. Western has significantly outperformed both indices since the Company's inception.

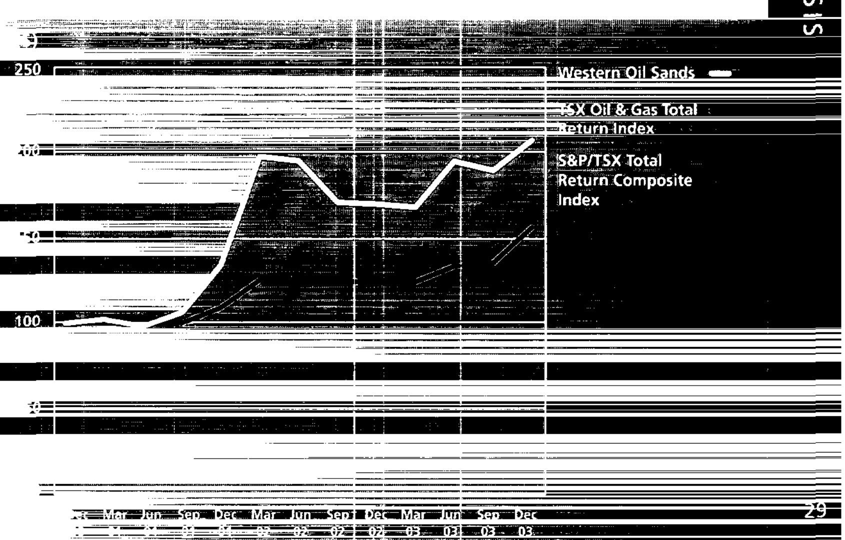
### Capital Expenditures

Construction activities have been conducted under a Joint Venture agreement whereby we participate in the operations of the Project to our 20 per cent working interest and are responsible for our respective share of the costs. Our net capital expenditures totaled $148.5 million in 2003 and included: $122.6 million of project related expenditures; $22.9 million of direct capitalized finance costs; and $3.0 million in other assets. Included in the project related expenditures were $41.0 million for our share of construction costs and sustaining capital for the Project; $29.9 million of capital repairs for the January fire and freeze damages, net of insurance recoveries; $49.5 million of net capitalized pre-operating costs for the Project; and $2.2 million of diluent purchases.

As a result of fluctuations in the exchange rate of US to Canadian dollars between January 1, 2003 and May 30, 2003, we capitalized an unrealized foreign exchange gain on our US denominated Notes of $94.0 million. As of December 31, 2003, a net cumulative unrealized foreign exchange gain of $92.0 million had been capitalized as finance costs during the pre-commercial operations period.

**SHARE PERFORMANCE**

**A $100 INVESTMENT IN WESTERN'S IPO HAS OUT PERFORMED BOTH THE TSX OIL & GAS TOTAL RETURN INDEX AND THE S&P/TSX TOTAL RETURN COMPOSITE INDEX OVER THE PAST THREE YEARS.**



We capitalized a further $2.6 million in 2003 related to our share of the costs for construction of the Hydrogen Manufacturing Unit ("HMU"), down from $15.7 million in 2002. The HMU costs are being financed through a capital lease.

**CAPITAL ASSETS**

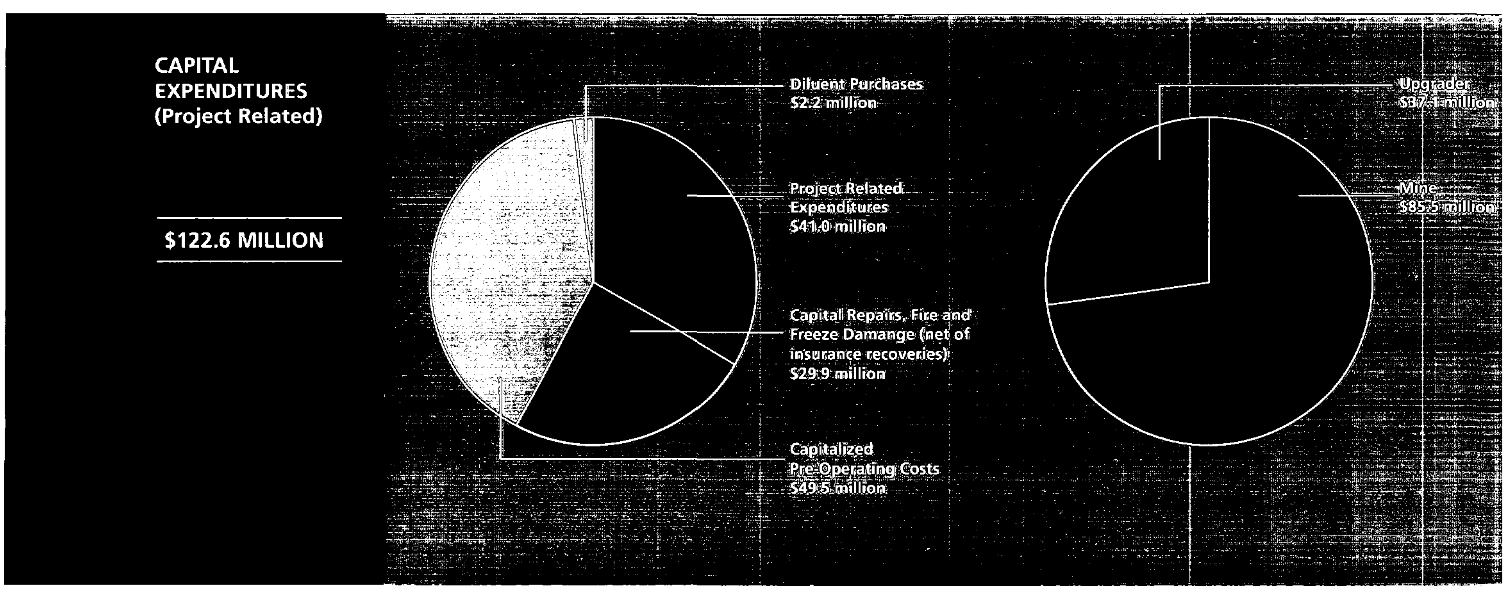
| (millions) | 2003 | 2002 | 2001 | 2000 | 1999 | Since Inception |
|---|---|---|---|---|---|---|
| Project Expenditures [2] | $ 122.6 | $ 464.6 | $ 422.1 | $ 184.7 | $ 9.4 | $ 1,203.4 |
| Capitalized Finance Costs | 22.9 | 53.0 | 9.5 | 6.4 | – | 91.8 |
| Entry Fee | – | (0.4) | 1.2 | – | 34.2 | 35.0 |
| Shell Interest [1] | – | 2.7 | – | – | – | 2.7 |
| Other Assets | 3.0 | 7.6 | 0.8 | 1.0 | 3.1 | 15.5 |
| Net Cash Expenditures [2] | 148.5 | 527.5 | 433.6 | 192.1 | 46.7 | 1,348.4 |
| Non-Cash Capitalized Costs: | | | | | | |
| Shell Fees and Interest [1] | – | – | 6.4 | 7.3 | 40.0 | 53.7 |
| HMU | 2.6 | 15.7 | 17.8 | 17.3 | – | 53.4 |
| Other | 2.5 | – | – | – | – | 2.5 |
| Unrealized Foreign Exchange (Gain) Loss | (94.0) | 2.0 | – | – | – | (92.0) |
| Asset Retirement Obligation | 6.7 | – | – | – | – | 6.7 |
| Other Assets | – | – | – | – | 1.1 | 1.1 |
| Total | $ 66.3 | $ 545.2 | $ 457.8 | $ 216.7 | $ 87.8 | $ 1,373.8 |

[1] *Shell fees and accrued interest liability were paid in full in April 2002 from the proceeds of the Senior Secured Notes offering.*

[2] *Net of $9.7 million of insurance recoveries related to the fire and freeze damage repairs.*

## Analysis of Cash Resources

Our cash balances decreased by $10.6 million during 2003, from $14.4 million at December 31, 2002 to $3.8 million at December 31, 2003. Cash inflows included: $126 million of long-term debt issued during the year (net of repayments and refinancings); $49.5 million of net equity raised; $9.7 million of insurance proceeds; and net operating cash flow of $5.8 million. Cash outflows included: gross capital expenditures of $158.2 million; a working capital increase of $38.3 million; debt issue costs and deferred charges of $1.0 million; a charge for Convertible Notes of $3.6 million; and repayment of other long-term liabilities of $0.5 million throughout the year.



For the most part, since June 1, 2003, cash flow from operations has funded our operational activities with debt and equity capital used to fund project expenditures and related working capital during construction. Capital expenditures are expected to be lower in 2004 as we are now in operations. Western anticipates spending approximately $46 million on capital activities throughout 2004. This includes: $10 million for de-bottlenecking activities; $14 million for AOSP project capital; $9 million for sustaining capital; $9 million for the Muskeg River Mine Expansion; and the remaining $4 million for other corporate purposes.

## Contractual Obligations and Commitments

We have assumed various contractual obligation and commitments in the normal course of our operations. Summarized below are significant financial obligations that are known as of February 18, 2004, and 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 Joint Venture.

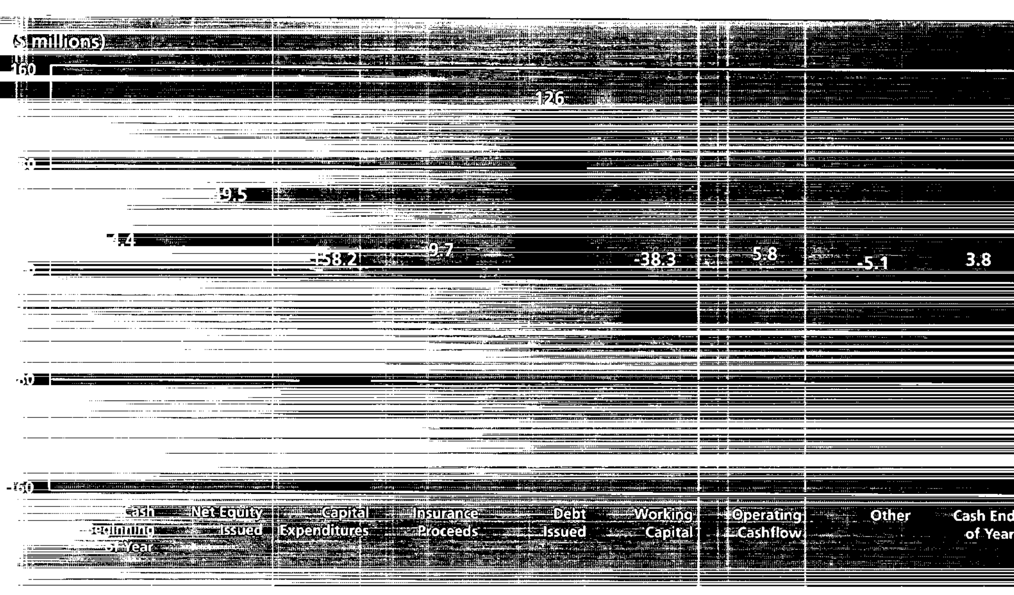
### CONTRACTUAL OBLIGATIONS AND COMMITMENTS

| | Payments Due By Period | | | | |
|---|---|---|---|---|---|
| | <1 Year | 1 – 3 Years | 4 – 5 Years | After 5 Years | Total |
| US$450 Million Senior Secured Notes | $ – | $ – | $ – | $ 581,580 | $ 581,580 |
| Senior Credit Facility | – | 91,000 | – | – | 91,000 |
| Revolving Credit Facility [1] | – | – | – | 188,000 | 188,000 |
| Obligations Under Capital Lease | 1,340 | 1,340 | 1,340 | 48,930 | 52,950 |
| Obligations Under Operating Lease | 2,380 | 8,900 | 13,140 | 26,340 | 50,760 |
| Feedstock and Transportation | 71,581 | 154,017 | 98,282 | 305,600 | 629,480 |
| Electrical and Thermal Energy | 21,102 | 41,801 | 42,180 | 307,709 | 412,792 |
| Total Contractual Obligations | $ 96,403 | $ 297,058 | $ 154,942 | $ 1,458,159 | $ 2,006,562 |

[1] *The Revolving Credit Facility is a 364-day extendible facility that incorporates a two year term-out. Management considers this to be part of our long-term capital structure.*

[2] *In addition, we have an obligation to fund Western's share of the Project's Pension Fund and have made commitments related to our risk management program: see Notes 15 and 16, respectively, of the Consolidated Financial Statements.*

**2003 CASH ANALYSIS**



## Insurance Claims

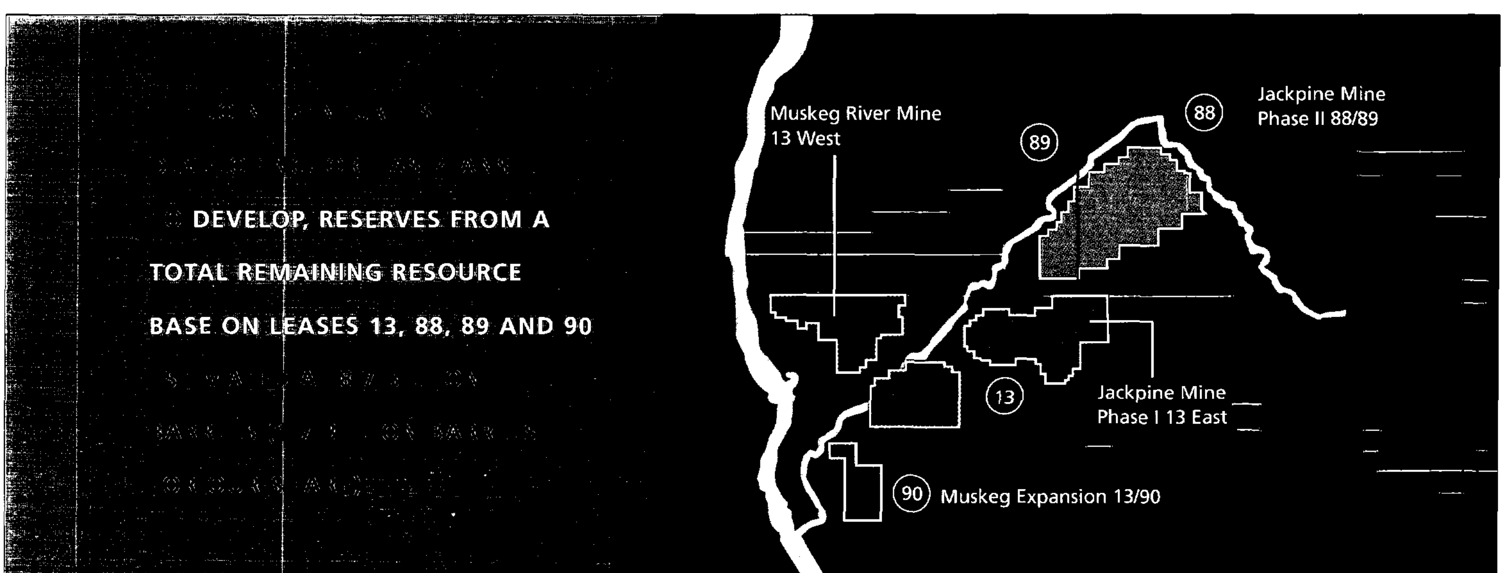
Arbitration proceedings have been initiated to resolve the disputes with insurers surrounding the claims for payment pursuant to our Cost Overrun and Project Delay Insurance Policy. We have filed insurance claims for the full limit of the policy, being $200 million, and will also be seeking interest and other damages. The arbitration panel has now been constituted and we anticipate proceedings will commence shortly. In order to preserve Western's rights with regard to the policy, we have filed a Statement of Claim in the Court of Queen's Bench of Alberta against such parties in an amount exceeding $200 million. Aggravated and punitive damages totaling $650 million have also been claimed against the insurers. The Statement of Claim will only be served on the defendants and pursued in the courts in the event that resolution procedures cannot otherwise be agreed to on a timely basis.

During the year, the Joint Venture also submitted claims under the insurance coverage provided in our Joint Venture construction policies, in respect of the fire that occurred in January 2003 at the Muskeg River Mine Extraction Plant. The Joint Venture has extensive insurance coverage in place and is seeking to recover from the insurers the full amount of the costs incurred for repairs. A total of $9.7 million has been received by Western as of December 31, 2003 for property damages. Insurers involved in the Cost Overrun and Delay Insurance dispute with Western have withheld insurance proceeds payable to Western for damages related to the January fire. With the exception of the amounts withheld, these claims have now been resolved. The Joint Venture has also filed a $500 million claim ($100 million for our share) in respect of loss of profits due to production delays from the fire.

No amounts, other than those collected at December 31, 2003, have been recognized in these statements relating to these insurance policies nor will an amount be recognized until the proceeds are received due to the uncertainty in the timing of receipt of these payments.

## OUTLOOK

Our immediate focus is on continuous improvement as we look to stabilize production volumes by increasing plant availability. In 2004 we anticipate that production volumes will increase towards sustained design capacity rates and unit operating costs will improve over levels achieved in 2003. We expect to provide further guidance on unit operating costs and annual production volumes during the year, as ramp-up continues. The long-term target range for unit operating costs is $12.00 to $14.00 per barrel at Alberta gas price levels experienced in 2003 ($10.00 to $12.00 per barrel based on $4.00 per thousand cubic feet natural gas prices). Unit cash costs will be above this target in 2004 primarily due to the production ramp-up curve and additional non-recurring costs during ramp-up. Gas costs are a significant variable cost representing



approximately 20 per cent of total operating cost. There has historically been a linkage between oil and gas prices that could provide a partial natural hedge. Our capital expenditure program in 2004 will be approximately $46 million including: $10 million for de-bottlenecking activities; $14 million for AOSP project capital; $9 million for sustaining capital; $9 million for the Muskeg River Mine Expansion; and the remaining $4 million for other corporate purposes. Excess free cash flow will be applied to reduce our credit facilities.

We are evaluating opportunities to further expand our production base through de-bottlenecking and development of the remaining oil sands leases that we have access to under the Joint Venture agreement with our Joint Venture partners. De-bottlenecking activities are being initiated in 2004 and are expected to further increase production to 180,000 barrels per day over the next two years.

The Joint Venture is developing, or has plans to develop, reserves from a total remaining resource base on Leases 13, 88, 89 and 90 estimated at 8.7 billion barrels (1.7 billion barrels for our share). We have commenced work on permitting the expansion of our existing operations at the Muskeg River Mine (MRM). Once approvals for the MRM Expansion are received, we will move ahead with the project development phase, which will include feasibility studies and continued community dialogue. Western anticipates that the MRM Expansion may increase the production capacity of our existing facilities by up to 50 per cent. We recently received preliminary approval from a joint panel of the AEUB and the Federal Government for the Jackpine Mine — Phase 1 development of the eastern portion of Lease 13. The application is subject to 19 conditions and must now be approved by the Cabinets of both the Provincial and Federal governments. Once approvals are received, we will move ahead with the project development phase, which includes feasibility studies and continued community dialogue. This expansion project has the potential to add 200,000 barrels per day (40,000 barrels per day net to us) of bitumen production. A potential expansion to include Phase 2 of the Jackpine Mine Expansion could contribute a further 100,000 barrels per day (20,000 barrels per day net to Western). The timing and details of any expansion will be subject to the outcome of future evaluations of economics, market needs, regulatory requirements and sustainable development considerations. We are also considering the acquisition of additional oil sands leases that are or may become available in the Athabasca oil sands area.

## SUSTAINABILITY

We and our Joint Venture partners in the Project are committed to carrying out operational activities in a manner that is fully compatible with the principles of sustainable development. To us, this means creating value for our shareholders while protecting the environment, managing resources, respecting and safeguarding people, benefiting communities and working with stakeholders. We at Western believe that our commitment to sustainable development and corporate responsibility is critical to sound operations and forms the foundation upon which we will build our future.

### Environment

Environmental performance was impressive with a sulphur recovery rate exceeding the 98 per cent requirement, and only one Class 2 incident[3] for the year. We have worked hard in the design of the Project to ensure environmental effects can be managed, and so that there will be no unacceptable long-term effects — upon closure and ultimate reclamation. As part of our commitment to sound environmental management, reclamation is carried out progressively and is initiated at the earliest opportunity. The raw water intake area is the most recent example of achieving successful progressive reclamation. By next summer, the site will be introducing a variety of native grasses and shrubs as well as aspen and spruce trees.

[3] *A minor effect. An incident sufficiently large to impact the environment. Single breach of statutory or prescribed limit, or single complaint. No long-term effect on the environment.*

The AOSP is implementing a comprehensive greenhouse gas (GHG) management plan. The plan will focus on monitoring actual GHG emissions at both the Mine and the Upgrader, identifying and pursuing opportunities for energy efficiency and the capture of carbon dioxide, and investing in other emissions reduction activities outside of the AOSP. The GHG management plan takes into consideration both voluntary targets and the emerging regulatory framework.

### Safety

Significant achievements were recorded in 2003 in the critical area of safety. For the Project as a whole, no employee experienced serious injury, including during the most significant incident of the year, the fire and hydrocarbon release at the Muskeg River Mine, as we recorded:

- A Lost Time Injury frequency [4] of 0.03 per 200,000 hours worked compared with the oil sands mining and extraction industry average [5] of 0.08.
- A total Recordable Injury frequency [4] of 0.90 per 200,000 hours worked compared with the the oil sands mining and extraction industry average[5] of 1.12.

### Communities

The Project continues to build on the commitments made during early consultation for the AOSP, including maximizing local benefits. In 2003, local procurement figures were $229 million to Wood Buffalo contractors, including close to $25 million to Aboriginal companies. As well, jobs created by the AOSP are filled by our neighbours whenever possible. This has resulted in 60 per cent local hire rate for the Muskeg River Mine. In the mining area we are closer to 90 per cent local hires.

Over the life of the Project, the Regional Municipality of Wood Buffalo has also benefited through community investments of over $1.5 million by the Joint Venture. This includes donations towards capital funding to build the new Technology Centre at Keyano College, and contributions toward the purchase of two medical outreach vehicles for outlying aboriginal communities.

## RISK AND SUCCESS FACTORS RELATING TO OIL SANDS

We face a number of risks that we need to manage in conducting our business affairs. The following discussion identifies some of the key areas of exposure for us and, where applicable, sets forth measures undertaken to reduce or mitigate these exposures. A complete discussion of risk factors that may impact our business is provided in our Annual Information Form.

### Operational Risks

We are currently a single asset company, that asset being our investment in oil sands through the Project. As such, all capital expenditures are directly or indirectly related to oil sands construction and development with the majority of our operating cash flow being derived from oil sands operations.

We are subject to the operational risks inherent in the oil sands business. Any unplanned operational outage or slowdown can impact production levels, costs and financial results. Factors that could influence the likelihood of this include, but are not limited to, ramp-up difficulties, extreme weather conditions and mechanical difficulties.

[4] *Calculated as the number of incidents multiplied by 200,000 (100 person years) divided by the number of combined exposure hours of all direct contractors and employees.*

[5] *Oil sands mining and extraction industry average based on the average of Shell, Syncrude and Suncor.*

We sell our share of synthetic crude oil production to refineries in North America. These sales compete with the sales of both synthetic and conventional crude oil. Other suppliers of synthetic crude oil exist and there are several additional projects being contemplated. If undertaken and completed, these projects will result in a significant increase in the supply of synthetic crude oil to the market. In addition, not all refineries are able to process or refine synthetic crude oil. There can be no assurance that sufficient market demand will exist at all times to absorb our share of the Project's synthetic crude oil production at economically viable prices.

As a partner in the AOSP, we actively participate in operational risk management programs implemented by the Joint Venture to mitigate the above risks. Our exposure to operational risks is also managed by maintaining appropriate levels of insurance. To that end, in October 2003 we established US$500 million of Property and Business Interruption Insurance as well as US$100 million of Liability Insurance to protect our ownership interest against losses or damages to the owners' facilities, to preserve our operating income and to protect against our risk of loss to third parties.

The Project depends upon successful operation of facilities owned and operated by third parties. The Joint Venture partners are party to certain agreements with third parties to provide for, among other things, the following services and utilities:

- Pipeline transportation is provided through the Corridor Pipeline;
- Electricity and steam are provided to the Mine and the Extraction Plant from the Muskeg River cogeneration facility;
- Transportation of natural gas to the Muskeg River cogeneration facility is provided by the ATCO pipeline;
- Hydrogen is provided to the Upgrader from the HMU and Dow Chemicals Canada Inc., or Dow; and
- Electricity and steam are provided to the Upgrader from the Upgrader cogeneration facility.

All of these third party arrangements are critical for the successful operation of the Project. Disruptions in respect of these facilities could have an adverse impact on future financial results.

We may be faced with competition from other industry participants in the oil sands business. This could take the form of competition for skilled people, increased demands on the Fort McMurray infrastructure (housing, roads, schools, etc.), or higher prices for the products and services required to operate and maintain the plant.

We have significant plans for expansion and the strong working relationship the Project's management has developed with the trade unions will be an important factor in our future activities. Our relationship with our employees and provincial building trade unions is important to our future because poor productivity and work disruptions have the potential to adversely affect the Project, whether in construction or in operations.

### Financial Risks

The following table details the sensitivities of our cash flow and net earnings per share to certain relevant operating factors once the Project achieves stable production rates. The base case upon which the sensitivities are calculated assumes our share of bitumen production is 31,000 barrels per day, a constant WTI price of US$27.00 per barrel, a foreign exchange rate of US$0.75 per Canadian dollar and a constant Alberta gas cost of Cdn$5.01 per thousand cubic feet.

### SENSITIVITY ANALYSIS

| Variable | Variation | Cash Flow ($ millions) | Basic Cash Flow per Share | Earnings ($ millions) | Basic Earnings per Share |
|---|---|---|---|---|---|
| Production | 1,000 bbls/day | $ 4.44 | $ 0.09 | $ 4.82 | $ 0.10 |
| Oil Prices | US$1.00 | $ 15.40 | $ 0.30 | $ 9.85 | $ 0.19 |
| Non-Gas Operating Costs | $1.00/bbl | $ 11.32 | $ 0.22 | $ 7.24 | $ 0.14 |
| Gas Prices [2] | $0.10/Mcf | $ 0.56 | $ 0.01 | $ 0.36 | $ 0.01 |
| Foreign Exchange [1] | US/Cdn .01 | $ 2.40 | $ 0.05 | $ 3.52 | $ 0.07 |

(1) *Excludes unrealized foreign exchange gains or losses on long-term monetary items. The impact of the Canadian dollar strengthening by US$0.01 would increase net earnings by $3.06 million based on December 31, 2003 US dollar denominated debt levels.*

(2) *Each $1.00 per thousand cubic feet change in gas price results in a change of $0.41 per barrel in operating cost.*

Our financial results will be dependent upon the prevailing price of crude oil and the Canadian/US currency exchange rate. Oil prices and currency exchange rates fluctuate significantly in response to supply and demand factors beyond our control, which could have an impact on future financial results.

Any prolonged period of low oil prices could result in a decision by the Joint Venture partners to suspend or reduce production. Any such suspension or reduction of production would result in a corresponding substantial decrease in our future revenues and earnings and could expose us to significant additional expense as a result of certain long-term contracts. In addition, because natural gas comprises a substantial part of variable operating costs, any prolonged period of high natural gas prices could negatively impact our future financial results.

Our debt level and restrictive covenants will have important effects on our future operations. Our ability to make scheduled payments or to refinance our debt obligations will depend upon our financial and operating performance which in turn, will depend upon prevailing industry and general economic conditions beyond our control. There can be no assurance that our operating performance, cash flow, and capital resources will be sufficient to repay our debt and other obligations in the future.

To mitigate our exposure to these financial risks, we have established a financial risk management program in consultation with our Board of Directors.

The objective of our hedging program is to mitigate exposure to the volatility of crude oil prices, thereby stabilizing current and future cash flows from the sale of our synthetic crude products. Our strategy is to protect the base capital program and ensure funding of debt obligations by providing a stable platform of cash flow. To this end Western has entered into the following swaps:

### HEDGING SUMMARY

| Instrument | Notional Volume | Hedge Period | Swap Price | Unrealized Increase (Decrease) to Future Revenue (thousands) |
|---|---|---|---|---|
| WTI Swaps | 20,000 bbls/d | Jan 1, 2004 to Dec 31, 2004 | US$27.37 | (Cdn$25,955) |
| WTI Swaps | 16,000 bbls/d | Jan 1, 2005 to Mar 31, 2005 | US$26.17 | (Cdn$3,221) |
| WTI Swaps | 7,000 bbls/d | Apr 1, 2005 to Dec 31, 2005 | US$26.87 | (Cdn$850) |

We must finance our share of the Project's operating costs in the face of a volatile commodity pricing environment and ramp-up challenges. Should insufficient cash flow be generated from operations, additional financing may be required to fund capital projects and future expansion projects. If there is a business interruption, we may need additional financing to fund our activities until Business Interruption Insurance proceeds are received.

As part of our original financing plan, we established a Cost Overrun and Project Delay Insurance Policy in the amount of $200 million. This insurance policy, which took effect in March 2000 and continued through April 2004, covers certain costs, expenses and losses of revenue through the construction period arising from causes beyond our control and including: (i) costs and expenses or loss of revenues arising from a delay in achieving a guaranteed production level; (ii) costs and expenses incurred in connection with the modification, repair or replacement of equipment or material, which are directly related to achieving guaranteed production levels; (iii) escalation in Project costs beyond the budgeted Project costs, which are directly related to achieving guaranteed production levels; and (iv) debt service costs related to obligations incurred to finance any of (i), (ii) or (iii). In effect, the program provides coverage for increased costs for Western's share of the Project of up to $200 million to the extent the increased costs are incurred to meet bitumen production levels of 155,000 barrels per day as contemplated in the initial design of the Project.

## ENVIRONMENTAL RISKS

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nation wide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". The Project will be a significant producer of some greenhouse gases covered by the treaty. The Government of Canada has put forward a Climate Change Plan for Canada which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas production. Future federal legislation, together with existing provincial emission reduction legislation, such as in Alberta's Climate Change and Emissions Management Act, may require the reduction of emissions and/or emissions intensity from the Project. The direct or indirect costs of such legislation may adversely affect the Project. There can be no assurance that future environmental approvals, laws or regulations will not adversely impact the Owners' ability to operate the Project or increase or maintain production or will not increase unit costs of production. Equipment from suppliers that can meet future emission standards or other environmental requirements may not be available on an economic basis, or at all, and other methods of reducing emissions to required levels may significantly increase operating costs or reduce output.

We will be responsible for compliance with terms and conditions set forth in the Project's environmental and regulatory approvals and all laws and regulations regarding the decommissioning and abandonment of the Project and reclamation of its lands. The costs related to these activities may be substantially higher than anticipated. It is not possible to accurately predict these costs since they will be a function of regulatory requirements at the time and the value of the equipment salvaged. In addition, to the extent we do not meet the minimum credit rating required under the Joint Venture agreement, we must establish and fund a reclamation trust fund. We currently do not hold the minimum credit rating. Even if we do hold the minimum credit rating, in the future it may be determined that it is prudent or be required by applicable laws or regulations to establish and fund one or more additional funds to provide for payment of future decommissioning, abandonment and reclamation costs. Even if we conclude that the establishment of such a fund is prudent or required, we may lack the financial resources to do so.

The Joint Venture partners have established programs to monitor and report on environmental performance including reportable incidents, spills and compliance issues. In addition, comprehensive quarterly reports are prepared covering all aspects of health, safety and sustainable development on Lease 13 and the Upgrader to ensure that the Project is in compliance with all laws and regulations and that management are accountable for performance set by the Joint Venture partners.

## NON-GAAP FINANCIAL MEASURES

Western includes cash flow from operations per share and earnings before interest, taxes, depreciation, depletion and amortization, and foreign exchange gains ("EBITDA") as investors may use this information to better analyze our operating performance. We also include certain per barrel information, such as realized crude oil sales price, to provide per unit numbers that can be compared against industry benchmarks, such as the West Texas Intermediate ("WTI") benchmark. The additional information should not be considered in isolation or as a substitute for measures of operating performance prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP").

Non-GAAP financial measures do not have any standardized meaning prescribed by Canadian GAAP and are therefore unlikely to be comparable to similar measures presented by other issuers. Management believes that, in addition to Net Earnings (Loss) per Share and Net Earnings (Loss) Attributable to Common Shareholders (both Canadian GAAP measures), cash flow from operations per share and EBITDA provide a better basis for evaluating our operating performance, as they both exclude fluctuations on the US dollar denominated Senior Secured Notes and certain other non-cash items, such as depreciation, depletion and amortization, and future income tax recoveries. In addition, EBITDA provides a useful indicator of our ability to fund our financing costs and any future capital requirements.

## CRITICAL ACCOUNTING ESTIMATES

Western's critical accounting estimates are defined as those estimates that have a significant impact on the portrayal of our financial position and operations and that require management to make judgments, assumptions and estimates in the application of Canadian GAAP. Judgments, assumptions and estimates are based on historical experience and other factors that Management believes to be reasonable under current conditions. As events occur and additional information is obtained, these judgments, assumptions and estimates may be subject to change. We believe the following are the critical accounting estimates used in the preparation of our Consolidated Financial Statements.

### Commencement of Commercial Operations

Effective June 1, 2003, Western commenced commercial operations as determined by Management, as all aspects of the facilities became fully operational and the Project achieved 50 per cent of the stated design capacity of 155,000 barrels per day. Accordingly, we have recorded revenues and expenses relating to our share of operations for the Project from that date. Prior to June 1, 2003 all revenues, operating costs and interest were capitalized as part of the costs of the Project, and no depreciation, depletion or amortization were expensed.

### Capital Assets

Western capitalizes costs specifically related to the acquisition, exploration, development and construction of the Project. This includes interest, which is capitalized during the construction and start-up phase for each project. Depletion on the Project is provided over the life of proved and probable reserves on a unit of production basis, and commenced when the facilities were substantially complete and after commercial production had begun. Other capital assets are depreciated on a straight-line basis over their useful lives, except for lease acquisition costs and certain Mine assets, which are amortized and depreciated over the life of proved and probable reserves. Reserve estimates can have a significant impact on earnings, as they are a key component to the calculation of depletion. A downward revision in the reserve estimate would result in increased depletion and a reduction of earnings.

Capital assets are reviewed for impairment whenever events or conditions indicate that their net carrying amount may not be recoverable from estimated future cash flows. If an impairment is identified the assets are written down to the estimated fair market value. The calculation of these future cash flows are dependent on a number of estimates, which includes reserves, timing of production, crude oil price, operating cost estimates and foreign exchange rates. As a result future cash flows are subject to significant management judgment.

### Asset Retirement Obligation

Effective January 1, 2003, Western elected early adoption of the CICA 3110 "Asset Retirement Obligations". The new standard requires that we recognize an asset and a liability for any existing asset retirement obligations, which is determined by estimating the fair value of this commitment at the balance sheet date. We determine the fair value by first obtaining third party estimates for the expected timing and amount of cash flows that will be required for future dismantlement and site restoration, and then present valuing these future payments using a credit adjusted risk free rate appropriate for Western. Any change in timing or amount of the cash flows subsequent to initial recognition results in a change in the asset and liability, which then impacts the depletion on the asset and the accretion charged on the liability. Estimating the timing and amount of third party cash flows to settle this obligation is inherently difficult and is based on Management's current experience.

### Future Income Tax

We have recognized future income tax assets and liabilities at December 31, 2003. These assets and liabilities are recognized at the tax rates at which Management expects the temporary differences to reverse. Management bases this expectation on future earnings, which require estimates for reserves, timing of production, crude oil price, operating cost estimates and foreign exchange rates. As a result future earnings are subject to significant Management judgment and changes could result in the temporary differences reversing at different tax rates.

## CHANGE IN ACCOUNTING POLICIES

### Asset Retirement Obligation

Effective January 1, 2003 Western early adopted CICA 3110 "Asset Retirement Obligations". The new standard requires that we recognize an asset and a liability for any existing asset retirement obligations, which is determined by estimating the fair value of this commitment at the balance sheet date. We determine the fair value by first obtaining third party estimates for the expected timing and amount of cash flows that will be required for future dismantlement and site restoration, and then present valuing these future payments using a credit adjusted risk free rate appropriate for Western. Any change in timing or amount of the cash flows subsequent to initial recognition results in a change in the asset and liability. Over the estimated life of the asset and liability Western recognizes depletion on the asset and accretion on the liability.

### Stock-based Compensation Plan

We have a stock-based compensation plan, which is described in Note 13. Effective January 1, 2002, we adopted CICA 3870 "Stock-based Compensation and Other Stock-based Payments". CICA 3870 is applied to all stock-based payments to non-employees and to employee awards that are direct awards of stock, stock appreciation rights and similar awards to be settled in cash. CICA 3870 is applied to all grants of stock options on or after January 1, 2002.

During the fourth quarter, effective for January 1, 2003, we began prospectively recognizing compensation expense for options granted under the plan in accordance with the fair value method. Under the transitional provisions in CICA 3870, we are required only to apply the fair value based method, and record compensation expense and Contributed Surplus, to awards granted, modified or settled on or after the beginning of the fiscal year, in which we adopt the fair value method for those awards. Accordingly, only awards issued from January 1, 2003 require compensation expense to be recognized in accordance with CICA 3870. Compensation expense for options granted during 2003 is determined based on the fair values at the time of grant and is recognized over the estimated vesting periods of the respective options. For options granted prior to January 1, 2003, we continue to disclose the pro forma net earnings (loss) impact of the related compensation expense. Pro forma compensation-related earnings impacts are determined on the same basis as the 2003 options.

Consideration received on the exercise of stock options granted is credited to share capital, and if related to any stock options that were granted during the year ended December 31, 2003, then an amount equal to the compensation expense recognized to that date is reclassified from Contributed Surplus to Common Shares.

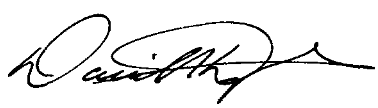
The accompanying Consolidated Financial Statements and all information in the annual report including Management's Discussion and Analysis are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in accordance with the accounting policies described in the notes to the Consolidated Financial Statements. In the opinion of Management, the Consolidated Financial Statements have been prepared within acceptable limits of materiality and are in accordance with Canadian Generally Accepted Accounting Principles appropriate in the circumstances. The financial information contained elsewhere in the annual report has been reviewed to ensure consistency with that in the Consolidated Financial Statements.

Management has developed and maintains systems of internal controls, policies and procedures in order to provide reasonable assurance as to the reliability of the financial records and the safeguard of assets.

PricewaterhouseCoopers LLP, independent external auditors appointed by the shareholders of the Company, review Western's system of internal controls and conduct their work to the extent they deem appropriate. They have examined the Consolidated Financial Statements and have expressed an opinion on the statements. Their report is included with the Consolidated Financial Statements. Western also retains independent petroleum engineering consultants, Gilbert Laustsen Jung Associates Ltd. to conduct independent evaluations or audits of the company's oil and gas reserves.

The Board of Directors of the Company has established an Audit Committee, consisting of three non-management directors. The Audit Committee reviews with Management and the external auditors any significant financial reporting issues, the presentation and impact of significant risks and uncertainties, and key estimates and judgments of Management that may be material for financial reporting purposes. On an annual basis, the Audit Committee meets with the independent petroleum consultants and reviews the Company's annual reserve estimates. The Audit Committee meets quarterly to review and approve interim financial statements prior to their release, as well as annually to review Western's annual financial statements, Management's Discussion and Analysis and Annual Information Form/Form 40-F, and recommend their approval to the Board of Directors. The external auditors have unrestricted access to the company, the Audit Committee and the Board of Directors.

Guy J. Turcotte
*President and Chief Executive Officer*
*Calgary, Canada*
*February 18, 2004*



David A. Dyck
*Vice President, Finance and Chief Financial Officer*

**TO THE SHAREHOLDERS OF WESTERN OIL SANDS INC.**

We have audited the Consolidated Balance Sheets of Western Oil Sands Inc. as at December 31, 2003 and 2002 and the Consolidated Statements of Operations and Deficit, and Cash Flows for the years then ended. These financial statements are the responsibility of the Corporation'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 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 Western Oil Sands Inc. 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, Canada*
*February* 18, 2004

| December 31 (thousands) | 2003 | 2002 |
|---|---|---|
| **ASSETS** | | |
| Current Assets | | |
| Cash | $ 3,770 | $ 14,428 |
| Accounts Receivable | 57,994 | 6,624 |
| Inventory (Note 3) | 9,100 | 4,175 |
| Prepaid Expense | 7,033 | – |
| | 77,897 | 25,227 |
| Capital Assets (Note 4) | 1,353,317 | 1,306,989 |
| Deferred Charges (Note 5) | 20,903 | 27,422 |
| Future Income Taxes (Note 11) | 6,307 | – |
| | 1,380,527 | 1,334,411 |
| | $ 1,458,424 | $ 1,359,638 |
| **LIABILITIES** | | |
| Current Liabilities | | |
| Accounts Payable and Accrued Liabilities | $ 65,949 | $ 40,953 |
| Convertible Notes (Note 6) | – | 4,055 |
| Obligations Under Capital Lease (Note 8) | 1,340 | – |
| | 67,289 | 45,008 |
| Long-term Liabilities | | |
| Long-term Debt (Note 7) | 860,580 | 775,820 |
| Obligations Under Capital Lease (Note 8) | 51,610 | 50,859 |
| Other (Note 9) | 9,720 | – |
| Future Income Taxes (Note 11) | – | 454 |
| | 921,910 | 827,133 |
| | 989,199 | 872,141 |
| **SHAREHOLDERS' EQUITY** | | |
| Share Capital (Note 12) | 476,667 | 426,275 |
| Contributed Surplus (Note 13) | 278 | – |
| Convertible Notes (Note 6) | – | 83,945 |
| Deficit | (7,720) | (22,723) |
| | 469,225 | 487,497 |
| | $ 1,458,424 | $ 1,359,638 |

Commitments and Contingencies (Note 17)

*See accompanying Notes to the Consolidated Financial Statements*

Approved by the Board of Directors

Robert G. Puchniak
Director

Brian F. MacNeill
Director

# CONSOLIDATED STATEMENTS OF OPERATIONS AND DEFICIT

| Year ended December 31 (thousands, except amounts per share) | 2003 | 2002 |
|---|---|---|
| **REVENUES** | $ **281,093** | $ – |
| **EXPENSES:** | | |
| Operating | **106,825** | – |
| Purchased Feedstocks and Transportation | **117,580** | – |
| Royalties | **1,151** | – |
| General and Administrative | **6,539** | 5,688 |
| Insurance | **1,661** | 10 |
| Interest (Note 10) | **38,429** | – |
| Accretion on Asset Retirement Obligation (Note 9) | **471** | – |
| Depreciation, Depletion and Amortization | **27,531** | 192 |
| Write-off of Deferred Charges (Note 7) | – | 22,759 |
| Foreign Exchange Gain | **(34,976)** | – |
| **NET EARNINGS (LOSS) BEFORE INCOME TAXES** | **15,882** | (28,649) |
| Income Tax Recovery (Note 11) | **(1,251)** | (19,646) |
| **NET EARNINGS (LOSS)** | **17,133** | (9,003) |
| Charge for Convertible Notes (Note 6) | **2,130** | 1,283 |
| **NET EARNINGS (LOSS) ATTRIBUTABLE TO COMMON SHAREHOLDERS** | $ **15,003** | $ (10,286) |
| Deficit at Beginning of Year | **22,723** | 12,437 |
| Deficit at End of Year | $ **7,720** | $ 22,723 |
| Net Earnings (Loss) Per Share (Note 12): | | |
| Basic | $ **0.30** | $ (0.21) |
| Diluted | $ **0.29** | $ (0.21) |

*See accompanying Notes to the Consolidated Financial Statements*

# CONSOLIDATED STATEMENTS OF CASH FLOWS

| Year ended December 31 (thousands) | 2003 | 2002 |
|---|---|---|
| **CASH PROVIDED BY (USED IN)** | | |
| **OPERATING ACTIVITIES** | | |
| Net Earnings (Loss) | **$ 17,133** | $ (9,003) |
| Non-cash items: | | |
| Depreciation, Depletion and Amortization | **27,531** | 192 |
| Accretion on Asset Retirement Obligation (Note 9) | **471** | – |
| Stock-based Compensation (Note 13) | **278** | – |
| Write-off of Deferred Charges (Note 7) | **–** | 22,759 |
| Unrealized Foreign Exchange Gain (Note 7) | **(35,280)** | – |
| Future Income Tax Recovery (Note 11) | **(4,330)** | (22,551) |
| Cash from Operations | **5,803** | (8,603) |
| Increase in Non-Cash Working Capital (Note 18) | **(7,133)** | (7,965) |
| | **(1,330)** | (16,568) |
| **FINANCING ACTIVITIES** | | |
| Issue of Share Capital (Note 12) | **51,682** | 1,977 |
| Share Issue Expenses (Note 12) | **(2,211)** | – |
| Issue of Long-term Debt | **214,000** | 773,840 |
| Repayment of Long-term Debt | **–** | (279,481) |
| Deferred Charges | **(1,017)** | (17,927) |
| (Repayment) Issue of Convertible Notes | **(88,000)** | 88,000 |
| Charge for Convertible Notes (Note 6) | **(3,640)** | (1,283) |
| Repayment of Other Long-term Liabilities | **(470)** | (53,687) |
| **Cash Generated** | **170,344** | 511,439 |
| **INVESTING ACTIVITIES** | | |
| Capital Expenditures | **(158,153)** | (527,541) |
| Insurance Proceeds | **9,680** | – |
| Increase in Non-Cash Working Capital (Note 18) | **(31,199)** | (5,875) |
| **Cash Invested** | **(179,672)** | (533,416) |
| Decrease in Cash | **(10,658)** | (38,545) |
| Cash at Beginning of Year | **14,428** | 52,973 |
| Cash at End of Year | **$ 3,770** | $ 14,428 |

*See accompanying Notes to the Consolidated Financial Statements*

*(Tabular dollar amounts in thousands, except for share amounts)*

## 1. BUSINESS OF THE CORPORATION

Western Oil Sands Inc. (the "Corporation") was incorporated on June 18, 1999 under the laws of the Province of Alberta. The Corporation holds an undivided 20 per cent working interest in an oil sands project in the Athabasca region of northeast Alberta (the "Oil Sands Project"). Shell Canada Limited and Chevron Canada Limited hold the remaining 60 per cent and 20 per cent interests, respectively. The Oil Sands Project consists of direct or indirect participation in the design, construction and operation of mining, extracting, transporting and upgrading of oil sands deposits. The Corporation is also actively pursuing other oil sands and related business opportunities.

## 2. SUMMARY OF ACCOUNTING POLICIES

### (a) Principles of Consolidation

The consolidated financial statements include the accounts of the Corporation and its wholly-owned subsidiary corporations and limited partnership, 852006 Alberta Limited, Western Oil Sands, L.P., Western Oil Sands Finance Inc. and Western Oil Sands (USA) Inc. (inactive). The Corporation's oil sands activities are conducted jointly with others. These financial statements reflect only the Corporation's proportionate interest in such activities.

### (b) Commencement of Commercial Operations

Effective June 1, 2003, the Corporation commenced commercial operations, as determined by management, as all aspects of the facilities became fully operational and the Oil Sands Project achieved 50 per cent of the stated design capacity of 155,000 barrels per day. Accordingly, the Corporation has recorded revenues and expenses related to the Corporation's share of operations of the Oil Sands Project from that date. Prior to June 1, 2003 all revenues, operating costs and interest were capitalized as part of the costs of the Oil Sands Project, and no depreciation, depletion and amortization expensed.

### (c) Measurement Uncertainty

The preparation of financial statements in conformity with Canadian Generally Accepted Accounting Principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Such estimates relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. Actual results may differ from these estimated amounts as future events occur.

Specifically, amounts recorded for Depreciation, Depletion and Amortization are based on estimates of crude oil reserves, for Asset Retirement Obligation are based on assumptions of the future costs to dismantle the assets and restore the site of the Oil Sands Project and for Future Income Tax are based on assumptions of the timing and at which tax rates temporary differences are expected to reverse. These estimates of reserves and assumptions of future costs and timing of tax pool use are subject to measurement uncertainty, and the impact to the Consolidated Financial Statements of future periods could be material.

### (d) Foreign Currency Translation

Transactions in foreign currencies are translated into Canadian dollars at exchange rates prevailing at the transaction dates. Monetary assets and liabilities denominated in a foreign currency are translated into Canadian dollars at rates of exchange in effect at the end of the period, with the resulting unrealized gain or loss being recorded in the Consolidated Statement of Operations and Deficit, after the commencement of operations. Prior to the commencement of operations these unrealized gains and losses were capitalized.

### (e) Cash

Cash presented in the Consolidated Financial Statements is comprised of cash and cash equivalents and includes short-term investments with a maturity of three months or less when purchased.

### (f) Inventory

Product and Parts, Supplies and Other inventories are stated at the lower of average cost and net realizable value.

### (g) Capital Assets

Capital assets are recorded at cost less accumulated provisions for depreciation, depletion and amortization. Capitalized costs include costs specifically related to the acquisition, exploration, development and construction of the related project. This includes interest, which is capitalized during the construction and start-up phase for each project. Capital assets are reviewed for impairment whenever events or conditions indicate that their net carrying amount may not be recoverable from estimated future cash flows. If an impairment is determined the assets are written down to the fair market value.

Depletion on the Oil Sands Project is provided over the life of proved and probable reserves on a unit of production basis, commencing when the facilities were substantially complete and after commercial production had begun. Other capital assets are depreciated on a straight-line basis over their useful lives, except for lease acquisition costs and certain mine assets, which are amortized and depreciated over the life of proved and probable reserves. The estimated useful lives of depreciable capital assets are as follows:

| | |
|---|---|
| Leasehold improvements | 5 years |
| Furniture and fixtures | 5 years |
| Computers | 3 years |

### (h) Asset Retirement Obligation

Effective January 1, 2003 the Corporation early adopted CICA 3110 "Asset Retirement Obligations". The new standard requires that the Corporation recognize an asset and a liability for any existing asset retirement obligations, which is determined by estimating the fair value of this commitment at the balance sheet date. The fair value is determined by the Corporation by first estimating the expected timing and amount of cash flows, using third party costs, that will be required for future dismantlement and site restoration, and then present valuing these future payments using a credit adjusted risk free rate appropriate for the Corporation. Any change in timing or amount of the cash flows subsequent to initial recognition results in a change in the asset and liability. Over the estimated life of the asset and liability the Corporation recognizes depletion on the asset and accretion on the liability.

### (i) Convertible Notes

Amounts drawn under the Note Purchase Facility are deemed to consist of both an equity and a liability component in accordance with Canadian GAAP. The initial carrying amounts recognized for the equity and debt component are adjusted for accretion to bring the equity component to the stated principal amount of the Note Purchase Facility at maturity and to remove the debt component. Accretion is charged directly to the Deficit. Upon maturity of the Note Purchase Facility the equity component amount was refinanced by the Corporation under the Revolving Credit Facility, see Note 7(c).

### (j) Stock-based Compensation Plan

The Corporation has a stock-based compensation plan, which is described in Note 13. Effective January 1, 2002, the Corporation adopted CICA 3870 "Stock-based Compensation and Other Stock-based Payments". CICA 3870 is applied to all stock-based payments to non-employees and to employee awards that are direct awards of stock, stock appreciation rights and similar awards to be settled in cash. CICA 3870 is applied to all grants of stock options on or after January 1, 2002.

During the fourth quarter, effective for January 1, 2003 the Corporation began prospectively recognizing compensation expense for options granted under the plan in accordance with the fair value method. Under the transitional provisions in CICA 3870 the Corporation is required only to apply the fair value based method, and record compensation expense and Contributed Surplus, to awards granted, modified or settled on or after the beginning of the fiscal year, in which the Corporation adopts the fair value method for those awards. Accordingly, only awards issued from January 1, 2003 require compensation expense to be recognized in accordance with CICA 3870. Compensation expense for options granted during 2003 is determined based on the fair values at the time of grant and are recognized over the estimated vesting periods of the respective options. For options granted prior to January 1, 2003 the Corporation continues to disclose the pro forma net earnings (loss) impact of the related compensation expense. Pro forma compensation-related earnings impacts are determined on the same basis as the 2003 options.

Consideration received on the exercise of stock options granted is credited to share capital, and if related to any stock options that were granted during the year ended December 31, 2003, then an amount equal to the compensation expense recognized to that date is reclassified from Contributed Surplus to Common Shares.

**(k) Revenue Recognition**

The revenue associated with the sale of crude oil products is recorded as title and other significant risks and rewards of ownership are passed to the customer.

**(l) Net Earnings (Loss) per Share**

The Corporation uses the treasury stock method to determine the dilutive effects of stock options and other dilutive instruments.

**(m) Derivative Financial Instruments**

Financial instruments are used by the Corporation to hedge its exposure to market risks relating to commodity prices and foreign currency exchange rates. The Corporation's policy is not to utilize financial instruments for speculative purposes.

The Corporation formally documents all relationships between hedging instruments and hedged items as well as its risk management objectives and strategies for undertaking various hedge transactions. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Corporation also assesses, both at the hedges' inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items.

The Corporation enters into hedges with respect to a portion of its oil production to achieve a more predictable cash flow by reducing its exposure to price and currency fluctuations. These transactions are entered into with major Canadian financial institutions. Gains and losses from these financial instruments are recognized in oil revenues as the hedge sale transactions occur.

**(n) Employee Future Benefits (Pension Plan)**

The Corporation has a defined contribution pension plan for its direct employees and as a result of the 20 per cent ownership in the Oil Sands Project has a defined benefit pension plan for employees of the Oil Sands Project. For the defined contribution pension plan the expense is recognized as payments are made or entitlements are earned.

For the defined benefit pension plan the costs are determined using the projected benefit method based on length of service and reflects the Oil Sands Project's best estimate of expected plan investment performance, salary escalation, retirement ages of employees, withdrawal rates and mortality rates. The expected return on plan assets is based on the fair value of those assets and the obligation is discounted using a market interest rate at the beginning of the year on high quality corporate debt instruments. Pension expense includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of adjustments arising from pension plan amendments and the excess of the net actuarial gain or loss over 10 per cent of the greater of the benefits obligation and the fair value of plan assets. The amortization period covers the expected average remaining service lives of employees covered by the plans.

**(o) Comparative amounts**

Certain comparative amounts have been reclassified to conform to the current year's presentation.

## 3. INVENTORY

| | 2003 | 2002 |
|---|---|---|
| Product Inventory | **$ 3,381** | $ 4,175 |
| Parts, Supplies and Other | **5,719** | – |
| | **$ 9,100** | $ 4,175 |

## 4. CAPITAL ASSETS

| 2003 | Cost | Accum. DD&A* | Net |
|---|---|---|---|
| Oil Sands Project | **$ 1,304,460** | **$ (18,954)** | **$ 1,285,506** |
| Oil Sands Project Assets Under Capital Lease | **52,744** | **(795)** | **51,949** |
| Other Assets | **16,639** | **(777)** | **15,862** |
| | **$ 1,373,843** | **$ (20,526)** | **$ 1,353,317** |

| | | | |
|---|---|---|---|
| Oil Sands Project | $ 1,243,061 | $ – | $ 1,243,061 |
| Oil Sands Project Assets Under Capital Lease | 50,859 | – | 50,859 |
| Other Assets | 13,601 | (532) | 13,069 |
| | $ 1,307,521 | $ (532) | $ 1,306,989 |

* *Accumulated Depreciation, Depletion and Amortization*

## 5. DEFERRED CHARGES

| | 2003 | 2002 |
|---|---|---|
| Deferred Charges | **$ 28,440** | $ 27,422 |
| Less: Amortization | **(7,537)** | – |
| | **$ 20,903** | $ 27,422 |

Deferred charges include primarily debt financing costs that have been incurred in establishing the Corporation's various debt facilities. These amounts are being amortized over the term of the related debt facilities following start-up of the Oil Sands Project.

## 6. CONVERTIBLE NOTES

On October 25, 2001 the Corporation established an $88.0 million two-year Note Purchase Facility (the "Note Purchase Facility") with a Canadian chartered bank. Borrowings under the Note Purchase Facility bore interest at the bank's prime lending rate, the bankers' acceptance rate or the LIBOR rate plus applicable margins ranging from 125 to 225 basis points. The notes issuable pursuant to draws on the Note Purchase Facility were convertible, at maturity at the option of the Corporation and in the event of a default at the option of the bank, into Common Shares of the Corporation. The Convertible Notes matured on October 25, 2003, and the Corporation refinanced these Convertible Notes using availability that it had under its new Revolving Credit Facility (see Note 7 (c)). For the year ended December 31, 2003 the Corporation accreted $3.6 million ($2.1 million net of tax) in respect to the interest paid on the Note Purchase Facility.

## 7. LONG-TERM DEBT

| | | 2003 | 2002 |
|---|---|---|---|
| US$450 million Senior Secured Notes | (a) | **$ 581,580** | $ 710,820 |
| Senior Credit Facility | (b) | **91,000** | 45,000 |
| Revolving Credit Facility | (c) | **188,000** | 20,000 |
| | | **$ 860,580** | $ 775,820 |

(a) On April 23, 2002, the Corporation issued Senior Secured Notes in the amount of US$450.0 million, bearing interest at 8.375 per cent, with a maturity of May 1, 2012 (the "Offering"). The net proceeds of the Offering were used to repay all amounts outstanding under the Corporation's original $535.0 million bank facility (which was cancelled upon repayment) and repay an amount of $53.7 million due to Shell Canada Limited (representing the acquisition cost of the Corporation's interest in the Oil Sands Project lease plus accumulated interest), with the balance of the proceeds used to fund the Corporation's share of remaining construction costs for the Oil Sands Project. The Senior Secured Notes provide the holders with security over all the assets of the Corporation, subordinated to the Senior Credit Facility, until the Corporation achieves an investment grade corporate credit rating, at which time the Senior Secured Notes become unsecured. Upon completion of the offering, $22.8 million of issue costs and charges relating to non-continuing debt facilities were written off.

The Senior Secured Notes are recorded in Canadian dollars at the exchange rate in effect at the balance sheet date. An unrealized foreign exchange gain totaling $129.3 million was recognized during the year as a result of changes in the foreign exchange rate between the US and Canadian dollars. Of this gain $94.0 million was capitalized as it occurred prior to commercial operations and the balance of $35.3 million was recognized in the Statement of Operations and Deficit.

(b) In conjunction with the Offering, the Corporation established a new $100.0 million Senior Credit Facility (the "Senior Credit Facility") with a syndicate of Canadian chartered banks, up to $75.0 million of which was to be used to fund the first year's debt service under the Offering and construction completion costs; the remaining $25.0 million was to be used for working capital and letter of credit requirements. Borrowings under the facility bear interest at the lenders' prime lending rate, the bankers' acceptance rate or the LIBOR rate plus applicable margins ranging from 100 to 200 basis points. The Senior Credit Facility matures and is repayable on April 23, 2005. The Senior Credit Facility contains certain covenants and other provisions, which restrict the Corporation's ability to incur additional indebtedness, pay dividends or make distributions of any kind, undertake an expansion of the Oil Sands Project, dispose of its interest in the Oil Sands Project, or change the nature of its business. The Senior Credit Facility provides the banks with security over all of the assets of the Corporation, with the exception of certain intercompany notes and note guarantees issued in connection with the Offering detailed in Note 7(a). At December 31, 2003, an amount of $91.0 million ($45.0 million — 2002) had been drawn under this Senior Credit Facility and letters of credit for $7.1 million ($15.4 million — 2002) had been issued.

(c) On November 19, 2002, the Corporation established a $50.0 million 364-day Extendible Revolving Credit Facility (the "Revolving Facility") with a syndicate of Canadian chartered banks. On January 30, 2003 the Corporation increased the availability under the Revolving Facility with the addition of another Canadian chartered bank to the syndicate by $25.0 million to a total of $75.0 million. On May 1, 2003 the Corporation further increased the availability with the existing lenders by $35.0 million to a total of $110.0 million. Borrowings under the Revolving Facility bore interest at the lenders' prime lending rate, the bankers' acceptance rate or the LIBOR rate plus applicable margins ranging from 100 to 200 basis points. The Revolving Facility provided the banks with security over all of the assets of the Corporation, with the exception of certain intercompany notes and note guarantees in connection with the Offering detailed in Note 7(a). The Revolving Facility contained a two-year term-out provision should the facility not be renewed.

On October 16, 2003 the Corporation established a new Revolving Credit Facility ("Revolving Credit Facility") in the amount of $240.0 million, $15.0 million of which is available only for letter of credit requirements. This new Revolving Credit Facility refinanced the Corporation's Convertible Notes and the existing Revolving Facility, and provided additional working capital availability. The new Revolving Credit Facility has the same terms and conditions as described in the above paragraph for the Revolving Facility and in addition established certain financial covenants including a limit on the amount available for drawdown. At December 31, 2003 the limit available for drawdown was $215.0 million, of which $188.0 million ($20.0 million — 2002) had been drawn. In addition letters of credit for $0.5 million (nil — 2002) had been issued.

## 8. OBLIGATIONS UNDER CAPITAL LEASE

| | 2003 | 2002 |
|---|---|---|
| Obligations Under Capital Lease | $ **52,950** | $ 50,859 |
| Less: Current Portion | **(1,340)** | – |
| | $ **51,610** | $ 50,859 |

The capital lease obligation relates to the Corporation's share of capital costs for the hydrogen-manufacturing unit within the Oil Sands Project. Repayment of the principal obligation is scheduled to be $1.3 million in 2004 and thereafter until fully repaid.

## 9. OTHER LONG-TERM LIABILITIES

| | 2003 | 2002 |
|---|---|---|
| Operating Lease Guarantee Obligation | $ **2,583** | $ – |
| Asset Retirement Obligation | **7,137** | – |
| | $ **9,720** | $ – |

Under the Mobile Equipment Lease, described in Note 17(a), the Corporation is committed to pay its 20 per cent share of an amount equal to 85 per cent of the original cost of the equipment to the lessor at the end of the terms of the lease. Accordingly, the Corporation recognizes, as a liability, a portion of this future payment as it relates to the service life of the equipment that has passed.

The Corporation, in association with its 20 per cent working interest in the Oil Sands Project, is also responsible for its share of future dismantlement costs and site restoration costs in the mining, extracting and upgrading activities. The Corporation currently estimates that the total undiscounted amount of its share of these costs to be approximately $37.3 million, with the majority of that amount to be paid at the end of the current reserves for the Project. The Corporation has assumed a credit adjusted risk free rate of 7.0 per cent, resulting in the Corporation recognizing a Capital Asset and a long-term liability of

$6.7 million at January 1, 2003. Accretion expense of $0.5 million has been recognized during 2003 on the long-term liability and the amount included in Capital Assets has been depleted in accordance with the Capital Assets policy. During the year the Corporation incurred $0.1 million of restoration costs in respect of this liability.

## 10. INTEREST EXPENSE

| | | 2003 | | 2002 |
|---|---|---|---|---|
| Interest on Long-term Debt | $ | 60,522 | $ | 48,126 |
| Capitalized Interest in Oil Sands Project | | (23,479) | | (48,126) |
| Interest Expense, Net | | 37,043 | | – |
| Interest on Obligations Under Capital Lease | | 1,386 | | – |
| | $ | 38,429 | $ | – |

It is the Corporation's policy to capitalize carrying costs including interest expense for capital assets acquired, constructed or developed over time. As at December 31, 2003, $87.1 million of net interest expense (December 31, 2002 — $63.6 million) had been capitalized as part of the cost of the Oil Sands Project, representing the interest expense from inception to June 1, 2003, the date the Corporation commenced commercial operations.

On a cash basis interest paid for the year ended December 31, 2003 was $63.8 million (December 31, 2002 — $40.6 million). Cash interest received for the year ended December 31, 2003 was $0.2 million (December 31, 2002 — $2.3 million).

## 11. INCOME TAXES

| | | 2003 | | 2002 |
|---|---|---|---|---|
| Large Corporations Tax | $ | 3,079 | $ | 2,905 |
| Future Income Tax | | (4,330) | | (22,551) |
| **Income Tax Recovery** | $ | (1,251) | $ | (19,646) |

Cash taxes paid during the year ended December 31, 2003 were $4.5 million (December 31, 2002 — $2.4 million) and related solely to Large Corporations Tax.

At December 31, the future income tax liability consists of:

| | | 2003 | | 2002 |
|---|---|---|---|---|
| Future Income Tax Assets | | | | |
| Net Losses Carried Forward | $ | 49,682 | $ | 19,069 |
| Share Issue Costs | | 1,723 | | 2,096 |
| Debt Issue Costs | | – | | 1,386 |
| Future Income Tax Liabilities | | | | |
| Capital Assets in Excess of Tax Values | | (38,860) | | (23,005) |
| Unrealized Foreign Exchange Gain | | (6,209) | | – |
| Debt Issue Costs | | (29) | | – |
| **Net Future Income Tax Asset (Liability)** | $ | 6,307 | $ | (454) |

The following table reconciles income taxes calculated at the Canadian statutory rate of 41.12 per cent (2002 — 42.12 per cent) with actual income taxes:

| | 2003 | 2002 |
|---|---|---|
| Net Earnings (Loss) Before Income Taxes | $ 15,882 | $ (28,649) |
| Income Tax Expense (Recovery) at Statutory Rate | 6,531 | (12,067) |
| Effect of Tax Rate Changes | 1,851 | – |
| Non-Taxable Portion of Foreign Exchange Gain | (8,298) | – |
| Resource Allowance | (4,414) | – |
| Recognition of Losses Brought Forward | – | (10,484) |
| Large Corporations Tax | 3,079 | 2,905 |
| **Income Tax Recovery** | $ (1,251) | $ (19,646) |

At December 31, 2003, the Corporation had approximately $1.5 billion of tax pools available. Included in the tax pools are $129.3 million of tax loss carry forward balances as evaluated at December 31, 2003, with expiry dates as follows:

| Year Created | Amount | Expiry |
|---|---|---|
| 1999 | $ 1.2 million | 2006 |
| 2000 | $ 11.7 million | 2007 |
| 2001 | $ 8.8 million | 2008 |
| 2002 | $ 24.7 million | 2009 |
| 2003 | $ 82.9 million | 2010 |

## 12. SHARE CAPITAL

### (a) Authorized

The Corporation is authorized to issue an unlimited number of Class A shares ("Common Shares"), an unlimited number of non-voting Convertible Class B Equity Shares ("Class B Shares"), an unlimited number of non-voting Class C Preferred Shares and an unlimited number of Class D Preferred Shares, issuable in series.

The Common Shares are without nominal or par value. The Class B Shares were convertible into Common Shares upon successful completion of a public offering or certain other events, but with no additional consideration owing to the Corporation. There have been no Class C Preferred Shares issued. The Class D Preferred Shares, Series A, which have been issued, are convertible into Common Shares at the holders' options prior to redemption on a one for one basis.

### (b) Issued and Outstanding

| | Number of Shares | | Amount |
|---|---|---|---|
| **Common Shares** | | | |
| Balance at December 31, 2001 | 47,513,971 | $ | 435,340 |
| Issued for cash | 228,500 | | 1,977 |
| Renunciation of Flow-Through Shares [1] | – | | (23,005) |
| Balance at December 31, 2002 | 47,742,471 | | 414,312 |
| Issued for Cash | 2,050,000 | | 50,225 |
| Issued on Exercise of Employee Stock Options | 163,800 | | 1,457 |
| Share Issue Costs, Net of Tax | – | | (1,290) |
| Balance at December 31, 2003 | 49,956,271 | | 464,704 |
| **Class D Preferred Shares** | | | |
| Balance at December 31, 2002 and 2003 | 666,667 | $ | 11,963 |
| **Total Share Capital** | 50,622,938 | $ | 476,667 |

(1) *In accordance with certain provisions of the Income Tax Act, Canadian exploration expenses or Canadian development expenses related to expenditures of the subscribed funds for shares issued on a flow-through basis are transferred to the shareholders. Effective December 31, 2002, all the expenditures related to these shares had been renounced and the tax deductions were transferred to the shareholders. Accordingly, a future income tax liability is created and share capital is reduced by the tax effect of the renounced expenditures.*

### (c) Net Earnings (Loss) Per Share

The following table summarizes the Common Shares used in calculating Net Earnings (Loss) per Common Share:

| | 2003 | 2002 |
|---|---|---|
| Weighted Average Common Shares Outstanding – Basic | **50,344,332** | 48,330,320 |
| Effect of Stock Options and Warrants | **965,308** | – |
| **Weighted Average Common Shares Outstanding – Diluted** | **51,309,640** | 48,330,320 |

Due to a loss for the 12 months ended December 31, 2002, zero incremental shares are included in the 2002 diluted weighted average common shares outstanding.

### (d) Class D Preferred Shares

The Corporation has 666,667 Class D Preferred Shares, Series A outstanding. The Class D Preferred Shares, Series A, can be converted into Common Shares at the holders' option prior to redemption on a one for one basis. If not previously converted, they are redeemable at the option of the Corporation at any time at a price equal to their issue price, plus a cumulative dividend of 12 per cent per year compounded semi-annually until January 1, 2007, from which date the dividend increases by 3 per cent per quarter to a maximum of 24 per cent per year. Cash dividends are not paid on the Class D Preferred Shares.

## (e) Call Obligations

The Corporation entered into call obligation agreements with certain shareholders, which obligated the holders of the obligations to purchase up to 3,040,000 Class B Shares for $5.00 per share. The Corporation was entitled to require the subscriber to exercise their call obligations at its discretion upon the satisfaction of certain conditions. These call obligations were to have expired on December 31, 2001, but were extended until March 31, 2003 at which time they expired unexercised. An additional 2,589,641 call obligations were entered into in July 2001, whereby each call obligation is exercisable into one Class B Share and one warrant to purchase a Class B Share upon the payment of $13.00 per call obligation. These call obligations were exercisable until March 31, 2003 and the underlying warrant was exercisable at the then market price for a period of four years after the call obligation exercise. These obligations expired unexercised.

## (f) Warrants

The Corporation has 494,224 Class A Warrants outstanding. Each Class A Warrant entitles the holder to purchase one Common Share at $2.50 per share until five years after start-up of the Oil Sands Project.

## (g) Issuances

On February 7, 2003, the Corporation completed a public offering for the issuance of 2,050,000 Common Shares for aggregate proceeds of $50.2 million, before consideration of share issue costs of $2.2 million ($1.3 million net of tax). The offering was underwritten by a syndicate of Canadian underwriters and undertaken through the filing of a short form prospectus. Proceeds of the offering were used to pay down certain amounts that had been drawn on the bank debt and to fund capital expenditures.

# 13. STOCK OPTIONS

## (a) Stock Option Plan

The Corporation has established a Stock Option Plan for the issuance of options to purchase Common Shares to directors, officers and employees of the Corporation and its subsidiaries. Options granted under the Stock Option Plan generally vest on an annual basis over four years. The stock options expire five years from each vesting date.

| | 2003 | | 2002 | |
|---|---|---|---|---|
| | Number of Options | Weighted Average Exercise Price | Number of Options | Weighted Average Exercise Price |
| Outstanding at Beginning of Year | **1,329,500** | **$ 14.40** | 1,238,000 | $ 9.52 |
| Granted | **233,000** | **25.72** | 429,000 | 23.91 |
| Exercised | **(163,800)** | **8.90** | (228,500) | 8.64 |
| Cancelled | **(54,000)** | **9.13** | (109,000) | 8.50 |
| Outstanding at End of Year | **1,344,700** | **$ 17.25** | 1,329,500 | $ 14.40 |
| Exercisable at End of Year | **660,700** | **$ 11.46** | 550,000 | $ 9.02 |

The following table summarizes Stock Options outstanding and exercisable under the Stock Option Plan at December 31, 2003:

| | Options Outstanding | | | Options Exercisable | |
|---|---|---|---|---|---|
| Exercise Price | Number of Options | Weighted Average Remaining Life (months) | Weighted Average Exercise Price | Number of Options | Weighted Average Exercise Price |
| \$ 8.50 – \$12.00 | 504,100 | 44.8 | \$ 8.57 | 486,600 | \$ 8.55 |
| \$12.01 – \$16.00 | 178,600 | 63.7 | 14.66 | 81,850 | 14.70 |
| \$20.01 – \$24.00 | 411,500 | 69.1 | 23.85 | 87,875 | 23.82 |
| \$24.01 – \$28.00 | 200,500 | 80.3 | 25.07 | 4,375 | 25.43 |
| \$28.01 – \$32.00 | 50,000 | 90.0 | 28.22 | – | – |
| | 1,344,700 | 61.7 | \$ 17.25 | 660,700 | \$ 11.46 |

The number of Common Shares reserved for issuance under the Stock Option Plan was 2,607,700 at December 31, 2003 (3,000,000 at December 31, 2002).

**(b) Stock-based Compensation**

During 2003 the Corporation recognized \$0.3 million (nil — 2002) in compensation expense related to stock-based compensation issued during 2003. This is the portion of stock-based compensation that is related to 2003 employee services rendered. The weighted average fair value of the 233,000 options granted during 2003 was \$9.08 using the Black-Scholes option pricing model. In 2002 there were 429,000 options granted at a weighted average fair value of \$8.39, however in accordance with CICA 3870 no compensation expense has been recognized. The following table sets out the assumptions used in applying the Black-Scholes model:

| | 2003 | 2002 |
|---|---|---|
| Risk Free Interest Rate, Average for Year | **4.54%** | 4.55% |
| Expected Life (in years) | **5.00** | 5.00 |
| Expected Volatility | **0.30** | 0.30 |
| Dividend per Share | – | – |

No compensation expense has been recognized for stock options granted before January 1, 2003, in accordance with Note 1(j). Had compensation expense been determined based on the fair value method for awards made after December 31, 2001 but before January 1, 2003, the Company's net earning (loss) attributable to common shareholders and earnings (loss) per share would have been adjusted to the proforma amounts indicated below:

| | 2003 | 2002 |
|---|---|---|
| Net Earnings (Loss) Attributable to Common Shareholders – As Reported | **\$ 15,003** | \$ (10,286) |
| Compensation Expense | **1,177** | 703 |
| Net Earnings (Loss) Attributable to Common Shareholders – Proforma | **\$ 13,826** | \$ (10,989) |
| Basic Earnings (Loss) Per Share: | | |
| As Reported | **\$ 0.30** | \$ (0.21) |
| Proforma | **\$ 0.27** | \$ (0.23) |
| Diluted Earnings (Loss) Per Share: | | |
| As Reported | **\$ 0.29** | \$ (0.21) |
| Proforma | **\$ 0.27** | \$ (0.23) |

## 14. SHAREHOLDERS' RIGHTS PLAN

The Corporation has a shareholders' rights plan (the "Plan"). Under the Plan, one right will be issued with each Common Share issued. The rights remain attached to the Common Share and are not exercisable or separable unless one or more certain specified events occur. If a person or group acting in concert acquires 20 per cent or more of the Common Shares of the Corporation, the rights will entitle the holders thereof (other than the acquiring person or group) to purchase Common Shares of the Corporation at a 50 per cent discount from the then market price. The rights are not triggered by a "Permitted Bid", as defined in the Plan.

## 15. EMPLOYEE FUTURE BENEFITS

The Corporation has a defined contribution pension plan for its direct employees and as a result of the 20 per cent ownership in the Oil Sands Project has a defined benefit pension plan for employees of the Oil Sands Project. All of the information pertaining to the defined benefit pension plan in this Note represents the Corporation's 20 per cent ownership in the Oil Sands Project.

The total expense for the year ended December 31, 2003 for the Corporation's defined contribution plan was $0.2 million (December 31, 2002 — $0.09 million).

Information for the defined benefit pension plan is as follows:

| | | 2003 |
|---|---|---|
| Accrued Benefit Obligation, Beginning of Year | $ | – |
| Current Service Cost | | 824 |
| Interest Cost | | 88 |
| Other | | 200 |
| Benefits Paid | | (28) |
| Accrued Benefit Obligation, End of Year | $ | 1,084 |
| Fair Value of Plan Assets, Beginning of Year | $ | – |
| Employer Contributions | | 1,078 |
| Actual Return on Plan Assets | | 81 |
| Benefits Paid | | (28) |
| Fair Value of Plan Assets, End of Year | $ | 1,131 |
| Funded Status – Plan Surplus | $ | 47 |
| Other | | 165 |
| Accrued Benefit Asset | $ | 212 |
| Components of Expense | | |
| Current Service Cost | $ | 824 |
| Interest Cost | | 88 |
| Expected Return on Plan Assets | | (70) |
| Other | | 8 |
| Net Expense | $ | 850 |

The significant actuarial assumptions used to determine the periodic expense and accrued benefit obligations are as follows:

| | 2003 |
|---|---|
| Discount Rate | **6.50%** |
| Expected Long-term Rate of Return on Plan Assets | **7.00%** |
| Rate of Compensation Increase | **4.25%** |

## 16. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Corporation's financial instruments that are included in the Consolidated Balance Sheets are comprised of cash, accounts receivable, accounts payable and accrued liabilities, long-term borrowings and the Convertible Notes.

### (a) Commodity Price Risk

The Corporation has entered into various commodity pricing agreements designed to mitigate the exposure to the volatility of future crude oil prices. As at December 31, 2003 the agreements are summarized as follows:

| Instrument | Notional Volume (bbls/d) | Hedge Period | Average Swap Price ($/bbl) | Unrealized Increase (Decrease) To Future Revenue |
|---|---|---|---|---|
| WTI Swaps | 20,000 | Fiscal 2004 | US$27.37 | (Cdn$25,955) |
| WTI Swaps | 16,000 | January to March 2005 | US$26.17 | (Cdn$3,221) |
| WTI Swaps | 7,000 | April to December 2005 | US$26.87 | (Cdn$850) |
| | | | | (Cdn$30,026) |

### (b) Credit Risk

A significant portion of the Corporation's accounts receivable is with customers in the oil and gas industry, and is subject to normal industry credit risks. The Corporation has in place credit practices that limit transactions to counterparties of minimum investment grade quality.

The Corporation's crude oil swap agreements are all with major financial institutions in Canada.

### (c) Interest Rate Risk

At December 31, 2003, the increase or decrease in net earnings for each one per cent change in the interest rates on floating debt amounts to $2.8 million. At December 31, 2002, there would be no increase or decrease in net earnings from a one per cent change in the interest rates on floating rate debt as all interest had been capitalized as part of the cost of the Oil Sands Project.

### (d) Foreign Currency Risk

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and foreign currencies will affect the Corporation's operating and financial results. At December 31, 2003, the Corporation has revenue and expenses transacted in US dollars, and has US dollar denominated Senior Secured Notes, as described in Note 7(a). At December 31, 2002, the Corporation's only significant exposure to these foreign exchange risks was in connection with its Senior Secured Notes.

### (e) Fair Values of Financial Assets and Liabilities

The fair values of financial instruments that are included in the Consolidated Balance Sheets, other than long-term borrowings, approximate their carrying amount due to the relatively short period to maturity of these instruments.

The estimated fair values of long-term borrowings have been determined based upon market prices at December 31, 2003 for other similar liabilities with similar terms and conditions, or by discounting future payments of interest and principal at estimated interest rates that would be available to the Corporation at year-end.

| | 2003 | | 2002 | |
|---|---|---|---|---|
| | Balance Sheet Amount | Fair Value | Balance Sheet Amount | Fair Value |
| Floating Rate Debt: | | | | |
| Revolving Credit and Term | | | | |
| Loan Borrowings | $ 279,000 | $ 279,000 | $ 65,000 | $ 65,000 |
| Other Long-term Liabilities | 62,670 | 62,670 | 50,859 | 50,859 |
| Fixed Rate Debt: | | | | |
| US Senior Secured Notes | 581,580 | 661,547 | 710,820 | 700,158 |
| Long-term Borrowings | $ 923,250 | $ 1,003,217 | $ 826,679 | $ 816,017 |

## 17. COMMITMENTS AND CONTINGENCIES

### (a) Commitments

The Corporation has executed long-term third party agreements to provide for pipeline transportation of bitumen and upgraded products, electrical and thermal energy, production and supply of hydrogen and transportation of natural gas. Under the terms of certain of these agreements, the Corporation is committed to pay for these utilities and services on a long-term basis, regardless of the extent that such services and utilities are actually used. If due to project delay, suspension, shut down or other reason, the Corporation fails to meet its commitment under these agreements, the Corporation may incur substantial costs and may, in some circumstances, be obligated to purchase the facilities constructed by the third parties for a purchase price in excess of the fair market value of the facilities. The Corporation has also entered into long-term third party agreements to purchase certain feedstocks on a 'take or pay' basis.

The Corporation and the other owners of the oil sands Joint Venture have entered into long-term operating lease obligations for certain equipment related to the Oil Sands Project. The term of the lease obligations is between three and seven years. The Corporation anticipates its share of the final value of the leased equipment will total between $40.0 to $60.0 million. A guarantee has been provided to the lessor in order to secure attractive leasing terms and is payable when the equipment is returned to the lessor. At December 31, 2003, the Corporation's share of the maximum payable under the guarantee was $41.1 million. However, any proceeds received from the sale of the equipment would be used to offset against the payment required under the guarantee. At December 31, 2003, the Corporation's share of committed lease payments amounted to $50.8 million. The estimate of lease interest obligations, excluding any committed payments, is $2.0 million per year for each of 2004 through 2006, $1.9 million for 2007 and $1.8 million for 2008.

The following table summarizes the Corporation's operating commitments at December 31, 2003:

| | Feedstocks and Transportation | Electrical and Thermal Energy | Mobile Equipment Lease | Total |
|---|---|---|---|---|
| 2004 | $ 71,581 | $ 21,102 | $ 2,380 | $ 95,063 |
| 2005 | 72,837 | 21,105 | 5,960 | 99,903 |
| 2006 | 81,180 | 20,696 | 2,940 | 104,815 |
| 2007 | 81,482 | 20,928 | 3,340 | 105,750 |
| 2008 | 16,800 | 21,252 | 9,800 | 47,852 |
| Thereafter | 305,600 | 307,709 | 26,340 | 639,949 |
| Total | $ 629,480 | $ 412,792 | $ 50,760 | $ 1,093,051 |

### (b) Contingencies

During the year the Corporation has submitted claims, under the insurance coverage provided in our Joint Venture construction policies, in respect of the fire that occurred in January 2003 at the Muskeg River Mine extraction plant. The Corporation has extensive insurance coverage in place and is seeking to recover these costs from insurers. Claims for $125.0 million ($25.0 million for the Corporation's share) have been submitted and a total of $9.7 million received by the Corporation as of December 31, 2003 for property damages. The Joint Venture has also filed a $500.0 million claim ($100.0 million for the Corporation's share) in respect of loss of profits due to production delays from the fire.

The Corporation has filed a Statement of Claim, against the parties involved in placing and issuing the cost overrun and start-up delay insurance policy, in an amount exceeding $200.0 million. Aggravated and punitive damages totaling $650.0 million have also been claimed against the insurers. The Statement of Claim will only be served on the insurers and pursued in the courts in the event that resolution procedures cannot otherwise be agreed to on a timely basis. Arbitration proceedings under the terms of the insurance policy have been initiated to resolve the disputes with insurers surrounding these claims for payment.

No amounts, other than those collected at December 31, 2003, have been recognized in these statements relating to these insurance policies nor will an amount be recognized until the proceeds are received.

## 18. NET CHANGE IN NON-CASH WORKING CAPITAL

| Source/(Use) | 2003 | 2002 |
|---|---|---|
| Operating Activities | | |
| Accounts Receivable | **$ (53,309)** | $ (4,071) |
| Inventory | **(4,925)** | (4,175) |
| Prepaid Expenses | **(7,033)** | – |
| Accounts Payable and Accrued Liabilities | **58,134** | 281 |
| | **$ (7,133)** | $ (7,965) |
| Investing Activities | | |
| Accounts Receivable | **$ 1,939** | $ 4,675 |
| Accounts Payable and Accrued Liabilities | **(33,138)** | (10,550) |
| | **$ (31,199)** | $ (5,875) |

## 19. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING

The Consolidated Financial Statements have been prepared in Canadian dollars in accordance with accounting principles generally accepted in Canada (Canadian GAAP) which, in most respect, conform to accounting principles generally accepted in the United States (US GAAP). Canadian GAAP differs from US GAAP in the following respects:

### Reconciliation of Net Earnings (Loss) under Canadian GAAP to US GAAP

| Year Ended December 31 | Note | 2003 | 2002 |
|---|---|---|---|
| Net Earnings (Loss) – Canadian GAAP | | $ 17,133 | $ (9,003) |
| Impact of US GAAP | | | |
| Pre-Operating Items and Borrowing Costs | iv | 17,716 | (4,669) |
| Loss on Derivative Financial Instruments | v | (1,348) | (39) |
| Interest on Convertible Notes | vii | (3,640) | 163 |
| Pre-Feasibility Costs | viii | (923) | – |
| Deferred Income Tax | iii | 22,174 | (19,929) |
| Net Earnings (Loss) – US GAAP | | $ 51,112 | $ (33,477) |
| Net Earnings (Loss) Per Share – US GAAP | | | |
| Basic | | $ 1.02 | $ (0.69) |
| Diluted | | $ 1.00 | $ (0.69) |

### Consolidated Statement of Other Comprehensive Income

| Year Ended December 31 | Note | 2003 | 2002 |
|---|---|---|---|
| Net Earnings (Loss) – US GAAP | | $ 51,112 | $ (33,477) |
| Change in Realized and Unrealized Losses | v | (15,666) | (1,483) |
| Other Comprehensive Income | | $ 35,446 | $ (34,960) |

### Consolidated Statement of Cash Flows – US GAAP

| Year Ended December 31 | Note | 2003 | 2002 |
|---|---|---|---|
| Cash Provided By (Used In) | | | |
| Operating Activities – Canadian GAAP | | $ (1,330) | $ (16,568) |
| Pre-Operating Items and Borrowing Costs | iv | (102,676) | (4,669) |
| Interest on Convertible Notes | vii | (3,640) | 163 |
| Pre-Feasibility Costs | viii | (923) | – |
| Operating Activities – US GAAP | | (108,569) | (21,074) |
| Financing Activities – Canadian GAAP | | 170,344 | 511,439 |
| Interest on Convertible Notes | vii | 3,640 | 1,283 |
| Financing Activities – US GAAP | | 173,984 | 512,722 |
| Investing Activities – Canadian GAAP | | (179,672) | (533,416) |
| Pre-Operating Items and Borrowing Costs | iv | 102,676 | 4,669 |
| Interest on Convertible Notes | vii | – | (1,446) |
| Pre-Feasibility Costs | viii | 923 | – |
| Investing Activities – US GAAP | | (76,073) | (530,193) |
| Decrease in Cash | | $ (10,658) | $ (38,545) |

### Consolidated Balance Sheet

| As at December 31 | | 2003 | | 2002 | |
|---|---|---|---|---|---|
| | Note | As Reported | US GAAP | As Reported | US GAAP |
| **Assets** | | | | | |
| Current Assets | | **$ 77,897** | **$ 77,897** | $ 25,227 | $ 25,227 |
| Capital Assets | iv,vii,viii | **1,353,317** | **1,358,201** | 1,306,989 | 1,293,987 |
| Deferred Charges | iv | **20,903** | **19,810** | 27,422 | 27,422 |
| Future Income Taxes | iii | **6,307** | **37,837** | – | – |
| | | **$ 1,458,424** | **$ 1,493,745** | $ 1,359,638 | $ 1,346,636 |
| **Liabilities** | | | | | |
| Current Liabilities | | **$ 67,289** | **$ 67,289** | $ 45,008 | $ 128,953 |
| Financial Liabilities | v | – | **30,026** | – | 2,600 |
| Long-term Debt | | **860,580** | **860,580** | 775,820 | 775,820 |
| Obligations Under Capital Lease | | **51,610** | **51,610** | 50,859 | 50,859 |
| Other Long-term Liabilities | | **9,720** | **9,720** | – | – |
| Future Income Taxes | iii | – | – | 454 | – |
| | | **989,199** | **1,019,225** | 872,141 | 958,580 |
| **Shareholders' Equity** | | | | | |
| Share Capital | ix | **476,667** | **495,972** | 426,275 | 445,580 |
| Contributed Surplus | | **278** | **278** | – | – |
| Convertible Notes | vii | – | – | 83,945 | – |
| Deficit | iv,v,viii,ix | **(7,720)** | **(4,581)** | (22,723) | (55,693) |
| Accumulated Other Comprehensive Income | v | – | **(17,149)** | – | (1,483) |
| | | **$ 1,458,424** | **$ 1,493,745** | $ 1,359,638 | $ 1,346,636 |

### i. Stock-based Compensation

The Corporation accounts for its stock-based compensation plans under CICA 3870, under which no compensation expense was recognized in the Consolidated Financial Statements for stock options granted between January 1, 2002 to December 31, 2002. If compensation expense had been recorded in accordance with Statement of Financial Accounting Standard ("FAS") No. 123, the Corporation's net earnings (loss) and net earnings (loss) per share would approximate the following pro forma amounts:

| Year Ended December 31 | 2003 | 2002 |
|---|---|---|
| Compensation Expense | **$ 1,177** | $ 703 |
| Net Earnings (Loss): | | |
| As Reported - US GAAP | **51,112** | (33,477) |
| Proforma | **$ 49,935** | $ (34,180) |
| Basic Earnings (Loss) Per Share: | | |
| As Reported - US GAAP | **$ 1.02** | $ (0.69) |
| Proforma | **$ 0.99** | $ (0.71) |
| Diluted Earnings (Loss) per Share: | | |
| As Reported – US GAAP | **$ 1.00** | $ (0.69) |
| Proforma | **$ 0.97** | $ (0.71) |

The fair value of each option granted is estimated on the date of grant using the Black-Scholes pricing model with weighted average assumptions for grants as follows:

| Year Ended December 31 | 2003 | 2002 |
|---|---|---|
| Risk Free Interest Rate, Average for Year | **4.54%** | 4.55% |
| Expected Life (In Years) | **5.00** | 5.00 |
| Expected Volatility | **0.30** | 0.30 |
| Dividend Per Share | **–** | – |

### ii. Recent Accounting Pronouncements

A. *FASB Interpretation 46 Consolidation of Variable Indirect Entities*

In February 2003, FASB issued FASB Interpretation 46, to be effective for the first interim or annual reporting period beginning after June 14, 2003. The standard mandates that certain special-purpose entities be consolidated by their primary beneficiary. The Corporation does not expect that the adoption of this pronouncement will have an impact on its financial statements.

B. *Hedge Accounting*

The CICA issued Accounting Guideline 13 "Hedging Relationships", effective for fiscal years beginning on or after July 1, 2003. The guideline establishes certain conditions when hedge accounting may be applied, but does not specify hedge accounting methods. The Corporation does not expect that the adoption of this pronouncement will have an impact on its financial statements.

C. FAS 143 *Accounting for Asset Retirement Obligations*

FASB issued FAS 143, effective for fiscal years beginning after June 15, 2002. FAS 143 applies to legal obligations associated with the retirement of a tangible long-lived asset that result from the acquisition, construction, development and/or the normal operation of a long-lived asset, except for certain obligations of lessees. The Corporation adopted CICA 3110 "Asset Retirement Obligations" during the year, and the impact is reflected in Corporation's Consolidated Financial Statements as described in Notes 1(h) and 9.

### iii. Income Taxes

Under US GAAP, the net deferred income tax liability as at December 31, 2003 and 2002 consists of:

| Year Ended December 31 | 2003 | 2002 |
|---|---|---|
| Future Income Tax Asset | | |
| Net Losses Carried Forward | **$ 49,682** | $ 19,069 |
| Share Issue Costs | **1,723** | 2,096 |
| Debt Issue Costs | **–** | 1,386 |
| Financial Liabilities in Excess of Tax Values | **12,046** | 1,078 |
| Future Income Tax Liabilities | | |
| Capital Assets in Excess of Tax Values | **(3,188)** | (23,584) |
| Unrealized Foreign Exchange Gain | **(22,397)** | – |
| Debt Issue Costs | **(29)** | – |
| Less: Valuation Allowance | **–** | (45) |
| Net Future Income Tax Liability – US GAAP | **$ 37,837** | $ – |

The following table reconciles income taxes calculated at the Canadian statutory rate of 41.12 per cent (2002 — 42.12 per cent) with actual income taxes:

| Year Ended December 31 | 2003 | 2002 |
|---|---|---|
| Loss Before Income Taxes – Canadian GAAP | $ 15,882 | $ (28,649) |
| US GAAP Adjustments | 11,805 | (4,545) |
| Loss Before Income Taxes – US GAAP | 27,687 | (33,194) |
| Expected Income Tax | 11,385 | (13,981) |
| Effect of Tax Rate Changes | 665 | – |
| Non-Taxable Portion of Foreign Exchange Gain | (30,397) | – |
| Resource Allowance | (4,414) | – |
| Loss on Derivative Financial Instruments | (556) | – |
| Tax Values in Excess of Book Capital Assets | (1,677) | – |
| Interest on Convertible Notes | (1,510) | – |
| Recognition of Losses Brought Forward | – | (7,946) |
| Large Corporations Tax | 3,079 | 2,905 |
| Renunciation of Deductions for Flow-Through Shares | – | 19,305 |
| Income Tax Expense – US GAAP | $ (23,425) | $ 283 |

**iv. Borrowing Costs and The End of Pre-Operating Period**

Under Canadian GAAP, the Corporation is deemed to have ended its pre-operating period upon commencement of commercial production, which occurred on June 1, 2003. Until that time, revenues, training and start-up costs, interest and foreign exchange gains associated with the Project during the pre-operating period were deferred and capitalized as part of the Project. Under US GAAP, the Corporation is deemed to have ended its pre-operating period upon mechanical completion of the Project, which occurred on December 1, 2002, such that these pre-operating items are expensed thereafter. Consistent with the December 1, 2002 end of the pre-operating period depreciation, depletion and amortization of the Corporation's Capital Assets and Deferred Charges should have also commenced.

Under Canadian GAAP during the pre-operating period, standby fees and foreign exchange gains or losses associated with borrowing facilities can be deferred. Under US GAAP, during the pre-operating period these costs would be expensed as incurred.

The following table illustrates each of these differences:

| Year Ended December 31 | 2003 | 2002 |
|---|---|---|
| Pre-Operating Items: | | |
| Revenues | $ 29,653 | $ – |
| Feedstocks and Operating Expenses | (79,197) | (1,374) |
| Interest Expense | (23,479) | (3,295) |
| Depreciation, Depletion and Amortization | (3,221) | – |
| Foreign Exchange Gains | 93,960 | – |
| Impact on Net Earnings (Loss) Before Income Tax | 17,716 | (4,669) |
| US GAAP Adjustments – Prior Years | (14,448) | (9,779) |
| | $ 3,268 | $ (14,448) |
| Adjustment to Capital Assets | $ 4,361 | $ (14,448) |
| Adjustment to Deferred Charges | (1,093) | – |
| Adjustment to Assets | $ (3,268) | $ (14,448) |

v. **Derivative Financial Instruments and Hedging**

Under Canadian GAAP, the derivative financial instruments qualify for hedge accounting and the payments or receipts on these contracts are recognized in earnings concurrently with the hedged transaction and changes in the fair values of the contracts are not reflected in the Consolidated Financial Statements. US GAAP requires that all derivative financial instruments be recorded on the balance sheet as either assets or liabilities at their fair values. When specific hedging criteria is met, then changes in the derivative's fair value can be recorded in other comprehensive income and any ineffectiveness of the hedge is recorded in earnings for the period.

Management has designated the derivative financial instruments described in Note 16(a) as hedges and as a result, under US GAAP, the effect is to record the change in the fair value of the hedges of $28.6 million (2002 — $2.56 million), $17.1 million net of tax (2002 — $1.48 million), in other comprehensive income and $1.4 million (2002 — $0.04 million) in expenses. In addition, liabilities increased by $30.0 million (2002 — $2.6 million), being the full amount of the unrealized losses.

vi. **Other Comprehensive Income**

Comprehensive income is measured in accordance with FAS 130 "Reporting Comprehensive Income". This Standard defines comprehensive income as all changes in equity other than those resulting from investments by owners and distributions to owners. The Corporation had other comprehensive income arising due to unrealized losses on derivative financial instruments designated as hedge transactions. At December 31, 2003 this other comprehensive income amounted to a loss net of tax of $17.1 million (2002 — $1.48 million).

**vii. Convertible Notes**

Under Canadian GAAP, amounts drawn under the Note Purchase Facility are deemed to consist of both an equity and a liability component, recognized as convertible notes. The initial carrying amount of the equity component is adjusted for accretion to bring it up to the stated principal amount of the Note Purchase Facility at maturity. This accretion is charged to the Deficit. Under US GAAP, all amounts drawn under the Note Purchase Facility are classified as a liability and any charges paid on these notes are treated as interest expense. During the pre-operating period, which ended December 1, 2002 under US GAAP, the interest on the Note Purchase Facility, in place to finance the Oil Sands Project, could be capitalized as part of the Oil Sands Project costs.

The effect of this difference in 2002 was to reclassify the $83.9 million of Convertible Notes from Shareholders' Equity to Current Liabilities. In addition, the accretion was reversed and capitalized as part of the costs for the Oil Sands Project. The effect was to decrease expenses by $0.16 million, decrease the Deficit by $1.28 million and increase capital assets by $1.44 million. Subsequent to the pre-operating period the interest on the Note Purchase Facility would have been expensed and not accreted to the Deficit. The effect of this difference in 2003 was to reclassify $3.6 million to interest expense and $1.5 million to future income tax recovery.

**viii. Pre-Feasibility Costs**

Under Canadian GAAP costs associated with projects that have yet to be determined to be technically feasible can be capitalized as part of Capital Assets if certain criteria are met. Under US GAAP costs associated with projects that have not yet been determined to be technically feasible must be expensed. During the year the Corporation had expenditures of $0.9 million relating to projects that have not yet been determined to be technically feasible. The effect of this difference is to reduce capital assets by $0.9 million and decrease net earnings by $0.9 million.

**ix. Flow-Through Shares**

Under Canadian GAAP flow-through shares are recorded at their face value within share capital. When the expenditures are renounced and the tax deductions transferred to the shareholders, future income tax liabilities will increase and the share capital will be reduced. Under US GAAP when the shares are issued the proceeds are allocated between the offering of the shares and the sale of tax benefits. The allocation is made based on the difference between the quoted price of the existing shares and the amount the investor pays for the flow-through shares (given no other differences between the securities). A liability is recognized for this difference. The liability is reversed when tax benefits are renounced and a deferred tax liability recognized at that time. Income tax expense is the difference between the amount of the deferred tax liability and the liability recognized on issuance. At December 31, 2002, the Corporation had recognized all renouncements of the tax deductions to the investors. The effect of this difference is to increase share capital by $19.3 million and increase deferred income tax expense by $19.3 million and no effect on current liabilities.

Western's Board is committed to a high standard of corporate governance practices. The Board believes that this commitment is not only in the best interests of shareholders but that it also promotes effective decision making at the Board level. The Board is of the view that its approach to corporate governance is appropriate and complies with the objectives and guidelines relating to corporate governance adopted by the Toronto Stock Exchange.

## COMPOSITION OF THE BOARD

The Board currently consists of 10 directors who provide a wide diversity of business experience. Nine of the Board members are independent of management and are unrelated directors. Each of the unrelated directors is free from any business or other interest or relationship, other than interests and relationships which arise solely as a result of shareholding, which could reasonably be perceived to materially interfere with the director's ability to act in the best interests of Western.

## BOARD COMMITTEES AND THEIR MANDATES

The Board has four committees, each comprised of three or four directors, all of whom are unrelated directors. The committees are: Audit Committee, Compensation Committee, Corporate Governance Committee and the Health, Safety and Environment Committee.

## AUDIT COMMITTEE

Chair: Robert G. Puchniak
*Members: Brian F. MacNeill, Mac H. Van Wielingen*

The Audit Committee approves Western's interim unaudited consolidated financial statements and press releases and reviews the annual audited consolidated financial statements and certain corporate disclosure documents including the annual information form, management's discussion and analysis, and offering documents, including all prospectuses and other offering memoranda, before they are approved by the Board. The Committee reviews and makes a recommendation to the Board in respect of the appointment of the external auditor and it monitors accounting, financial reporting, control and audit functions. The Audit Committee meets to discuss and review the audit plans of external auditors. The Committee questions the external auditor independently of management and reviews a written statement of its independence based on the criteria found in the recommendations of the Canadian Institute of Chartered Accountants. The Committee must be satisfied that adequate procedures are in place for the review of the Corporation's public disclosure of financial information extracted or derived from its financial statements and it periodically assesses the adequacy of those procedures. The Audit Committee must approve or pre-approve, as applicable, any non-audit services to be provided to the Corporation by the external auditor. In addition, it reviews and reports to the Board on Western's risk management policies and procedures and reviews the internal control procedures to determine their effectiveness and to ensure compliance with Western's policies and avoidance of conflicts of interest. The Committee has established procedures for dealing with complaints or confidential submissions which come to its attention with respect to accounting, internal accounting controls or auditing matters.

The Audit Committee is also charged with reviewing the report of the independent qualified reserves evaluator relating to Western's reserves and resources. The Committee meets independently of management with the independent qualified reserves evaluator to review the evaluation report, the corporate summary of the reserves and future net revenues of the oil sands properties and other related matters. In addition, it reviews Western's relationship with the independent consulting firm and makes a recommendation to the Board in respect of the appointment of the independent qualified reserves evaluator.

### COMPENSATION COMMITTEE

Chair: John W. Lill

*Members: Geoffrey A. Cumming, Glen F. Andrews*

The Compensation Committee reviews succession plans for key management positions within Western, human resource policies and plans, the performance and development of the CEO and other senior officers of Western. The Committee makes recommendations to the Board with respect to the salary and other remuneration to be awarded to senior executive officers of Western. It also makes recommendations to the Board in respect of all other compensation matters including long-, medium- and short-term incentives such as bonus, stock option and performance share unit plans and other benefits and is responsible for developing these programs. The Committee is responsible for ensuring that the Corporation's compensation is linked to meaningful and measurable performance targets.

### CORPORATE GOVERNANCE COMMITTEE

Chair: Mac H. Van Wielingen

*Members: Geoffrey A. Cumming, Brian F. MacNeill*

The Corporate Governance Committee's mandate is to assess the effectiveness of the Board as a whole, the various other committees, as well as individual directors. It also assesses Western's approach to corporate governance and monitors the relationship between management and the Board. This Committee is responsible for recommending candidates to the Board for nomination as directors and for the composition of various Board committees and for recommendations regarding Chairmanship of the Board.

The Committee, together with the Compensation Committee, also reviews and recommends compensation for Board and committee service. The Corporate Governance Committee is also mandated to undertake those initiatives as are necessary to maintain a high standard of corporate governance practices and in this respect monitors and considers for implementation the corporate governance standards which are proposed by various Canadian regulatory authorities or which are published by various non-regulatory organizations in Canada.

### HEALTH, SAFETY AND ENVIRONMENT COMMITTEE

Chair: Glen F. Andrews

*Members: Tullio Cedraschi, Walter W. Grist, Oyvind Hushovd*

The Health, Safety and Environment Committee's mandate is to monitor the health, safety and environmental practices and procedures of Western and its subsidiaries for compliance with applicable legislation, conformity with industry standards and prevention or mitigation of losses. It reviews, reports and, when appropriate, makes recommendations to the Board on Western's policies and procedures related to health, safety and the environment.

## DIRECTORS

### Glen F. Andrews
*Bainbridge Island, Washington*
*Director since October, 1999*

Retired businessman. Previously President of BHP Copper North America until June 1999. Prior thereto, Executive Vice-President and General Manager, BHP Copper of the South America and Pacific regions from 1996 to 1998 and North American region in 1998.

### Tullio Cedraschi
*Montreal, Quebec*
*Director since October, 2000*

President and Chief Executive Officer of CN Investment Division, the entity responsible for investing the assets of the Canadian National Railways Pension Trust Funds.

### Geoffrey A. Cumming
*Auckland, New Zealand*
*Chairman since February, 2002 and Director since October, 1999*

Vice-Chairman of Gardiner Group Capital Limited, Toronto, a private Canadian investment corporation, and Deputy Chairman of Emerald Capital Limited, a private New Zealand investment corporation.

### Walter W. Grist
*New York, New York*
*Director since December, 1999*

Managing Director, Brown Brothers Harriman & Co., a private investment management and banking partnership which is general partner of The 1818 Fund III, L.P.

### Oyvind Hushovd
*Toronto, Ontario*
*Director since December, 2003*

Chairman and Chief Executive Officer of Gabriel Resources Ltd. a Canadian mining company listed on the Toronto Stock Exchange. From 1996 to 2002, President and Chief Executive Officer of Falconbridge Ltd.

### John W. Lill
*Richmond Hill, Ontario*
*Director since December, 2003*

Executive Vice-President and Chief Operating Officer of Dynatec Corporation, a Canadian mining company listed on the Toronto Stock Exchange that provides a range of services principally to mineral and refining companies.

### Brian F. MacNeill
*Calgary, Alberta*
*Director since October, 1999*

Chairman of Petro-Canada since 2000. President and Chief Executive Officer of Enbridge Inc., an energy transportation, distribution and services corporation, from 1990 to September 1, 2000.

### Robert G. Puchniak
*Winnipeg, Manitoba*
*Director since October, 1999*

Executive Vice-President and Chief Financial Officer of James Richardson & Sons, Limited ("James Richardson"), an investment and holding corporation, since March 2001. Prior thereto, Vice-President, Finance and Investment, James Richardson since 1996.

### Guy J. Turcotte
*Calgary, Alberta*
*President, Chief Executive Officer and Director since July, 1999*

President of Western since January 2002 and Chief Executive Officer of Western since July 1999; Chairman of Fort Chicago Energy Partners, L.P. since September 1997 and Chief Executive Officer until December 2002; Chief Executive Officer of Stone Creek Properties since March 1998; prior thereto, founder, Chairman and/or President and Chief Executive Officer of Chauvco Resources Ltd. from January 1981 to December 1997.

### Mac H. Van Wielingen
*Calgary, Alberta*
*Director since December, 1999*

Co-Chairman of ARC Financial Corporation ("ARC"), a private investment management company focused on the energy sector in Canada, and Chairman of ARC Energy Trust. Previously, President of ARC since 1989.

## OFFICERS

### Charles W. Berard
*Calgary, Alberta*
*Corporate Secretary*

Partner with Macleod Dixon LLP, Barristers & Solicitors.

### David A. Dyck
*Calgary, Alberta*
*Vice President, Finance and Chief Financial Officer*

Vice President, Finance and Chief Financial Officer of Western since April 2000; prior thereto, Senior Vice President Finance & Administration and Chief Financial Officer of Summit Resources Limited ("Summit") since September 1998; Vice President Finance and Chief Financial Officer of Summit from October 1996 to September 1998.

### John Frangos
*Calgary, Alberta*
*Executive Vice President and Chief Operating Officer*

Executive Vice President and Chief Operating Officer of Western since January 2002; prior thereto Corporate Development, Western since May 1999; previously Vice President International Business Development of BHP Minerals from 1997 to May 1999.

# CORPORATE INFORMATION

**GEOFFREY A. CUMMING**
*Chairman of the Board*

**GUY J. TURCOTTE**
*President and Chief Executive Officer*

**JOHN FRANGOS**
*Executive Vice President and Chief Operating Officer*

**DAVID A. DYCK**
*Vice President, Finance and Chief Financial Officer*

**CHARLES W. BERARD**
*Corporate Secretary*

**STEVE REYNISH**
*Chief Operating Officer, Albian Sands*

**GERRY LUFT**
*Vice President, Marketing*

**JACK D. JENKINS**
*Vice President, Corporate Planning & Human Resources*

**RAY MORLEY**
*Vice President, Business Development*

**GEOFFREY A. CUMMING**
*Chairman of the Board, Western Oil Sands Inc.*
*Vice Chairman, Gardiner Group Capital Limited, Toronto*
*Deputy Chairman, Emerald Capital Limited*
*Auckland, New Zealand*

**GLEN F. ANDREWS**
*Retired, formerly President,*
*BHP Copper North America*
*Bainbridge Island, Washington*

**TULLIO CEDRASCHI**
*President & Chief Executive Officer,*
*CN Investment Division*
*Montreal, Quebec*

**WALTER W. GRIST**
*Managing Director,*
*Brown Brothers Harriman & Co.*
*New York, New York*

**OYVIND HUSHOVD**
*Chairman and Chief Executive Officer,*
*Gabriel Resources Limited*
*Toronto, Ontario*

**JOHN W. LILL**
*Executive Vice President and Chief Operating Officer,*
*Dynatec Corporation*
*Richmond Hill, Ontario*

**BRIAN F. MACNEILL**
*Chairman,*
*Petro-Canada*
*Calgary, Alberta*

**ROBERT G. PUCHNIAK**
*Executive Vice President, Chief Financial Officer,*
*James Richardson & Sons Limited*
*Winnipeg, Manitoba*

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