6K

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

05045943

Report of Foreign Issuer
Pursuant to Rule 13a-16 or 15d-16 of
the Securities Exchange Act of 1934

P.E.

Date: January 27, 2005

TALISMAN ENERGY INC.
Commission File No. 1-6665
[Translation of registrant's name into English]

3400, 888 - 3rd Street S.W.,
Calgary, Alberta, Canada, T2P 5C5
[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 by furnishing the information contained in this Form, the registrant is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes [ ] No [√]

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

This Report on Form 6-K incorporates by reference the exhibit attached hereto which was filed by Talisman Energy Inc. with the Canadian Securities Commissions (the "Commissions") on the date specified in the exhibit list.

SIGNATURES

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.

TALISMAN ENERGY INC.
[Registrant]

Date: January 27, 2005

By: CHRISTINE D. LEE
Christine D. Lee
Assistant Corporate Secretary

TALISMAN ENERGY

OUR MISSION:
VALUE CREATION
IN THE GLOBAL
UPSTREAM OIL
AND GAS BUSINESS

2003 ANNUAL REPORT

Talisman Energy Continues to Create Value for Its Shareholders

Talisman Energy Inc. is a large independent oil and gas producer with global operations. Talisman's common shares are widely held and listed on the Toronto and New York stock exchanges under the symbol TLM. The Company had 128 million shares outstanding at year end 2003.

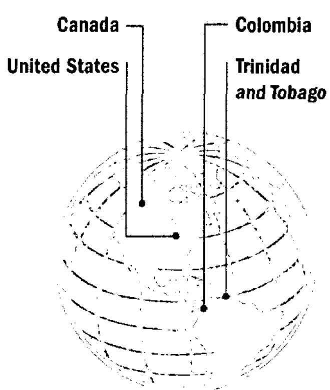
Talisman is a $12 billion company, employing 1,758 people in its North American and international operations. The Company's headquarters are in Calgary, Alberta, Canada.

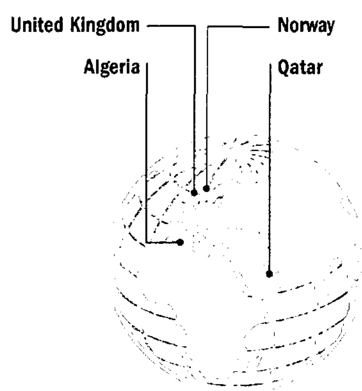
Established as an independent company in 1992, Talisman has a track record of growth and creating value for its shareholders. Over the past 11 years, the Company has grown production per share at an average compound annual rate of 10% and is committed to continuing production per share growth of at least 5-10% per annum.

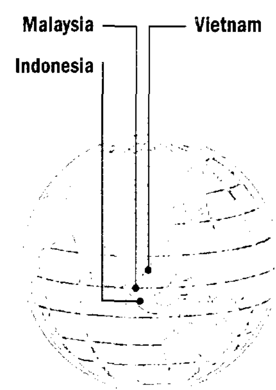
Talisman generated a record $2.7 billion in cash flow in 2003. The Company produced 398,000 boe/d and at year end had 1.4 billion boe of proved reserves that are predominantly natural gas and light oil. During 2003, Talisman repurchased 3.3 million shares and reduced long-term debt by $800 million. Talisman plans to spend $2.3 billion on exploration and development in 2004.

Talisman has a strong commitment to its stakeholders, including shareholders, debt holders, employees, customers, suppliers, governments and the communities where it operates. The Company is committed to high standards of social and environmental responsibility wherever it does business.

Talisman's Unique Positioning Provides a Competitive Advantage







Contents

Readers are referred to the Advisories and Abbreviations at the back of this Annual Report. Unless the context indicates otherwise, a reference in this Annual Report to "Talisman" or the "Company" includes direct or indirect subsidiaries of Talisman Energy Inc. and partnership interests held by Talisman Energy Inc. and its subsidiaries.

The President's Report

Dr. James W. Buckee
President and Chief Executive Officer

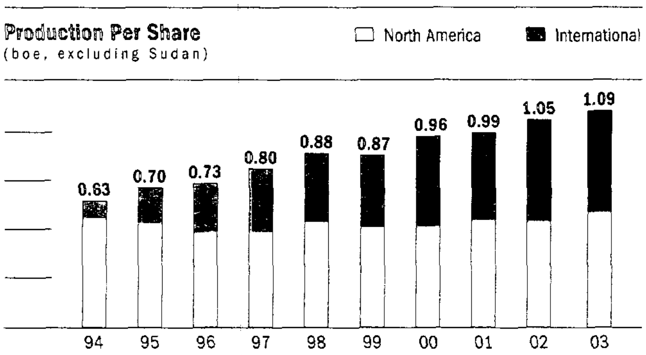
Talisman's mission is to create value for its shareholders in the upstream oil and gas business. What differentiates us from other large independents is that Talisman is a successful international operator, as well as a major North American gas producer.

From inception, we had the view that Western Canada was mature and that bigger prizes lie elsewhere. The confidence and competence to operate internationally arose partly because Talisman was founded from a Canadian subsidiary of one of the super-majors and many of our senior technical and management staff had extensive international experience. Since then, we have generated our own internal technical and commercial expertise.

Our current positioning has been achieved by consistently executing our strategy over the past 11 years. In 1992, when Talisman was created, the Company produced about 51,000 boe/d, with operations solely in Canada.

Through a number of corporate and asset acquisitions, Talisman quickly established operations in the North Sea, North Africa and Southeast Asia and subsequently added value through the drill bit. Increasing size and experience became an advantage in the international business, allowing Talisman to take on larger projects and undertake more high impact exploration.

About the Cover
This is the Central Processing Platform in the Block PM-3 Commercial Arrangement Area in Malaysia/Vietnam. Talisman completed the $1 billion oil and gas project in September 2003.



Over the 1992-2003 period, we averaged 20% compound annual production growth and exited 2003 at 437,000 boe/d, effectively replacing production from our previous interests in the Sudan project, which produced about 65,000 bbls/d earlier in the year.

Talisman's Diverse International Portfolio Gives Us a Competitive Advantage

I believe that Talisman now has an enviable set of international exploration and development opportunities. The attraction of international operations will be increasingly evident as the maturity of the North America basins continues to give rise to a sequential increase in both replacement costs and operating costs, while conventional production is declining. Larger companies are finding it increasingly difficult to grow North American production.

Our Goal is to Increase Production per Share by 5-10% Annually

Talisman is committed to growing production per share by 5-10% per annum. We think this is one of the best and most transparent measures of value creation. With our existing prospect inventory, strong balance sheet and demonstrated technical and commercial expertise, I am confident we can achieve these growth rates in 2004, 2005 and 2006.

We will continue to target selected North American gas opportunities and large international development opportunities. With our focus on the Canadian Foothills, the relatively under explored Deep Basin in Alberta and the Appalachian basin in the eastern United States, we believe we can continue to grow our North American gas production and generate surplus cash for opportunities elsewhere.

In 2003, Talisman's international production averaged 195,000 boe/d, accounting for approximately 50% of the Company's total. Of this, two-thirds came from the North Sea. However, combined production from Malaysia, Vietnam, Indonesia, Algeria and Trinidad is expected to grow at rates of approximately 30% compounded annually over the next three years from developments currently underway.

Talisman plans to participate in more higher risk, high reward exploration drilling. We have built an inventory of prospects in Colombia, Qatar, Trinidad and Alaska and are evaluating larger opportunities in the North Sea. If successful, any one of our larger prospects could be material to Talisman. Although the individual risks are higher, we are of sufficient size to drill enough wells to avoid gamblers ruin, while, on the other hand, maintaining strict capital discipline.

Five Years of Cash Flow Growth

Cash flow reached a record high $2.7 billion or $21.21 per share in 2003, with Talisman's realized oil and gas prices up 25% over 2002. Net income was also a record high $1.0 billion, or $7.65 per share.

Our major achievement last year was the completion and startup of the largest petroleum development ever undertaken by a Canadian company in Southeast Asia. The $1 billion oil and gas project in the PM-3 Commercial Arrangement Area (CAA) in Malaysia and Vietnam was completed on schedule and on budget. With capacity of 60,000 bbls/d of oil and 270 mmcf/d of natural gas, Talisman's share (41%) of production is just over 40,000 boe/d.

We believe this region holds significant opportunities and potential for Talisman using the same strategy that has proved successful elsewhere. Our acreage is located in a prolific hydrocarbon basin with substantial remaining potential. Talisman expanded its position in 2003, acquiring a very large offshore block in Vietnam, adjacent to PM-3 CAA. Drilling success continued with five new discoveries in both Malaysia and Vietnam.

Elsewhere in Southeast Asia, we continued to monetize the very large gas reserves in the Corridor Block in Indonesia. Talisman has signed a memorandum of understanding to sell over 2.4 tcf of gas (Talisman 36%) for power generation in West Java. We also commenced gas sales to Singapore. The pipeline between the two countries forms an important link in the trans-Asian gas grid.

2003 – A Pivotal Year

In March, Talisman sold its 25% indirect working interest in the Greater Nile Oil Project in Sudan for $1.1 billion. I believe Talisman's presence and community development work were highly beneficial. I also think subsequent events will show that the responsible development of hydrocarbon resources will play a fundamental role in the development of the country and will bring great benefits to all the people of Sudan.

In the UK North Sea, Talisman had three successful new exploration wells, which cumulatively tested at over 19,000 bbls/d.

Talisman obtained an entry position in Norway with the acquisition of a 61% interest and operatorship of the Gyda field, which at year end was producing 7,000 boe/d (net Talisman). This was followed by additions to our acreage position both through licence rounds and acquisitions.

First sales from the Ourhoud and MLN fields in Algeria commenced in 2003, reaching 15,000 bbls/d (net Talisman) in December.

In Trinidad, development of the offshore Greater Angostura oil and natural gas project is underway with first oil sales of 18,000-25,000 bbls/d (net Talisman) expected early in 2005. Talisman also started its seismic program on the onshore Eastern Block. This is by far the largest onshore 3D seismic program ever shot in Trinidad.

In Colombia, Talisman drilled its first exploration wells during the year and plans to drill at least one more in 2004.

The Company also made a number of strategic moves in North America in 2003. Talisman completed the acquisition of a number of natural gas properties in the Appalachian basin in upper New York State, with 60 mmcf/d of production and almost 400,000 net acres of land. This is high value gas, close to markets, in a deeper play system that is still relatively unexplored. To date, we have had five successful wells, testing cumulatively at rates of 69 mmcf/d.

We also expanded our midstream operations in west central Alberta with the completion of a pipeline in the Alberta Foothills and the acquisition of gas processing and gathering facilities. These assets complement our other midstream operations in the area and enhance Talisman's ability to control its production, spending and timing in a highly prospective part of the basin.

Talisman also made small but strategic steps into the North American frontiers in 2003. We acquired interests in up to 10 townships (360 square miles) in Alaska and drilled our first well in January 2004. The Company also earned a 30% interest in two offshore blocks in eastern Canada by participating in an exploration well.

High Quality Proved Reserves

Talisman replaced 150% of production from all sources in 2003, including discoveries, net purchases, revisions and transfers, excluding Sudan. On a proved only basis, the comparable number is 127%.

Excluding Sudan, proved reserves increased 3% to 1,362 mmbbls of oil equivalent. In addition, Talisman has 873 mmboe of probable reserves, equating to a reserve life index of 16 years. Approximately 60% of our reserves are natural gas and the remainder light-medium quality crude oil and natural gas liquids.

Finding and development costs increased to $14.28/boe (US$11.71/boe net) in 2003, however, this doesn't reflect over 100 mmboe of international probable reserves that we expect will be booked as proved in 2004. Had these been included last year, the net effect would have been to lower our finding and development costs to under $8.50/boe. The disconnect between capital spending and reserves booking, particularly on the international side makes Talisman's three year average finding and development cost of $8.76/boe (US$7.72 net) a more representative number.

Although finding and development costs in North America are generally increasing, this is a direct reflection of the maturity of the basin.

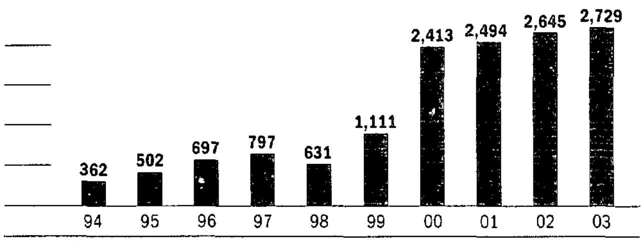
Over the past two years, Talisman has played a leading role in the Alberta Securities Commission (ASC) process to develop new disclosure standards for reserves. We support the objective of fostering investor confidence in reserves and have advocated uniformity with our North American peer group. In response to the ASC recommendations, Talisman reviewed its procedures for evaluating and booking reserves. The Company also established a committee of the Board of Directors to review reserves processes and disclosure and has established the position of an internal qualified reserves evaluator (IQRE). The IQRE provides a report to the Reserves Committee and a regulatory certificate regarding reserves and related cash flows. We continue to do a complete internal evaluation of proved reserves annually, supported by external audits. Approximately 90% of Talisman's proved reserves have been independently audited over the past three years. I am confident that Talisman's reserves booking procedures and internal controls accurately capture and report our reserves. The empirical evidence for this is our growing production, positive historical reserves revisions and low percentage of proved undeveloped reserves in North America.

Continued Financial Strength

Talisman's cash flow increased for the fifth consecutive year. With increases from Malaysia/Vietnam and Algeria, production in the fourth quarter averaged 419,000 boe/d. Excluding Sudan, this represented organic growth of 10% over the fourth quarter of 2002 and 15% production per share growth. Talisman's shares reached a record high $81.80 in early March 2004, which in my opinion doesn't reflect the full value of our assets and opportunities.

During the year, Talisman repurchased 3.3 million common shares, reduced long term debt by $800 million and increased its annual dividend rate from $0.60 to $0.80 per common share. The Company has also adopted a cash payment feature for stock options, which is tax effective for the Company and better addresses the issue of reporting option expenses. However, since the ongoing income exposure is based on Talisman's share price performance, the change also had the effect of lowering reported net income by $130 million as Talisman share prices continued to climb. More importantly, we expect that very few shares will be issued from treasury in the future compared to the stock option program before it was amended.

Cash Flow
(millions of Canadian dollars)



2004 – A Year of Momentum and Growth

We enter 2004 in excellent financial health, with quality producing assets, a solid reserves base and an opportunity set that we expect will provide built-in growth for several years. Our production guidance for 2004 is 415,000-445,000 boe/d, consistent with the objective of 5-10% annual production per share growth. We plan to spend $2.3 billion, with two-thirds of this directed at development projects and one-third for exploration.

A major milestone this year will be completion of the Greater Angostura development in Trinidad, which will contribute to continued production growth in 2005.

Energy is a Vital Business and Talisman is Well Positioned

Key to Talisman's strategy is a belief that energy is a vital but finite resource. The OECD countries enjoy a standard of living that is heavily dependent on energy, while at the same time the energy demands of developing countries are increasing rapidly. World oil demand reached an all time high in 2003. Total consumption was 28.6 billion barrels, with demand in the emerging market economies growing by 2.3% over the prior year.

Even at current prices, crude oil and natural gas will continue to dominate the energy mix. History has taught us that commodity prices are volatile and we cannot predict the next cycle. However, the world continues to consume hydrocarbons, particularly oil, at rates faster than reserves are being replaced. The challenge for the industry is to meet these growing energy demands.

Despite higher prices, the oil and gas industry is struggling to increase production. It is estimated that natural gas production from the largest 100 North American producers fell by 3-4% in 2003.

This supply tightness in both oil and natural gas has produced a step change in prices. Talisman is well positioned to benefit from these higher prices with its substantial North American gas production and increasing international oil production. Talisman realized an average netback of $23/boe in 2003, a record high.

We continued to develop and implement our corporate responsibility program in 2003 and revised our Policy on Business Conduct and Ethics to better reflect our position on issues such as human rights, security and community relations. Talisman is committed to providing a safe work place and operating in an environmentally responsible fashion. I believe that we must continue our efforts to publicly report on our social, environmental and economic performance in a balanced manner, to allow stakeholders to develop a more complete picture of our positive impact on society.

I would like to thank Talisman's employees and contractors for their hard work and commitment. I would also like to acknowledge the guidance and help of the Board of Directors. In particular, I will miss the contribution and wise counsel of Roland Priddle, who is retiring after four years on the Board.

Talisman will continue to generate wealth for our shareholders, and be an exciting and rewarding place to work. I see a bright future ahead.

J.W. Buckee
President and Chief Executive Officer
March 3, 2004

Highlights

	2003	2002	2001	2000	1999
Financial (millions of Canadian dollars)					
Cash flow[1]	**2,729**	2,645	2,494	2,413	1,111
Net income	**1,007**	524	733	857	255
Exploration and development expenditures	**2,180**	1,848	1,882	1,179	996
Total assets	**11,365**	11,594	10,819	8,625	7,806
Long-term debt	**2,203**	2,997	2,983	1,733	2,195
Shareholders' equity	**4,959**	4,502	4,126	3,614	3,621
Production (daily average production)[2]					
Oil and liquids (bbls/d)					
North America	**59,578**	62,676	66,056	66,374	58,489
North Sea	**113,075**	127,486	110,828	111,902	59,256
Southeast Asia	**24,430**	22,469	20,873	20,206	28,852
Algeria	**6,594**	–	–	–	–
Sudan	**13,039**	60,109	53,257	45,869	11,726
Total oil and liquids	**216,716**	272,740	251,014	244,351	158,323
Natural gas (mmcf/d)					
North America	**864**	820	809	755	681
North Sea	**109**	122	108	122	115
Southeast Asia	**117**	94	93	111	108
Total natural gas	**1,090**	1,036	1,010	988	904
Total mboe/d[2,4]	**398**	445	419	409	309
Total mboe/d (net of royalties)[3,4]	**334**	366	337	335	259
Shares outstanding at December 31 (millions)	**128**	131	134	135	138
Number of permanent employees at December 31	**1,758**	1,565	1,358	1,263	1,113

1 Non-GAAP measure. See inside back cover.
2 Production numbers are before royalties, unless otherwise indicated.
3 Net production (after royalties).
4 Six mcf of natural gas equals one boe.
Additional information for US Readers can be found on page 76.

Reserves and Finding and Development Costs

Talisman replaced approximately 150% of its production in 2003 (excluding Sudan) from all sources, including discoveries, net acquisitions, revisions and transfers (proved and probable). Talisman's proved reserves (excluding Sudan) increased 3%, totaling 1.36 billion boe at year end. Net reserves (after royalties, excluding Sudan) increased 4% to 1.09 billion boe. Approximately 40% of the Company's reserves are medium-light quality oil and liquids and 60% are natural gas.

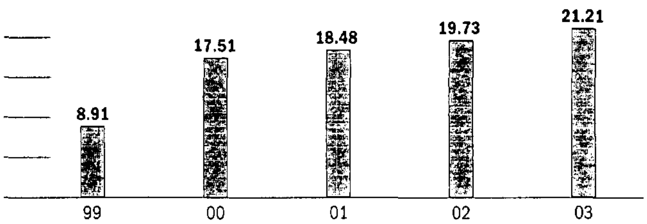
Finding and development costs averaged $14.28/boe for the year (US$11.71/boe net). However, Talisman believes the three-year average results better reflects its ongoing performance. At year end, Talisman had over 100 mmboe of probable international reserves pending booking as proved.

	2003		3-year Average	
($/boe)	C$ Gross[1]	US$ Net[2]	C$ Gross[1]	US$ Net[2]
Finding and development costs	14.28	11.71	8.76	7.72
Finding and development and acquisition costs[3]	14.67	12.12	9.79	8.62

1 Gross proved reserves before deduction of royalties.
2 Net proved reserves after deduction of royalties.
3 Excludes Sudan sale.
For additional details on Talisman's reserves and finding and development costs, please see pages 75-77 and 83-86.

Talisman at a Glance

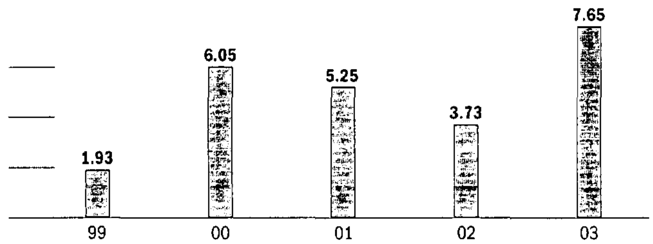
Cash Flow Per Share[1]
(dollars)



1 Non-GAAP measure. See inside back cover.

Cash flow per share increased for the fifth straight year to a record $21.21. Higher oil and natural gas prices and increased natural gas volumes offset lower oil volumes and higher royalties.

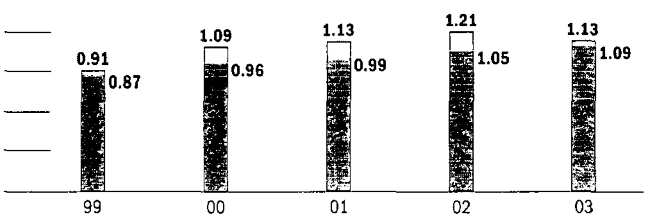
Earnings Per Share
(dollars)



Talisman's earnings per share more than doubled in 2003 with the gain on the sale of the Sudan interests, higher cash flow and tax rate reductions.

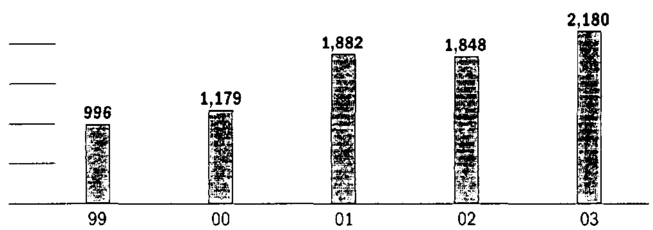
Production Per Share
(boe)

Excluding Sudan   Sudan Portion



Production per share increased 4% last year, excluding Sudan. Talisman repurchased 3.3 million shares during 2003.

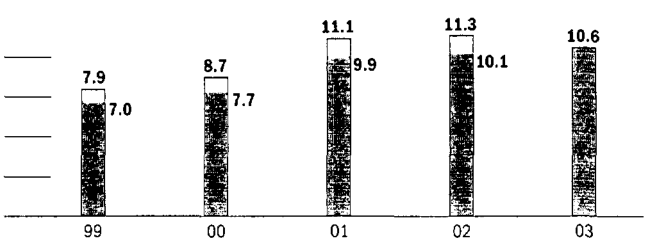
Exploration and Development Spending
(millions of dollars)



Exploration and development spending was $2,180 million. North America accounted for half of this spending.

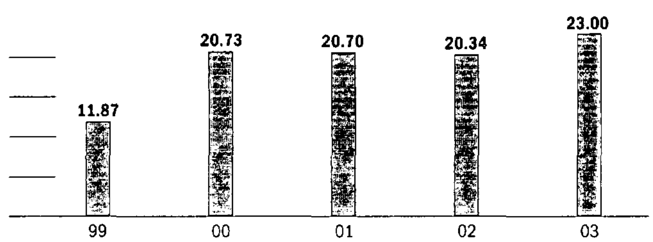
Proved Reserves Per Share
(boe)

Excluding Sudan   Sudan Portion



Gross proved reserves per share, excluding Sudan, increased by 5% in 2003.

Netbacks
($/boe)



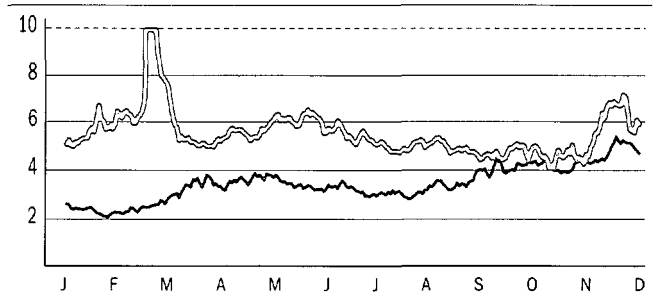
Talisman's netbacks increased $2.66/boe in 2003, largely on the strength of a 61% increase in the Company's realized natural gas price in North America.

Business Environment

Natural Gas Prices

North American natural gas prices averaged US$5.44/mmbtu at Henry Hub, an increase of 60% over 2002. Higher prices have prompted an increase in drilling activity; however, production amongst the large producers declined by an estimated 3-4% in 2003. North American gas production is likely at or near effective capacity for the first time in the history of the industry. Gas to gas competition, which was the dominant feature of the marketplace, has virtually disappeared and the lack of incremental supplies and high prices have effectively capped demand. Early in 2004, gas prices remain above US$5/mmbtu, however, both weather and economic growth will continue to have a major influence on price. Talisman is forecasting NYMEX prices to average between US$4.75-5.50/mmbtu in 2004.

Henry Hub Natural Gas Prices
(US$/mmbtu)



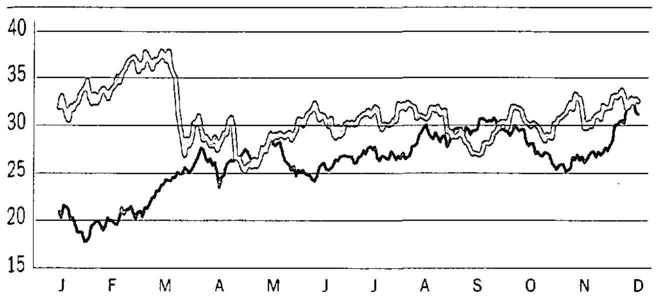
Oil Prices

WTI prices increased 19%, averaging US$30.99/bbl as world oil demand grew by an estimated 2%, led by growth in China and other emerging market economies. However, in many parts of the world the price of oil fell in local currency due to a weaker US dollar.

Lower production from Iraq was offset by increases from other OPEC countries and growing production from the former Soviet Union. Prices have remained high in early 2004 in part because strong demand and anemic supply continued to keep inventories at historically low levels.

Talisman is using a forecast for WTI of US$25-30/bbl in 2004, which may prove to be conservative. However, much depends on economic and energy demand growth and OPEC's willingness to continue to cut production if demand weakens.

WTI Oil Prices
(US$/bbl)



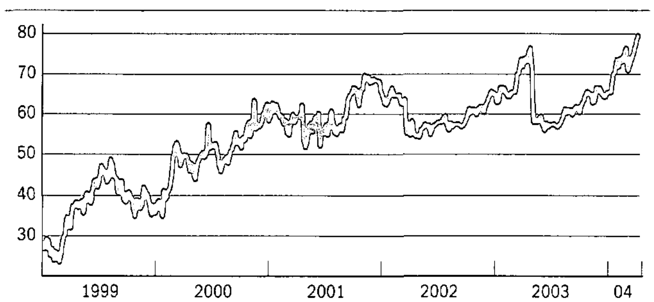
Share Price Performance

Talisman's shares reached an all time high in 2003, closing the year at $73.52, a 29% increase over year end 2002. This was likely due to high commodity prices, the Company's continuing guidance of 5-10% production per share growth, Talisman's opportunity set and strong balance sheet.

Market indices in general were up last year. The S&P/TSX Composite increased 24%, with continuing low interest rates, high levels of consumer confidence and continued economic growth.

High commodity prices buoyed the oil and gas sector and the average share price for Talisman's Canadian and US peers increased 23% over the 2002 close.

Weekly Closing Price – January 1999 to March 2004
($/Share)



The Management Team

Our Mission is to Create Value in the Upstream Oil and Gas Business

To achieve this, Talisman will continue to develop its large North American gas business, with significant growth expected from its international operations.

The Company's international assets provide large opportunities outside the mature North American sedimentary basins. Talisman continues to build new core areas based on materiality, growth potential and competitive advantage.

Talisman owns, operates and controls key assets and infrastructure where they provide a competitive advantage or add value.

Talisman operates over three-quarters of its production in North America, 60% in the North Sea and is the operator of major projects in Southeast Asia. This control has contributed to the Company's success, adds value and enables Talisman to influence costs and timing.

Talisman will grow through both exploration and acquisitions, creating opportunities that add significant shareholder value.

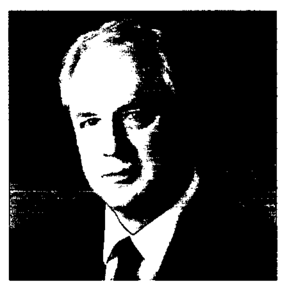
In addition, the Company is pursuing selected, higher impact, higher risk exploration targets.

Jim Buckee
President and Chief Executive Officer

Ron Eckhardt
Executive Vice-President, North American Operations

Nigel Hares
Executive Vice-President, Frontier and International Operations

Joe Horler
Executive Vice-President, Marketing



Mike McDonald
Executive Vice-President, Finance and Chief Financial Officer

Bob Redgate
Executive Vice-President, Corporate Services

Jackie Sheppard
Executive Vice-President, Corporate and Legal, and Corporate Secretary

John 't Hart
Executive Vice-President, Exploration

Objectives and Performance

Objectives from Talisman's 2002 Annual Report	Performance in 2003
The sale of the interests in the Sudan properties was expected to close in the first quarter of 2003.	Talisman completed the sale of its indirect interest in the Sudan properties for $1.1 billion on March 12.
The Company's objective was to grow production per share by 5-10% in 2003 and 2004 (excluding Sudan).	In the fourth quarter of 2003, production per share was up 15% (excluding Sudan), compared to fourth quarter 2002. In the three quarters following the sale of its interest in the Sudan assets, Talisman's production per share increased 6% over the corresponding period in 2002.
Talisman expected to participate in 700 exploration and development wells, spending $2.1 billion.	Talisman participated in 702 wells, with exploration and development spending of $2.18 billion.
Significant production increases were expected from Malaysia, Vietnam and Algeria in the second half of 2003.	Fourth quarter 2003 production from these areas averaged 31,000 boe/d, compared to 6,000 boe/d a year earlier.
Unit operating costs were expected to average approximately $7.00/ boe.	Unit operating costs averaged $7.15/boe.
The Company expected cash flow per share of over $21 in 2003, based on US$28.50/bbl WTI oil and US$5/mcf NYMEX gas.	Cash flow per share was $21.21. Although oil and gas prices were higher than expected in US$ terms, this benefit was offset by the stronger Canadian dollar.

In 2004 ...

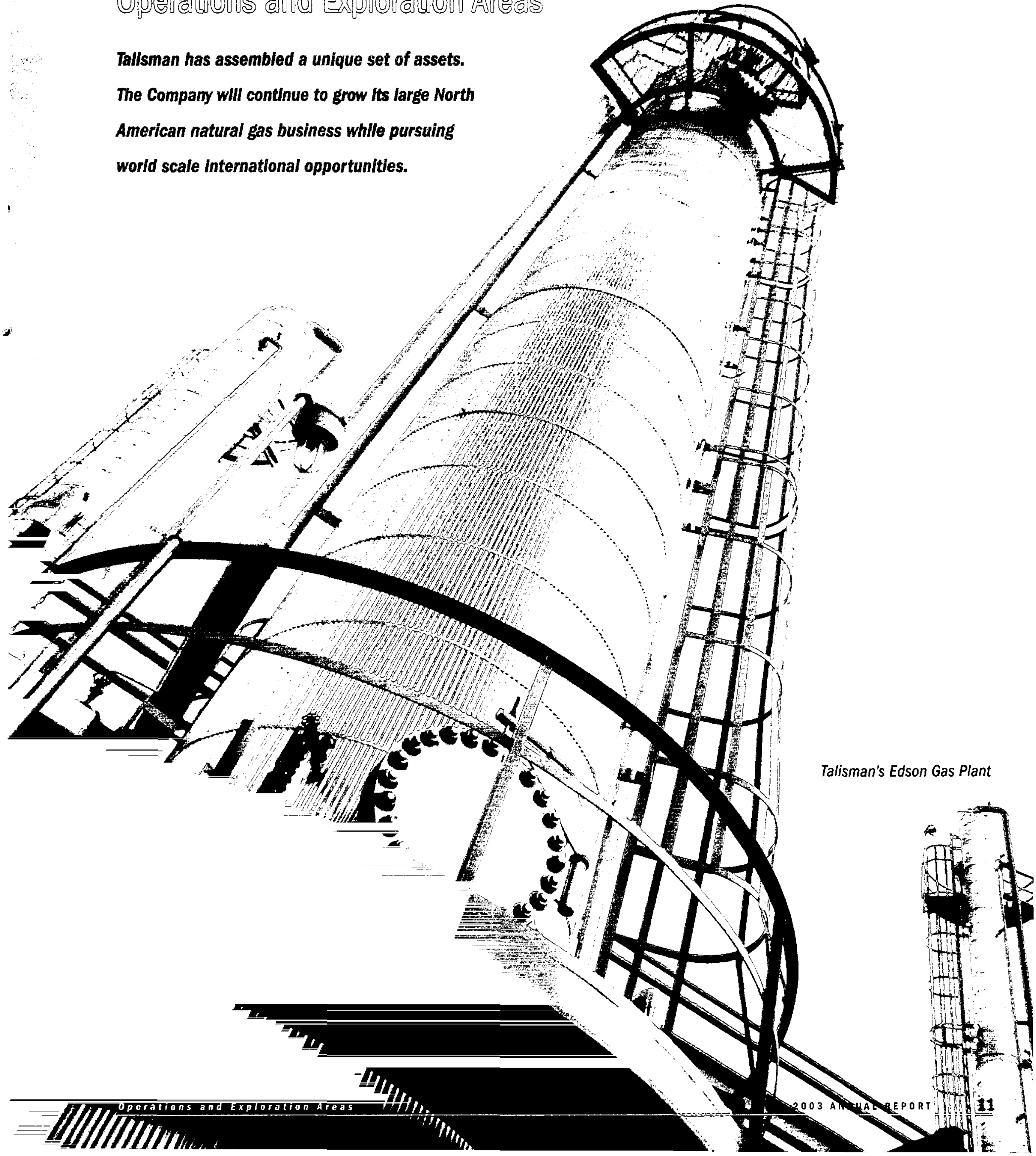
- Talisman's production is expected to average between 415,000-445,000 boe/d.
- The Company expects to participate in approximately 640 North American and 118 international gross exploration and development wells.
- Talisman plans to spend $2.3 billion on exploration and development.
- With the recent strength in the pound sterling, unit operating costs are expected to increase 5-10%.
- Talisman expects to generate $17-22 cash flow per share. This is based on US$25-30/bbl WTI oil prices, US$4.75-5.50/mmbtu NYMEX gas prices and a Canadian dollar exchange rate of US$0.73-0.77.

Other 2003 Highlights ...

- Record high closing share price.
- Net debt down $800 million.
- Annual dividend rate increased to $0.80/share.
- Repurchase of 3.3 million shares.

Operations and Exploration Areas

Talisman has assembled a unique set of assets. The Company will continue to grow its large North American natural gas business while pursuing world scale international opportunities.



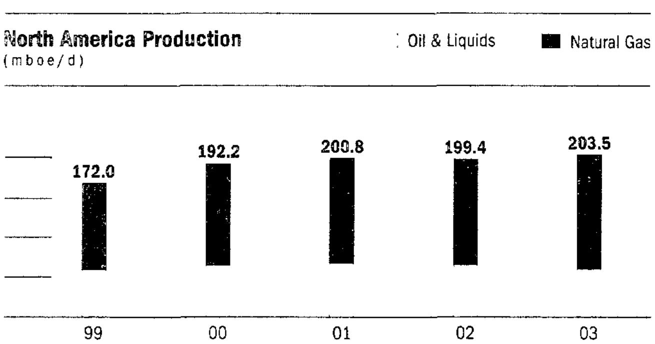
Talisman's Edson Gas Plant

North America

Talisman's large North American gas business generates well in excess of $1 billion/year in cash that is reinvested for growth both here and abroad. The Company focuses on deep, high potential gas plays along the Rocky Mountain Foothills. Talisman has also established a new core gas area in upper New York State. Talisman expects to grow its North American gas production at rates of 3-5% annually over the next five years.

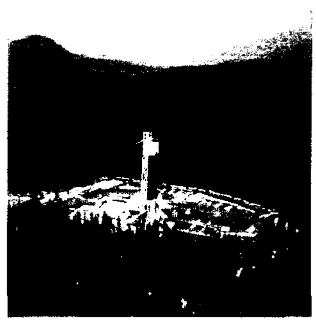
2003 in Review

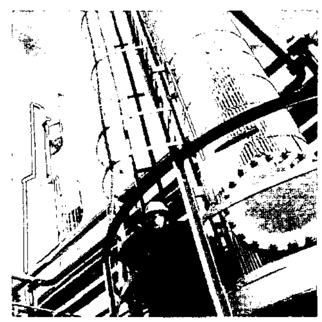
- Natural gas production averaged 864 mmcf/d, up from 820 mmcf/d in 2002.
- Liquids production averaged 59,578 bbls/d, compared to 62,676 bbls/d in 2002.
- Talisman drilled 378 natural gas wells and 204 oil wells with a 93% success rate.
- Exploration and development spending was $1.1 billion.
- The Company added 74.6 mmboe of proved reserves, excluding revisions and transfers, and had 631 mmboe of proved reserves at year end (93% developed).
- Conventional operating costs averaged $5.01/boe, up from $4.65/boe in 2002.
- Talisman drilled 30 successful wells in the Alberta Foothills.
- Talisman completed the construction of and commissioned the Erith pipeline in the fourth quarter of 2003.
- The Company purchased Vista Midstream Solutions Ltd., including the Cutbank gas plant and an extensive gas gathering system.
- Talisman earned a 30% interest in two East Coast offshore exploration licences.
- The Company entered into an agreement to acquire interests in up to 10 townships in Alaska.
- Talisman has tested five wells at combined rates of 69 mmcf/d in the Appalachia region of upper New York State.
- The Company achieved daily production records at Chauvin (16,200 bbls/d), West Whitecourt (56 mmcf/d), Alberta Foothills (160 mmcf/d) and Deep Basin (61 mmcf/d).

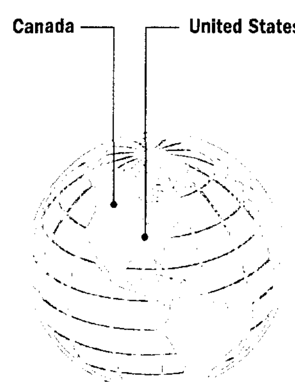


2004 Outlook

- Exploration and development spending is expected to be $1.1 billion, with over 77% directed towards natural gas projects.
- Production targets are 885-905 mmcf/d of natural gas and 54,000-56,000 bbls/d of oil and liquids.
- Talisman plans to participate in 640 wells, including 11 in Appalachia.
- Talisman commissioned a new gas plant in the Turner Valley area in January 2004.
- Talisman plans to spend $50 million expanding and optimizing its operated pipeline systems and associated infrastructure.
- Talisman drilled its first well in the National Petroleum Reserve Area of the Alaskan North Slope.







North Sea

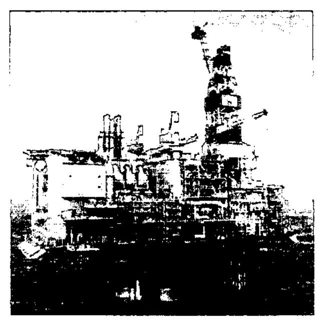
In the UK Central North Sea, Talisman has established a number of operated commercial hubs, which provide significant value through low risk development, adjacent exploration opportunities, secondary recovery and third-party tariff receipts. Talisman is also building a new core area in the Norwegian sector of the Central North Sea. The North Sea was Talisman's highest netback area in 2003. The Company has a large drilling program underway designed to increase oil and liquids production by 5-10% in 2005.

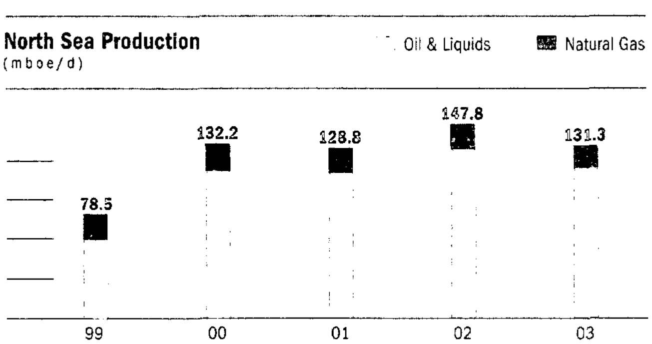
2003 in Review

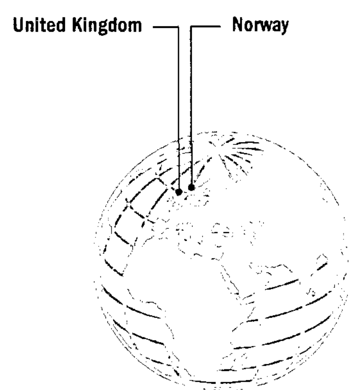
- Liquids production averaged 113,075 bbls/d, compared to 127,486 bbls/d in 2002; however, fourth quarter liquids production recovered to 128,697 bbls/d.
- Natural gas production averaged 109 mmcf/d, compared to 122 mmcf/d in 2002.
- Talisman drilled 17 successful oil and natural gas wells.
- Exploration and development spending was $496 million.
- Talisman added 54 mmboe of proved reserves and had 299 mmboe of proved reserves at year end (84% developed).
- Operating costs averaged $11.36/boe, up from $10.08/boe in 2002.
- First oil from the Blake Flank development started on schedule at 5,200 bbls/d.
- Talisman participated in three successful exploration wells. The J5 well, adjacent to the Buchan field, tested at 7,100 bbls/d, the Tartan North well tested at 8,100 bbls/d and the Affleck well, east of the Orion field, tested at 4,000 bbls/d. The Drum, Dunnottar and Eta-2 wells were unsuccessful.
- The Company acquired an entry position in Norway with the purchase of a 61% operated interest in two blocks in the Norwegian North Sea containing the producing Gyda field and platform facilities and 61% of the Gyda gas export pipeline.
- Talisman was awarded four new exploration blocks in the UK North Sea.

2004 Outlook

- Early in 2004 Talisman was awarded two additional licences in the Norwegian North Sea, one of which is adjacent to the Gyda field. The Company also acquired interests in a further two licences in the area. Talisman plans to drill three wells in Norway in 2004.
- The Tartan North development (Talisman 100%) is expected to start production in the fourth quarter.
- Development approval of the J1/J5 oil project is expected.
- Exploration and development spending is expected to be $606 million, with $119 million on exploration and $487 million on development.
- Production targets are 120-130 mmcf/d of natural gas and 109,000-122,000 bbls/d of oil and liquids.
- Talisman plans to participate in eight exploration and 25 development wells.







Southeast Asia

Talisman is poised for continued strong production growth in Southeast Asia. The Company continues to develop its very large gas reserves in Indonesia and is actively negotiating new gas sales and transportation agreements. In Malaysia/Vietnam in 2003, Talisman completed its development project in the PM-3 Commercial Arrangement Area on time and on budget and made five new discoveries including South Angsi in Block PM-305.

Indonesia

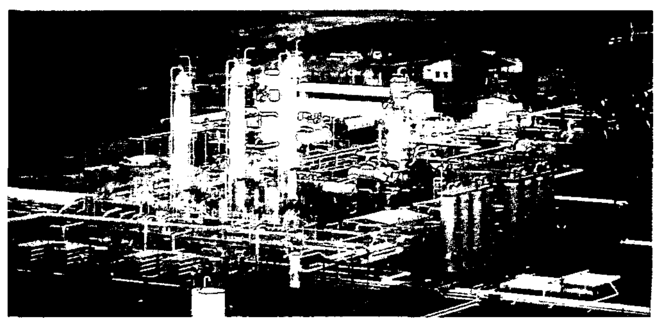
In Indonesia, Talisman continues to develop its large gas reserves in the Corridor Block. Talisman's Corridor Block reserves have been independently evaluated. The Company is actively negotiating new gas sales contracts with the objective of doubling sales by 2007.

2003 in Review

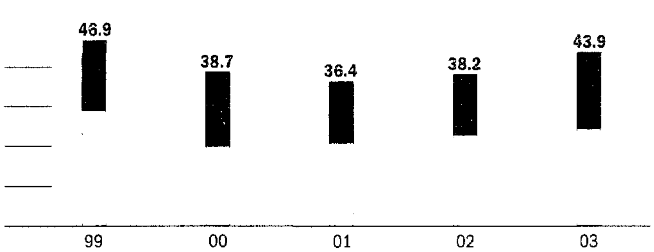
- Production averaged 112 mmcf/d of natural gas, an increase of 19% and 15,758 bbls/d of liquids.
- Exploration and development spending totaled $41 million.
- Gas sales from Corridor to Singapore commenced on schedule in mid-September.
- Talisman entered into a new gas sales agreement to sell Corridor gas to Island Power in Singapore.
- A heads of agreement was signed and negotiations are underway to sell 2.4 tcf (Talisman 36%) of natural gas to West Java.
- Contracts are being finalized and pipeline tie ins are being prepared to sell 300 bcf of gas (Talisman 36%) to the island of Batam.

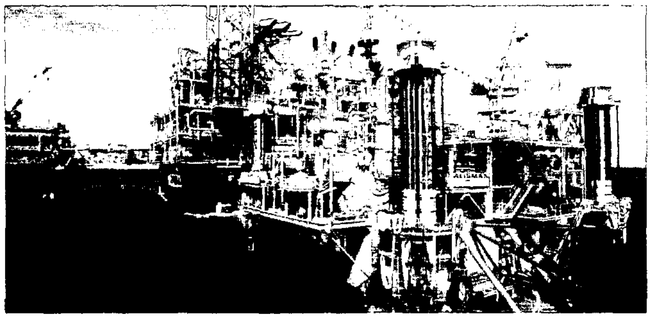
2004 Outlook

- Exploration and development spending is expected to be $65 million, with $12 million on exploration and $53 million on development.
- Production targets are 135-140 mmcf/d of natural gas and 12,000-13,000 bbls/d of oil and liquids.
- The Suban Phase 2 project is expected to commence on completion of the West Java gas sales arrangements. The project involves installation of two new gas trains, additional pipelines and infrastructure in the Corridor PSC.



Southeast Asia Production
(mboe/d)





Malaysia/Vietnam

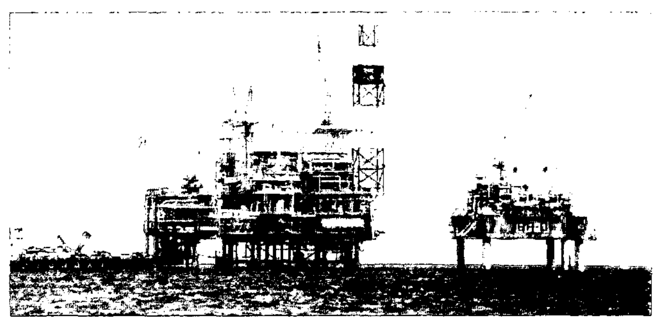
Talisman completed the $1 billion PM-3 CAA Phase 2/3 oil and gas development project on time and on budget.

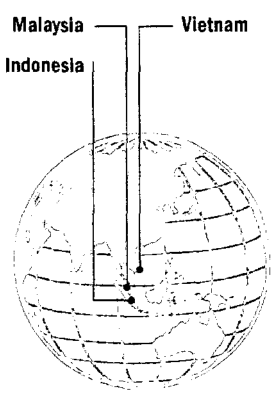
2003 in Review

- First oil production from the PM-3 CAA Phase 2/3 oil and gas project commenced in September. Overall production averaged 9,502 boe/d for the year, with 19,427 boe/d in the fourth quarter.
- First natural gas production commenced in the fourth quarter.
- The Company had four successful discovery and appraisal wells on PM-3 CAA: North Bunga Orkid-1, East Bunga Orkid-2, North Bunga Pakma-2 and Bunga Tulip-1.
- Talisman made a significant oil discovery at South Angsi on Block PM-305 in Malaysia, which tested at 11,300 bbls/d. The South Angsi field development was sanctioned in late 2003 and first production is expected in mid-2005.
- Talisman discovered natural gas on Block 46-Cai Nuoc in Vietnam at the Hoa Mai exploration well, testing at 36 mmcf/d.
- Talisman made an oil discovery at Song Doc in Block 46/02 in Vietnam, which tested 7,300 bbls/d.
- Exploration and development spending totalled $275 million.

2004 Outlook

- Exploration and development spending is expected to be $250 million, with $50 million on exploration and $200 million on development.
- Production targets are 90-100 mmcf/d of natural gas and 21,000-25,000 bbls/d of oil and liquids.
- Talisman plans to drill five exploration and 32 development wells.
- Development of the South Angsi field will commence with first production expected in mid-2005.





The Caribbean and Latin America

Talisman is working in a number of high impact exploration areas, utilizing its expertise in structurally complex plays. In Trinidad, development of the Greater Angostura oil and gas project is underway. Talisman is continuing its exploration drilling programs in Trinidad and Colombia.

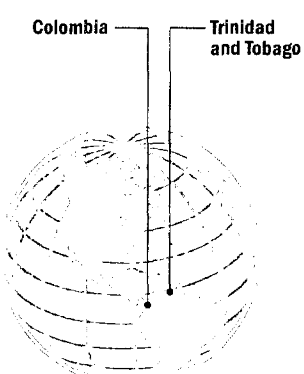
Trinidad and Tobago

Talisman has a 25% interest in the Greater Angostura project, a major oil and gas development in Block 2(c) offshore Trinidad. Field development is progressing, with first production anticipated in early 2005. Plans for 2004 include development drilling and the fabrication and installation of a central processing platform and three wellhead platforms. Further exploration and appraisal drilling is also planned for the southern portion of Block 2(c) where the Company holds a 35.7% interest.

Talisman also holds a 30% interest in Block 3(a), immediately east of Block 2(c). The Company drilled three exploration wells on Block 3(a) and one on Block 2(c) in 2003. All four wells encountered hydrocarbons, including the Puncheon-1 well on Block 3(a), which was drilling at year end.

Talisman carried out a major 3D seismic acquisition program on the Eastern Block onshore Trinidad. The program will continue into 2004, with plans for the first exploration well in early 2005.

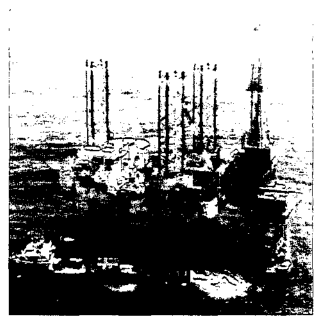
In Trinidad, the capital spending program is estimated to be $170 million, which includes completion of the Angostura project, participation in 15 development and four exploration and appraisal wells and completion of onshore seismic operations.



Colombia

In Colombia, Talisman has non-operated interests in a number of blocks. During 2003, Talisman participated in two exploration wells. The El Encanto-2 well in the Huila Norte Block and the Candelo-1 well on the Acevedo Block both commenced drilling in September and were plugged and abandoned in early 2004. The exploration program in 2004 remains highly prospective with large potential targets.

Talisman's 2004 capital spending program in Colombia is expected to be $28 million and includes seismic acquisition and drilling at least one additional exploration well.



Africa and the Middle East

Talisman has production and development interests in Algeria and exploration acreage in Qatar. The Company continues to evaluate new opportunities in this part of the world.

Algeria

During 2003, development of the first phase of the Greater MLN project located in Block 405a in eastern Algeria was completed, with production commencing in June. Talisman has a 35% non-operated interest in the block. In addition, the Company has a 2% interest in the unitized Ourhoud field, a small portion of which extends onto Block 405a. By the fourth quarter of 2003, Talisman's share of production was 11,804 bbls/d.

In 2004, Talisman plans capital spending of approximately $44 million, which includes drilling 10 development wells at Ourhoud and six development wells in the Greater MLN area.

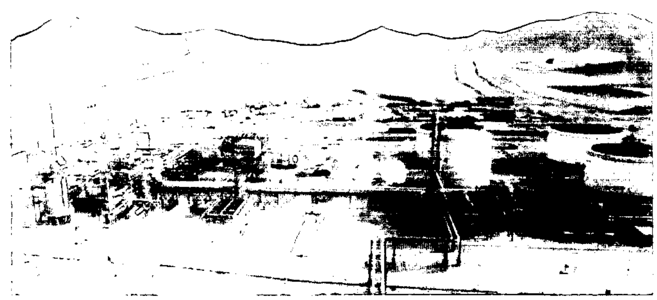
Talisman's share of production is expected to average between 14,000-16,000 bbls/d in 2004.

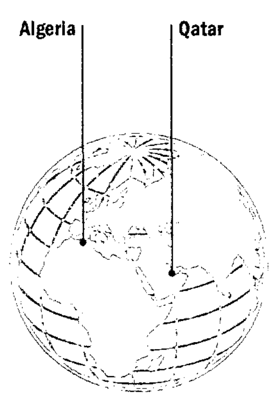
Qatar

In April 2003, Talisman received official ratification by the Emir of Qatar of an Exploration and Production Sharing Agreement entered into in late 2002 for offshore Block 10 (Talisman 100%). Geophysical work commenced in November and the Company plans to shoot 2D and 3D seismic in 2004.

Sudan

On March 12, 2003, Talisman completed the sale of its indirectly held interest in the Greater Nile Oil Project to ONGC Videsh Limited, a subsidiary of India's national oil company.





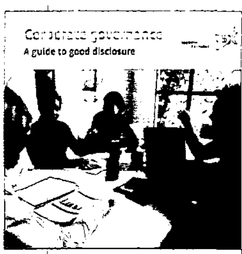
Corporate Governance

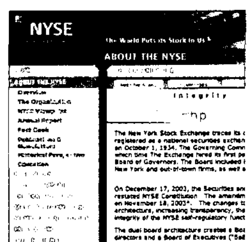
Talisman's corporate governance practices satisfy all the existing guidelines for effective corporate governance established by the Toronto Stock Exchange (TSX) and substantially all of the New York Stock Exchange (NYSE) corporate governance listing standards.

With the exception of the President and Chief Executive Officer, all directors have been determined by the Board to be "independent" within the meaning of the NYSE rules. Other than the Executive Committee of which only one member is a related, non-independent director, all of the Board committees are comprised of unrelated, independent directors. Each committee has a formal written mandate that addresses the purposes and responsibilities of the committee. Committee mandates can be found on Talisman's website at www.talisman-energy.com/aboutus/board_directors/corporate_governance.html.

In December 2003, Talisman revised its longstanding code of ethics to better reflect the evolving area of corporate responsibility and to incorporate the latest corporate governance requirements. The code, entitled the "Policy on Business Conduct and Ethics", can be obtained from Talisman's website at www.talisman-energy.com/socialresponsibility/business_conduct.html, or upon request from: Investor and Corporate Communications, Suite 3400, 888 Third Street SW, Calgary, Alberta T2P 5C5, or by email: tlm@talisman-energy.com.

A list of the existing TSX *corporate governance guidelines* is set out on the next page. Talisman complies with each guideline. A full description of Talisman's approach to corporate governance can be found in the Company's 2004 Management Proxy Circular.





Talisman's Compliance

TSX Corporate Governance Guidelines

The Board should explicitly assume responsibility for the stewardship of the Company and explicitly for:

Talisman's Compliance	
✓	(a) adoption of a strategic planning process;
✓	(b) identification of the principal risks of the Company's business and ensuring implementation of appropriate systems to manage these risks;
✓	(c) succession planning, including appointing, training and monitoring senior management;
✓	(d) a communications policy, and
✓	(e) the integrity of the Company's internal controls and management information systems.
✓	A majority of the Company's directors should be unrelated.
✓	The Board has responsibility for applying to each individual director, the definition of "unrelated director" and disclosing on an annual basis the analysis of the application of the principles supporting this conclusion.
✓	The Board of every Company should appoint a committee of directors composed exclusively of outside, i.e., non-management directors, a majority of whom are unrelated directors, with the responsibility for proposing to the Board new nominees to the Board and for assessing directors on an ongoing basis.
✓	Every Board of Directors should implement a process to be carried out by the nominating committee or other appropriate committee, for assessing the effectiveness of the Board as a whole, its committees and the contribution of individual directors.
✓	The Company should provide an orientation and education program for new Board members.
✓	The Board should examine its size and undertake where appropriate, a program to reduce the number of directors to a number which facilitates more effective decision-making.
✓	The Board should review the adequacy and form of the compensation of directors and ensure the compensation realistically reflects the responsibilities and risk involved in being an effective director.
✓	Committees of the Board of Directors should generally be composed of outside directors, a majority of whom are unrelated directors, although some Board committees may include one or more inside directors.
✓	The Board should assume responsibility for, or assign to a committee of directors, the general responsibility for developing the Company 's approach to governance issues. This committee would, amongst other things, be responsible for the Company's response to these governance guidelines.
✓	The Board, together with the CEO, should develop position descriptions for the Board and for the CEO, involving the definition of the limits to management's responsibilities. In addition, the Board should approve or develop the corporate objectives that the CEO is responsible for meeting.
✓	The Board of Directors should have in place appropriate structures and procedures to ensure that it can function independently of management. An appropriate structure would be to (i) appoint a chair of the Board who is not a member of management with responsibility to ensure the Board discharges its responsibilities or (ii) adopt alternate means such as assigning this responsibility to a committee of the Board or to a director, sometimes referred to as the "lead director". Appropriate procedures may involve the Board meeting on a regular basis without management present or may involve expressly assigning the responsibility for administering the Board's relationship to management to a committee of the Board.
✓	The Audit Committee should be composed only of outside directors. The roles and responsibilities of the Audit Committee should be specifically defined so as to provide appropriate guidance to Audit Committee members as to their duties. The Audit Committee should have a direct communication channel with the internal and external auditors to discuss and review specific issues as appropriate. The Audit Committee duties should include oversight responsibility for management reporting on internal controls. Although it is management's responsibility to design and implement an effective system of internal controls, it is the responsibility of the Audit Committee to ensure that management has done so.
✓	The Board should implement a system that enables an individual director to engage an outside adviser at the Company's expense in appropriate circumstances. The engagement of the outside advisor should be subject to the approval of an appropriate committee of the Board.

Corporate Responsibility

Talisman conducts its business worldwide according to applicable international laws and the high standards set out in its Policy on Business Conduct and Ethics.

There is a public expectation that, beyond profitability, companies must maintain high ethical, environmental and social standards. These standards have evolved over time, reflecting the changing values and priorities in society. Companies must enhance their efforts to publicly report on their standards and performance against these standards, to allow stakeholders to develop a more complete picture of companies' impact on society.

While Talisman strives to maximize shareholder value by conducting profitable operations in accordance with all applicable laws, our license to operate ultimately comes from the acceptance and goodwill of our stakeholders, including our employees, host governments and local communities. At Talisman, we operate in accordance with our Policy on Business Conduct and Ethics, which sets out our high standards in the areas of ethical business conduct, employee relations, environmental practices, human rights and community relations.

Some of Talisman's key accomplishments in 2003:

Social Performances:

- *We completed a year-long review and update of our Policy on Business Conduct and Ethics, including the development of human rights and community relations principles for all Talisman employees and operations.*
- *We confirmed our participation in the Global Compact initiative led by the United Nations.*
- *We established formal security arrangements with our coventurers in Colombia in the spirit of the Voluntary Principles on Security and Human Rights.*
- *We worked with about 45,000 stakeholders, both individually and on a community-wide basis across Canada, to build awareness for the over 900 projects we were involved in.*
- *We developed formalized Aboriginal Relations Guidelines to help direct our relations with aboriginal communities across North America. We also established an Aboriginal Community Investment Fund.*
- *We established a community development legacy office in Sudan.*
- *We contributed approximately $5 million to hundreds of community projects across our global operations.*
- *We contributed over $663,000 to Calgary, Alberta's United Way, thanks to more than $327,000 in employee donations, a corporate match of $327,000 as well as numerous fundraising activities.*

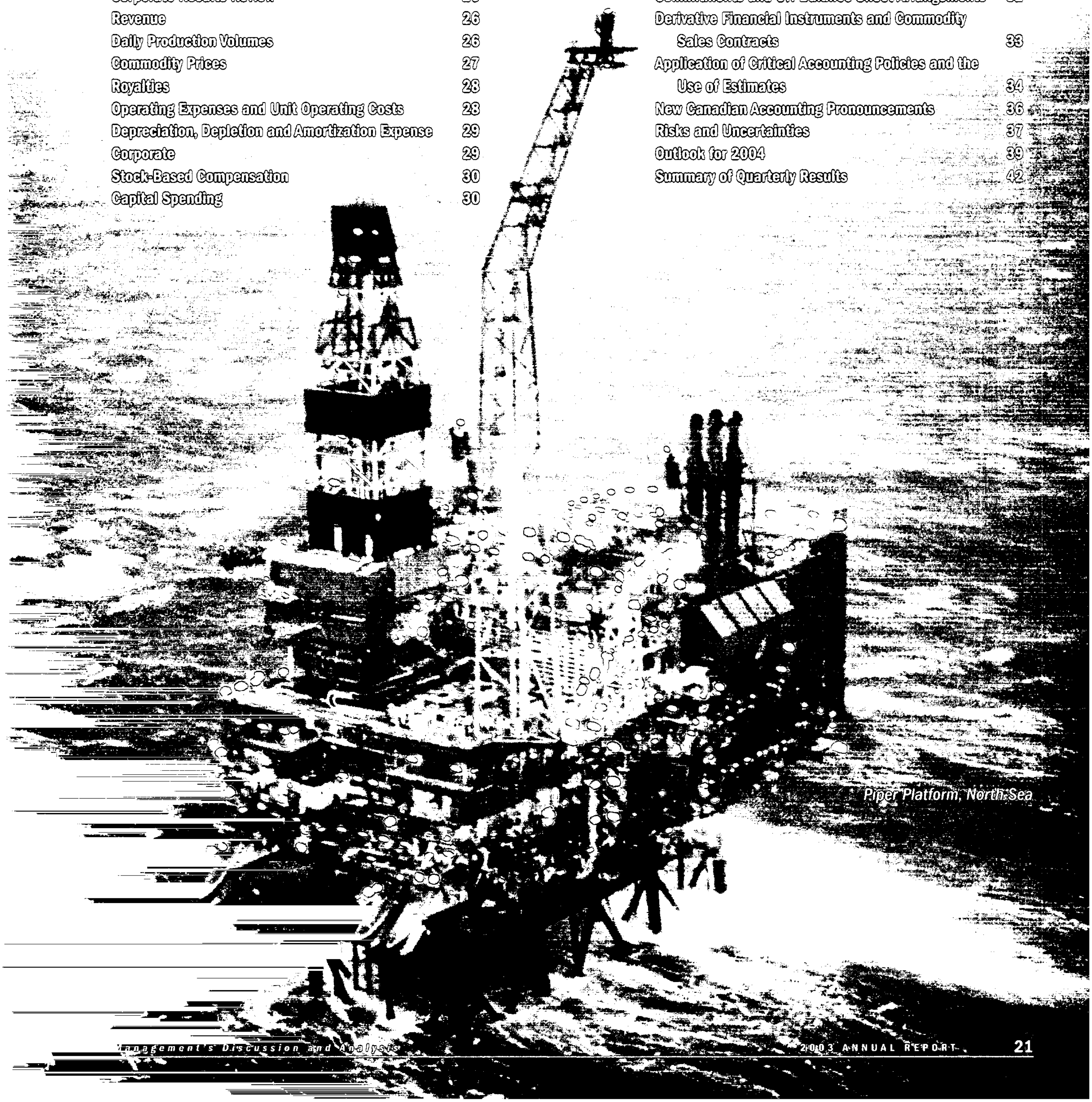
Talisman has published a separate Corporate Responsibility Report. You can view it on our website, or write, phone or email Talisman's main office in Calgary and we will be pleased to send you a copy.

Environmental Performance:

- *We received a Certificate of Environmental Clearance in Trinidad with respect to our onshore exploration program.*
- *We began development of a cogeneration facility in Edson, Alberta and a potential offshore windfarm at our Beatrice platform in the North Sea.*
- *We completed environmental audits at our Canadian operations at Inga, Carlyle, Warburg and Grande Prairie and at all of our UK platforms and onshore terminals.*
- *We improved our Production Carbon Intensity by 5% from 2001 levels thanks to, among other things, gas conservation projects and reductions in venting.*
- *We decreased the overall concentration of oil in produced water discharged at all North Sea platforms by 18% to 20.4 parts per million in 2003.*
- *We achieved Gold Champion-Level Reporter status in the Voluntary Challenge and Registry (VCR) for our most recent submission (2002) to the VCR after two years at the Silver Level by reducing our current emissions or emissions intensity to levels below 1994 levels.*
- *During our first full year of operation of the Diamond Valley Soil Treatment Facility located near Turner Valley, Alberta, we treated approximately 10,000 tonnes of contaminated soil, which will be used as clean backfill in ongoing remediation projects in the area.*

Management's Discussion and Analysis

(March 3, 2004)



Piper Platform, North Sea

Highlights

(millions of Canadian dollars, unless otherwise stated)	**2003**	2002	2001
Cash flow[1]	**2,729**	2,645	2,494
Net income	**1,007**	524	733
Per share (Canadian dollars)			
Cash flow[1]	**21.21**	19.73	18.48
Net income	**7.65**	3.73	5.25
Dividends	**0.70**	0.60	0.60
Diluted per share (Canadian dollars)			
Cash flow[1]	**20.95**	19.43	18.15
Net income	**7.57**	3.67	5.16
Gross sales	**5,295**	5,299	5,047
Exploration and development spending	**2,180**	1,848	1,882
Total assets	**11,365**	11,594	10,819
Total long-term financial liabilities	**2,203**	2,997	2,794
Production (mboe/d)	**398**	445	419
Production per share (boe/share)	**1.13**	1.21	1.13
Average sales price ($/boe)	**37.67**	32.10	32.91
Operating costs ($/boe)	**7.15**	6.48	5.79
Proved reserves additions (before acquisitions and divestitures) (mmboe)	**143**	157	336
Finding and development costs[2] ($/boe)	**14.28**	11.03	5.34

1 Cash flow and cash flow per share are non-GAAP financial measures that represent net income before exploration costs, DD&A, future taxes and other non-cash expenses. The components of cash flow are set out in note 14 of the Consolidated Financial Statements. Cash flow for 2003 is cash provided by operating activities ($2,616 million) before changes in non-cash working capital ($104 million) and the deferred gain on unwound hedges ($9 million). The equivalent amounts for 2002 are $2,439 million, $163 million and $43 million, respectively. In 2001, the amounts are $2,369 million, $177 million less $52 million for the deferred gain on the unwound hedges.

2 See the MD&A section entitled Reserves Replacement for method of calculation.

This Management's Discussion and Analysis (MD&A) dated March 3, 2004, should be read in conjunction with the Consolidated Financial Statements of the Company. In particular, note 18 provides segmented financial information that forms the basis for much of the following discussion and analysis. The Company's Consolidated Financial Statements and the financial data included in the MD&A have been prepared in accordance with accounting principles generally accepted in Canada. A summary of the difference between accounting principles generally accepted in Canada (Canadian GAAP) and those generally accepted in the United States (US) is contained in note 19 of the Consolidated Financial Statements.

Reported production represents Talisman's working interest share before royalties. Throughout the MD&A the calculation of barrels of oil equivalent (boe) is calculated at a conversion rate of six thousand cubic feet (mcf) of natural gas for one barrel of oil and is based on an energy equivalence conversion method. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalence conversion method primarily applicable at the burner tip and does not represent a value equivalence at the wellhead.

Dollar amounts included in the MD&A are expressed in Canadian dollars unless otherwise indicated. All comparative percentages are between the years ended December 31, 2003 and December 31, 2002, unless stated otherwise.

Included in the MD&A are references to financial measures commonly used in the oil and gas industry such as cash flow and cash flow per share. These financial measures have no standardized meaning and are not defined by accounting principles generally accepted in either Canada or the US. Consequently, these are referred to as non-GAAP measures. Cash flow, as commonly used, appears as a separate caption on the Company's cash flow statement and is reconciled to both net income and cash flow from operations. Cash flow is used by the Company to assess operating results between years and between peer companies with different accounting policies. Our reported amounts may not be comparable to similarly titled measures reported by other companies. Cash flow should not be considered an alternative to, or more meaningful than, cash provided by operating, investing and financing activities or net income as determined in accordance with Canadian GAAP as an indicator of the Company's performance or liquidity.

Additional information relating to the Company, including the Company's Annual Information Form, can be found on the Canadian System for Electronic Document Analysis and Retrieval (SEDAR) at www.sedar.com. The Company's annual report on Form 40-F may be found in the EDGAR database at www.sec.com.

Talisman's Performance Highlights in 2003

Talisman posted record cash flow per share of $21.21 ($2.7 billion) and exited 2003 with production of 437 mboe/d during December, replacing much of the production from the Sudan operations, which were sold in early 2003 for $1.13 billion. Net income surpassed $1 billion ($7.65/share) for the first time in the Company's history, helped by high commodity prices, the gain on the Sudan disposition and tax rate reductions in Canada. During 2003, 3.3 million shares were repurchased at an average price of $58.24/share, debt was reduced by $794 million and the Company's semi-annual dividend rate increased 33% to $0.40/share.

Operational highlights for the year included the startup of the PM-3 CAA development project in Malaysia/Vietnam, commencement of production in Algeria, first oil from Blake Flank in the North Sea and first natural gas sales from Indonesia to Singapore. A number of acquisitions were completed during 2003 for $768 million including natural gas properties in the US, a producing field in Norway and midstream assets in Canada.

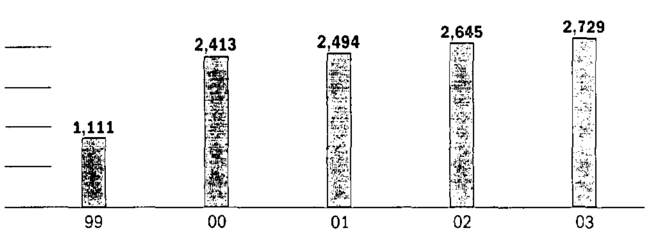
In Appalachia, Talisman drilled several successful exploration wells, adding significant productive capacity to the region. The North Sea saw three consecutive exploration successes, with discoveries at Tartan North, J5 and Affleck. In Malaysia and Vietnam, all exploration wells, except one, were either successful appraisals or new hydrocarbon discoveries. The Company also achieved good success in Trinidad with all four exploration wells discovering hydrocarbons.

Cash flow and cash flow per share increased for the fifth consecutive year to $2.7 billion and $21.21, respectively. This represents an 8% increase in cash flow per share over last year. Net income nearly doubled to $1 billion ($7.65/share) and included the gain on the Sudan sale ($296 million or $2.30/share) and tax rate reductions in Canada ($160 million or $1.24/share). These items were partially offset by an expense arising from amending the Company's stock option plans to include a cash payment feature, which resulted in what management believes to be more transparent accounting ($185 million, $130 million or $1.01/share net of tax). Combined, these added $326 million of net income ($2.53/share).

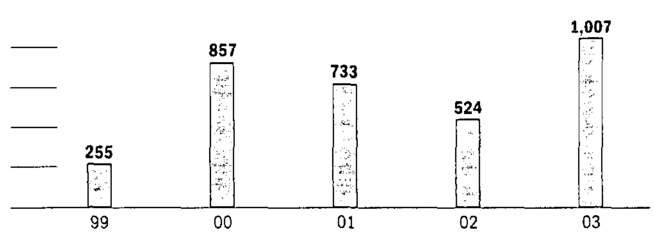
Production averaged 398 mboe/d for the year, within the target range originally set at the beginning of 2003. Production per share, after adjusting for the sale of the Sudan operations, increased 4%. Talisman spent $2.2 billion on exploration and development activities and participated in drilling 651 successful wells in 2003. Excluding the impacts of the Sudan sale, 210 mmboe of proved plus probable reserves were added, replacing 150% of production.

Operating costs for 2003 were as expected and averaged $7.15/boe, compared to $6.48/boe in 2002.

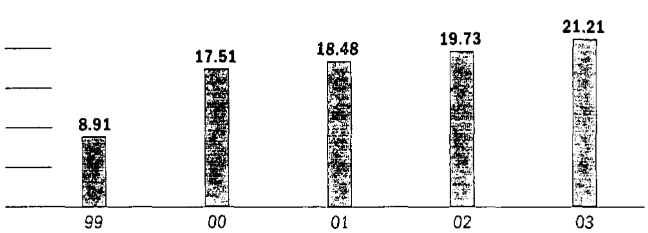
Cash Flow
(millions of dollars)



Net Income
(millions of dollars)

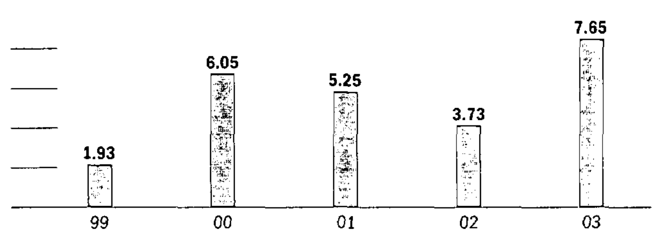


Cash Flow Per Share[1]
(dollars)



1 Non-GAAP measure. See inside back cover.

Net Income Per Share
(dollars)



2003 Variances

The significant variances from 2002 as summarized in the net income and cash flow variance table are:

- ☐ Higher commodity prices more than offset the impact of the sale of the Sudan operations, lower North Sea production, the strengthening of the Canadian dollar and higher royalties.
- ☐ Higher prices increased hedging losses.
- ☐ Interest expense fell due to lower average debt levels and lower effective borrowing costs, while current taxes fell primarily in the UK.
- ☐ Stock-based compensation payments reduced cash flow by $47 million.
- ☐ The gain on the sale of the Sudan operations was $296 million.
- ☐ The non-cash portion of the stock-based compensation expense reduced net income by $138 million (before tax).
- ☐ Future taxes were lower in 2003 due to tax rate reductions in Canada. Future tax expense in 2002 included the impact of a tax rate increase in the UK.

2004 Outlook Summary

Talisman anticipates 4-12% production growth in 2004 from existing projects. Cash flow for 2004 is anticipated to be $17-22 per share and assumes reduced commodity prices as expressed in Canadian dollars compared to 2003. Additional discussion of management's estimates and assumptions for 2004 can be found in the MD&A section entitled Outlook for 2004.

- ☐ Production is expected to average 415,000-445,000 boe/d.
- ☐ Production increases are expected in most of the Company's geographic segments with the majority coming from international projects.
- ☐ Exploration and development spending is expected to be $2.35 billion ($1.1 billion in North America and $606 million in the North Sea).
- ☐ Significant progress on the Trinidad development is expected with first oil anticipated in early 2005.
- ☐ Average unit operating costs are expected to increase 5-10% reflecting an assumed strengthening of the UK pound sterling exchange rate against the Canadian dollar.
- ☐ Long-term debt is expected to increase partly due to the redemption of a portion of the Company's preferred securities.
- ☐ Stock-based compensation expense is expected to decrease, as 2003 included a catch-up charge due to amendments to the Company's stock option plans.

Net Income and Cash Flow Variance (millions of dollars)

2002 Net income	524
Favorable (unfavorable)	
Cash flow variance	
Sale of the Sudan operations	(281)
Oil and liquids volumes	(117)
Natural gas volumes	128
Natural gas prices	747
Oil and liquids prices	115
Hedging – Commodities	(270)
Royalties	(198)
Other revenue	8
Operating expense	(50)
Interest expense	27
Current taxes (including PRT)	(3)
General and administrative	(9)
Stock-based compensation payments	(47)
Other	34
Total cash flow variance	84
Non-cash items	
Sale of Sudan (including gain of $296 million)	390
Depreciation, depletion and amortization expense	(21)
Dry hole expense	(90)
Exploration expense	(29)
Future taxes (including PRT)	219
Stock-based compensation (non-cash)	(138)
Other	68
Total non-cash items	399
2003 Net income [1]	1,007

1 Net income, cash flow and cash flow per share are before preferred security charges of $22 million, net of tax ($38 million, before tax). Net income per share is after preferred security charges. The components of cash flow are set out in note 14 of the Consolidated Financial Statements.

Sale of Sudan Operations

On March 12, 2003, Talisman completed the sale of an indirectly held subsidiary, which owned an interest in the Greater Nile Oil Project in Sudan, to ONGC Videsh Limited ("OVL"), a subsidiary of India's national oil company. The aggregate amount realized by Talisman from the transaction (including interest and cash received by Talisman between September 1, 2002 and closing) was $1.13 billion (US$771 million). (See note 17 of the Consolidated Financial Statements.)

The following table has been provided to assist readers in understanding the Company's results after taking into account the sale of the Sudan operations. The pro forma amounts presented below exclude the $296 million gain on sale of the Sudan operations and the Sudan results of operations during the respective years. These pro forma results have been derived from the information contained in notes 13 and 18 of the Company's December 31, 2003 Consolidated Financial Statements.

Pro Forma Results, Excluding the Sudan Operations and Gain On Sale

(millions of Canadian dollars, unless otherwise stated)		Pro forma	
	2003	2002	2001
Cash flow	**2,653**	2,291	2,230
Net income	**666**	298	576
Per share (Canadian dollars)			
Cash flow	**20.61**	17.09	16.53
Net income	**5.00**	2.04	4.09
Diluted per share (Canadian dollars)			
Cash flow	**20.37**	16.82	16.23
Net income	**4.94**	2.01	4.02
Exploration and development expenditures	**2,178**	1,750	1,765
Production (daily average production)			
Oil and liquids (mbbls/d)	**203.7**	212.6	197.8
Natural gas (mmcf/d)	**1,090**	1,036	1,010
Total mboe/d (6mcf=1boe)	**385**	385	366

The pro forma amounts included in the above table do not include any adjustment for the assumed use of proceeds received on the sale of the Sudan operations.

Segmented Results Review

Talisman is an independent international upstream oil and gas company whose main business activities include exploration, development, production, transporting and marketing of crude oil, natural gas and natural gas liquids. The Company's operations in 2003 were conducted principally in four geographic segments: North America, the North Sea, Southeast Asia and Algeria. The Company is also participating in a significant development project in Trinidad. Exploration is being conducted in other areas outside the principal geographic segments including Colombia and Qatar. The Company's Sudan operations were sold on March 12, 2003. The following is a brief summary of the financial results of each geographic segment. Additional geographic financial results disclosure may be found in note 18 of the Consolidated Financial Statements. The Company's pre-tax segmented income as discussed below is before the gain on the sale of the Sudan operations, corporate general and administration, interest, stock-based compensation, taxes and non-segmented foreign exchange gains and losses. More detailed analysis on the Company's results can be found after this Segmented Results Review.

North America

During 2003, the North America operations contributed $888 million or 56% of the Company's pre-tax segmented income of $1.5 billion, up from $437 million (31% of $1.4 billion) in 2002. Gross sales in North America increased 34% to $2.7 billion due principally to higher natural gas prices and production. North American production averaged 203,500 boe/d, up 2%, representing 51% of the Company's total production in 2003. North American operating expense increased 11% to $395 million due to increased natural gas volumes, higher processing fees and higher power costs. DD&A increased to $693 million, up from $614 million due to higher production and recent acquisitions while dry hole expense increased to $135 million due to the expanded exploration budget. Total exploration and development spending for North America in 2003 was $1.1 billion, up 35% over 2002.

North Sea

The North Sea pre-tax segmented income decreased to $435 million and accounted for 27% of the Company's segmented income during 2003, down from 38% in 2002. North Sea gross sales decreased due to lower liquids production, which also contributed to a lower DD&A expense. Production averaged 131,250 boe/d or 33% of the Company's total production. Royalty expense decreased due to the abolition of government royalties at the start of the year and the settlement of outstanding royalty issues. Dry hole expense increased with the inclusion of costs associated with the Eta-2 and Dunnottar wells. Exploration and development spending for the North Sea was $496 million, up 15% from 2002.

Southeast Asia

Production from the PM-3 CAA development project in Malaysia/Vietnam started in 2003 with oil production commencing in September and natural gas in the fourth quarter. Southeast Asia contributed 12% ($183 million) to the Company's pre-tax segmented income in 2003. Gross sales increased 14% to $556 million with higher production from PM-3 CAA and Corridor in Indonesia. Southeast Asia production averaged 44,000 boe/d and contributed 11% to the Company's total production. Total operating expenses were unchanged from 2002, but unit costs were down 12% as a result of the 15% increase in production. DD&A expense increased with the growth in production. Capital spending for Southeast Asia was $316 million, up 17%.

Algeria

Sales from Algeria commenced in January 2003 with the startup of the Ourhoud field. Production increased through 2003 with first oil from the Menzel Lejmat North (MLN) field in late June and additional production from MLN satellite fields in the fourth quarter. Production for 2003 averaged 6,600 bbls/d. Operating costs in 2003 included expenses associated with startup activities. Capital spending for Algeria was $34 million, down 68% from 2002 due to the completion of the initial phase of the Greater MLN project.

Other Exploration and Development

Development continued on the Angostura oil and gas field located on Block 2(c) offshore Trinidad with the Company spending $128 million during 2003. First production is expected in early 2005. Talisman spent $21 million in Colombia on seismic and exploration drilling which commenced in the third quarter. Talisman also acquired a 100% interest in offshore Block 10 in Qatar with exploration drilling expected to commence in 2005.

Corporate Results Review

Revenue

Revenues from oil, liquids and natural gas sales in 2003 were $5.3 billion, the same as in 2002. Higher natural gas prices ($747 million), gas volumes ($128 million) and oil prices ($144 million) were offset by increased hedging losses ($268 million) and lower oil and liquids volumes ($766 million), primarily due to the sale of the Sudan operations.

Daily Production Volumes

	2003	2002	2001
Oil and liquids (mbbls/d)			
North America	**59.6**	62.7	66.0
North Sea	**113.1**	127.5	110.8
Southeast Asia	**24.4**	22.5	20.9
Algeria	**6.6**	–	–
Sudan	**13.0**	60.0	53.3
	216.7	272.7	251.0
Natural gas (mmcf/d)			
North America	**864**	820	809
North Sea	**109**	122	108
Southeast Asia	**117**	94	93
	1,090	1,036	1,010
Total (mboe/d @ 6:1)	**398**	445	419
Production per share (boe/share)	**1.13**	1.21	1.13

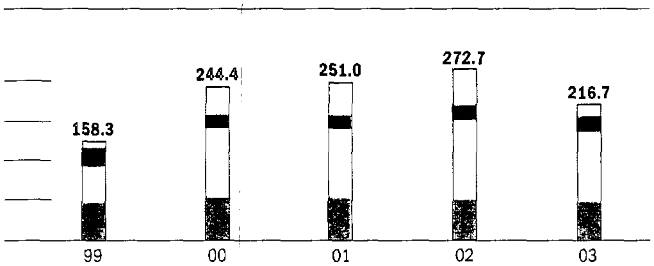
North America natural gas production increased 5% to 864 mmcf/d during 2003. This production growth is due to Talisman's successful drilling programs, the addition of infrastructure which helped alleviate production bottlenecks and strategic acquisitions. During 2003, Talisman drilled 625 wells in North America with a 93% success rate. The commissioning of the Erith pipeline and dehydration project and the acquisition of Vista Midstream will allow Talisman to continue to increase production in the Foothills and Deep Basin areas. At the end of 2002 and during the first quarter of 2003, Talisman purchased a number of high netback natural gas properties in upper New York State. These properties added 60 mmcf/d during the year. However, production was constrained by access to infrastructure. This issue is being addressed. North America oil and liquids production averaged 59,578 bbls/d, down slightly from 2002 as the Company's North America exploration and development activities continue to focus on natural gas.

North Sea oil and liquids production averaged 113,075 bbls/d, down 11% from 2002, due primarily to natural decline. Production in the fourth quarter averaged 128,697 bbls/d, up 15% over the third quarter and 4% over the final quarter of 2002. North Sea production highlights for 2003 included the startup of the Blake Flank development, the acquisition of the Gyda field in Norway in the third quarter and the tie in of new wells at Halley, Hannay, Claymore and Braemar. The Ross/Blake core area, including Blake Flank, averaged 22,437 bbls/d during 2003, down from 2002 due to shutdowns to tie in Blake Flank and natural decline. Production from Gyda averaged 6,700 bbls/d in the fourth quarter. North Sea natural gas production decreased to 109 mmcf/d as 2002 production benefited from a temporary increase in access to export pipeline capacity at Brae.

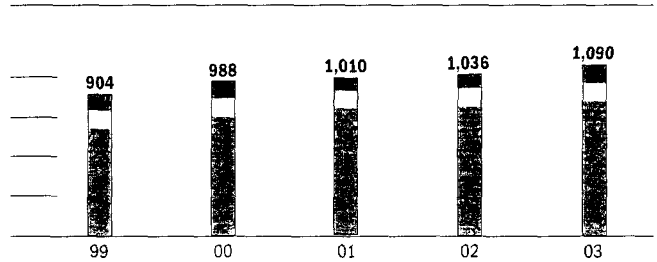
Southeast Asia oil and liquids production increased 9% over 2002 to average 24,430 bbls/d in 2003. In the fourth quarter, production averaged 31,138 bbls/d, an increase of 39% over the final quarter of 2002. The PM-3 CAA development project came on stream at the end of September and increased total production in Malaysia/Vietnam to 22,738 bbls/d in December (32,506 boe/d including natural gas). Total Malaysia/Vietnam oil and liquids production for the year averaged 8,672 bbls/d. Indonesia oil and liquids production averaged 15,758 bbls/d, down slightly from 2002 due to natural decline.

Southeast Asia natural gas production increased 24% to 117 mmcf/d and exited 2003 with production of 196 mmcf/d in December. Natural gas production from the PM-3 CAA development project started in the fourth quarter and increased to 59 mmcf/d in December. First natural gas sales from Corridor in Indonesia to Singapore commenced in September under a 20 year contract with Gas Supply Pte Ltd. and averaged 13.5 mmcf/d during the fourth quarter. The majority of the remainder of the

Oil and Liquids Production
(mbbls/d) North America North Sea Southeast Asia Algeria Sudan



Natural Gas Production
(mmcf/d) North America North Sea Southeast Asia



Indonesia natural gas production is sold to PT Caltex Pacific Indonesia (Caltex) under long-term variable demand contracts with minimum purchase requirements.

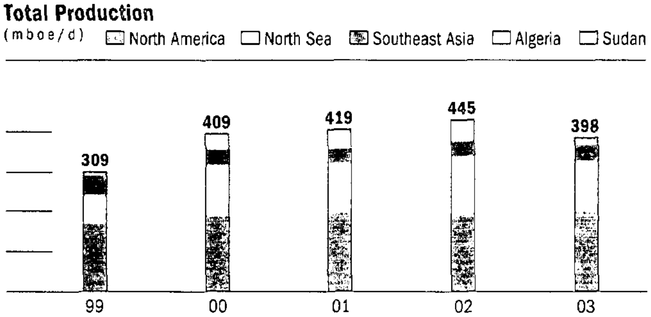
Algeria oil production for the year averaged 6,594 bbls/d and increased to 15,287 bbls/d during the month of December with the startup of the MLN satellite fields.

Commodity Prices

	2003	2002	2001
Oil and liquids ($/bbl)			
North America	**35.30**	32.43	30.80
North Sea	**39.72**	38.76	36.07
Southeast Asia	**41.05**	39.46	35.97
Algeria	**39.01**	–	–
Sudan	**43.89**	37.79	32.66
	38.93	37.20	33.99
Natural gas ($/mcf)			
North America	**6.37**	3.96	5.39
North Sea	**4.57**	3.89	4.35
Southeast Asia	**4.95**	4.72	4.80
	6.03	4.03	5.22
Company $/boe (6 mcf=1 boe)	**37.67**	32.10	32.91
Hedging loss (income) excluded from the above prices			
Oil and liquids ($/bbl)	**2.05**	0.09	(0.16)
Natural gas ($/mcf)	**0.08**	(0.22)	0.02
Total $/boe (6mcf=1boe)	**1.34**	(0.46)	(0.05)
Benchmark prices			
WTI (US$/bbl)	**30.99**	26.15	25.92
Dated Brent (US$/bbl)	**28.83**	25.03	24.46
NYMEX (US$/mmbtu)	**5.44**	3.25	4.38
AECO (C$/gj)	**6.35**	3.86	5.97

Prices are before hedging activities and do not include synthetic oil.

Total Production
(mboe/d)



World oil prices increased in 2003 over 2002 with WTI averaging US $30.99, up 19%. North American natural gas prices also increased considerably over 2002 with NYMEX averaging US$5.44/mmbtu, up 67%.

More than 90% of the Company's revenues are either received in US dollars or are closely referenced to US dollars. The Company converts these revenues to Canadian dollars for reporting purposes. The strengthening of the Canadian dollar reduced Talisman's reported oil and liquids price by $4.71/bbl. Talisman's North America oil and liquids price averaged $35.30/bbl, up 9% from last year. The Company's North Sea oil price averaged $39.72/bbl, up 2% over 2002. The Company's Southeast Asia oil price averaged $41.05/bbl, up 4% over 2002.

Talisman's average natural gas price in North America increased 61% to $6.37/mcf. The strengthening of the Canadian dollar during 2003 reduced Talisman's reported North America natural gas price by $0.70/mcf. The Company's North Sea natural gas price increased 17% as a result of a higher proportion of the gas being sold under long-term contracts.

The Company's natural gas price in Southeast Asia averaged $4.95/mcf, up 5% from 2002. A majority of Corridor gas production, which constituted approximately 90% of the Company's 2003 gas sales in Southeast Asia, is exchanged for Duri crude oil on an energy equivalent relationship and is sold offshore with payment in US dollars. The majority of the Company's other natural gas sales in Southeast Asia are referenced to Singapore fuel oil spot market prices. A 2002 adjustment to Corridor's gas price, relating to 2001, decreased Talisman's average Southeast Asia reported gas price in 2002 by $0.22/mcf.

The Company's average sales prices are before a net hedging loss of $194 million, comprised of a $0.08/mcf loss on gas hedges (2002 – $0.22/mcf gain) and a $2.05/bbl loss on oil hedges (2002 – $0.09/bbl loss). The physical and financial commodity price contracts for 2004 outstanding at year end are disclosed in notes 9 and 10 of the Consolidated Financial Statements with additional discussion in the MD&A section entitled Derivative Financial Instruments and Commodity Sales Contracts. Additional discussion of the expected impact of commodity price contracts on the Company's 2004 results can be found in the Outlook for 2004 section of this MD&A. The Company's accounting policy with respect to derivative financial instruments and commodity contracts is disclosed in note 1(k) of the Consolidated Financial Statements.

Royalties

	2003		2002		2001	
	Rates (%)	$millions	Rates (%)	$millions	Rates (%)	$millions
Oil and liquids						
North America	**21**	**155**	21	149	22	164
North Sea	**–**	**(3)**	4	74	5	75
Southeast Asia	**39**	**143**	38	122	30	82
Algeria	**49**	**46**	–	–	–	–
Sudan	**46**	**97**	40	328	39	248
	14	**438**	18	673	18	569
Natural gas						
North America	**22**	**432**	19	224	25	394
North Sea	**6**	**11**	12	21	11	18
Southeast Asia	**6**	**13**	5	9	5	8
	19	**456**	17	254	22	420
	16	**894**	18	927	20	989

Royalty rates do not include synthetic oil.

The consolidated royalty expense decreased to $894 million in 2003, with the sale of the Sudan operations accounting for most of the drop. In addition, effective January 1, 2003, the UK abolished government royalties. Agreement was also reached on various outstanding UK royalties issues in respect of prior years, which also reduced the North Sea royalty expense for 2003. North Sea royalties are expected to average 2% during 2004 due to non-government royalty interests.

Talisman's North America natural gas royalties, which are largely determined on a sliding scale based on price, averaged 22%, up from 19% in 2002. The royalty rate in 2003 on North America natural gas production did not reach the rate incurred during 2001, when prices were at similar highs due to increased production being sourced from lower royalty rate regions such as the Company's Appalachia production, which had a royalty rate of 14% in 2003.

The Company's royalty rate for oil and liquids decreased, year-over-year, to 14% due to the reduction in the North Sea and the sale of the Sudan operations. Without Sudan, the Corporate royalty rate for oil and liquids would have been 12% in 2003 (2002 – 12%; 2001 – 13%). Southeast Asia oil and liquids royalties averaged 39% in 2003 and 2002 primarily due to the depletion of a cost recovery pool at Tanjung during 2002. Oil from PM-3 CAA in Malaysia/Vietnam has a current royalty rate of 30%, while natural gas sales have a royalty rate of 25%.

Corridor's natural gas royalty rate averaged 5% during 2003, consistent with prior years; however, the royalty rate is expected to increase to approximately 22% in 2004 and 30% in 2005.

Under the terms of the Algerian production sharing contractual arrangement, Talisman is subject to a 51% royalty rate during the first five years of production. During the first four years of production, Talisman receives accelerated production entitlement. At the end of year five, any accelerated production entitlement received by Talisman during the first four years in excess of 49% on a cumulative basis reverts to the government. Accordingly, during the first four years of production, Talisman will record a deferred royalty expense and liability for any production entitlement received in excess of 49%. During 2003, Talisman recorded deferred Algerian royalties of $14 million.

Operating Expenses and Unit Operating Costs

	2003		2002		2001	
Oil and liquids	$/bbl	$millions	$/bbl	$millions	$/bbl	$millions
North America	**6.28**	**131**	5.55	121	5.22	121
North Sea	**12.67**	**523**	11.11	517	10.06	407
Southeast Asia	**7.33**	**65**	7.93	65	7.13	54
Algeria	**6.84**	**16**	–	–	–	–
Sudan	**3.73**	**18**	3.82	84	3.40	66
	9.63	**753**	7.99	787	7.15	648
Natural gas	$/mcf	$millions	$/mcf	$millions	$/mcf	$millions
North America	**0.75**	**237**	0.71	212	0.67	198
North Sea	**0.54**	**21**	0.61	27	0.46	18
Southeast Asia	**0.50**	**22**	0.59	21	0.47	16
	0.70	**280**	0.69	260	0.63	232
Company (boe)	**7.15**	**1,033**	6.48	1,047	5.79	880
Synthetic oil	**22.63**	**22**	18.00	19	20.05	20
Pipeline	**–**	**44**	–	49	–	46
	–	**1,099**	–	1,115	–	946

Total operating expenses for the Company were $1.1 billion. The reduction due to the sale of the Sudan operations was largely offset by higher natural gas operating expenses in North America due to increased volumes and higher processing and power costs and the startup of Algeria. On a unit basis, oil and liquids costs increased to $9.63/bbl due to the sale of the Sudan operations and lower North Sea volumes.

Oil and liquids unit operating costs in North America during 2003 increased to $6.28/bbl, largely due to lower production and higher power costs. Unit operating costs for natural gas increased to $0.75/mcf with higher processing and power costs partially offset by the lower unit operating costs ($0.18/mcf) in Appalachia.

In 2003, North Sea oil and liquids operating expenses of $523 million in part reflected the weaker pound sterling. However, unit costs averaged $12.67/bbl on lower volumes. The UK pound sterling strengthened against the Canadian dollar during 2002 and accounted for over half of the unit cost increase in 2002 over 2001, with the remainder due to higher maintenance and well workover costs.

Southeast Asia unit operating costs decreased 12% to $5.41/boe due to higher sales volumes at Corridor and the startup of the PM-3 CAA development project. The strengthening of the Canadian dollar against the US dollar helped keep total operating expenses flat compared to 2002. Oil and liquids unit costs averaged $7.33/bbl with PM-3 CAA averaging

$6.14/bbl and the Indonesia blocks averaging $7.98/bbl. Natural gas unit costs averaged $0.51/mcf at Corridor, down from 2002 on higher volumes.

Algeria unit operating costs averaged $6.84/bbl and included costs associated with startup activities.

Depreciation, Depletion and Amortization Expense

	2003		2002		2001	
	$/boe	$millions	$/boe	$millions	$/boe	$millions
North America	**9.33**	**693**	8.44	614	7.98	585
North Sea	**12.91**	**619**	12.99	701	11.86	558
Southeast Asia	**5.92**	**95**	6.24	87	7.00	93
Algeria	**6.99**	**17**	–	–	–	–
Sudan	**3.98**	**19**	4.24	93	3.98	77
	9.92	**1,443**	9.19	1,495	8.58	1,313

The Company's depreciation, depletion and amortization (DD&A) expense decreased $52 million to $1.4 billion due to the sale of the Sudan operations but was up on a unit basis to $9.92/boe. The DD&A rate in North America increased with recent acquisitions including the US property acquisitions at the end of 2002 and the beginning of 2003, Petromet in 2001 and Vista Midstream in 2003. In the North Sea, the DD&A rate decreased $0.08/boe. The Southeast Asia rate decreased to $5.92/boe due in part to the strengthening Canadian dollar and higher Corridor production.

For additional information relating to DD&A refer to the MD&A section entitled Application of Critical Accounting Policies and to note 4 of the Consolidated Financial Statements.

Dry Hole Expense

(millions of dollars)	2003	2002	2001
North America	**135**	128	54
North Sea	**69**	9	21
Southeast Asia	**9**	4	8
Algeria	**1**	–	5
Sudan	**–**	13	16
Other[1]	**37**	20	9
	251	174	113

1 Other includes Trinidad, Colombia and frontier North America.

A high risk exploration well offshore Nova Scotia and the Eta-2 and Dunnottar wells in the North Sea contributed to the increase in dry hole expense in 2003. The increase in North America reflects increased drilling during 2003. The Company wrote off two wells in Colombia, two in Indonesia and one in Malaysia. Under the Successful Efforts method of accounting for oil and gas activities, the costs of unsuccessful exploration wells are written off to dry hole expense in the year such determination is made. Until such determination is made, the costs are included in non-depleted capital. At year end, $283 million of costs relating to exploration wells (2002 – $353 million; 2001 – $399 million), were included in non-depleted capital and not subject to DD&A pending final determination.

Exploration Expense

(millions of dollars)	2003	2002	2001
North America	**87**	66	69
North Sea	**21**	20	30
Southeast Asia	**17**	19	8
Algeria	**–**	5	2
Sudan	**5**	6	11
Other	**83**	69	27
	213	185	147

Exploration expense consists of geological and geophysical costs, seismic, land lease rentals and indirect exploration expenses. These costs are expensed as incurred under Successful Efforts accounting. There has been a steady increase in the Company's exploration spending since 1999. Exploration expense is closely tied to the total amount of exploration capital spent in a year. Expenses constituting "Other" in 2003 and 2002 relate mostly to activities in Trinidad, East Coast offshore North America and Colombia.

Corporate

(millions of dollars)	2003	2002	2001
G&A expense	**152**	138	108
Interest expense	**137**	164	139
Capitalized interest	**24**	25	19
Stock-based compensation	**185**	–	–
Preferred securities charges, net of tax	**22**	24	24
Other revenue	**76**	80	82
Other expense	**16**	113	78

General and administrative (G&A) expense increased due to additional documentation requirements associated with recently implemented corporate governance initiatives, higher legal and pension costs, salary increases and additional personnel due to expanding investment and operations. On a unit basis, G&A was $1.05/boe and increased in part due to lower oil and liquids production (2002 – $0.85/boe; 2001 – $0.71/boe).

As a result of lower average debt levels and lower effective interest rates during the year, interest on long-term debt, including capitalized interest, decreased to $161 million. Interest capitalized over the last three years is primarily associated with the Malaysia/Vietnam PM-3 CAA development, which came on production during 2003. Capitalized interest in 2003 also included interest associated with the Angostura development in Trinidad.

Preferred securities charges, net of taxes, of $22 million have been charged directly to retained earnings and are deducted from net income to determine net income per share. Preferred security charges, before tax, totalled $38 million.

Other revenue includes pipeline and custom treating revenues and miscellaneous income. Other expense for 2003 included foreign exchange losses of $7 million and property impairment in the North

Sea of $30 million due to unsuccessful development drilling at Ivanhoe and was partially offset by gains on property dispositions of $14 million. Other expense for 2002 included the Kildrummy and Beechnut write-offs ($74 million), foreign exchange losses ($28 million) and losses on property dispositions ($10 million).

Stock-Based Compensation

The Company's stock option plans were amended during 2003 to provide employees and directors who hold stock options with the choice upon exercise to purchase a share of the Company at the stated exercise price or to receive a cash payment in exchange for surrendering the option. The cash payment is equal to the appreciated value of the stock option as determined based on the difference between the option's exercise price and the Company's share price at the time of surrender. The cash payment alternative is expected to result in reduced shareholder dilution in the future as it is anticipated that most holders of the stock options (now and in the future) will elect to take a cash payment. Such cash payments made by the Company to stock option holders are deductible by the Company for income tax purposes, making these plans more cost effective.

As a result of the Company's decision to start expensing stock options, the Company's second quarter results included a $105 million ($74 million, or $0.57/share, net of tax) stock-based compensation expense relating to the appreciated value of the Company's outstanding stock options and cash units at June 30, 2003. The total stock-based compensation expense for the year was $185 million ($130 million, net of tax) including $80 million during the second half of 2003 due to the appreciation of the Company's stock price during the period July 1 to December 31. Additional stock-based compensation expense or recoveries in future periods is dependent on the movement of the Company's share price and the number of outstanding options and cash units.

Income Taxes

The Company's effective tax rate for 2003, after deducting Production Revenue Tax (PRT), was 15% compared to 44% in 2002 and 36% in 2001. A number of events in the past two years have significantly impacted the Company's effective tax rates including the 2003 tax rate reductions in Canada, the sale of the Sudan operations and a supplemental oil and gas tax enacted in the UK in 2002.

Effective Income Tax Rate

(millions of dollars)	**2003**	2002	2001
Income before tax	**1,277**	1,068	1,296
Less PRT	**92**	124	149
	1,185	944	1,147
Income tax expense (recovery)			
Current	**229**	258	342
Future	**(51)**	162	72
	178	420	414
Effective income tax rate (%)	**15**	44	36

In 2003, the Company recorded a future tax recovery of $160 million due to a reduction in Canadian federal and provincial tax rates. A similar rate reduction in the Alberta corporate tax rate in 2002 resulted in a future tax recovery of $12 million. Effective April 17, 2002, the UK increased its corporate income tax rate applicable to North Sea oil and gas profits by enacting a 10% supplementary charge. This increased the Company's future tax expense for 2002 by $128 million. Partially offsetting this tax increase was the acceleration of tax allowances for capital expenditures incurred after April 17, 2002.

A normalized effective tax rate after removing the impact of the Canadian and UK tax rate changes and the impact of the gain on disposal of the Sudan operations would have been 38% in 2003, 32% in 2002 and 36% in 2001. See note 13 of the Consolidated Financial Statements for additional information on the Company's income taxes.

Current income tax expense decreased to $229 million in 2003, primarily due to the sale of the Sudan operations. An increase in current taxes in Canada due to higher natural gas prices was partially offset by lower current taxes in the North Sea.

The UK Government levies PRT on North Sea fields which received development approval before April 1993, based on gross profit after deducting allowable expenditures, a cost uplift, a portion of losses from certain other fields, abandonment costs and government royalties. PRT is deductible for purposes of calculating corporate income tax.

Capital Spending

(millions of dollars)	**2003**	2002	2001
North America	**1,580**	939	976
North Sea	**693**	518	664
Southeast Asia	**316**	269	149
Algeria	**34**	107	63
Sudan	**2**	98	117
Other	**223**	121	52
Non-segmented	**38**	26	30
	2,886	2,078	2,051

Includes exploration, development and net asset acquisitions expenditures but excludes the Sudan disposition in 2003 and the Lundin and Petromet acquisitions in 2001.

Natural gas continues to be the focus of the Company's capital investment activities in North America, supplemented by low risk oil projects and strategic acquisitions. Of the $1.6 billion of capital spending in North America, $453 million related to exploration activities while development accounted for $656 million. The Company participated in 378 gas wells and 204 oil wells in North America and had a success rate of 93%. Development spending was concentrated in the predominantly gas producing core area in the Alberta Foothills, Greater Arch, Deep Basin, Monkman and Edson area and included the Erith pipeline and dehydration project which was commissioned in the fourth quarter. In addition, the Company spent $471 million on acquisitions, net of dispositions, including US properties ($385 million) and Vista Midstream Solutions Ltd. ($130 million). The Company's US properties located in New York State, including those purchased at the end of 2002, contributed 60 mmcf/d of production during 2003. The Vista acquisition provides Talisman access to infrastructure and midstream revenues in the Deep Basin area of Alberta, one of Talisman's key natural gas growth areas.

Total capital spending in the North Sea of $693 million included $99 million for exploration and $397 million for development with the remaining $197 million for net property acquisitions. Development expenditures included Blake Flank and drilling within the Clyde, Buchan, Ross, Tartan and Claymore core areas. A total of 14 successful development wells were drilled during 2003 in the North Sea. Exploration drilling included the successful Tartan North, J5 and Affleck (Clyde) exploration wells. The Eta-2 and Dunnottar exploration wells were written off to dry hole expense. During 2003, the Company completed the purchase of a 61% operating interest in the Norwegian offshore Gyda field, associated facilities and adjacent acreage for $112 million, including $21 million of assumed working capital deficiency. Goodwill of $31 million was recorded related to this acquisition. The Company also acquired additional minor working interests in eight North Sea fields and exploration blocks.

The PM-3 CAA development in Malaysia/Vietnam accounted for a majority of the $316 million (including $22 million of capitalized interest) of total capital spending in Southeast Asia. Talisman participated in drilling 21 successful development wells in Malaysia/Vietnam during 2003. In addition, two successful exploration wells were drilled in PM-3 CAA and one in each of Block PM 305, Block 46-Cai Nuoc and Block 46/02. A total of $41 million was spent in Indonesia with over half going to develop Corridor in order to support gas sales to Singapore and possible future sales to West Java. Talisman participated in drilling seven successful oil and gas wells in Indonesia during 2003.

Capital spending in Algeria totaled $34 million in 2003 and the Company participated in 12 successful wells during the year.

Other areas accounted for $223 million of the 2003 capital spending. Talisman spent $130 million in Trinidad to advance the Angostura development on offshore Block 2(c) with first oil anticipated in early 2005. Four exploration wells were drilled offshore Trinidad during 2003 and all four encountered hydrocarbons, including the one drilling over year end. The Company spent $21 million in Colombia on seismic and to participate in drilling two exploration wells, which were drilling at year end but have subsequently been abandoned.

Reserves Replacement

Talisman drilled 651 successful wells in 2003, adding 143 mmboe of proved reserves and replacing 99% of conventional production at a cost of $14.28/boe before acquisitions and dispositions. The Company's total proved reserves decreased 8% to 1,362 mmboe, primarily due to the sale of the Sudan operations (156 mmboe). Excluding the impacts of the Sudan sale, both proved and probable reserves increased by approximately 3% each and, in total, production replacement from all sources (including proved and probable discoveries, revisions and net acquisitions excluding Sudan) was 150%.

Over the last three years, the Company has replaced approximately 139% of production before acquisitions and divestitures at a cost of $8.76/boe on a proved reserves basis. Net revisions and transfers over the past three years, which are included in the above replacement rate, have resulted in a cumulative reduction of 8 mmboe or less than 1% of the Company's proved reserves.

Finding, Development and Acquisition Costs (gross before royalties)

Proved F&D costs ($/boe)	**2003**	2002	2001	3-year Average	5-year Average
F&D[1]	**14.28**	11.03	5.34	8.76	7.89
FD&A[2] (excluding Sudan sale[3])	**14.67**	12.15	7.08	9.79	8.64

1 F&D costs have been calculated by dividing finding and development costs (excluding net acquisition costs), as reconciled in the table below, by proved gross before royalties reserves additions including revisions but excluding net acquired proved gross before royalties reserves.

2 FD&A costs have been calculated by dividing finding and development costs (including net acquisition costs), as reconciled in the table below, by proved gross before royalties reserves additions including revisions and net acquired proved gross before royalties reserves.

3 FD&A including the impacts of the Sudan sale for 2003 is $72.84/boe.

The finding and development costs have been calculated based on current year's exploration and development spending excluding synthetic oil operations capital, midstream expenditures, indirect exploration costs, enhanced oil recovery and capitalized interest divided by current year proved reserves additions. No amount of future capital has been included in the above calculation, which is consistent with calculations performed in prior years. The costs used in the above calculation has been reconciled to exploration and development expenditures as set out in the notes to the Consolidated Financial Statements.

Reconciliation of Costs Included in F&D Calculations

(gross before royalties)

(millions of dollars)	**2003**	2002	2001
Exploration and development expenditures	**2,180**	1,848	1,882
Less:			
Midstream capital	**27**	21	27
Indirect costs	**52**	41	34
Capitalized interest	**24**	25	19
Synthetic oil operations capital	**30**	24	8
Enhanced recovery expenditures	**4**	2	2
	2,043	1,735	1,792

The following finding and development costs have been calculated in US dollars in a manner consistent with US practice which is calculated based on current additions to proved reserves net after royalties. Costs used in the US$/boe, net of royalties F&D calculations have been reconciled in the table below to the property acquisition, exploration and development costs as set out in the Supplementary Oil and Gas Information under the heading Costs Incurred in Oil and Gas Activities.

Finding, Development and Acquisition Costs (net after royalties)

US$/boe Proved F&D costs, net	**2003**	2002	2001	3-year Average	5-year Average
F&D[1], net	**11.71**	11.80	4.40	7.72	7.33
FD&A[2], net (excluding Sudan sale)	**12.12**	12.24	6.04	8.62	7.76

1 F&D net costs have been calculated by dividing finding and development costs (excluding acquisition costs) in US dollars, as reconciled in the table below, by proved net after royalties reserves additions including revisions but excluding acquired proved net after royalties reserves.

2 FD&A net costs have been calculated by dividing finding and development costs (including acquisition costs) in US dollars, as reconciled in the table below, by proved net after royalties reserves additions including revisions and acquired proved net after royalties reserves.

Reconciliation of Costs Included in F&D Calculations (net of royalties)

US$ millions	**2003**	2002	2001
Exploration and development costs (FAS 69)	**1,430**	1,111	1,152
Less: Capitalized interest	**(17)**	(16)	(12)
Exploration and development costs	**1,413**	1,095	1,140
Acquisition costs (FAS 69)	**533**	212	1,080
Total exploration, development and acquisition costs	**1,946**	1,307	2,220

Liquidity and Capital Resources

Talisman's long-term debt at year end was $2.2 billion ($2.1 billion, net of cash and cash equivalents), down from $3 billion at the end of last year. At year end, the Company had not drawn on any of its available $1,135 million bank lines of credit. The Company maintains a shelf prospectus under which it may issue up to $500 million of medium term notes in aggregate in the Canadian public debt market. The shelf prospectus expires in April 2004. In December 2003, the Company filed a debt shelf prospectus in the US under the Multi-jurisdictional Disclosure System (MJDS) under which it may issue up to US$1 billion of debt securities in the US public debt market.

In 2003, the Company received approximately $1 billion in net proceeds from the sale of its Sudan operations. Use of these proceeds to repay debt accounted for the majority of the decrease in long-term debt during the year, along with the impact of a stronger Canadian dollar on US dollar denominated debt, which reduced long-term debt by $349 million. The Company generated $2.7 billion of cash flow and spent $2.2 billion on exploration and development and a net $600 million on acquisitions.

In 2004, $107 million ($75 million and US$25 million) of long-term debt matures and will be repaid. None of the long-term debt has been classified as a current liability as the Company has the ability and intention to refinance amounts due within one year with existing bank facilities. At year end, the Company had outstanding two issues of preferred securities totaling US$300 million. The preferred securities are carried on the Company's balance sheet as equity at $431 million, which is based on the historical exchange rate at the time of their issuance. These securities are callable, in whole or in part, at par by Talisman starting in 2004. Subsequent to year end, the Company redeemed US$150 million of these securities. The difference between the carrying value of the redeemed preferred securities ($215 million) and the cost of redemption ($197 million) will be credited directly to retained earnings.

The Company repurchased 3,335,600 of its common shares under its normal course issuer bid (NCIB) during 2003 for a total of $194 million ($58.24/share). The NCIB expires in March 2004 and is expected to be renewed, which will allow the Company to repurchase up to 5% of the Company's outstanding common shares.

Two common share dividends were paid in 2003 (total dividends were $0.70/share). The Company's dividend is determined semi-annually by the Board of Directors. Commencing with the December 2003 payment, the semi-annual dividend was increased to $0.40/share ($0.80/share annually). At year end, there were 128 million common shares outstanding.

Talisman targets long-term debt of less than 2:1 on a debt to cash flow basis and 45% on a debt to debt-plus-equity basis. These targets incorporate the debt refinancing of the Company's preferred securities during 2004. At the end of 2003, Talisman met the debt targets with ratios of 0.8:1 for debt to cash flow and 31% for debt to debt-plus-equity. For purposes of these calculations the Company's preferred securities have been classified as equity.

For additional information regarding the Company's liquidity and capital resources, refer to note 5 of the Consolidated Financial Statements. In addition, refer to the Sensitivities table included in the Outlook Section of this MD&A for possible 2004 impacts of various factors on the Company's estimated 2004 net income and cash flows.

Talisman's investment grade corporate credit and senior unsecured long-term debt credit ratings remain unchanged with Dominion Bond Rating Service ("DBRS"), Moody's Investor Service, Inc. ("Moody's") and Standard & Poor's ("S&P") at BBB (high), Baa1 and BBB+ respectively. Due to the subordinated nature of the preferred securities, they have a lower rating. DBRS, Moody's and S&P have rated the preferred securities as Pfd-3(high)y, Baa3 and BBB-, respectively.

Commitments and Off Balance Sheet Arrangements

As part of its normal business, the Company has entered into arrangements and incurred obligations that will impact the Company's future operations and liquidity, some of which are reflected as liabilities in the Consolidated Financial Statements at year end. The principal commitments of the Company are in the form of: debt repayments; abandonment obligations; settlements of derivative financial instruments; lease commitments relating to corporate offices and ocean-going vessels; firm commitments for gathering, processing and transmission services; minimum work commitments under various international agreements; other service contracts; and fixed price commodity sales contracts.

Additional disclosure of the Company's debt repayment obligations and significant commitments can be found in notes 5 and 10 of the Consolidated Financial Statements. A discussion of the Company's derivative financial instruments and commodity sales contracts can be found in the next section of this MD&A.

Derivative Financial Instruments and Commodity Sales Contracts

The Company may manage its exposure to fluctuations in foreign exchange rates, interest rates, electricity costs and commodity prices in part through the use of derivative financial instruments and commodity sales contracts. The accounting policy with respect to derivative financial instruments is set out in note 1(k) of the Consolidated Financial Statements. Derivative financial instruments outstanding at December 31, 2003, including their respective fair values, are detailed in note 9 of the Consolidated Financial Statements.

During 2003, the Company's commodity price derivative financial instruments resulted in a net decrease to recorded sales of $194 million (2002 – $75 million increase; 2001 – $8 million increase). At December 31, 2003, the Company had outstanding commodity price derivative contracts that cover approximately 55 mmcf/d (6%) of the Company's anticipated 2004 North American natural gas production and 79,000 bbls/d (37%) of the Company's anticipated 2004 worldwide oil and liquids production. An additional 56 mmcf/d (6%) of anticipated 2004 North American natural gas production has been committed under fixed price and three-way collar commodity sales contracts. See notes 9 and 10 of the Consolidated Financial Statements for additional details regarding the contracts outstanding at year end.

In order to support the Company's investments in natural gas projects outside North America and the North Sea, Talisman has entered into a number of long-term sales contracts. In conjunction with the PM-3 CAA development project the Company has entered into a long-term firm supply contract for approximately 100 mmcf/d at prices referenced to the Singapore fuel oil spot market. Natural gas production from the development commenced during the fourth quarter. The majority of Talisman's Corridor natural gas production in Indonesia is sold to Caltex under long-term sales agreements and is exchanged for crude oil on an energy equivalent relationship. The crude oil received from Caltex is then sold offshore. Sales to Singapore from Corridor are also under long-term sales agreements referenced to the spot price of fuel oil in Singapore. The Company anticipates having sufficient production to meet all future delivery commitments.

During 2003, the Company had £250 million of US dollar cross currency swap contracts and interest rate swap contracts outstanding. These contracts were designated as hedges of the £250 million Eurobond, which in effect converted this indebtedness into US dollars with a floating interest rate based on three month US LIBOR. The cross currency and interest rate swap contracts reduced the Company's 2003 interest expense by $27 million (2002 – $15 million) and the year end Canadian dollar reported debt by $106 million. As discussed in the MD&A section entitled Change in Accounting Policies, effective

The following table includes the Company's expected future payment commitments and estimated timing of such payments.

			Payments expected[1,2] (millions of dollars)					
Commitments	Recognized in financial statements	**Total**	Due within 1 year	Due within 2-3 years	Due within 4-5 years	Due within 6-10 years	Due within 11-15 years	Due after 15 years
Long-term debt	Yes – Liability	**2,203**	107	271	766	200	471	388
Abandonment obligations[3]	Yes – Partially accrued as liability	**2,018**	9	34	92	373	552	958
Preferred securities[4]	Yes – Equity	**388**	194	–	–	–	–	194
Office leases	No	**196**	19	32	32	80	24	9
Ocean-going vessel leases	No	**95**	95	–	–	–	–	–
Transportation and processing commitments	No	**1,079**	135	181	146	284	192	141
Min. work commitments[5]	No	**308**	203	77	28	–	–	–
Other service contracts	No	**131**	19	32	9	24	24	23
Stock options and cash units[6]	Yes – Liability	**164**	123	41	–	–	–	–
Total		**6,582**	904	668	1,073	961	1,263	1,713

1 Payments exclude ongoing operating costs related to certain leases, interest on long-term debt, preferred securities charges and payments made to settle derivative contracts.
2 Payments denominated in foreign currencies have been translated at the December 31, 2003 exchange rate.
3 The abandonment obligation represents management's probability weighted, undiscounted best estimate of the cost and timing of future dismantlement, site restoration and abandonment obligations based on engineering estimates and in accordance with existing legislation and industry practice.
4 Subsequent to year end, US$150 million were redeemed.
5 Minimum work commitments include contracts awarded for capital projects and those commitments related to exploration or drilling obligations.
6 The liability for stock options and cash units recognized on the balance sheet is based on the Company's year end stock price and the number of options and cash units outstanding, adjusted for vesting terms. The amount included in this table includes the full value of unvested options and cash units. Timing of payments is based on vesting. Actual payments are dependent on the Company's stock price at the time of exercise.

January 1, 2004, these contracts are no longer designated hedges of the Eurobond. Subsequent to year end, the Company terminated approximately three-quarters of these contract positions for cash proceeds, before tax, of $108 million.

The Company has established a system of internal controls to minimize risks associated with its derivatives program and credit risk associated with derivatives counterparties. Management believes its commodity derivatives and fixed priced sales program to be prudent in that it provides a degree of price support during periods of falling commodity prices while providing the ability to participate in price increases and, in the case of certain fixed price sales contracts, guaranteed market access.

Application of Critical Accounting Policies and the Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect reported assets and liabilities, disclosures of contingencies and revenues and expenses. Management is also required to adopt accounting policies that require the use of significant estimates. Actual results could differ from those estimates. A summary of significant accounting policies adopted by Talisman can be found in note 1 to the December 31, 2003, Consolidated Financial Statements. In assisting the Company's Audit Committee to fulfill its financial statement oversight role, management regularly meets and reviews with the Committee the Company's significant accounting policies, estimates and any significant changes thereto including those discussed below.

Management believes the most critical accounting policies, including judgments in their application, that may have an impact on the Company's financial results relate to the accounting for property, plant and equipment, abandonment and goodwill. The rate at which the Company's assets are depreciated or otherwise written off and the abandonment liability provided for are subject to a number of judgments about future events, many of which are beyond management's control. Reserves recognition is central to much of the accounting for an oil and gas company as described below.

Reserves Recognition

Underpinning Talisman's oil and gas assets and goodwill are its oil and gas reserves. Detailed rules and industry practice, to which Talisman adheres, have been developed to provide uniform reserves recognition criteria. However, the process of estimating oil and gas reserves is inherently judgmental. There are two principle sources of uncertainty; technical and commercial. Technical reserves estimates are made using all available geological and reservoir data as well as production performance data. As new data becomes available, including actual reservoir performance, reserves estimates may change. Reserves can be classified as proved or probable with decreasing levels of certainty as to the likelihood that the reserves will be ultimately produced.

Reserves recognition is also impacted by economic considerations. In order for reserves to be recognized they must be reasonably certain of being produced under existing economic and operating conditions, which is viewed as being at year end commodity prices with a cost profile based on current operations. In particular, in international operations consideration includes the status of field development planning and gas sales contracts. As economic conditions change, primarily as a result of changes in commodity prices and, to a lesser extent, operating and capital costs, marginally profitable production, typically experienced in the later years of a field's life cycle, may be added to reserves or conversely may no longer qualify for reserves recognition.

The Company's reserves and revisions to those reserves, though not separately reported on the Company's balance sheet or income statement, impact the Company's reported net income through the amortization of the Company's property, plant and equipment (PP&E), asset and goodwill impairments and the provision for future abandonment and reclamation costs.

During 2003, Talisman's Board of Directors established a Board committee to review the Company's reserves booking process and related public disclosures and has established the position of an internal qualified reserves evaluator (IQRE). The IQRE provides a report to the Reserves Committee and delivers a regulatory certificate regarding reserves and their related cash flows. The primary responsibilities of the Reserves Committee of the Board of Directors include, amongst other things, reviewing the Company's reserves booking process and recommending to the Board of Directors of Talisman the Company's annual statement of reserves data and other oil and gas information.

Depreciation, Depletion and Amortization Expense (DD&A)

A significant portion of the Company's property, plant and equipment is amortized based on the unit of production method with the remaining assets being amortized equally over their expected useful lives. The unit of production method attempts to amortize the asset's cost over its proved oil and gas reserves base. Accordingly, revisions to reserves or changes to management's view as to the operational life span of an asset will impact the Company's future DD&A expense.

As outlined in the Company's DD&A accounting policy and PP&E note (notes 1(d) and 4 of the Consolidated Financial Statements), $866 million (2002 – $1.2 billion) of the Company's Property, Plant and Equipment is not currently subject to DD&A. Half of these costs ($429 million) relate to development projects such as Angostura and PM-305 that are expected to be on production by 2005, at which time amortization will commence. The remaining half of the $866 million of non-depleted capital relates to the costs of acquired probable reserves ($154 million) and incomplete drilling activities, including those wells under evaluation or awaiting production to commence ($283 million). Uncertainty exists with these costs. For example, if the evaluation of the acquired probable reserves or recently drilled exploration wells were determined to be unsuccessful, the associated capitalized costs would be expensed in the year such determination is made, except that in the case of acquired probable reserves associated with producing fields, these costs would be amortized over the reserve base of the associated producing field. Accordingly, the rate at which these costs are written off depends on management's view of the likelihood of the existence of economically producible reserves.

Asset Impairments

The Company's oil and gas assets and goodwill are subject to impairment tests. An impairment charge is recorded in the year an asset is determined to be impaired. Individual oil and gas assets are considered impaired under the Successful Efforts method if their undiscounted future cash flows fall below their carrying value. Goodwill is considered to be impaired if its fair value, principally determined based on discounted cash flows, falls below its carrying value. Both tests require management to make assumptions regarding cash flows well into the distant future that are subject to revisions due to changes in commodity prices, costs, recoverable reserves, production profiles and in the case of goodwill, discount rates. During the past three years, isolated asset impairments have occurred (2003 – $30 million; 2002 – $74 million) however, it is possible that future impairments may be material.

Purchase Price Allocations

The costs of corporate and asset acquisitions are allocated to the acquired assets and liabilities based on their fair value at the time of acquisition. In many cases the determination of fair value requires management to make certain assumptions and estimates regarding future events. Typically in determining fair value, management develops a number of possible future cash flow scenarios to which probabilities are judgmentally assigned. The allocation process is inherently subjective and impacts the amounts assigned to the various individually identifiable assets and liabilities as well as goodwill. The acquired assets and liabilities may span multiple geographical segments and may be amortized at different rates, or not at all as in the case of goodwill or initially for acquired probable reserves. Accordingly, the allocation process impacts the Company's reported assets and liabilities and future net income due to the impact on future depreciation, depletion and amortization expense and impairment tests.

Future Abandonment and Site Restoration Activities

Upon retirement of its oil and gas assets, the Company anticipates incurring substantial costs associated with abandonment and reclamation activities. Estimates of the associated costs are subject to uncertainty associated with the method, timing and extent of future retirement activities. A liability for these costs is accrued on a unit of production basis over the associated reserves base. Accordingly, the annual expense associated with future abandonment and reclamation activities is impacted by changes in the estimates of the expected costs and reserves. During 2003, the abandonment expense included in DD&A was $132 million. The total abandonment liability is currently estimated at $2 billion, which is based on management's probability weighted estimate of costs and in accordance with existing legislation and industry practice. If this liability had been estimated to be 10% higher, an additional $13 million may have been recorded as DD&A during 2003. Past revisions to the abandonment estimate have not been significant.

As indicated in the MD&A section entitled New Accounting Pronouncements, the accounting for Future Abandonment and Site Restoration Activities has changed effective January 1, 2004. A similar change occurred for US GAAP effective January 1, 2003. Under the new accounting requirements, the fair value of the Company's Asset Retirement Obligations (ARO) is to be recorded as a liability on the Company's balance sheet. In determining the fair value of the Company's ARO liability management develops a number of possible abandonment scenarios to which probabilities are judgmentally assigned. At December 31, 2003, the fair value of the Company's ARO liability is estimated to be $1.2 billion. As an indication of possible future changes in the estimated liability, if all of the Company's abandonment obligations could be deferred by one additional year, the fair value of the liability would have decreased by approximately $60 million.

Foreign Exchange Accounting

Talisman's worldwide operations expose the Company to transactions denominated in a number of different currencies which are required to be translated into one currency for financial statement reporting purposes. Talisman's foreign currency translation policy, as detailed in note 1(i) of the Consolidated Financial Statements, is designed to reflect the economic exposure of the Company's operations to the various currencies. The adoption of the US dollar, effective for 2002, as the Company's functional currency is a reflection of Talisman's overall exposure to US dollar denominated transactions, assets and liabilities; oil prices are largely denominated in US dollars as is much of the Company's corporate debt and international capital spending and operating costs. However, the Company's operations in the UK and Canada are largely self-sufficient (self-sustaining) and their economic exposure is more closely tied to their respective domestic currencies. Accordingly, these operations are measured in UK pound sterling and Canadian dollars, respectively. Currently, the Company's foreign exchange exposure principally relates to US dollar denominated UK and Canadian oil sales.

During 2003, the Company's debt was denominated in US dollars, Canadian dollars and UK pound sterling with the UK pound sterling debt effectively swapped into US dollars through the use of cross currency and interest rate swap contracts. During 2003, a portion of the Company's debt (net of cash) was allocated to the self-sustaining Canadian operations based on the Company's net investment in Canada. Foreign exchange gains resulted from the debt allocation as the total amount of net debt allocated exceeded the Company's total Canadian dollar denominated debt.

Production Sharing Contractual Arrangements

A significant portion of the Company's operations outside North America and the North Sea are governed by production sharing contracts (PSCs). Under PSCs, Talisman, along with its working interest partners, typically bears all risk and costs for exploration, development and production. In return, if exploration is successful, Talisman is given the opportunity to recover its investment and operating costs from the production and sale of the associated hydrocarbons ('cost oil'). Talisman is also entitled to receive a share of the 'profit oil', the sharing of which varies from contract to contract. Profit oil is that production in excess of what is required to recover the Company's investment and operating costs. The cost oil, together with the Company's share of profit oil represents Talisman's hydrocarbon entitlement. Talisman records production, sales and reserves based on its working interest ownership. The difference between the Company's working interest ownership and its annual entitlement is accounted for as a royalty expense. In addition, certain of the Company's contracted arrangements in foreign jurisdictions stipulate that income taxes are to be paid by the respective national oil company out of its entitlement share of production. Such amounts are included in income taxes expense at the statutory tax rate in effect at the time of production.

The amount of cost oil required to recover Talisman's investment and costs in a PSC is dependent on commodity prices while Talisman's share of profit oil is also impacted by commodity prices and the profit oil sharing terms. Accordingly, the amount of royalty paid by Talisman over the term of a PSC and the corresponding net after royalty oil and gas reserves booked by the Company is dependent on the amount of initial investment and past costs yet to be recovered and anticipated future costs, commodity prices and production.

Fair Value of Derivative Financial Instruments under US GAAP

As disclosed in note 1(k) of the Consolidated Financial Statements, during 2003, all of the Company's derivative financial instruments were treated as hedges for Canadian GAAP. Accordingly, gains and losses on these instruments are not recorded in the income statement until the hedged transaction occurs. These instruments are carried at cost. For US GAAP purposes, these instruments are not treated as hedges and are recorded on the balance sheet at fair value with changes in fair value being recorded as either income or an expense. The fair value of certain commodity based instruments are highly volatile. The determination of fair value for certain non-market traded instruments requires management to make significant estimates. In addition, the meaningfulness of an instrument's fair value on December 31, 2003 and the appropriateness of recognizing income based on such daily values should be viewed with caution. In determining the fair value of its commodity based instruments, the Company uses an options pricing model based on market determined price forecasts. For other fair values such as those for its interest rate swaps, forward currency contracts and preferred securities, the Company obtains multiple price quotes from external sources.

Oil and Gas Drilling Rights

Talisman has classified all of its mineral drilling rights as oil and gas properties under the heading property, plant and equipment. We believe this treatment is consistent with industry practice and our understanding of the relevant accounting standards. It is our understanding that the Staff of the Securities and Exchange Commission (SEC) is questioning certain SEC registrants regarding the appropriateness of this accounting treatment, specifically as to whether these costs should be classified as intangible assets on the balance sheet separate from other property, plant and equipment. Further, it is our understanding that this issue is being considered by the US Financial Accounting Standards Board (FASB). We believe resolution of this issue will not materially affect the Company's results of operations.

New Canadian Accounting Pronouncements

The Canadian Institute of Chartered Accountants (CICA) has issued a number of accounting pronouncements, some of which may impact the Company's reported results and financial position in future periods.

Disposal of Long-Lived Assets and Discontinued Operations

Effective for disposition activities initiated after May 1, 2003, this pronouncement expands the scope of what assets or operations are to be reclassified as Discontinued Operations and the conditions required to reclassify them as such. This eliminates a difference between US and Canadian GAAP.

Asset Retirement Obligations (future site restoration and abandonment liabilities)

Effective January 1, 2004, the CICA has adopted a new accounting standard that will change the method of accruing for costs associated with the retirement of fixed assets which an entity is legally obligated to incur. The standard will require entities to record the fair value of a liability for an asset retirement obligation in the period it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Currently, these obligations are provided for using the unit of production method or, for certain assets, using the straight-line method over the estimated remaining lives of the assets. The US has adopted a similar rule commencing January 1, 2003.

The accounting standard requires the retroactive restatement of the Company's financial statements upon adoption in 2004. The adjustment required to the December 31, 2003 balance sheet and income statement to implement this change in accounting would be as follows:

(millions of dollars, except per share amounts)	As Reported December 31, 2003	Adjustment upon adoption of ARO standard in 2004	Restated December 31, 2003
Property, plant and equipment	9,778	407	10,185
Provision for future site restoration	840	311	1,151
Future income taxes	2,088	37	2,125
Retained Earnings	1,844	59	1,903
DD&A expense	1,443	(67)	1,376
Other expenses	16	58	74
Future income tax (recovery)	(51)	3	(48)
Net income	1,007	6	1,013
Net income per share ($/share)	7.65	0.05	7.70
Diluted net income per share ($/share)	7.57	0.05	7.62

Impairments of Long-Lived Assets

The CICA issued a new accounting standard on Impairment of Long-Lived Assets. The new standard is effective for 2004. Under this standard, if a long-term asset is identified as being impaired, as determined by its undiscounted future cash flows, the amount of impairment is to be calculated based on the asset's fair value (present value of expected future cash flows). This is consistent with the US GAAP methodology. Prior to this standard, the impairment as calculated under Canadian GAAP was based on the asset's undiscounted future cash flows.

Hedge Accounting

The CICA has issued a new accounting guideline on Hedging Relationships (AcG 13), which is effective for 2004. This guideline, in addition to supplementing and interpreting existing hedging requirements under Canadian GAAP, establishes certain other conditions required before hedge accounting may be applied. Effective January 1, 2004, the Company's US dollar cross currency swap contracts and interest rate swap contracts are no longer designated as hedges of the Eurobond. As a result, on January 1, 2004, in accordance with the Company's accounting policy as detailed in note 1(k) of the December 31, 2003 Consolidated Financial Statements, the Company will record these contracts as an asset on the balance sheet at their fair value of $123 million, record a deferred gain of $17 million and an increase to long-term debt of $106 million, based on the year end exchange rate. The unrealized gain of $17 million on these contracts at year end will be deferred and amortized over the period to 2009, the original term of the contracts. Starting in January 1, 2004, these contracts will be revalued at the end of each period with changes in their fair value being recorded in other income as a gain or loss. Approximately three-quarters of the swap contracts were terminated in early 2004 for cash proceeds of $108 million. The termination of these contracts does not accelerate the recognition of the deferred gain into income.

The Company's long-term debts denominated in UK pound sterling and Canadian dollars have been designated as hedges of the Company's net investments in the UK and Canadian self-sustaining operations. Unrealized foreign exchange gains and losses resulting from the translation of these debts are deferred and included in a separate component of shareholders' equity described as cumulative foreign currency translation. Had the Company not designated these debts as hedges of the Company's net investments in its self-sustaining operations, the Company's net income could have been subject to increased volatility in the future upon revaluation into US dollars of the UK pound sterling and Canadian dollar denominated debts.

Variable Interest Entities

In 2003, the CICA issued a new accounting guideline on Consolidation of Variable Interest Entities (AcG 15), which is effective January 1, 2004. AcG 15 provides guidance as to when a company should consolidate another entity into its Consolidated Financial Statements. Simply put, a variable interest entity (VIE) is a corporation, partnership, trust, or any other legal structure used for business purposes that either (i) does not have equity investors with voting rights or (ii) has equity investors that do not provide sufficient financial resources for the entity to support its activities. AcG 15 requires a VIE to be consolidated by a company if that company is subject to a majority of the risk of loss from the VIE's activities, is entitled to receive a majority of the VIE's residual returns, or both. If a company has previously consolidated a VIE but is not subject to a majority of the risk of loss of its activities nor entitled to receive a majority of its residual returns, such a VIE is required to be deconsolidated. Management is currently evaluating the potential impact of this guideline but does not expect its application would have a significant impact on the Company's financial position, operating results or cash flows.

Risks and Uncertainties

Talisman is exposed to a number of risks inherent in exploring for, developing and producing crude oil and natural gas. The process of estimating oil and gas reserves is complex and involves a significant number of decisions and assumptions in evaluating available geological, geophysical, engineering and economic data; therefore, reserves estimates are inherently uncertain. The Company may adjust estimates of proved reserves based on production history, results of exploration and development drilling, prevailing oil and gas prices and other factors, many of which are beyond the Company's control. In addition, there are numerous uncertainties in forecasting the amounts and timing of future production, costs, expenses and the results of exploration and development projects.

The Company's future success depends largely on its ability to find, develop or acquire additional oil and gas reserves that are economically recoverable. Exploration and development drilling may not result in commercially productive reserves. Successful acquisitions require an assessment of a number of factors, many of which are uncertain. These factors include recoverable reserves, exploration potential, future oil and gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain.

Oil and gas drilling and producing operations are subject to many risks including the possibility of fire, explosions, mechanical failure, pipe failure, chemical spills, accidental flows of oil, natural gas or well fluids, sour gas releases, and other occurrences or accidents which could result in personal injury or loss of life, damage or destruction of properties, environmental damage, interruption of business, regulatory investigations and penalties and liability to third parties. The Company mitigates insurable risks to protect against significant losses by maintaining a comprehensive insurance program, while maintaining levels and amounts of risk within the Company which management believes to be acceptable. Talisman believes its liability, property and business interruption insurance is appropriate to its business and consistent with common industry practice, although such insurance will not provide coverage in all circumstances.

The Company's operations may be adversely affected by changes in governmental policies and legislation or social instability or other political or economic developments which are not within the control of Talisman including, among other things, a change in crude oil or natural gas pricing policy, the risks of war, terrorism, abduction, expropriation, nationalization, renegotiation or nullification of existing concessions and contracts, taxation policies, economic sanctions, the imposition of specific drilling obligations, the development and abandonment of fields, fluctuating exchange rates and currency controls. In addition, both Indonesia and Algeria are members of the Organization of Petroleum Exporting Countries. Accordingly, Talisman's operations in these countries may be impacted by the application of production quotas. Indonesia, Algeria and Colombia have been subject to recent economic or political instability and social unrest, military or rebel hostilities.

Talisman's financial performance is highly sensitive to prevailing prices of crude oil and natural gas. Fluctuations in crude oil or natural gas prices could have a material adverse effect on the Company's operations and financial condition and the value of its oil and natural gas reserves. Prices for crude oil and natural gas fluctuate in response to changes in the supply of and demand for crude oil and natural gas, market uncertainty and a variety of additional factors that are largely beyond the Company's control. A substantial and extended decline in the prices of crude oil or natural gas could result in delay or cancellation of drilling, development or construction programs, or curtailment in production or result in unutilized long-term transportation commitments all of which could have a material adverse impact on the Company. Talisman conducts an annual assessment of the carrying value of its assets in accordance with Canadian GAAP. If oil and natural gas prices decline, the carrying value of the Company's assets could be subject to downward revisions, which could adversely affect Talisman's reported income for the periods in which the revisions are made. However, Talisman believes that estimates of forward-looking prices it uses in its planning process are realistic.

Talisman's Consolidated Financial Statements are presented in Canadian dollars. Results of operations are affected primarily by the exchange rates between the Canadian dollar, the US dollar and the UK pound sterling. These exchange rates have varied substantially in the last five years. Most of the Company's revenue is received in or is referenced to US dollar denominated prices, while the majority of Talisman's expenditures are denominated in Canadian dollars, US dollars and UK pound sterling. A change in the relative value of the Canadian dollar against the US dollar would also result in an increase or decrease in our US dollar denominated debt, as expressed in Canadian dollars and the related interest expense.

All phases of the oil and natural gas business are subject to environmental regulation pursuant to a variety of laws and regulations in Canada, the UK, the US and other countries in which Talisman does business. These regulatory regimes are laws of general application that apply to the Company's business in the same manner as they apply to other companies or enterprises in the energy industry. Environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. Environmental legislation also requires that pipelines, wells, facility sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects, may require the submission and approval of environmental impact assessments or permit applications. Compliance with environmental legislation can require significant expenditures and failure to comply with environmental legislation may result in the imposition of fines and penalties and liability for clean up costs and damages. Additionally, the Company's business is subject to the trend toward increased civil liability for environmental matters. Although Talisman currently believes that the costs of complying with environmental legislation and dealing with environmental civil liabilities will not have a material adverse effect on the Company's financial condition or results of operations, there can be no assurance that such costs in the future will not have such an effect. Talisman expects to incur site restoration costs over a prolonged period as existing fields are depleted. The Company provides for future abandonment and reclamation costs in its Consolidated Financial Statements in accordance with Canadian GAAP. Additional information regarding future abandonment and reclamation costs is set forth in the notes to the annual Consolidated Financial Statements.

In 1994, the United Nations' Framework Convention on Climate Change came into force and three years later led to the Kyoto Protocol (the "Protocol") which requires, upon ratification, certain nations to reduce their emissions of carbon dioxide and other greenhouse gases. In December 2002, the Canadian federal government ratified the Protocol. If certain conditions are met and the Protocol enters into force internationally, *Canada will be required to reduce its greenhouse gas (GHG) emissions to* 6% below 1990 levels over the period beginning in 2008 and ending in 2012. Currently, Canadian oil and gas producers are in discussions with the provincial and federal levels of government regarding implementation mechanisms for the industry. It is premature to predict what impact implementation could have on Canadian oil and gas producers but it is likely that any mandated reduction in GHG emissions will result in increased costs. The federal government has stated that these costs would not be expected to exceed $15/tonne of carbon dioxide emissions reduced and that producers would not be required to reduce GHG emissions per unit of production by more than 15%. The federal government has also indicated its support for several important principles that are intended to protect the competitiveness of the oil and gas industry beyond 2012, including a 10-year emissions target lock-in period for all new projects and additional flexibility mechanisms for achieving compliance.

The UK has also ratified the Kyoto Protocol, with a reduction commitment of 12.5% below 1990 levels by 2008 – 2012. The UK Government, however, has set a more aggressive national goal of moving towards a 20% reduction in carbon dioxide emissions by 2010. Talisman's UK installations will participate in the first phase of the European Union Emission Trading Scheme ("EU ETS"), which runs from 2005 to 2007, inclusive. The UK Government's draft National Allocation Plan ("NAP") for the first phase of the EU ETS was published for broad consultation in January 2004. When finalized in September 2004, the NAP will dictate the total cap on carbon dioxide emissions for the covered sectors, the methods for allocating emission allowances to covered installations and the number of emission allowances to be allocated to each covered installation. Cost of compliance will vary with a number of factors including the final allocation numbers and liquidity of the carbon markets.

From time to time, Talisman is the subject of litigation arising out of the Company's operations. Damages claimed under such litigation, including the litigation discussed below, may be material or may be indeterminate and the outcome of such litigation may materially impact the Company's financial condition or results of operations. While Talisman assesses the merits of each lawsuit and defends itself accordingly, the Company may be required to incur significant expenses or devote significant resources to defending itself against such litigation. These claims are not currently expected to have a material impact on the Company's financial position.

Talisman continues to be subject to a lawsuit brought by the Presbyterian Church of Sudan and others under the Alien Tort Claims Act in the United States District Court for the Southern District of New York. The lawsuit, which is seeking class action status, alleges that the Company conspired with, or aided and abetted, the Government of Sudan to commit violations of international law in connection with the Company's now disposed of indirect interest in oil operations in Sudan. In July 2003, Talisman filed a motion to dismiss the lawsuit for lack of personal jurisdiction of the Court over Talisman. In August 2003, the plaintiffs filed a motion seeking certification of the case as a class action. Talisman is in the process of challenging this certification. No decision is expected on either of these motions prior to the third quarter of 2004. Talisman believes these claims to be entirely without merit and is continuing to vigorously defend itself against this lawsuit and does not expect this to have a material adverse effect.

Outlook for 2004

			Estimated for 2004	Actual 2003
Cash flow [1]			$2.2-2.8 billion	$2.7 billion
Cash flow per share [1]			$17-22	$21.21
Exploration and development spending (millions of dollars)	**Exploration**	**Development**	**Total**	**Total E&D**
North America	431	704	1,135	1,109
North Sea	119	487	606	496
Southeast Asia	62	253	315	316
Algeria	–	44	44	34
Trinidad	40	130	170	130
Other	85	–	85	95
	737	1,618	2,355	2,180
Production (daily average)		**Lower estimate**	**Upper estimate**	**Actual 2003**
Oil and liquids (bbls/d)				
North America		54,000	56,000	59,578
North Sea		109,000	122,000	113,075
Southeast Asia		33,000	38,000	24,430
Algeria		14,000	16,000	6,594
Sudan		–	–	13,039
		210,000	232,000	216,716
Natural gas (mmcf/d)				
North America		885	905	864
North Sea		120	130	109
Southeast Asia		225	240	117
		1,230	1,275	1,090
Barrel of oil equivalent (mboe/d)		415	445	398
Commodity price and exchange rate assumptions				
US$/bbl WTI oil price		25	30	30.99
US$/mmbtu NYMEX		4.75	5.50	5.44
C$/US$ exchange rate		0.77	0.73	0.71
C$/£ exchange rate		2.50	2.25	2.29

1 Cash flow and cash flow per share are considered to be non-GAAP financial measures. The estimate for 2004 is calculated using the same method as in 2003. A 2004 estimate of net income and net income per share has not been provided due to the inherent difficulties of estimating certain non-cash expenses, such as dry hole, property impairments and non-cash stock based compensation.

Talisman expects to increase production 4-12% in 2004. Production for 2004 is expected to average approximately 415,000-445,000 boe/d with a full year's production from the PM-3 CAA development and Algeria and increased North America natural gas production resulting from increased exploration and development spending and the impact of the recently completed infrastructure projects.

The Company expects cash flow per share of $17-22 in 2004 ($2.2-2.8 billion), assuming US$25-30/bbl WTI oil, US$4.75-5.50/mmbtu NYMEX gas and C$1=US$0.73-0.77. Unit operating costs are expected to increase by 5-10% largely due to an anticipated strengthening of the UK pound sterling against the Canadian dollar. However, unit production costs, in addition to being impacted by currency exchange rates are dependent on achieving expected production levels. Net capital spending is expected to be $2.35 billion and excludes significant corporate and asset acquisitions. The Company anticipates participating in the drilling of 640 North American and 118 international wells during 2004. Cash flow is expected to be sufficient to fund budgeted capital spending during 2004.

North America

Natural gas continues to be the focus of the Company's exploration activities in North America with a shift towards the remaining underdeveloped parts of the Western Canadian Sedimentary Basin supplemented by low risk oil projects. North American natural gas production in 2004 is expected to increase between 2-5% to average between 885-905 mmcf/d, while oil and liquids is expected to average 54,000-56,000 bbls/d, with the Company spending less than 30% of the North America budget on oil exploration and development. The Company expects to spend $1.1 billion on capital projects and drilling in 2004, up 2% from 2003. The Company plans to participate in approximately 640 wells in 2004, including 11 in Appalachia. Unit operating costs are expected to increase to slightly over $5/boe due to industry wide cost issues such as higher power and water handling charges.

North Sea

North Sea production is expected to average 109,000-122,000 bbls/d and 120-130 mmcf/d in 2004. The Company's North Sea strategy is to focus on development projects and adjacent exploration opportunities around core operated properties and infrastructure. Of the $606 million of planned capital spending, a 22% increase over 2003, 80% is related to development projects. Eight exploration and 25 development wells are planned for 2004. Total North Sea operating expenses are expected to increase in 2004 with the addition of Gyda and a strengthening of the pound sterling against the Canadian dollar. At current exchange rates (approximately £1=C$2.50) unit operating costs could be in the $14/boe range.

Southeast Asia

Natural gas sales in Indonesia have recently increased with new sales to Singapore and increased demand from Caltex. Indonesian natural gas sales are expected to average 135-140 mmcf/d in 2004. Discussions are currently underway to secure additional long-term gas sales in Southeast Asia to monetize Corridor's large existing natural gas reserves. An expansion of the gas plant facilities at Corridor PSC from 300-700 mmcf/d over the next three years is planned in order to accommodate additional anticipated gas sales. This plant expansion accounts for a majority of the planned capital spending of $65 million in Indonesia during 2004. Oil and liquids production in the Indonesian blocks is expected to average 12,000-13,000 bbls/d with natural decline.

With the startup of the PM-3 CAA development project, Talisman's oil and liquids production in Malaysia/Vietnam is expected to average between 21,000-25,000 bbls/d. Natural gas production from the project is expected to average 90-100 mmcf/d during 2004. Total Malaysia/Vietnam daily average production in 2004 is expected to exceed 36,000 boe/d, with an upper range of 42,000 boe/d.

Talisman's capital requirements in Malaysia/Vietnam are expected to fall in 2004 due to the commissioning of the PM-3 CAA development project in 2003. Total forecasted capital spending in Malaysia/Vietnam is expected to be $250 million and will be primarily focused on drilling 32 development wells in PM-3 CAA. Five exploration wells are also planned for 2004: three on PM-3 CAA and Block PM-305 and two on Block 46-02 offshore Vietnam. Development of the South Angsi discovery in Block PM-305, with first oil expected in 2005, will begin in 2004 with the drilling of two development wells and facilities fabrication.

Operating costs in Southeast Asia are expected to decrease to approximately $3/boe in 2004 with the higher anticipated volumes from PM-3 CAA and additional anticipated natural gas sales in Indonesia.

Algeria

Production from the Ourhoud and MLN fields in Algeria is expected to average 14,000-16,000 bbls/d. Operating costs are expected to fall to below $6/boe due to higher forecasted production. A capital budget of $44 million is estimated and includes drilling six wells in the Greater MLN area, 10 wells at Ourhoud and an expansion of the Greater MLN facility to increase production capacity.

Trinidad

Capital spending in Trinidad is budgeted at $170 million with the majority related to the completion of the Angostura oil and gas development project on offshore Block 2(c), including facilities construction and participation in drilling 15 development wells. First production is expected in early 2005. Talisman expects to participate in drilling four offshore exploration and appraisal wells, two each on Blocks 2(c) and 3(a). The Company expects to complete an onshore seismic program in the Eastern Block prior to drilling in 2005.

Other

The Company is actively exploring in Colombia where it expects to spend $28 million in 2004 to participate in one exploration well and acquire seismic. The Company drilled its first prospect in Alaska in early 2004 with a $15 million budget. The Company also plans to conduct a seismic program in Block 10 in Qatar and to continue technical evaluation of its acreage offshore East Coast Canada.

Economic Assumptions

Talisman's 2004 business plan was formulated on the assumption of US$25-30/bbl WTI oil and US$4.75-5.50/mmbtu NYMEX gas prices. The 2004 business plan also incorporates exchange rate assumptions of C$1=US$0.73-0.77 and £1=C$2.25-2.50.

Currently, Talisman has committed approximately 12% of its anticipated 2004 North American natural gas production under both commodity sales contracts and commodity price derivative contracts at an average price of $5/mcf. In addition, approximately 37% of the Company's 2004 anticipated oil and liquids production has been hedged with 56,000 bbls/d using collars with floor and ceiling prices averaging US$24-29/bbl and 23,000 bbls/d fixed at an average price of US$28/bbl.

A summary of the contracts outstanding at year end can be found in notes 9 and 10 of the Consolidated Financial Statements. Additional discussion of the Company's commodity price hedging program can be found in the MD&A section entitled 'Derivative Financial Instruments and Commodity Sales Contracts'.

Liquidity

An increase in the Company's 2004 year end net debt position is anticipated due to an expected softening of commodity prices, the debt refinancing of the redeemed US$150 million of preferred securities and an increase in planned capital spending. Significant acquisitions or dispositions, a change from expected commodity prices or the continuation of share repurchases would impact the Company's projected 2004 year end net debt position.

Sensitivities

Talisman's financial performance is affected by factors such as changes in production volumes, commodity prices and exchange rates. The estimated impact of these factors on the Company's 2004 financial performance is summarized in the following table and is based on a WTI oil price of US$30/bbl, a NYMEX natural gas price of US$5/mmbtu and exchange rates of C$1=US$0.76 and £1=C$2.50.

Approximate impact in 2004

(millions of dollars)	Net Income	Cash Flow[1]
Volume changes		
Oil – 1,000 bbls/d	4	7
Natural gas – 10 mmcf/d	6	13
Price changes[2]		
Oil – US$1.00/bbl	35	36
Natural gas (North America)[3] – C$0.10/mcf	15	21
Exchange rate changes		
US$ increased by US$0.01	24	38
£ increase by C$0.031	(8)	1

1 Cash flow is a non-GAAP measure, the components of which are set out in note 14 of the Consolidated Financial Statements.

2 The impact of commodity contracts outstanding for 2004 has been included.

3 Price sensitivity on natural gas relates to North American natural gas only. The Company's exposure to changes in North Sea and Malaysia/Vietnam natural gas prices is not material. Most of the Indonesia natural gas price is based on the price of crude oil and accordingly has been included in the price sensitivity for oil except for a small portion which is sold at a fixed price.

Summary of Quarterly Results

The following is a summary of quarterly results of the Company for the eight most recently completed quarters:

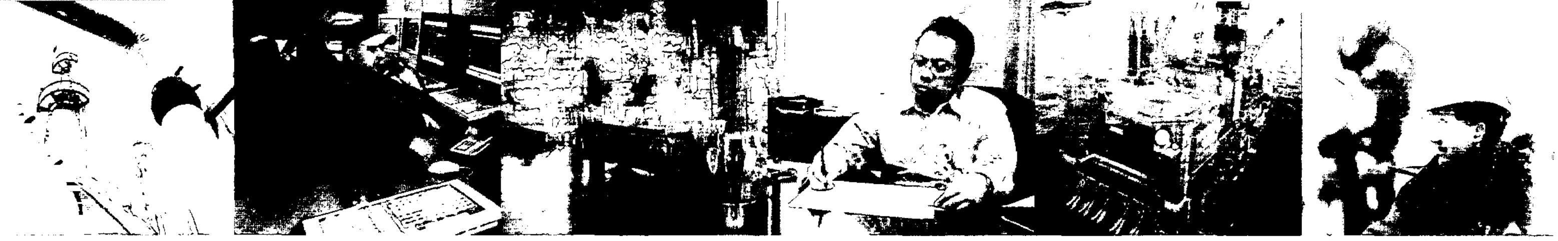
			Three months ended			
(millions of Canadian dollars, unless otherwise stated)		Total Year	Dec. 31	Sept. 30	June 30	March 31
2003	Total revenue	**4,477**	**1,097**	**1,047**	**993**	**1,340**
	Net income[1]	**1,007**	**107**	**126**	**201**	**573**
	Net income available to common shareholders	**985**	**102**	**120**	**196**	**567**
	Cash flow	**2,729**	**644**	**640**	**600**	**845**
	Total assets	**11,365**	**11,365**	**11,219**	**11,066**	**11,434**
	Total long-term liabilities	**5,188**	**5,188**	**5,240**	**5,119**	**5,617**
	Capital expenditures					
	Exploration	**784**	**221**	**215**	**165**	**183**
	Development	**1,396**	**437**	**360**	**327**	**272**
	Per common share (dollars)					
	Net income[1]	**7.65**	**0.80**	**0.94**	**1.52**	**4.37**
	Diluted net income	**7.57**	**0.78**	**0.92**	**1.50**	**4.32**
	Cash flow	**21.21**	**5.03**	**4.99**	**4.65**	**6.52**
	Daily average production					
	Oil and liquids (bbls/d)	**216,716**	**229,166**	**202,008**	**188,682**	**247,369**
	Natural gas (mmcf/d)	**1,090**	**1,138**	**1,064**	**1,061**	**1,096**
	Total (mboe/d)	**398**	**419**	**379**	**365**	**430**
2002	Total revenue	4,452	1,242	1,110	1,111	989
	Net income[1]	524	182	151	90	101
	Net income available to common shareholders	500	176	145	84	95
	Cash flow	2,645	759	657	652	577
	Total assets	11,594	11,594	11,471	10,996	11,032
	Total long-term liabilities	6,103	6,103	5,763	5,655	5,658
	Capital expenditures					
	Exploration	628	174	146	130	178
	Development	1,220	283	297	256	384
	Per common share (dollars)					
	Net income[1]	3.73	1.33	1.08	0.62	0.71
	Diluted net income	3.67	1.31	1.06	0.61	0.70
	Cash flow	19.73	5.72	4.87	4.84	4.31
	Daily average production					
	Oil and liquids (bbls/d)	272,740	270,582	267,393	275,157	277,971
	Natural gas (mmcf/d)	1,036	1,028	1,024	1,051	1,044
	Total (mboe/d)	445	442	438	450	452

1 Net income and net income before discontinued operations and extraordinary items are the same.

The following discussion highlights some of the more significant factors that impacted the net income in the eight most recently completed quarters.

In the first quarter of 2003, the gain on the sale of the Sudan operations increased net income by $296 million. The sale of these operations contributed to the drop in revenues during the following three quarters of 2003, which was partially offset by production increases in other areas and continued high commodity prices. Net income during the second quarter of 2003 was increased $160 million due to a reduction in the Canadian federal and provincial tax rates. The Company began recording stock-based compensation in the second quarter of 2003. The second quarter's net income was reduced by a $105 million ($70 million after tax) catch-up expense relating to outstanding stock options. The third and fourth quarters of 2003 included an additional $80 million ($50 million after tax) of stock-based compensation expense.

During the second quarter of 2002 the Company recorded a $128 million future tax expense related to an increase in UK corporate tax rates. Total revenue generally increased throughout the four quarters of 2002. A decrease in production primarily due to scheduled maintenance and other operational issues during the third and fourth quarters of 2002 was more than offset by higher commodity prices.



Financial Statements and Supplementary Information

Consolidated Financial Statements

Supplementary Information

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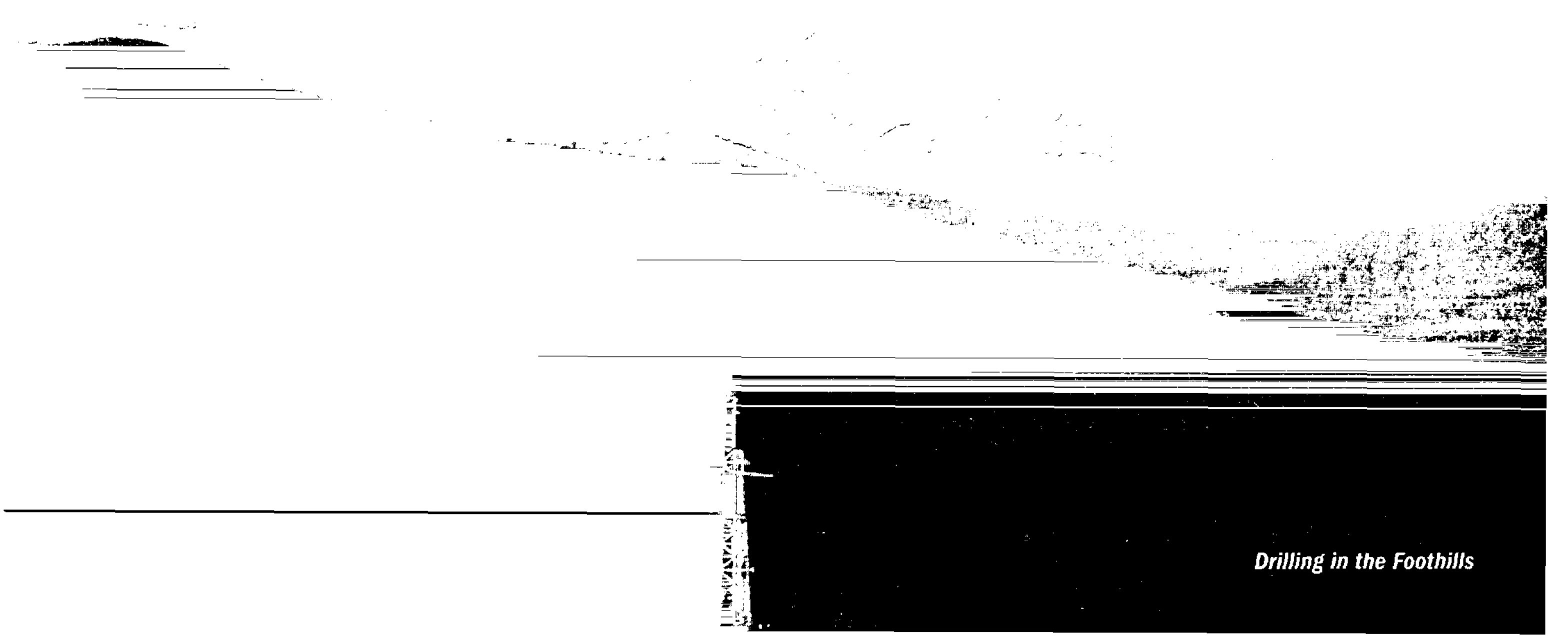
ADDITIONAL INFORMATION FOR US READERS

FINANCIAL

RESERVES

DETAILED PROPERTY REVIEWS



Drilling in the Foothills

Report of Management

The Board of Directors is responsible for the Consolidated Financial Statements but has delegated responsibility for their preparation to management.

Management has prepared the Consolidated Financial Statements in accordance with accounting principles generally accepted in Canada (with a reconciliation to accounting principles generally accepted in the United States). If alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has ensured that the Consolidated Financial Statements are presented fairly in all material respects. Management has also prepared the financial information presented elsewhere in the annual report and ensured that it is consistent with information in the Consolidated Financial Statements.

Talisman maintains internal accounting and administrative controls designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that assets are appropriately accounted for and adequately safeguarded.

The Board of Directors is responsible for reviewing and approving the Consolidated Financial Statements and Management's Discussion and Analysis and, primarily through its Audit Committee, ensures that management fulfills its responsibilities for financial reporting.

The Audit Committee is appointed by the Board and is composed entirely of unrelated, independent Directors. The Audit Committee meets regularly with management, and with the internal and external auditors, to discuss internal controls and reporting issues and to satisfy itself that each party is properly discharging its responsibilities. It reviews the Consolidated Financial Statements and the external auditors' report. The Audit Committee also considers, for review by the Board and approval by the shareholders, the engagement or reappointment of the external auditors.

Ernst & Young LLP, the external auditors, have audited the Consolidated Financial Statements in accordance with auditing standards generally accepted in Canada and the United States on behalf of the shareholders. Ernst & Young LLP have full and free access to the Audit Committee.

James W. Buckee
President and Chief Executive Officer

Michael D. McDonald
Executive Vice-President, Finance and Chief Financial Officer

February 27, 2004

Auditors' Report

To the Shareholders of Talisman Energy Inc.

We have audited the Consolidated Balance Sheets of Talisman Energy Inc. as at December 31, 2003 and 2002 and the Consolidated Statements of Income, Retained Earnings and Cash Flows for each of the years in the three year period ended December 31, 2003. These financial statements are the responsibility of the Company'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 and US 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 the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2003 in accordance with Canadian generally accepted accounting principles. We also report that, in our opinion, these principles have been applied, except for the change in the method of accounting for goodwill as explained in note 1(o) to the Consolidated Financial Statements, on a basis consistent with that of the preceding year.

Ernst & Young LLP

Calgary, Canada
February 27, 2004

Ernst & Young LLP
Chartered Accountants

Consolidated Balance Sheets

(December 31)

(millions of Canadian dollars)	**2003**	2002
Assets		
Current		
Cash and cash equivalents	**98**	27
Accounts receivable	**760**	719
Inventories (note 3)	**100**	147
Prepaid expenses	**17**	24
	975	917
Accrued employee pension benefit asset (note 16)	**63**	67
Other assets	**76**	99
Goodwill (note 2)	**473**	469
Property, plant and equipment (note 4)	**9,778**	10,042
	10,390	10,677
Total assets	**11,365**	11,594
Liabilities		
Current		
Accounts payable and accrued liabilities	**1,064**	803
Income and other taxes payable	**154**	186
	1,218	989
Deferred credits	**57**	57
Provision for future site restoration (note 10)	**840**	813
Long-term debt (note 5)	**2,203**	2,997
Future income taxes (note 13)	**2,088**	2,236
	5,188	6,103
Contingencies and commitments (note 10)		
Shareholders' equity		
Preferred securities (note 6)	**431**	431
Common shares (note 7)	**2,725**	2,785
Contributed surplus	**73**	75
Cumulative foreign currency translation (note 8)	**(114)**	140
Retained earnings	**1,844**	1,071
	4,959	4,502
Total liabilities and shareholders' equity	**11,365**	11,594

See accompanying notes.

On behalf of the board:

Douglas D. Baldwin
Chairman of the Board

Dale G. Parker
Director

Consolidated Statements of Income
(Years ended December 31)

(millions of Canadian dollars)	**2003**	2002	2001
Revenue			
Gross sales	**5,295**	5,299	5,047
Less royalties	**894**	927	989
Net sales	**4,401**	4,372	4,058
Other (note 11)	**76**	80	82
Total revenue	**4,477**	4,452	4,140
Expenses			
Operating	**1,099**	1,115	946
General and administrative	**152**	138	108
Depreciation, depletion and amortization	**1,443**	1,495	1,313
Dry hole	**251**	174	113
Exploration	**213**	185	147
Interest on long-term debt	**137**	164	139
Stock-based compensation (note 7)	**185**	–	–
Other (note 12)	**16**	113	78
Total expenses	**3,496**	3,384	2,844
Gain on sale of Sudan operations (note 17)	**296**	–	–
Income before taxes	**1,277**	1,068	1,296
Taxes (note 13)			
Current income tax	**229**	258	342
Future income tax (recovery)	**(51)**	162	72
Petroleum revenue tax	**92**	124	149
	270	544	563
Net income	**1,007**	524	733
Preferred security charges, net of tax	**22**	24	24
Net income available to common shareholders	**985**	500	709
Per common share (Canadian dollars) (note 15)			
Net income	**7.65**	3.73	5.25
Diluted net income	**7.57**	3.67	5.16
Average number of common shares outstanding (millions)	**129**	134	135
Diluted number of common shares outstanding (millions)	**130**	136	137

See accompanying notes.

Consolidated Statements of Retained Earnings
(Years ended December 31)

(millions of Canadian dollars)	**2003**	2002	2001
Retained earnings, beginning of year	**1,071**	787	257
Net income	**1,007**	524	733
Common share dividend	**(90)**	(80)	(81)
Purchase of common shares	**(122)**	(136)	(98)
Preferred security charges, net of tax	**(22)**	(24)	(24)
Retained earnings, end of year	**1,844**	1,071	787

See accompanying notes.

Consolidated Statements of Cash Flows

(Years ended December 31)

(millions of Canadian dollars)	**2003**	2002	2001
Operating			
Net income	**1,007**	524	733
Items not involving current cash flow (note 14)	**1,509**	1,936	1,614
Exploration	**213**	185	147
Cash flow	**2,729**	2,645	2,494
Deferred gain on unwound hedges	**(9)**	(43)	52
Changes in non-cash working capital (note 14)	**(104)**	(163)	(177)
Cash provided by operating activities	**2,616**	2,439	2,369
Investing			
Corporate acquisitions (note 2)	**–**	–	(1,213)
Proceeds on sale of Sudan operations (note 17)	**1,012**	–	–
Capital expenditures			
Exploration, development and corporate	**(2,218)**	(1,874)	(1,912)
Acquisitions (note 2)	**(661)**	(244)	(186)
Proceeds of resource property dispositions	**63**	30	47
Investments	**(11)**	(36)	–
Changes in non-cash working capital	**82**	2	52
Cash used in investing activities	**(1,733)**	(2,122)	(3,212)
Financing			
Long-term debt repaid	**(791)**	(1,397)	(568)
Long-term debt issued	**292**	1,417	1,617
Common shares purchased (net of proceeds on shares issued)	**(184)**	(184)	(117)
Common share dividends	**(90)**	(80)	(81)
Preferred security charges	**(38)**	(42)	(42)
Deferred credits and other	**27**	(21)	(25)
Cash (used in) provided by financing activities	**(784)**	(307)	784
Effect of translation on foreign currency cash	**(28)**	–	–
Net increase (decrease) in cash	**71**	10	(59)
Cash and cash equivalents, beginning of year	**27**	17	76
Cash and cash equivalents, end of year	**98**	27	17

See accompanying notes.

1. Significant Accounting Policies

The Consolidated Financial Statements of Talisman Energy Inc. ("Talisman" or the "Company") have been prepared by management in accordance with Canadian generally accepted accounting principles. A summary of the differences between accounting principles generally accepted in Canada and those generally accepted in the United States ("US") is contained in note 19 to these statements.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

a) Consolidation

The Consolidated Financial Statements include the accounts of Talisman and its subsidiaries. A substantial portion of Talisman's activities is conducted jointly with others and the Consolidated Financial Statements reflect only the Company's proportionate interest in such activities.

b) Inventories

Product inventories are valued at the lower of average cost and market value. Materials and supplies are valued at the lower of average cost and net realizable value.

c) Property, plant and equipment

The successful efforts method is used to account for oil and gas exploration and development costs. Under this method, acquisition costs of oil and gas properties and costs of drilling and equipping development wells are capitalized. Costs of drilling exploratory wells are initially capitalized and, if subsequently determined to be unsuccessful, are charged to dry hole expense. All other exploration costs, including geological and geophysical costs and annual lease rentals, are charged to exploration expense when incurred. Producing properties and significant unproved properties are assessed annually, or more frequent as economic events dictate, for potential impairment. Any impairment loss is the difference between the carrying value of the asset and its net recoverable amount (undiscounted).

d) Depreciation, depletion and amortization

Capitalized costs of proved oil and gas properties are depleted using the unit of production method. For purposes of these calculations, production and reserves of natural gas are converted to barrels on an energy equivalent basis.

Successful exploratory wells and development costs are depleted over proved developed reserves while acquired resource properties with proved reserves, including offshore platform costs, are depleted over proved reserves. Acquisition costs of probable reserves are not depleted or amortized while under active evaluation for commercial reserves. Costs are transferred to depletable costs as proved reserves are recognized. At the date of acquisition, an evaluation period is determined after which any remaining probable reserve costs associated with producing fields are transferred to depletable costs; costs not associated with producing fields are amortized over a period not exceeding the remaining lease term.

Costs associated with significant development projects are not depleted until commercial production commences. Unproved land acquisition costs that are individually immaterial are amortized on a straight-line basis over the average lease term until properties are determined to be productive or impaired. Gas plants, net of estimated salvage values, are depreciated on a straight-line basis over their estimated remaining useful lives, not to exceed the estimated remaining productive lives of related fields. Pipelines and corporate assets are depreciated using the straight-line method at annual rates of 7% and 4% to 33%, respectively.

e) Future site restoration

Estimated costs of future dismantlement, site restoration and abandonment of oil and gas properties, including offshore production platforms, are provided for using the unit of production method while those of gas plants and facilities are provided for using the straight-line method at rates approximating their useful lives but not exceeding the estimated remaining productive lives of related fields. The annual provision is included within depletion, depreciation and amortization expense and is based on engineering estimates and in accordance with existing legislation and industry practice. Expenditures are charged against the accumulated provision as incurred. When a property is disposed of, the associated accumulated provision is eliminated and included in determination of the gain or loss on disposal.

f) Capitalized Interest

Interest costs associated with major development projects are capitalized until the necessary facilities are completed and ready for use.

g) Royalties

Certain of the Company's foreign operations are conducted jointly with the respective national oil companies. These operations are reflected in the Consolidated Financial Statements based on Talisman's working interest in such activities. All other government stakes, other than income taxes, are considered to be royalty interests. Royalties on production from these joint foreign operations represent the entitlement of the respective governments to a portion of Talisman's share of crude oil, liquids and natural gas production and are recorded using rates in effect under the terms of contracts at the time of production.

h) Petroleum Revenue Tax

United Kingdom Petroleum Revenue Tax ("PRT") is accounted for using the life of the field method whereby total future PRT is estimated using current reserves and anticipated costs and prices and charged to income based on net operating income as a proportion of estimated future net operating income. Changes in the estimated total future PRT are accounted for prospectively.

i) Foreign currency translation

Effective January 1, 2002, the Company adopted the US dollar as its functional currency. Prior to January 1, 2002, the functional currency of the Company was the Canadian dollar. The Company's financial results have been reported in Canadian dollars as explained below.

The Company's self-sustaining operations, which include the Canadian and UK operations, are translated into US dollars using the current rate method, whereby assets and liabilities are translated at period-end exchange rates while revenues and expenses are converted using average rates for the period. Gains and losses on translation to US dollars relating to self-sustaining operations are deferred and included in a separate component of shareholders' equity described as cumulative foreign currency translation.

The remaining foreign operations are not considered self-sustaining and are translated using the temporal method. Under this method, monetary assets and liabilities denominated in foreign currencies are translated at exchange rates in effect at the balance sheet date. Non-monetary assets and liabilities denominated in foreign currencies are translated at rates in effect on the dates the assets were acquired or liabilities were assumed. Revenues and expenses are translated at rates of exchange prevailing on the transaction dates. Gains and losses on translation are reflected in income when incurred.

The Company's financial results have been reported in Canadian dollars with amounts translated to Canadian dollars as follows: assets and liabilities at the rate of exchange in effect at the applicable balance sheet date and revenues and expenses at the average exchange rates for the periods. The Company's share capital accounts including its preferred securities, common shares and contributed surplus are translated at rates in effect at the time of issuance. Unrealized gains and losses resulting from the translation to Canadian dollars are included in the cumulative foreign currency translation account.

j) Employee benefit plans

The cost of pensions and other retirement benefits earned by employees is determined using the projected benefit method prorated on service and management's best estimate of expected plan investment performance, salary escalation and retirement ages of employees. There is uncertainty relating to the assumptions used to calculate the net benefit plan expense and accrued benefit obligation which are long term, consistent with the nature of employee future benefits.

The discount rate used to determine the accrued benefit obligation is determined by reference to market interest rates at the measurement date on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. For purposes of calculating the expected return on plan assets, those assets are valued at fair value. The excess of the net actuarial gain or loss over 10% of the greater of the accured benefit obligation and the fair value of plan assets at the beginning of the year is amortized over the average remaining service life of active employees. The transitional asset and obligations are being amortized over the average remaining service period of active employees expected to receive benefits under the benefit plans.

k) Derivative financial instruments and commodity contracts

The Company may enter into derivative financial instruments to hedge against adverse fluctuations in foreign exchange rates, electricity rates, interest rates and commodity prices. Payments or receipts on derivative financial instruments that are designated and effective as hedges are recognized in income concurrently with the hedged transaction and are recorded in the consolidated statements of income and cash flows in the line item associated with the hedged transaction. For example, gains and losses on commodity hedges are included in revenues.

If the derivative financial instrument that has been designated as a hedge is terminated or is no longer designated as part of the hedging relationship, the gain or loss at that date is deferred and recognized concurrently with the anticipated transaction. If it is no longer probable that the anticipated transaction will occur substantially as and when identified at the inception of the hedging relationship, the gain or loss at that date is recognized immediately. Subsequent changes in the value of the derivative financial instrument are reflected in income. Any derivative financial instrument that does not constitute a hedge is recorded at fair value with any resulting gain or loss reflected in income.

All of the Company's derivative financial instruments outstanding during 2003 met the hedging requirements under Canadian GAAP. The hedging requirements as amended by AcG 13, consist of the designation of the instrument as a hedge, the identification of the nature of the risk exposure being hedged and that there is reasonable assurance that the instrument is expected to be an effective hedge throughout its term. In addition, in the case of anticipated transactions, it is also probable that the transaction designated as being hedged will occur. The Company assesses, both at the hedge's inception and on an ongoing basis, whether the derivative financial instruments that have been designated as hedges are highly effective in offsetting changes in fair value or cash flows of the hedged items.

The Company enters into commodity contracts in the normal course of business including contracts with fixed or optional pricing terms. The contracts outstanding at December 31, 2003 are disclosed in note 9. The Company's production is expected to be sufficient to deliver all required volumes under these contracts. No amounts are recognized in the Consolidated Financial Statements related to these contracts until such time as the associated volumes are delivered.

l) Income taxes

Talisman uses the liability method to account for income taxes. Under the liability method, future income taxes are based on the differences between assets and liabilities reported for financial accounting purposes from those reported for income tax. Future income tax assets and liabilities are measured using substantively enacted tax rates. The impact of a change in tax rate is recognized in net income in the period in which the tax rate is substantively enacted.

Certain of the Company's contractual arrangements in foreign jurisdictions stipulate that income taxes are to be paid by the respective national oil company out of its entitlement share of production. Such amounts are included in income tax expense at the statutory tax rate in effect at the time of production.

m) Revenue recognition

Revenues associated with the sale of crude oil, natural gas and liquids represents the sales value of the Company's share of petroleum production during the year (the entitlement method). Differences between production and amounts sold are not significant. Amounts received under take-or-pay gas sales contracts in respect of undelivered volumes are accounted for as deferred income.

n) Stock-based compensation

Talisman has stock option and cash unit plans for employees and directors, which are described in note 7. In 2003, the option plans were amended to provide holders of stock options the choice upon exercise to receive a cash payment in exchange for surrendering the option. Commencing in 2003, as a result of the amendment to the stock option plans, the Company began recording stock-based compensation expense based on the appreciated value of the outstanding stock options and cash units as determined using the period end closing share price.

A liability for the stock-based compensation is included in accounts payable and accrued liabilities.

o) Goodwill

Goodwill represents the excess purchase price over the fair value of identifiable assets and liabilities acquired in business combinations. Effective January 1, 2002, goodwill ceased to be amortized. Goodwill amortization of $10 million was expensed in 2001. Goodwill is subject to ongoing annual impairment reviews, or more frequent as economic events dictate, based on the fair value of reporting units. The fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's individual assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount. The Company's reporting units are consistent with the geographic segments included in note 18.

p) Net income and diluted net income per share

Net income per share is calculated by dividing net income after deducting preferred security charges, net of tax, by the weighted average number of common shares outstanding. Diluted net income per share is calculated giving effect to the potential dilution that could occur if convertible instruments, such as stock options, were exercised in exchange for common shares.

The Company uses the treasury method to determine the dilutive impact of convertible instruments. This method assumes that any proceeds from the exercise of a convertible instrument would be used to purchase common shares at the average market price during the period.

q) Cash and cash equivalents

Cash and cash equivalents include short-term investments with an original maturity of three months or less.

2. Acquisitions

The following acquisitions have been accounted for using the purchase method and the results have been included in these Consolidated Financial Statements from the date of acquisition.

Significant Corporate Acquisitions

Petromet Resources Limited

In May 2001, Talisman acquired Petromet Resources Limited ("Petromet"), an oil and gas exploration and development company, for $765 million and long-term debt assumed of $57 million.

Net Assets Acquired	
Property, plant and equipment	795
Goodwill	301
Net non-cash working capital	(6)
Future income tax	(264)
	826
Less acquisition costs	(4)
	822

Lundin Oil AB

In August 2001, Talisman acquired Lundin Oil AB ("Lundin"), an oil and gas exploration and development company, for $431 million (net of cash on hand) and long-term debt assumed of $70 million.

Net Assets Acquired	
Property, plant and equipment	515
Goodwill	176
Net non-cash working capital	(19)
Future income tax	(158)
	514
Less acquisition costs	(13)
	501

Other Acquisitions

During 2003, Talisman completed a number of individually insignificant oil and gas property and corporate acquisitions for a total cost of $768 million, comprised of $661 million in cash, $70 million of assumed debt and working capital deficiency and $37 million of properties exchanged. Four of the transactions account for the majority of the acquisitions and were acquired for a total cost of $626 million. These four acquisitions included oil and gas properties in North America and the North Sea and a company with midstream assets in North America.

Net assets acquired	North America	North Sea	Combined
Property, plant and equipment	541	112	653
Goodwill	–	31	31
Future income tax	(27)	(31)	(58)
	514	112	626

Goodwill Continuity

	2003	2002	2001
Opening balance at January 1	**469**	467	–
Acquired during year	**31**	–	477
Amortization	**–**	–	(10)
Foreign currency translation	**(27)**	2	–
Closing balance at December 31	**473**	469	467

Effective January 1, 2002 goodwill ceased to be subject to amortization.

3. Inventories

December 31	**2003**	2002
Materials and supplies	**95**	143
Product	**5**	4
	100	147

4. Property, Plant and Equipment

December 31, 2003	Cost	Accumulated DD&A	Net book value
Oil and gas properties	**10,426**	**4,774**	**5,652**
Gas plants, pipelines and production equipment	**5,860**	**1,813**	**4,047**
Corporate assets	**242**	**163**	**79**
	16,528	**6,750**	**9,778**
December 31, 2002			
Oil and gas properties	10,198	4,264	5,934
Gas plants, pipelines and production equipment	5,576	1,547	4,029
Corporate assets	213	134	79
	15,987	5,945	10,042

In the year ended December 31, 2003, interest costs of $24 million (2002 – $25 million, 2001 – $19 million) were capitalized.

Included in property, plant and equipment are the following costs that were not subject to depreciation, depletion or amortization ("DD&A") as at December 31:

Non-depleted capital at December 31	**2003**	2002
Acquired probable reserve costs [1]		
North America – associated with producing fields	**140**	102
North Sea – not associated with producing fields	**14**	13
Southeast Asia – not associated with producing fields	**–**	39
Exploration costs [2]	**283**	353
Development projects [3]		
Southeast Asia	**265**	437
North Sea	**17**	44
Algeria	**39**	175
Trinidad	**108**	30
	866	1,193

1 Acquisition costs of probable reserves are not depleted or amortized while under active evaluation for commercial reserves.
2 Exploration costs consist of drilling in progress and wells awaiting determination of proved reserves, approval of development plans or commencement of production.
3 Development projects are not depleted pending initial production.

The carrying values of property, plant and equipment, including acquired probable reserve costs, are subject to uncertainty associated with the quantity of oil and gas reserves, future production rates, commodity prices and other factors. Future events could result in material changes to the carrying values recognized in the Consolidated Financial Statements.

5. Long-Term Debt

December 31	**2003**	2002
Bank Credit Facilities [1]		
Bank Credit Facilities (2002 – 3.32%)	**–**	265
Debentures and Notes (Unsecured) [3]		
6.625% notes (£250 million), due 2017 [5]	**471**	576
7.25% debentures (US$300 million), due 2027	**388**	474
5.80% medium term notes, due 2007	**385**	385
6.96% notes (US$200 million), due 2005	**258**	316
7.125% debentures (US$175 million), due 2007	**226**	276
5.70% medium term notes, due 2003	**–**	180
8.06% medium term notes, due 2009	**174**	174
6.68% notes (US$100 million), due 2008	**129**	158
6.89% notes (US$50 million), Series B, due 2006 [4]	**65**	79
9.80% debentures, Series B, due 2004 [2]	**75**	75
6.71% notes (US$25 million), Series A, due 2004 [2]	**32**	39
	2,203	2,997

1 Rates reflect the weighted-average interest rate of instruments outstanding at December 31. Rates are floating rate-based and vary with changes in short-term market interest rates.
2 The amounts outstanding at December 31, 2003 have been classified as long-term debt since the Company has the ability and intention to replace the current portions with long-term borrowings under the revolving bank credit facilities.
3 Interest on debentures and notes is payable semi-annually except for interest on the 6.625% notes (£250 million) which is payable annually.
4 Repayable in five equal annual installments commencing 2006.
5 The £250 million Eurobond has been effectively swapped into a US$364 million indebtedness with floating interest payments based on three-month US LIBOR with an effective interest rate of 2.07% at December 31, 2003 (see note 9).

Bank Credit Facilities

Talisman has unsecured credit facilities totaling $1,135 million, consisting of facilities of $405 million ("Facility No. 1"), $530 million ("Facility No. 2"), $150 million ("Facility No. 3") and $50 million ("Facility No. 4"). The maturity date of Facility No. 1 is March 23, 2006, although this date may be extended from time to time upon agreement between the Company and the respective lenders. Prior to the maturity date, the Company may borrow, repay and reborrow at its discretion. The term dates of Facility Nos. 2, 3 and 4 are March 16, 2004, August 23, 2004 and November 24, 2004, respectively. Until each term date, the Company may borrow, repay and reborrow at its discretion. Annually, upon agreement between the Company and the respective lenders, each term date may be extended for an additional 364 days. Facility No. 2 expires two years after its term date and, if the term is not extended, must be repaid on the maturity date. Facility Nos. 3 and 4 expire one year after their term dates and, if the terms are not extended, must be repaid on the maturity date.

Borrowings under Facility Nos. 1 and 2 are available in the form of prime loans, Canadian or US dollar bankers' acceptances, US dollar base rate loans or LIBOR-based loans. In addition, drawings to a total of $467 million may be made by letters of credit. Borrowings under Facility No. 3 are available in the form of prime loans, Canadian or US dollar bankers' acceptances, US dollar base rate loans, LIBOR-based loans and letters of credit. Borrowings under Facility No. 4 are available in the form of prime loans, Canadian or US dollar guaranteed notes, US dollar base rate loans and LIBOR-based loans.

Repayment Schedule

The Company's contractual minimum repayments of long-term debt in the next five years are as follows:

Year	
2004 [1]	107
2005	258
2006	13
2007	624
2008	142
Subsequent to 2008	1,059
Total	2,203

1 The portion of long-term debt payable in 2004 has been classified as long-term debt since the Company has the ability and intention to replace the current portion with long-term borrowings under the revolving bank credit facilities.

6. Preferred Securities

During 1999, Talisman issued 12 million preferred securities ("securities") as unsecured junior subordinated debentures, at US$25 per security, of which six million 9% securities are due February 15, 2048 and six million 8.9% securities are due June 15, 2048. The securities are redeemable, in whole or in part, at par by Talisman through the payment of cash or issuance of common shares at any time on or after February 15, 2004 and June 15, 2004, respectively. The Company has the option to defer the payment of the security charges for up to 20 consecutive three-month periods and satisfy such deferred security charges with either cash or the issuance of common shares. Security charges are due quarterly.

In December 2003, the Company announced its intention to exercise its right to redeem the outstanding six million 9% securities for US$150 million. The difference between the carrying amount of the redeemed securities and the cost of the redemption will be credited directly to retained earnings.

7. Share Capital

Talisman's authorized share capital consists of an unlimited number of common shares without nominal or par value and first and second preferred shares. No preferred shares have been issued.

Continuity of common shares	**2003**		2002		2001	
	Shares	**Amount**	Shares	Amount	Shares	Amount
Balance, beginning of year	**131,039,435**	**2,785**	133,733,182	2,831	135,344,045	2,849
Issued on exercise of options	**294,893**	**11**	1,154,067	36	1,512,898	49
Purchased during year	**(3,335,600)**	**(71)**	(3,847,500)	(82)	(3,036,400)	(65)
Cancelled pursuant to terms of plans of arrangements	**–**	**–**	(314)	–	(87,361)	(2)
Balance, end of year	**127,998,728**	**2,725**	131,039,435	2,785	133,733,182	2,831

During the year ended December 31, 2003, Talisman repurchased 3,335,600 common shares of the Company pursuant to a normal course issuer bid for a total of $194 million (2002 – $220 million; 2001 – $166 million). The cost to repurchase common shares in excess of their average book value has been charged to retained earnings, contributed surplus and cumulative foreign currency translation. In 2001, Talisman cancelled 87,361 common shares of the Company pursuant to the terms of the offering agreements of certain past corporate acquisitions. As a result of the cancellation of these shares, $2 million was credited to contributed surplus. An additional 314 common shares were cancelled in 2002.

Stock Option Plans

Talisman has stock option plans that allow employees and directors to receive options to purchase common shares of the Company. Options granted under the plans are generally exercisable after three years and expire 10 years after the grant date. Option exercise prices approximate the market price for the common shares on the date the options are granted.

Effective 2003, the stock option plans were amended to provide option holders the choice upon exercise to receive a cash payment in exchange for surrendering the option. The cash payment is equal to the appreciated value of the stock option as determined based on the difference between the option's exercise price and the Company's share price at the time of surrender. As a result, in accordance with the accounting policy described in note 1(n), the Company's 2003 results included a $105 million ($74 million, or $0.57/share, net of tax) stock-based compensation expense relating to the appreciated value of the Company's outstanding stock options and cash units at June 30, 2003. The total stock-based compensation expense for the year was $185 million ($130 million, net of tax) including $80 million during the second half of 2003 due to the appreciation of the Company's stock price during the period July 1 to December 31. Additional stock-based compensation expense or recoveries in future periods is dependent on the movement of the Company's share price and the number of outstanding options and cash units.

The following table provides pro forma measures of net income and net income per common share had stock options been recognized as compensation expense based on the estimated fair value of the options on the grant date.

	2003	2002	2001
Net income as reported	**1,007**	524	733
Stock-based compensation expensed	**105**	–	–
Net income before stock-based compensation	**1,112**	524	733
Stock option expense based on fair market value	**21**	31	24
Pro forma net income [1]	**1,091**	493	709
Pro forma net income per share [1]			
Basic	**8.31**	3.50	5.08
Diluted	**8.21**	3.44	4.99

1 Pro forma net income and net income per share had stock options been recognized as compensation expense based on the estimated fair value of the options on the grant date.

Stock options granted in 2003 had an estimated weighted-average fair value of $22.91 per option (2002 – $26.19 per option; 2001 – $22.80 per option). All options issued by the Company permit the holder to purchase one common share of the Company at the stated exercise price, or effective 2003, to receive a cash payment equal to the appreciated value of the stock option.

The estimated fair value of stock options issued was determined using the Black-Scholes model using the following weighted-average assumptions:

	2003	2002	2001
Risk-free interest rate (%)	**4.1**	5.1	4.9
Estimated hold period prior to exercise (years)	**5.3**	5.4	5.3
Volatility in the price of the Company's common shares (%)	**40**	41	39
Dividends ($/share)	**0.60**	0.60	0.60

Continuity of stock options	**2003**		2002		2001	
	Number of Options	**Average Exercise Price**	Number of Options	Average Exercise Price	Number of Options	Average Exercise Price
Outstanding at January 1	**7,384,054**	**46.53**	7,497,611	41.49	6,854,806	33.84
Granted	**2,394,699**	**59.48**	1,100,710	64.73	2,301,828	58.39
Exercised for common shares	**294,893**	**33.81**	1,154,067	30.54	1,512,898	32.19
Exercised for cash payment	**1,420,237**	**35.51**	–	–	–	–
Forfeited	**196,540**	**58.88**	59,150	57.53	146,125	45.24
Expired	**551**	**30.53**	1,050	57.88	–	–
Outstanding at December 31	**7,866,532**	**52.64**	7,384,054	46.53	7,497,611	41.49
Exercisable at December 31	**2,580,955**	**37.38**	3,142,629	34.34	3,246,985	35.87
Options available for future grants pursuant to the Company's Stock Option Plans	**4,678,518**		3,155,889		4,196,399	

The range of exercise prices of the Company's outstanding stock options is as follows:

December 31, 2003	Outstanding Options			Exercisable Options	
Range of Exercise Prices	Number of Options	Weighted Average Exercise Price	Weighted Average Years to Expiry	Number of Options	Weighted Average Exercise Price
$24.25 to $29.99	672,555	25.62	4	672,555	25.62
$30.00 to $39.99	814,305	36.80	5	814,305	36.80
$40.00 to $49.99	932,000	42.25	4	932,000	42.25
$50.00 to $59.99	4,262,362	58.88	8	92,145	58.24
$60.00 to $68.36	1,185,310	64.55	8	69,950	64.73
$24.25 to $68.36	7,866,532	52.64	7	2,580,955	37.38

At December 31, 2003, 12,545,050 common shares were reserved for issuance related to the stock option plans.

Cash Units

In addition to the Company's stock option plans, Talisman's subsidiaries during 2003 issued 384,505 cash units with an average exercise price of $59.48/cash unit to certain employees. Cash units are similar to stock options except that the holder does not have a right to purchase the underlying share of the Company.

8. Cumulative Foreign Currency Translation

In accordance with the Company's foreign exchange translation accounting policy, as disclosed in note 1(i), foreign exchange gains or losses on translation of self-sustaining operations and the translation of the Company's financial results into Canadian dollars for reporting purposes are included in shareholders' equity in the cumulative foreign currency translation account.

The following components give rise to the exchange gains or (losses) included in the cumulative foreign currency translation account as at December 31:

	2003	2002
Property, plant and equipment	**(443)**	220
Future tax liabilities (including PRT)	**37**	(47)
Provision for site restoration	**(4)**	(71)
Long-term debt	**341**	13
Working capital	**(20)**	23
Goodwill	**(25)**	2
	(114)	140

9. Financial Instruments

Financial contracts

The Company entered into natural gas and crude oil price derivative contracts to reduce the volatility of the Company's cash flows associated with anticipated natural gas and crude oil sales. The amounts shown below are the weighted-average of the contracts outstanding.

Natural gas derivative contracts

Fixed price swaps (NYMEX)	2004	Two-way collars (AECO)	2004
Volumes (mcf/d)	48,400	Volumes (mcf/d)	6,900
Price ($/mcf)	5.91	Ceiling ($/mcf)	9.55
		Floor ($/mcf)	6.81

Crude oil derivative contracts

Fixed price swaps	2004	2005	Two-way collars	2004
(WTI oil index)			(WTI oil index)	
Volumes (bbls/d)	12,000	6,000	Volumes (bbls/d)	25,000
Price (US$/bbl)	29.20	26.97	Ceiling price (US$/bbl)	28.90
			Floor price (US$/bbl)	25.08
(Brent oil index)			(Brent oil index)	
Volumes (bbls/d)	11,000		Volumes (bbls/d)	31,000
Price (US$/bbl)	26.08		Ceiling price (US$bbl)	26.61
			Floor price (US&/bbl)	23.56

Interest rates

In December 1994, in anticipation of issuing the US$175 million 7.125% debentures, Talisman entered into interest rate swap contracts to hedge against possible adverse interest rate fluctuations. These contracts result in Talisman paying interest at a rate of 8.295% in exchange for receiving the three-month LIBOR rate on notional principal of US$100 million until May 16, 2005. Based on the LIBOR rate at December 31, 2003, these contracts result in an effective rate of interest on the debentures of 11.2%. Effective January 1, 2004 these contracts are no longer designated as hedges of the debentures. The accumulative loss on these contracts at December 31, 2003 will be deferred and amortized into income over their remaining term.

Cross currency and interest rate swaps

The Company had designated its US dollar cross currency and interest rate swap contracts outstanding during 2003 as hedges of the £250 million Eurobond. This in effect converted the Eurobond to US$364 million with a floating interest rate based on three-month US LIBOR. Effective January 1, 2004, these swap contracts are no longer designated as hedges of the Eurobond. The accumulative gain on these contracts at December 31, 2003 will be deferred and amortized into income over the original term of the swap contracts. Subsequent to year end, the Company terminated contracts totaling a nominal amount of £190 million for proceeds of $108 million. The remaining contracts expire December 5, 2009.

Carrying Amounts and Estimated Fair Values of Financial Instruments

Asset (liability) at December 31	**2003**			2002		
	Carrying Value	**Fair Value**	**Unrecognized**	Carrying Value	Fair Value	Unrecognized
Debentures and notes	**(2,203)**	**(2,535)**	**(332)**	(2,732)	(3,006)	(274)
Forward foreign currency swaps	**–**	**–**	**–**	–	14	14
Cross currency and interest rate swaps	**–**	**110**	**110**	–	72	72
Natural gas derivatives	**–**	**(21)**	**(21)**	–	(10)	(10)
Crude oil derivatives	**–**	**(81)**	**(81)**	–	(52)	(52)

Borrowings under bank credit facilities are for short terms and are market rate based, thus, carrying values approximate fair value. The fair value of debentures and notes is based on market quotations, which reflect the discounted present value of the principal and interest payments using the effective yield at December 31 for instruments having the same term and risk characteristics. Fair values for derivative instruments are determined based on the estimated cash payment or receipt necessary to settle the contract at December 31. Cash payments or receipts are based on discounted cash flow analysis using current market rates and prices.

The fair values of other financial instruments, including cash and cash equivalents, accounts receivable, accounts payable and income and other taxes payable, approximate their carrying values.

Credit Risk

A significant portion of the Company's accounts receivable is due from entities in the oil and gas industry. Concentration of credit risk is mitigated by having a broad domestic and international customer base, which includes a significant number of companies engaged in joint operations with Talisman. The Company routinely assesses the financial strength of its partners and customers, including parties involved in marketing or other commodity arrangements. The Company's largest credit exposure to a single party is approximately $60 million.

The Company is exposed to credit risk associated with possible non-performance by derivative instrument counterparties. The Company actively limits the total exposure to individual counterparties.

10. Contingencies and Commitments

From time to time, Talisman is the subject of litigation arising out of the Company's operations. These claims, including the lawsuit discussed below, are not currently expected to have a material impact on the Company's financial position.

Talisman is subject to a lawsuit brought by the Presbyterian Church of Sudan and others under the Alien Tort Claims Act in the United States District Court for the Southern District of New York. The lawsuit, which is seeking class action status, alleges that the Company conspired with, or aided and abetted, the Government of Sudan to commit violations of international law in connection with the Company's now disposed of indirect interest in oil operations in Sudan. In July 2003, Talisman filed a motion to dismiss the lawsuit for lack of personal jurisdiction of the Court over Talisman. In August 2003, the plaintiffs filed a motion seeking certification of the case as a class action. Talisman is in the process of challenging this certification. No decision is expected on either of these motions prior to the third quarter of 2004. Talisman believes these claims to be entirely without merit and is continuing to vigorously defend itself against this lawsuit and does not expect this to have a material adverse effect.

Talisman's estimated total undiscounted future dismantlement, site restoration and abandonment liability at December 31, 2003 was $2.0 billion (2002 – $1.7 billion), approximately 80% of which is denominated in UK Pounds Sterling. At December 31, 2003, Talisman had accrued $840 million (2002 – $813 million) of this liability. Estimated future dismantlement, site restoration and abandonment costs and the related provision in the Consolidated Financial Statements are subject to uncertainty associated with the method, timing and extent of future dismantlement, site restoration and abandonment. For example, changes in legislation or technology may result in actual future costs that differ materially from those estimated. The Company has provided letters of credit in 2004 in the amount of $547 million of which a majority were provided as security for the costs of future dismantlement, site restoration and abandonment obligations in the North Sea ($472 million). The remaining outstanding letters of credit primarily relate to a retirement compensation arrangement and the guarantee of a minimum work commitment.

Talisman has firm commitments for gathering, processing and transportation services that require the Company to pay tariffs to third parties for processing or shipment of certain minimum quantities of crude oil and liquids and natural gas. The Company has sufficient production to meet these commitments.

Talisman leases certain of its ocean-going vessels and corporate offices, all of which are accounted for as operating leases. The term of the Ross Floating Production, Storage and Offloading vessel ("FPSO") lease depends on the expected life of the Ross and Blake fields. A lease for an FPSO contracted in Malaysia expires in 2004. In addition, Talisman has ongoing operating commitments associated with the vessels.

Estimated future minimum commitments[1]

	2004	2005	2006	2007	2008	Subsequent to 2008	Total
Office leases	19	16	16	16	16	113	196
Vessel leases	95	–	–	–	–	–	95
Transportation and processing commitments[2]	135	99	82	76	70	617	1,079
Minimum work commitments	203	47	30	21	7	–	308
Abandonment obligations	9	9	25	80	12	1,883	2,018
Other service contracts	19	16	16	5	4	71	131
Total	480	187	169	198	109	2,684	3,827

1 Future minimum payments denominated in foreign currencies have been translated into Canadian dollars based on the December 31, 2003 exchange rate.
2 Certain of the Company's transportation commitments are tied to firm gas sales contracts.

The Company has entered into sales contracts for a portion of its future North American natural gas production. The following are the average volumes under contract and the weighted-average contract price in each of the years shown.

Fixed price sales	2004	2005	2006	Three-way collars	2004
Volumes (mcf/d)	40,250	14,650	14,650	Volumes (mcf/d)	15,300
Average price ($/mcf)	3.89	3.29	3.29	Call strike ($/mcf)	3.49
				Put strike ($/mcf)	3.32
				Sold put strike ($/mcf)	2.67

The three-way collars are similar to two-way commodity collars with the call and put strike prices being equivalent to the ceiling and floor prices, except that should the NIT (Nova Inventory Transfer) index fall below the sold put strike price, Talisman will receive NIT plus the difference between the put strike and sold put strike prices.

11. Other Revenue

Years ended December 31	**2003**	2002	2001
Pipeline and custom treating tariffs	**63**	69	63
Investment income	**9**	8	15
Marketing income	**4**	3	4
	76	80	82

12. Other Expenses (Income)

Years ended December 31	**2003**	2002	2001
Net loss (gain) on asset disposals	**(14)**	10	(11)
Foreign exchange losses	**7**	28	51
Project loan facility deferred costs write-off	**–**	–	17
Property impairments	**30**	74	–
Other expense (income)	**(7)**	1	21
	16	113	78

13. Taxes

Income Taxes

The current and future income taxes for each of the three years ended December 31 are as follows:

	2003	2002	2001
Current income taxes (recovery)			
North America[1]	**21**	(20)	45
North Sea	**99**	131	162
Southeast Asia	**84**	76	83
Sudan	**17**	68	50
Other	**8**	3	2
	229	258	342
Future income taxes (recovery)			
North America[1]	**(49)**	67	134
North Sea	**22**	116	(69)
Southeast Asia	**(13)**	(3)	15
Algeria	**4**	–	–
Sudan	**9**	16	3
Other	**(24)**	(34)	(11)
	(51)	162	72
Income taxes	**178**	420	414

1 Current North America income taxes include the Canadian federal tax on large corporations, net of Alberta royalty tax credits.

The components of the net future tax liability at December 31, are as follows:

	2003	2002
Future tax liabilities		
Property, plant and equipment	**2,251**	2,392
Pension assets	**22**	21
Other	**216**	184
	2,489	2,597
Future tax assets		
Provision for future site restoration	**332**	297
Other	**69**	64
	401	361
Net future tax liability	**2,088**	2,236

Future distribution taxes associated with operations in the UK have not been recorded because, based on current plans, repatriation of funds in excess of foreign reinvestment will not result in material amounts of tax expense. Unremitted earnings in other foreign jurisdictions are not material.

Income taxes vary from the amount that would be computed by applying the Canadian statutory income tax rate of 35.36% for the year ended December 31, 2003 (2002 – 42.08%; 2001 – 42.45%) as follows:

Years ended December 31	**2003**	2002	2001
Income taxes calculated at the Canadian statutory rate	**451**	442	572
Increase (decrease) in income taxes resulting from:			
Non-deductible royalties, mineral taxes and expenses	**158**	138	207
Resource allowances	**(122)**	(128)	(168)
Change in statutory tax rates	**(160)**	116	(34)
Non-taxable income	**(80)**	–	–
Deductible PRT expense	**(32)**	(51)	(62)
Lower foreign tax rates (net)	**(2)**	(80)	(90)
Provincial rebates and credits	**(12)**	(10)	(40)
Federal tax on large corporations	**10**	9	9
Other	**(33)**	(16)	20
Income taxes	**178**	420	414

Petroleum Revenue Tax

Petroleum Revenue Tax (PRT) expense primarily relates to the UK and is comprised of current tax expense of $72 million (2002 – $91 million; 2001 – $102 million) and deferred tax expense of $20 million (2002 – $33 million; 2001 – $47 million). The measurement of PRT expense and the related provision in the Consolidated Financial Statements is subject to uncertainty associated with future recovery of oil and gas reserves, commodity prices and the timing of future events, which could result in material changes to deferred amounts.

14. Consolidated Statements of Cash Flows

Selected cash flow information:

Years ended December 31	**2003**	2002	2001
Net income	**1,007**	524	733
Items not involving current cash flow			
Depreciation, depletion and amortization	**1,443**	1,495	1,313
Property impairments	**30**	74	–
Dry hole	**251**	174	113
Net loss (gain) on asset disposals	**(14)**	10	(11)
Gain on sale of Sudan	**(296)**	–	–
Stock-based compensation	**138**	–	–
Future taxes and deferred PRT	**(32)**	195	119
Other	**(11)**	(12)	80
	1,509	1,936	1,614
Exploration	**213**	185	147
Cash flow	**2,729**	2,645	2,494
Cash interest paid (net of capitalized interest)	**139**	156	137
Cash income taxes paid	**168**	274	365

Changes in operating non-cash working capital consisted of the following:

Years ended December 31	**2003**	2002	2001
Accounts receivable	**(32)**	(155)	266
Inventories	**32**	(42)	10
Prepaid expenses	**4**	5	(9)
Accounts payable and accrued liabilities	**(63)**	(16)	(323)
Income and other taxes payable	**(45)**	45	(121)
Net use of cash	**(104)**	(163)	(177)

15. Net Income and Diluted Net Income Per Share

The following table summarizes the calculation of net income and diluted net income per share.

	2003	2002	2001
Net income	**1,007**	524	733
Less preferred security charges, net of tax	**22**	24	24
Net income available to common shareholders	**985**	500	709
Weighted average number of common shares outstanding (millions) – basic	**129**	134	135
Dilution effect of stock options (millions)	**1**	2	2
Weighted average number of commons shares outstanding (millions) – diluted	**130**	136	137
Net income per share ($/share)			
Basic	**7.65**	3.73	5.25
Diluted	**7.57**	3.67	5.16

Outstanding stock options are the only instruments that are currently dilutive to earnings per share. For 2003, 1,168,210 stock options that were antidilutive have been excluded from the computation of diluted earnings per share (2002 – 1,080,035; 2001 – 2,249,145).

16. Employee Benefits

The Company sponsors both defined benefit and defined contribution pension arrangements covering substantially all employees. The Company uses actuarial reports prepared by independent actuaries for funding and accounting purposes. The Company uses a December 31 measurement date for the majority of its defined benefit pension plans. The following significant actuarial assumptions were employed to determine the periodic pension expense and the accrued benefit obligations:

	2003	2002	2001
Expected long-term rate of return on plan assets (%)	**7.5**	7.5	7.5
Discount rate (%)	**6.4**	6.5	6.5
Rate of compensation increase (%)	**4.5**	4.5	4.5

The Company's net benefit plan expense (credit) is as follows:

	2003	2002	2001
Current service cost – defined benefit	**7**	5	2
Current service cost – defined contribution	**7**	6	5
Interest cost	**8**	7	5
Expected return on plan assets	**(9)**	(11)	(10)
Amortization of net transitional asset	**(1)**	(1)	(1)
Amortization of actuarial losses	**2**	–	–
Net benefit plan expense	**14**	6	1

Information about the Company's defined benefit pension plans is as follows:

	2003		2002	
	Pension plans grouped *by funded status*		Pension plans grouped by funded status	
	Surplus	**Deficit**[1]	Surplus	Deficit[1]
Accrued benefit obligation				
Accrued benefit obligation, beginning of year	**54**	**63**	53	42
Current service cost	**1**	**6**	1	4
Interest cost	**4**	**4**	3	3
Actuarial losses	**7**	**8**	1	14
Plan participants' contributions	**–**	**1**	–	1
Benefits paid	**(4)**	**(4)**	(4)	(1)
Accrued benefit obligation, end of year	**62**	**78**	54	63
Plan assets				
Fair value of plan assets, beginning of year	**114**	**21**	128	21
Actual gain (loss) on plan assets	**14**	**3**	(4)	(5)
Employer contributions	**–**	**8**	–	5
Plan participants' contributions	**–**	**1**	–	1
Surplus applied to defined contribution plan	**(7)**	**–**	(6)	–
Benefits paid	**(4)**	**(4)**	(4)	(1)
Fair value of plan assets, end of year	**117**	**29**	114	21
Funded status – surplus (deficit)	**55**	**(49)**	60	(42)
Unamortized net actuarial loss	**19**	**26**	18	21
Unamortized net transitional (asset) obligation	**(11)**	**3**	(11)	2
Net accrued benefit asset (liability)	**63**	**(20)**	67	(19)

1 The net accrued benefit liability for pension plans with a deficit funding status is included in deferred credits on the Consolidated Balance Sheet.

At December 31, 2003, the actuarial net present value of the accrued benefit obligation for other post-retirement benefit plans was $8 million (2002 – $7 million).

The net benefit plan expense of $14 million for the year ended December 31, 2003 (2002– $6 million; 2001 – $1 million) is determined by using actuarial assumptions including expected return on plan assets and includes the amortization of net actuarial losses and net transitional assets and obligations as described in note 1(j). Had the net benefit expense for the year been calculated without deferring and amortizing net actuarial losses and net transitional assets and obligations, the net benefit expense for 2003 would have been $12 million (2002 – $37 million; 2001 – $23 million).

At December 31, 2003, the composition of plan assets as a percentage of fair value was 70% equities and 30% bonds. The approximate target allocation percentage is 70% equities, 30% bonds and expected return on assets is 8.5% equities and 5.3% bonds.

17. Sale of Sudan Operations

On March 12, 2003, the Company completed the sale of its 25% indirectly held interest in the Greater Nile Oil Project in Sudan. Total gross proceeds were $1.13 billion (US$771 million), including interest and cash received by Talisman during the interim period between September 1, 2002 and closing on March 12, 2003. The gain on sale is as follows:

Gross proceeds on sale of Sudan operations (US$771 million)	1,135
Less interim adjustments	(123)
	1,012
Property, plant and equipment	687
Working capital and other assets	72
Future income tax liability	(59)
Net carrying value at March 12, 2003	700
Closing costs	16
Gain on disposal	296

18. Segmented Information

Talisman's activities are conducted in five geographic segments: North America, the North Sea, Southeast Asia, Algeria and other international locations. The Sudan operations were sold in 2003. North America includes operations in Canada and the US. The North Sea includes operations in the UK, Netherlands and Norway. The Southeast Asia segment includes operations in Indonesia, Malaysia and Vietnam. All activities relate to the exploration, development, production and transportation of oil, liquids and natural gas.

	North America[2]			North Sea[3]		
	2003	2002	2001	**2003**	2002	2001
Revenue						
Gross sales						
Oil and liquids	**683**	706	714	**1,556**	1,798	1,466
Natural gas	**1,972**	1,270	1,583	**182**	173	172
Synthetic oil	**42**	42	40	**–**	–	–
Sulphur	**6**	(4)	(5)	**–**	–	–
Total gross sales	**2,703**	2,014	2,332	**1,738**	1,971	1,638
Royalties	**587**	373	558	**8**	96	93
Net sales	**2,116**	1,641	1,774	**1,730**	1,875	1,545
Other	**54**	38	34	**23**	40	46
Total revenue	**2,170**	1,679	1,808	**1,753**	1,915	1,591
Segmented expenses						
Operating						
Oil and liquids	**131**	121	121	**523**	517	407
Natural gas	**237**	212	198	**21**	27	18
Synthetic oil	**22**	19	20	**–**	–	–
Pipeline	**5**	5	4	**39**	44	42
Total operating expenses	**395**	357	343	**583**	588	467
DD&A	**693**	614	585	**619**	701	558
Dry hole	**135**	128	54	**69**	9	21
Exploration	**87**	66	69	**21**	20	30
Other	**(28)**	77	11	**26**	55	(23)
Total segmented expenses	**1,282**	1,242	1,062	**1,318**	1,373	1,053
Segmented income (loss) before taxes	**888**	437	746	**435**	542	538
Non-segmented expenses						
General and administrative						
Interest on long-term debt						
Gain on sale of Sudan operation						
Stock based compensation						
Currency translation						
Total non-segmented expenses						
Income before taxes						
Capital expenditures						
Exploration	**453**	321	314	**99**	134	106
Development	**629**	480	535	**397**	297	527
Midstream	**27**	21	27	**–**	–	–
Exploration and development	**1,109**	822	876	**496**	431	633
Property acquisitions[1]						
Midstream acquisitions						
Proceeds on dispositions						
Other non-segmented						
Net capital expenditures						
Property, plant and equipment	**5,642**	4,955	4,773	**2,710**	2,921	2,831
Goodwill	**291**	291	291	**74**	46	41
Other	**403**	350	265	**386**	387	371
Segmented assets	**6,336**	5,596	5,329	**3,170**	3,354	3,243
Non-segmented assets						
Total assets						

1 Excluding corporate acquisitions.

2

North America		**2003**	2002	2001
Revenues	Canada	**2,018**	1,674	1,808
	US	**152**	5	–
		2,170	1,679	1,808
Property, plant and equipment	Canada	**5,238**	4,848	4,769
	US	**404**	107	4
		5,642	4,955	4,773

3

North Sea		**2003**	2002	2001
Revenues	UK	**1,691**	1,888	1,561
	Netherlands	**26**	27	30
	Norway	**36**	–	–
		1,753	1,915	1,591
Property, plant and equipment	UK	**2,555**	2,875	2,791
	Netherlands	**39**	46	40
	Norway	**116**	–	–
		2,710	2,921	2,831

	Southeast Asia[4]			Algeria			Sudan			Other			Total[5]		
	2003	2002	2001	2003	2002	2001	2003	2002	2001	2003	2002	2001	2003	2002	2001
	345	323	276	89	–	–	209	828	638	–	–	–	2,882	3,655	3,094
	211	163	163	–	–	–	–	–	–	–	–	–	2,365	1,606	1,918
	–	–	–	–	–	–	–	–	–	–	–	–	42	42	40
	–	–	–	–	–	–	–	–	–	–	–	–	6	(4)	(5)
	556	486	439	89	–	–	209	828	638	–	–	–	5,295	5,299	5,047
	156	130	90	46	–	–	97	328	248	–	–	–	894	927	989
	400	356	349	43	–	–	112	500	390	–	–	–	4,401	4,372	4,058
	–	1	1	–	–		(1)	1	1	–	–	–	76	80	82
	400	357	350	43	–	–	111	501	391	–	–	–	4,477	4,452	4,140
	65	65	54	16	–	–	18	84	66	–	–	–	753	787	648
	22	21	16	–	–	–	–	–	–	–	–	–	280	260	232
	–	–	–	–	–	–	–	–	–	–	–	–	22	19	20
	–	–	–	–	–	–	–	–	–	–	–	–	44	49	46
	87	86	70	16	–	–	18	84	66	–	–	–	1,099	1,115	946
	95	87	93	17	–	–	19	93	77	–	–	–	1,443	1,495	1,313
	9	4	8	1	–	5	–	13	16	37	20	9	251	174	113
	17	19	8	–	5	2	5	6	11	83	69	27	213	185	147
	9	11	(2)	–	2	8	–	(5)	11	2	(9)	–	9	131	5
	217	207	177	34	7	15	42	191	181	122	80	36	3,015	3,100	2,524
	183	150	173	9	(7)	(15)	69	310	210	(122)	(80)	(36)	1,462	1,352	1,616
													152	138	108
													137	164	139
													(296)	–	–
													185	–	–
													7	(18)	73
													185	284	320
													1,277	1,068	1,296
	70	36	31	4	4	22	7	27	42	151	106	52	784	628	567
	246	233	110	30	103	40	(5)	71	75	72	15	1	1,369	1,199	1,288
	–	–	–	–	–	–	–	–	–	–	–	–	27	21	27
	316	269	141	34	107	62	2	98	117	223	121	53	2,180	1,848	1,882
													638	276	301
													130	–	–
													(100)	(72)	(162)
													38	26	30
													2,886	2,078	2,051
	1,079	1,093	924	202	244	143	–	772	767	145	57	23	9,778	10,042	9,461
	108	132	135	–	–	–	–	–	–	–	–	–	473	469	467
	217	205	137	27	6	4	–	56	44	18	12	3	1,051	1,016	824
	1,404	1,430	1,196	229	250	147	–	828	811	163	69	26	11,302	11,527	10,752
													63	67	67
													11,365	11,594	10,819

4 **Southeast Asia**

		2003	2002	2001
Revenues	Indonesia	**304**	302	332
	Malaysia	**85**	50	18
	Vietnam	**11**	5	–
		400	357	350
Property, plant and equipment	Indonesia	**383**	515	508
	Malaysia	**673**	565	407
	Vietnam	**23**	13	9
		1,079	1,093	924

5 Certain comparative segmented disclosures have been reclassified to be consistent with the current year presentation.

19. Information for US Readers

Accounting Principles Generally Accepted in the US

The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP") which, in most respects, conform to accounting principles generally accepted in the United States ("US GAAP"). Significant differences between Canadian and US GAAP are as follows:

Net income in accordance with US GAAP:

Years ended December 31 (millions of Canadian dollars)	Notes	**2003**	2002	2001
Net income – Canadian GAAP		**1,007**	524	733
Foreign exchange loss	4,6	**(62)**	(56)	(44)
Depreciation, depletion and amortization	1,2,3,6,8,9	**45**	(26)	(66)
(Loss) gain on derivative instruments	4	**(17)**	(129)	237
Preferred security charges	6	**(38)**	(42)	(42)
Deferred income taxes	2	**15**	51	(95)
Gain on sale of Sudan operations	8	**(296)**	–	–
ARO Accretion	9	**(58)**	–	–
Results of discontinued operations, net of tax	8	**(57)**	(237)	(157)
		(468)	(439)	(167)
Income from continuing operations		**539**	85	566
Results of discontinued operations, net of tax	8	**330**	237	157
Income before cumulative effect of changes in accounting principles		**869**	322	723
Cumulative effect of changes in accounting principles, net of tax	4,9	**53**	–	(48)
Net income – US GAAP		**922**	322	675
Income per common share (Canadian dollars)				
Basic				
Continuing operations		**4.19**	0.64	4.20
Discontinued operations		**2.56**	1.76	1.16
Before cumulative effect of changes in accounting principles		**6.75**	2.40	5.36
Cumulative effect of changes in accounting principles, net of tax		**0.41**	–	(0.36)
Net income		**7.16**	2.40	5.00
Diluted				
Continuing operations		**4.14**	0.63	4.12
Discontinued operations		**2.53**	1.74	1.14
Before cumulative effect of changes in accounting principles		**6.67**	2.37	5.26
Cumulative effect of changes in accounting principles, net of tax		**0.41**	–	(0.35)
Net income		**7.08**	2.37	4.91

Comprehensive income in accordance with US GAAP:

Years ended December 31 (millions of Canadian dollars)	Notes	**2003**	2002	2001
Net income – US GAAP		**922**	322	675
Other comprehensive income, net of tax:				
Foreign exchange gain on translation of self-sustaining operations	7	**650**	170	–
Comprehensive income – US GAAP		**1,572**	492	675

Balance sheet items in accordance with US GAAP are as follows:

December 31 (millions of Canadian dollars)	Notes	**2003**		2002	
		Canadian GAAP	**US GAAP**	Canadian GAAP	US GAAP
Current assets	8	**975**	**975**	917	861
Sudan assets held for sale	8	**–**	**–**	–	842
Property, plant and equipment	1,2,3,8,9	**9,778**	**10,531**	10,042	9,653
Other non-current assets	4,6	**612**	**607**	635	651
		11,365	**12,113**	11,594	12,007
Current liabilities	8	**1,218**	**1,218**	989	960
Sudan liabilities held for sale	8	**–**	**–**	–	87
Long-term debt	4,6	**2,203**	**2,696**	2,997	3,530
Future income taxes	2,8,9	**2,088**	**2,062**	2,236	2,127
Other non-current liabilities	9	**897**	**1,208**	870	870
		6,406	**7,184**	7,092	7,574
Shareholders' equity					
Preferred securities	6	**431**	**–**	431	–
Common shares		**2,725**	**2,725**	2,785	2,785
Contributed surplus	5	**73**	**90**	75	92
Cumulative foreign currency translation	4,6,7	**(114)**	**(832)**	140	(30)
Accumulative other comprehensive income	7	**–**	**820**	–	170
Retained earnings	1-9	**1,844**	**2,126**	1,071	1,416
Total liabilities and shareholders' equity		**11,365**	**12,113**	11,594	12,007

1 Gains on property exchanges – Under both US and Canadian GAAP, property exchanges are recorded at the carrying value of the assets given up unless the exchange transaction includes significant cash consideration, in which case it is recorded at fair value. Under US GAAP, asset exchange transactions are recorded at fair value if cash consideration is greater than 25% (10% under Canadian GAAP) of the fair value of total consideration given or received. The resulting differences in the recorded carrying values of these properties result in differences in depreciation, depletion and amortization expense in subsequent years.

2 Income taxes and depreciation, depletion and amortization expense – In 2000, the Company adopted the liability method to account for income taxes. The change to the liability method has eliminated a difference between Canadian and US GAAP, however, in accordance with the recommendations of the Canadian Institute of Chartered Accountants (the "CICA") the effect of the adoption under Canadian GAAP resulted in a charge to retained earnings, whereas, under US GAAP the future tax costs that gave rise to the Canadian GAAP adjustment have already been reflected in property, plant and equipment. As a result of the implementation method, further differences in depreciation, depletion and amortization expense result in subsequent years. Other adjustments to the Canadian GAAP net income required under US GAAP, as described in this note, have been tax effected as necessary.

3 **Impairments** – Under both US and Canadian GAAP, property, plant and equipment must be assessed for potential impairments. Under US GAAP, if the sum of the expected future cash flows (undiscounted and without interest charges) is less than the carrying amount of the asset, then an impairment loss (the amount by which the carrying amount of the asset exceeds the fair value of the asset) should be recognized. Fair value is calculated as the present value of estimated expected future cash flows. As disclosed in note 1(c), under Canadian GAAP, the impairment loss is the difference between the carrying value of the asset and its net recoverable amount (undiscounted). The resulting differences in recorded carrying values of impaired assets result in further differences in depreciation, depletion and amortization expense in subsequent years. The CICA has adopted a new standard effective for 2004 that will eliminate this US/Canadian GAAP difference.

4 **Forward foreign exchange contracts and other financial instruments** – The Company has designated, for Canadian GAAP purposes, its derivative financial instruments as hedges of anticipated revenue and expenses. In accordance with Canadian GAAP, payments or receipts on these contracts are recognized in income concurrently with the hedged transaction. The fair values of the contracts deemed to be hedges are not reflected in the Consolidated Financial Statements.

Effective January 1, 2001, for US GAAP purposes, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 133, as amended, Accounting for Derivative Instruments and Hedging Activities. Effective with the adoption of this standard, every derivative instrument, including certain derivative instruments embedded in other contracts, is recognized on the balance sheet at fair value. The statement requires that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

Management has not designated any of the currently held derivative instruments as hedges for US GAAP purposes and accordingly these derivatives have been recognized on the balance sheet at fair value with the change in their fair value recognized in earnings. In accordance with the transition provisions of SFAS No. 133, on January 1, 2001, the Company recorded a $48 million after-tax non-cash loss in current earnings as a cumulative effect of accounting change.

5 **Appropriation of contributed surplus** – In 1992, concurrent with a change in control of the Company, $17 million of contributed surplus was appropriated to retained earnings to eliminate the deficit at June 30, 1992. This restatement of retained earnings is not permitted under US GAAP as the events that precipitated it did not constitute a quasi-reorganization.

6 **Preferred securities** – Under US GAAP, the Company's preferred securities are treated as debt rather than equity and accordingly are translated at the rates of exchange in effect at the balance sheet date. Under Canadian GAAP, the preferred securities are translated at the historical rate of exchange. In addition, the annual preferred security charges under US GAAP are classified as an expense rather than a direct charge to retained earnings. Under US GAAP, the cost associated with the issuance of the preferred securities is recorded as an asset and is amortized over the term of the preferred securities. Under Canadian GAAP, this cost, net of tax, is charged directly to shareholders' equity. The fair market value of the preferred securities at December 31, 2003 was $389 million (2002 – $494 million).

7 **Foreign exchange gains and losses on translation of self sustaining operations** – Under US GAAP, foreign exchange gains and losses on translation of self-sustaining foreign operations are added, net of tax, to net income in determining comprehensive income. Under Canadian GAAP, such gains and losses are included as a separate component of shareholders' equity referred to as cumulative translation adjustment.

8 **Discontinued operations** – Under US GAAP, effective November 1, 2002, the Sudan assets were classified as Assets Held For Sale with the Sudan operating results, net of tax, classified on the income statement as results of operations held for sale. No depreciation, depletion or amortization has been recorded commencing November 1, 2002 related to these assets. The sale closed March 12, 2003.

9 **Asset Retirement Obligations (future site restoration and abandonment liabilities)** – Effective January 1, 2003, for US GAAP purposes, the Company adopted SFAS No. 143, which changes the method of accruing for costs associated with the retirement of fixed assets which an entity is legally obligated to incur. The standard requires entities to record the fair value of a liability for an asset retirement obligation in the period it is incurred and a corresponding increase in the carrying amount of the related long-lived asset.

The majority of the Company's asset retirement obligations relate to the abandoning of oil and gas wells, pipelines, processing facilities and offshore production platforms. During 2003, the Company's asset retirement obligation changed as follows.

(millions of Canadian dollars)	
ARO liability at January 1, 2003	1,123
Liabilities incurred during year	97
Liabilities settled during year	(28)
Accretion expense	58
Foreign currency translation	(99)
ARO liability at December 31, 2003	1,151

SFAS No. 143 calls for the ARO liability to include as a component of expected costs, an estimate of the price that a third party would demand and could expect to receive, for bearing the uncertainty inherent in the obligations. This is referred to as the market-risk premium. No amount of market-risk premium has been included in the estimate of the Company's ARO liability as management does not believe there to be sufficient evidence in the oil and gas industry to estimate any such market premium.

The following table presents the pro forma effects of the retroactive application of this change in accounting principle. There was no pro forma effect on income from discontinued operations.

	2003	2002	2001
Pro forma net income [1]	**869**	342	665
Pro forma per common share			
Basic	**6.75**	2.55	4.93
Diluted	**6.67**	2.51	4.84

1 Pro forma net income for 2003 has been adjusted to remove the $53 million cumulative effect of a change in accounting principle attributable to SFAS No. 143.

Newly Issued US Accounting Standards

Variable Interest Entities

In 2003, the Financial Accounting Standards Board (FASB) issued Interpretation No. 46 Consolidation of Variable Interest Entities (FIN 46), which is effective January 1, 2004. The Canadian Institute of Chartered Accountants (CICA) issued a similar accounting guideline (AcG 15). FIN 46 and AcG 15 provide guidance as to when a company should consolidate another entity into its Consolidated Financial Statements. A variable interest entity (VIE) is a corporation, partnership, trust, or any other legal structure used for business purposes that either (i) does not have equity investors with voting rights or (ii) has equity investors that do not provide sufficient financial resources for the entity to support its activities. FIN 46 and AcG 15 require a VIE to be consolidated by a company if that company is subject to a majority of the risk of loss from the VIE's activities, is entitled to receive a majority of the VIE's residual returns, or both. If a company has previously consolidated a VIE but is not subject to a majority of the risk of loss of its activities nor entitled to receive a majority of its residual returns, such a VIE is required to be deconsolidated. Management is currently evaluating the potential impact of FIN 46 and AcG 15 but does not expect their application to have a significant impact on the Company's financial position, operating results or cash flows.

Oil and Gas Drilling Rights

Talisman has classified all of its mineral drilling rights as oil and gas properties under the heading property, plant and equipment. Management believes this treatment is consistent with industry practice and management's understanding of the relevant accounting standards. It is management's understanding that the Staff of the Securities and Exchange Commission (SEC) is questioning registrants regarding the appropriateness of this accounting treatment, specifically as to whether these costs should be classified as intangible assets on the balance sheet separate from other property, plant and equipment. Further, it is management's understanding that this issue is being considered by the US Financial Accounting Standards Board (FASB). Management believes resolution of this issue will not materially affect the Company's results of operations.

Summary US Dollar Information

Unless otherwise noted, all amounts in the Consolidated Financial Statements, including Accounting Principles Generally Accepted in the United States above, are reported in millions of Canadian dollars. The following information reflects summary financial information prepared in accordance with US GAAP translated from Canadian dollars to US dollars at the average exchange rate prevailing in the respective year.

US$ million (except as noted)	**2003**	2002	2001
Total revenue	**3,194**	2,835	2,673
Net income	**658**	205	436
Net income per common share (US$/share)	**5.11**	1.53	3.23
Average exchange rate (US$/C$)	**0.7135**	0.6368	0.6457

Supplementary Information – FAS 69

(unaudited)

The supplemental data on the Company's oil and gas activities was prepared in accordance with the FASB's SFAS No. 69: Disclosures About Oil and Gas Producing Activities. Activities not directly associated with conventional crude oil and natural gas production, including synthetic oil operations, are excluded from all aspects of this supplementary oil and gas information.

Results of Operations from Oil and Gas Producing Activities

Years ended December 31 (millions of Canadian dollars)		North America	North Sea	Southeast Asia[1]	Sudan	Algeria	Trinidad	Other	Total
2003	Net oil and gas revenue derived from proved reserves[2]	**2,070**	**1,754**	**400**	**112**	**43**	–	–	**4,379**
	Less: Production costs	**367**	**583**	**87**	**18**	**16**	–	–	**1,071**
	Exploration and dry hole expense	**222**	**90**	**26**	**5**	**1**	**34**	**86**	**464**
	Depreciation, depletion and amortization	**647**	**635**	**95**	–	**17**	–	–	**1,394**
	Tax expense (recovery)	**328**	**237**	**77**	**30**	**3**	**(12)**	**(31)**	**632**
	Results of operations	**506**	**209**	**115**	**59**	**6**	**(22)**	**(55)**	**818**
2002	Net oil and gas revenue derived from proved reserves[2]	1,634	1,914	356	500	–	–	–	4,404
	Less: Production costs	339	588	86	84	–	–	–	1,097
	Exploration and dry hole expense	194	29	23	19	5	46	43	359
	Depreciation, depletion and amortization	583	701	87	92	–	–	–	1,463
	Tax expense (recovery)	205	430	75	85	(2)	(22)	(18)	753
	Results of operations	313	166	85	220	(3)	(24)	(25)	732
2001	Net oil and gas revenue derived from proved reserves[2]	1,744	1,584	350	389	–	–	–	4,067
	Less: Production costs	323	467	70	66	–	–	–	926
	Exploration and dry hole expense	123	51	16	27	7	15	21	260
	Depreciation, depletion and amortization	549	558	93	77	–	–	–	1,277
	Tax expense (recovery)	273	247	95	52	(3)	(6)	(9)	649
	Results of operations	476	261	76	167	(4)	(9)	(12)	955

1 Includes operations in Indonesia and Malaysia/Vietnam.
2 Net oil and gas revenue derived from proved reserves is net of applicable royalties.

Capitalized Costs Related to Oil and Gas Activities

Years ended December 31 (millions of Canadian dollars)		North America	North Sea	Southeast Asia[1]	Sudan	Algeria	Trinidad	Other	Total
2003	Proved properties	**7,751**	**6,339**	**1,466**	–	**151**	**120**	–	**15,827**
	Unproved properties	**227**	**88**	**95**	–	**67**	**16**	**3**	**496**
	Incomplete wells and facilities	**31**	**1**	**22**	–	–	**1**	**5**	**60**
		8,009	**6,428**	**1,583**	–	**218**	**137**	**8**	**16,383**
	Less: accumulated depreciation, depletion and amortization	**2,694**	**3,451**	**498**	–	**16**	–	–	**6,659**
	Net capitalized costs	**5,315**	**2,977**	**1,085**	–	**202**	**137**	**8**	**9,724**
2002	Proved properties	6,939	5,592	1,422	986	217	45	–	15,201
	Unproved properties	214	14	156	36	29	9	–	458
	Incomplete wells and facilities	33	66	22	17	–	–	–	138
		7,186	5,672	1,600	1,039	246	54	–	15,797
	Less: accumulated depreciation, depletion and amortization	2,339	2,774	509	271	–	–	–	5,893
	Net capitalized costs	4,847	2,898	1,091	768	246	54	–	9,904
2001	Proved properties	6,183	4,454	1,092	889	26	–	–	12,644
	Unproved properties	408	284	195	30	94	17	–	1,028
	Incomplete wells and facilities	24	37	56	22	23	6	–	168
		6,615	4,775	1,343	941	143	23	–	13,840
	Less: accumulated depreciation, depletion and amortization	1,926	1,965	419	178	–	–	–	4,488
	Net capitalized costs	4,689	2,810	924	763	143	23	–	9,352

1 Includes operations in Indonesia and Malaysia/Vietnam.

Costs Incurred in Oil and Gas Activities

Years ended December 31 (millions of Canadian dollars)			North America	North Sea	Southeast Asia[1]	Sudan	Algeria	Trinidad	Other	Total
2003	Property acquisition costs	Proved	**369**	**189**	**–**	**–**	**–**	**–**	**–**	**558**
		Unproved	**184**	**2**	**–**	**–**	**–**	**–**	**3**	**189**
	Exploration costs		**336**	**99**	**70**	**7**	**4**	**58**	**90**	**664**
	Development costs		**600**	**397**	**246**	**(5)**	**30**	**72**	**–**	**1,340**
	Asset retirement cost		**115**	**285**	**7**	**–**	**–**	**–**	**–**	**407**
	Total costs incurred		**1,604**	**972**	**323**	**2**	**34**	**130**	**93**	**3158**
2002	Property acquisition costs	Proved	174	88	–	–	–	–	–	262
		Unproved	50	13	–	–	–	9	–	72
	Exploration costs		271	134	36	27	3	54	43	568
	Development costs		457	297	233	71	103	14	–	1,175
	Total costs incurred		952	532	269	98	106	77	43	2,077
2001	Property acquisition costs	Proved	828	213	129	–	–	–	–	1,170
		Unproved	240	19	245	–	–	–	–	504
	Exploration costs		251	106	31	42	22	31	21	504
	Development costs		527	527	110	75	41	–	–	1,280
	Total costs incurred		1,846	865	515	117	63	31	21	3,458

1 Includes operations in Indonesia and Malaysia/Vietnam.

Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves

Future net cash flows were calculated by applying the respective year end prices to the Company's estimated future production of proved reserves and deducting estimates of future development and production costs and income taxes. Future development and production costs have been estimated based on existing economic and operating conditions. Future income taxes have been estimated based on statutory tax rates enacted at year end. The present values of the estimated future cash flows were determined by applying a 10% discount rate prescribed by the FASB.

In order to increase the comparability between companies, the standardized measure of discounted future net cash flows necessarily employs uniform assumptions that do not necessarily reflect management's best estimate of future events and anticipated outcomes. Accordingly, the Company does not believe that the standardized measure of discounted future net cash flows will be representative of actual future net cash flows and should not be considered to represent the fair market value of the oil and gas properties. Actual future net cash flows will differ significantly from those estimated due to, but not limited to, the following:

- production rates will differ from those estimated both in terms of timing and amount. For example, future production may include significant additional volumes from unproved reserves;
- future prices and economic conditions will differ from those at year end. For example, changes in prices decreased the discounted future net cash flows by $3.2 billion in 2003;
- future production and development costs will be determined by future events and will differ from those at year end; and
- estimated income taxes will differ in terms of amounts and timing dependent on the above factors, changes in enacted rates and the impact of future expenditures on unproved properties.

The standardized measure of discounted future net cash flows was prepared using the following prices:

		2003	2002	2001
Crude oil and liquids ($/bbl)	North America	**33.32**	42.07	22.48
	North Sea	**37.89**	46.84	29.61
	Southeast Asia[1]	**41.71**	49.22	30.10
	Sudan	**–**	44.09	23.89
	Algeria	**38.91**	48.37	29.20
	Trinidad	**39.12**	45.72	–
		37.04	45.13	26.34
Natural Gas ($/mcf)	North America	**6.32**	6.06	3.49
	North Sea	**5.55**	5.59	4.97
	Southeast Asia[1]	**3.74**	4.94	2.54
	Trinidad	**1.03**	1.26	–
		5.17	5.43	3.25

1 Includes operations in Indonesia and Malaysia/Vietnam.

Discounted Future Net Cash Flows from Proved Reserves

As at December 31 (millions of Canadian dollars)		North America	North Sea	Southeast Asia [1]	Sudan	Algeria	Trinidad	Total
2003	Future cash inflows [2]	**18,444**	**11,032**	**5,930**	**–**	**645**	**928**	**36,979**
	Future costs							
	Production	**(4,958)**	**(5,686)**	**(1,107)**	**–**	**(165)**	**(122)**	**(12,038)**
	Development and site restoration	**(1,490)**	**(1,989)**	**(697)**	**–**	**(14)**	**(248)**	**(4,438)**
	Future net inflows before income taxes	**11,996**	**3,357**	**4,126**	**–**	**466**	**558**	**20,503**
	Future income and production revenue taxes	**(3,664)**	**(1,393)**	**(1,601)**	**–**	**(107)**	**(299)**	**(7,064)**
	Future net cash flows	**8,332**	**1,964**	**2,525**	**–**	**359**	**259**	**13,439**
	10% discount factor	**(3,740)**	**(147)**	**(1,118)**	**–**	**(86)**	**(112)**	**(5,203)**
	Discounted future net cash flows	**4,592**	**1,817**	**1,407**	**–**	**273**	**147**	**8,236**
2002	Future cash inflows [2]	19,639	13,160	6,627	4,090	675	1,143	45,334
	Future costs							
	Production	(4,325)	(5,577)	(1,040)	(999)	(230)	(157)	(12,328)
	Development and site restoration	(995)	(1,873)	(709)	(313)	(64)	(368)	(4,322)
	Future net inflows before income taxes	14,319	5,710	4,878	2,778	381	618	28,684
	Future income and production revenue taxes	(5,654)	(2,597)	(2,011)	(744)	(31)	(370)	(11,407)
	Future net cash flows	8,665	3,113	2,867	2,034	350	248	17,277
	10% discount factor	(3,913)	(554)	(1,387)	(655)	(97)	(161)	(6,767)
	Discounted future net cash flows	4,752	2,559	1,480	1,379	253	87	10,510
2001	Future cash inflows [2]	11,376	9,347	4,026	2,924	493	–	28,166
	Future costs							
	Production	(3,449)	(4,253)	(875)	(991)	(155)	–	(9,723)
	Development and site restoration	(567)	(1,616)	(850)	(217)	(71)	–	(3,321)
	Future net inflows before income taxes	7,360	3,478	2,301	1,716	267	–	15,122
	Future income and production revenue taxes	(2,509)	(1,284)	(929)	(361)	(26)	–	(5,109)
	Future net cash flows	4,851	2,194	1,372	1,355	241	–	10,013
	10% discount factor	(1,797)	(292)	(804)	(478)	(121)	–	(3,492)
	Discounted future net cash flows	3,054	1,902	568	877	120	–	6,521

1 Includes operations in Indonesia and Malaysia/Vietnam.
2 Future cash inflows are revenues net of royalties.

Principal Sources of Changes in Discounted Cash Flows

Years ended December 31 (millions of Canadian dollars)	**2003**	2002	2001
Sales of oil and gas produced, net of production costs	**(3,308)**	(3,307)	(3,141)
Net change in prices	**(3,200)**	9,709	(11,795)
Net change in production costs	**(357)**	(1,990)	(692)
Net change in future development and site restoration costs	**(87)**	(637)	(128)
Development costs incurred during the year	**672**	764	375
Extensions, discoveries and improved recovery	**1,229**	1,863	1,542
Revisions of previous reserve estimates	**92**	37	216
Net purchases and sales of reserves in place	**(1,225)**	17	550
Accretion of discount	**1,555**	972	2,110
Net change in taxes	**2,399**	(3,342)	4,726
Other	**(44)**	(97)	166
Net change	**(2,274)**	3,989	(6,071)
Balance, beginning of year	**10,510**	6,521	12,592
Balance, end of year	**8,236**	10,510	6,521

Continuity of Proved Net Reserves[1]

	North America[2]	North Sea	Southeast Asia[3]	Algeria	Sudan	Trinidad	Total
Crude Oil and Liquids (mmbbls)							
Total Proved							
Proved reserves at December 31, 2000	165.9	233.8	17.9	12.2	92.4	–	522.2
Discoveries, additions and extensions	17.9	53.9	15.3	7.1	22.5	–	116.7
Purchase of reserves	8.1	16.2	10.6	–	–	–	34.9
Sale of reserves	(2.9)	(4.8)	–	–	–	–	(7.7)
Net revisions and transfers	4.7	(0.5)	1.1	(2.4)	13.3	–	16.2
2001 Production	(17.9)	(38.4)	(5.3)	–	(11.9)	–	(73.5)
Proved reserves at December 31, 2001	175.8	260.2	39.6	16.9	116.3	–	608.8
Discoveries, additions and extensions	10.6	13.5	5.8	1.3	19.0	18.9	69.1
Purchase of reserves	1.1	7.5	–	–	–	–	8.6
Sale of reserves	(3.7)	(2.8)	–	–	–	–	(6.5)
Net revisions and transfers	(2.5)	13.9	(4.2)	(4.3)	(27.7)	–	(24.8)
2002 Production	(17.2)	(44.7)	(5.1)	–	(13.3)	–	(80.3)
Proved reserves at December 31, 2002	164.1	247.6	36.1	13.9	94.3	18.9	574.9
Discoveries, additions and extensions	**13.1**	**8.3**	**17.0**	**2.3**	**–**	**–**	**40.7**
Purchase of reserves	**1.1**	**21.1**	**–**	**–**	**–**	**–**	**22.2**
Sale of reserves	**(4.6)**	**–**	**–**	**–**	**(91.7)**	**–**	**(96.3)**
Net revisions and transfers	**1.1**	**19.4**	**4.8**	**0.5**	**–**	**(0.8)**	**25.0**
2003 Production	**(16.4)**	**(41.4)**	**(5.4)**	**(0.1)**	**(2.6)**	**–**	**(65.9)**
Proved reserves at December 31, 2003	**158.4**	**255.0**	**52.5**	**16.6**	**–**	**18.1**	**500.6**
Proved Developed							
December 31, 2000	160.9	173.3	15.2	–	77.4	–	426.8
December 31, 2001	168.6	203.8	13.3	–	89.6	–	475.3
December 31, 2002	157.2	210.8	11.9	2.4	84.1	–	466.4
December 31, 2003	**155.4**	**211.8**	**18.6**	**14.6**	**–**	**–**	**400.4**
Natural Gas (bcf)							
Total Proved							
Proved reserves at December 31, 2000	1,757.1	272.6	540.2	–	–	–	2,569.9
Discoveries, additions and extensions	293.8	13.7	455.2	–	–	–	762.7
Purchase of reserves	293.6	22.8	125.7	–	–	–	442.1
Sale of reserves	(44.7)	(1.5)	–	–	–	–	(46.2)
Net revisions and transfers	(24.9)	(5.0)	23.4	–	–	–	(6.5)
2001 Production	(222.3)	(35.3)	(32.4)	–	–	–	(290.0)
Proved reserves at December 31, 2001	2,052.6	267.3	1,112.1	–	–	–	3,432.0
Discoveries, additions and extensions	283.1	14.0	11.7	–	–	220.0	528.8
Purchase of reserves	31.5	0.4	–	–	–	–	31.9
Sale of reserves	(26.7)	–	–	–	–	–	(26.7)
Net revisions and transfers	(110.8)	(4.3)	(122.6)	–	–	–	(237.7)
2002 Production	(243.6)	(39.5)	(32.3)	–	–	–	(315.4)
Proved reserves at December 31, 2002	1,986.1	237.9	968.9	–	–	220.0	3,412.9
Discoveries, additions and extensions	**276.3**	**1.0**	**64.0**	**–**	**–**	**–**	**341.3**
Purchase of reserves	**92.2**	**14.4**	**–**	**–**	**–**	**–**	**106.6**
Sale of reserves	**(11.4)**	**–**	**–**	**–**	**–**	**–**	**(11.4)**
Net revisions and transfers	**(14.9)**	**19.8**	**(6.1)**	**–**	**–**	**(9.0)**	**(10.2)**
2003 Production	**(247.6)**	**(37.5)**	**(40.1)**	**–**	**–**	**–**	**(325.2)**
Proved reserves at December 31, 2003	**2,080.7**	**235.6**	**986.7**	**–**	**–**	**211.0**	**3,514.0**
Proved Developed							
December 31, 2000	1,568.4	215.9	120.0	–	–	–	1,904.3
December 31, 2001	1,804.7	213.8	252.0	–	–	–	2,270.5
December 31, 2002	1,746.9	210.0	471.6	–	–	–	2,428.5
December 31, 2003	**1,890.4**	**200.7**	**593.9**	**–**	**–**	**–**	**2,685.0**

1 Net reserves are after deducting royalties. See note 1(g) of the Consolidated Financial Statements for additional disclosure regarding royalties.

2 North American net proved reserves exclude synthetic crude oil reserves: 2001 – 36.4 mmbbls; 2002 – 36.7 mmbbls; 2003 – 35.8 mmbbls.

3 Includes operations in Indonesia and Malaysia/Vietnam.

Additional Information for US Readers

Note to US Readers

The US Securities and Exchange Commission (SEC) normally permits oil and gas companies to disclose in their filings with the SEC only proved reserves that have been demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. Accordingly, the probable reserves and the calculations with respect thereto included in this report do not meet the SEC's standards for inclusion in documents filed with the SEC.

Unless otherwise indicated, the financial statements and other Canadian financial information included in this Annual Report are presented in accordance with Canadian generally accepted accounting principles that differ from generally accepted accounting principles in the US. See note 19 to the Consolidated Financial Statements for information concerning significant differences between Canadian and US generally accepted accounting principles.

The following information is for US readers. Production, recycle ratio, finding and development costs, finding, development and acquisition costs as well as netbacks have been calculated net of royalties and have been translated to US$ at the average exchange rate for each of the years shown. (2003 US$1=C$1.40; 2002 US$1=C$1.57; 2001 US$1=C$1.55; 2000 US$1=C$1.49; 1999 US$1=C$1.49).

Net Production (after royalties)

	2003	2002	2001	2000	1999
Crude Oil and Liquids (bbls/d)					
North America	**45,035**	47,182	49,145	49,018	44,114
North Sea	**113,291**	122,231	105,138	107,554	58,039
Southeast Asia [1]	**14,853**	14,025	14,667	13,853	17,149
Algeria	**3,351**	–	–	–	–
Sudan	**6,997**	36,346	32,422	28,001	9,079
Total oil and liquids	**183,527**	219,784	201,372	198,426	128,381
Natural Gas (mmcf/d)					
North America	**678**	665	608	582	552
North Sea	**103**	107	97	117	111
Southeast Asia [1]	**110**	89	89	104	103
Total natural gas	**891**	861	794	803	766
Total conventional (mboe/d)	**332**	363	334	332	256
Synthetic Oil (Canada) (bbls/d)	**2,510**	2,788	2,387	1,927	2,556
Total (mboe/d)	**334**	366	337	335	259

1 Includes operations in Indonesia and Malaysia/Vietnam.

Recycle Ratio [1]

	1999	2000	2001	2002	**2003**	3-Year	5-Year
Netback (US$/boe) – average annual	9.53	17.04	16.64	15.78	**19.57**	17.28	16.00
Finding and development	1.2	3.0	3.8	1.3	**1.7**	2.2	2.2
Finding, development and acquisition	1.3	3.3	2.8	1.3	**1.6**	2.0	2.1

1 Average annual netback divided by finding, development and acquisition costs.

Finding, Development and Acquisition Costs (net after royalties)

	1999	2000	2001	2002	**2003**	3-year	5-year
Proved Reserves Additions (mmboe) [1]							
North America	32.4	74.8	67.5	36.9	**57.6**	162.0	269.2
International	49.2	52.9	191.5	55.9	**63.0**	310.4	412.6
Total	81.6	127.7	259.0	92.8	**120.6**	472.4	681.8
Proved Acquisitions (mmboe) [2]							
North America	98.4	5.9	57.0	6.4	**16.5**	79.9	184.2
International	75.5	54.8	51.6	7.6	**23.4**	82.6	212.8
Total	173.9	60.7	108.6	14.0	**39.9**	162.5	397.1
Capital Spending (millions of US dollars) [3]							
Exploration and development							
North America	195	410	502	464	**668**	1,634	2,239
International	425	321	638	631	**745**	2,014	2,760
Total Company	620	731	1,140	1,095	**1,413**	3,648	4,999
Acquisitions	1,292	254	1,080	212	**533**	1,825	3,371
Total Capital	1,912	985	2,220	1,307	**1,946**	5,473	8,370
Proved F&D Cost (US$/boe) [4]							
North America	6.01	5.48	7.44	12.56	**11.60**	10.09	8.32
International	8.63	6.07	3.33	11.29	**11.82**	6.49	6.69
Total	7.59	5.72	4.40	11.80	**11.71**	7.72	7.33
Proved FD&A Cost (US$/boe) [5]							
North America	7.91	6.13	9.57	14.02	**14.34**	11.83	9.68
International	7.02	4.55	4.23	11.04	**10.22**	6.65	6.36
Total	7.48	5.23	6.04	12.24	**12.12**	8.62	7.76

1 Proved discoveries and revisions for conventional oil only, excluding acquisitions.
2 Proved reserves purchased. Excludes dispositions.
3 Exploration and development spending excludes synthetic oil operations capital, Chauvin pipeline, Canadian midstream and capitalized interest.
4 F&D net costs/boe have been calculated by dividing finding and development costs (excluding acquisition costs) in US dollars by proved net after royalties reserves additions including revisions but excluding acquired proved net after royalties reserves.
5 FD&A net costs/boe have been calculated by dividing finding and development costs (including acquisition costs) in US dollars by proved net after royalties reserves additions including revisions and acquired proved net after royalties reserves. Dispositions are excluded from this calculation.

F&D and FD&A costs have been calculated in US dollars in a manner consistent with US practice. The calculation is based on current additions to proved reserves net after royalties.
Six mcf of natural gas equals one boe.

Reconciliation of Costs included in F&D Calculations (net after royalties)

US$ millions	1999	2000	2001	2002	**2003**	3-Year	5-Year
Exploration and development costs (FAS 69)	648	742	1,152	1,111	**1,430**	3,693	5,083
Less: capitalized interest	(28)	(11)	(12)	(16)	**(17)**	(45)	(84)
Exploration and development costs	620	731	1,140	1,095	**1,413**	3,648	4,999
Acquisition costs (FAS 69)	1,292	254	1,080	212	**533**	1,825	3,371
Total exploration, development and acquisition costs	1,912	985	2,220	1,307	**1,946**	5,473	8,370

US Readers:
Product Netbacks

(Net of Royalties) – US$		2003	2002	2001
North America	Oil and Liquids (US$/bbl)			
	Sales Price	**25.20**	20.65	19.89
	Hedging (gain)	**2.21**	0.04	(0.10)
	Operating costs	**5.67**	4.48	4.33
		17.32	16.13	15.66
	Natural Gas (US$/mcf)			
	Sales Price	**4.55**	2.52	3.48
	Hedging (gain)	**0.10**	(0.22)	0.02
	Operating costs	**0.68**	0.56	0.57
		3.77	2.18	2.89
North Sea	Oil and Liquids (US$/bbl)			
	Sales Price	**28.35**	24.68	23.29
	Hedging (gain)	**1.43**	0.08	(0.12)
	Operating costs	**9.02**	7.38	6.83
		17.90	17.22	16.58
	Natural Gas (US$/mcf)			
	Sales Price	**3.26**	2.48	2.81
	Hedging (gain)	**–**	–	–
	Operating costs	**0.41**	0.44	0.33
		2.85	2.04	2.48
Southeast Asia[1]	Oil and Liquids (US$/bbl)			
	Sales Price	**29.30**	25.13	23.22
	Hedging (gain)	**2.78**	0.06	(0.28)
	Operating costs	**8.60**	8.09	6.53
		17.92	16.98	16.97
	Natural Gas (US$/mcf)			
	Sales Price	**3.53**	3.01	3.10
	Hedging (gain)	**–**	–	0.01
	Operating costs	**0.38**	0.40	0.32
		3.15	2.61	2.77
Algeria	Oil (US$/bbl)			
	Sales Price	**27.84**	–	–
	Hedging (gain)	**3.13**	–	–
	Operating costs	**9.61**	–	–
		15.10	–	–
Sudan	Oil (US$/bbl)			
	Sales Price	**31.33**	24.06	21.09
	Hedging (gain)	**–**	0.08	(0.14)
	Operating costs	**4.96**	4.02	3.60
		26.37	19.96	17.63
Total Company	Oil and Liquids (US$/bbl)			
	Sales Price	**27.76**	23.74	21.95
	Hedging (gain)	**1.71**	0.07	(0.13)
	Operating costs	**8.02**	6.25	5.64
		18.03	17.42	16.44
	Natural Gas (US$/mcf)			
	Sales Price	**4.27**	2.57	3.37
	Hedging (gain)	**0.07**	(0.17)	0.01
	Operating costs	**0.61**	0.53	0.52
		3.59	2.21	2.84

1 Includes operations in Indonesia and Malaysia/Vietnam.

Netbacks do not include synthetic oil or pipeline operations.

Historical Financial Summary

(millions of Canadian dollars unless otherwise stated)

Years ended December 31	**2003**	2002	2001	2000	1999	1998	1997	1996	1995	1994
Balance Sheets										
Current assets	**975**	917	799	1,042	730	272	471	362	256	426
Other assets	**139**	166	92	82	93	100	88	63	51	61
Goodwill	**473**	469	467	–	–	–	–	–	–	–
Property, plant and equipment	**9,778**	10,042	9,461	7,501	6,983	4,997	4,441	3,333	2,733	2,772
Total assets	**11,365**	11,594	10,819	8,625	7,806	5,369	5,000	3,758	3,040	3,259
Current liabilities	**1,218**	989	1,204	1,311	1,060	576	497	338	225	241
Deferred credits and other liabilities	**2,985**	3,106	2,695	1,997	968	587	601	426	280	235
Long-term debt	**2,203**	2,997	2,794	1,703	2,157	2,071	1,739	899	906	1,203
Shareholders' equity	**4,959**	4,502	4,126	3,614	3,621	2,135	2,163	2,095	1,629	1,580
Total liabilities and shareholders' equity	**11,365**	11,594	10,819	8,625	7,806	5,369	5,000	3,758	3,040	3,259
Income Statements										
Revenue										
Gross sales	**5,295**	5,299	5,047	4,836	2,318	1,534	1,700	1,407	1,011	720
Less royalties	**894**	927	989	946	389	214	312	224	144	130
Net sales	**4,401**	4,372	4,058	3,890	1,929	1,320	1,388	1,183	867	590
Other	**76**	80	82	99	46	51	42	30	32	23
Total revenue	**4,477**	4,452	4,140	3,989	1,975	1,371	1,430	1,213	899	613
Expenses										
Operating	**1,099**	1,115	946	827	604	581	480	300	245	166
General and administrative	**152**	138	108	95	70	59	57	56	57	41
Depreciation, depletion and amortization	**1,443**	1,495	1,313	1,153	747	615	541	421	369	212
Dry hole	**251**	174	113	77	51	91	42	65	26	33
Exploration	**213**	185	147	100	79	102	92	63	50	44
Interest on long-term debt	**137**	164	139	136	120	91	51	69	86	41
Stock based compensation	**185**	–	–	–	–	–	–	–	–	–
Other	**16**	113	78	64	(140)	199	(15)	(25)	(33)	(18)
Total expenses	**3,496**	3,384	2,844	2,452	1,531	1,738	1,248	949	800	519
Gain on sale of Sudan operations	**296**	–	–	–	–	–	–	–	–	–
Income (loss) before taxes	**1,277**	1,068	1,296	1,537	444	(367)	182	264	99	94
Taxes										
Current income tax	**229**	258	342	334	49	15	38	51	11	24
Future income tax (recovery)	**(51)**	162	72	196	109	(88)	60	84	50	31
Petroleum revenue tax	**92**	124	149	150	31	20	32	35	–	–
	270	544	563	680	189	(53)	130	170	61	55
Net income (loss)	**1,007**	524	733	857	255	(314)	52	94	38	39
Preferred security charges, net of tax	**22**	24	24	22	13	–	–	–	–	–
Income from discontinued operations	**–**	–	–	–	–	–	–	–	6	25
Net income (loss) available to common shareholders	**985**	500	709	835	242	(314)	52	94	44	64

Consolidated Financial Ratios

The following financial ratios are provided in connection with the Company's shelf prospectuses filed with Canadian and US securities regulatory authorities and are based on the Company's consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

The asset coverage ratios are calculated as at December 31, 2003. The interest coverage ratios are for the 12-month period then ended.

December 31, 2003	Preferred Securities as Equity[5]	Preferred Securities as Debt[6]
Interest coverage (times)		
Income[1]	**8.21**	**6.65**
Cash flow[2]	**19.22**	**15.59**
Asset coverage (times)		
Before deduction of future income taxes and deferred credits[3]	**4.60**	**3.92**
After deduction of future income taxes and deferred credits[4]	**3.25**	**2.76**

1 Net income plus income taxes and interest expense; divided by the sum of interest expense and capitalized interest.
2 Cash flow plus current income taxes and interest expense; divided by the sum of interest expense and capitalized interest.
3 Total assets minus current liabilities; divided by long-term debt.
4 Total assets minus current liabilities and long-term liabilities excluding long-term debt; divided by long-term debt.
5 The Company's preferred securities are classified as equity and the related charges have been excluded from interest expense.
6 Reflect adjusted ratios had the preferred securities been treated as debt and the related charges been included in interest expense.

Ratios and Key Indicators

(millions of Canadian dollars unless otherwise stated)

Years ended December 31	**2003**	2002	2001	2000	1999	1998	1997	1996	1995	1994
Net income	**1,007**	524	733	857	255	(314)	52	94	38	39
Cash flow	**2,729**	2,645	2,494	2,413	1,111	631	797	697	502	362
Current tax expense	**229**	258	342	334	49	15	38	51	11	24
Capital expenditures	**2,986**	2,150	2,213	1,643	1,559	1,289	1,088	783	489	429
Proceeds on property dispositions	**(100)**	(72)	(162)	(99)	(197)	(222)	(71)	(58)	(100)	(230)
Net capital expenditures	**2,886**	2,078	2,051	1,544	1,362	1,067	1,017	725	389	199
Debt/debt+equity (%)	**31%**	40%	42%	32%	38%	49%	45%	30%	36%	43%
Debt/cash flow (times)	**0.81**	1.13	1.20	0.72	1.98	3.31	2.18	1.29	1.80	3.32
Per common share										
Net income (loss) ($)	**7.65**	3.73	5.25	6.05	1.93	(2.80)	0.48	0.90	0.46	0.82
Cash flow ($)	**21.21**	19.73	18.48	17.51	8.91	5.64	7.29	6.71	5.21	4.63
Production (boe)	**1.13**	1.21	1.13	1.09	0.91	0.88	0.80	0.73	0.70	0.63
Proved gross reserves (at year end) (boe)	**10.6**	11.3	11.1	8.7	7.9	7.5	6.8	5.6	5.0	4.9
Average royalty rate (%)	**16%**	18%	20%	18%	16%	14%	18%	16%	14%	18%
Unit operating costs ($/boe)	**7.15**	6.48	5.79	5.19	5.14	5.61	5.24	3.78	3.42	3.11
Unit DD&A ($/boe)	**9.92**	9.19	8.58	7.70	7.72	6.21	6.18	5.54	5.45	4.36
Return on capital employed (%)[1]	**13.7%**	7.2%	11.8%	15.4%	5.1%	(7.7%)	1.5%	3.4%	1.4%	2.1%
Return on active capital employed (%)[2]	**16.0%**	8.6%	14.4%	18.2%	6.3%	(10.5%)	2.0%	4.2%	1.7%	2.5%
Return on equity (%)[3]	**21.3%**	12.1%	18.9%	23.7%	8.9%	(14.6%)	2.4%	5.0%	2.4%	3.6%

1 Net income/(average shareholders equity+average debt).
2 Net income/(average shareholders equity+average debt – average non-depleted capital).
3 Net income/average shareholders equity.
For the above calculations, the Company's preferred securities have been classified as equity.

Product Netbacks

		2003					2002					2001
		Total	Three months ended				Total	Three months ended				Total
C$ Gross		Year	Dec 31	Sep 30	Jun 30	Mar 31	Year	Dec 31	Sep 30	Jun 30	Mar 31	Year
North America	Oil and liquids ($/bbl)											
	Sales price	**35.30**	**31.88**	**33.43**	**32.92**	**42.74**	32.43	34.57	35.57	32.76	26.82	30.80
	Hedging (gain)	**2.45**	**2.07**	**2.05**	**1.26**	**4.38**	0.06	0.36	0.52	0.11	(0.77)	(0.12)
	Royalties	**7.37**	**6.86**	**6.81**	**6.50**	**9.27**	6.85	7.42	7.74	6.35	5.90	6.88
	Operating costs	**6.28**	**6.76**	**6.21**	**5.89**	**6.27**	5.55	6.20	5.91	4.64	5.48	5.22
		19.20	**16.19**	**18.36**	**19.27**	**22.82**	19.97	20.59	21.40	21.66	16.21	18.82
	Natural gas ($/mcf)											
	Sales price	**6.37**	**5.11**	**5.92**	**6.41**	**8.03**	3.96	5.21	3.26	4.08	3.29	5.39
	Hedging (gain)	**0.11**	**(0.04)**	**0.03**	**0.12**	**0.32**	(0.28)	(0.11)	(0.37)	(0.21)	(0.42)	0.02
	Royalties	**1.37**	**1.08**	**1.18**	**1.54**	**1.69**	0.75	1.04	0.55	0.73	0.67	1.34
	Operating costs	**0.75**	**0.78**	**0.77**	**0.70**	**0.76**	0.71	0.78	0.74	0.65	0.66	0.67
		4.14	**3.29**	**3.94**	**4.05**	**5.26**	2.78	3.50	2.34	2.91	2.38	3.36
North Sea	Oil and liquids ($/bbl)											
	Sales price	**39.72**	**38.81**	**38.66**	**35.29**	**46.14**	38.76	41.77	41.89	37.71	33.87	36.07
	Hedging (gain)	**2.01**	**2.07**	**1.98**	**0.14**	**3.74**	0.12	0.38	0.75	0.11	(0.74)	(0.17)
	Royalties	**(0.08)**	**0.60**	**(0.27)**	**(0.89)**	**0.09**	1.60	1.72	1.68	1.41	1.60	1.85
	Operating costs	**12.67**	**11.82**	**12.12**	**12.91**	**14.04**	11.11	12.00	12.74	9.51	10.27	10.06
		25.12	**24.32**	**24.83**	**23.13**	**28.27**	25.93	27.67	26.72	26.68	22.74	24.33
	Natural gas ($/mcf)											
	Sales price	**4.57**	**4.86**	**4.08**	**4.16**	**4.93**	3.89	4.51	3.13	3.05	5.04	4.35
	Hedging (gain)	–	–	–	–	–	–	–	–	–	–	–
	Royalties	**0.28**	**0.63**	**0.09**	**0.04**	**0.25**	0.48	0.27	0.46	0.41	0.79	0.46
	Operating costs	**0.54**	**0.48**	**0.71**	**0.38**	**0.58**	0.61	0.92	0.61	0.49	0.45	0.46
		3.75	**3.75**	**3.28**	**3.74**	**4.10**	2.80	3.32	2.06	2.15	3.80	3.43
Southeast Asia [1]	Oil and liquids ($/bbl)											
	Sales price	**41.05**	**41.36**	**38.26**	**37.81**	**47.08**	39.46	45.04	41.27	38.77	32.84	35.97
	Hedging (gain)	**2.37**	**2.10**	**2.07**	**1.26**	**4.30**	0.06	0.36	0.53	0.11	(0.76)	(0.30)
	Royalties	**16.09**	**15.69**	**14.43**	**15.86**	**18.71**	14.83	17.13	16.13	13.76	12.34	10.69
	Operating costs	**7.33**	**6.83**	**7.13**	**7.22**	**8.37**	7.93	8.67	8.30	7.61	7.15	7.13
		15.26	**16.74**	**14.63**	**13.47**	**15.70**	16.64	18.88	16.31	17.29	14.11	18.45
	Natural gas ($/mcf)											
	Sales price	**4.95**	**4.63**	**4.41**	**5.05**	**6.09**	4.72	6.00	4.12	4.92	3.96	4.80
	Hedging (gain)	–	–	–	–	–	–	–	–	–	–	0.02
	Royalties	**0.29**	**0.33**	**0.24**	**0.27**	**0.34**	0.25	0.31	0.24	0.25	0.20	0.24
	Operating costs	**0.50**	**0.41**	**0.53**	**0.49**	**0.64**	0.59	0.80	0.69	0.49	0.42	0.47
		4.16	**3.89**	**3.64**	**4.29**	**5.11**	3.88	4.89	3.19	4.18	3.34	4.07
Algeria	Oil ($/bbl)											
	Sales price	**39.01**	**39.70**	**39.37**	**35.05**	**40.33**	–	–	–	–	–	–
	Hedging (gain)	**2.23**	**2.11**	**2.07**	**1.26**	**4.40**	–	–	–	–	–	–
	Royalties	**19.18**	**18.52**	**20.38**	**18.04**	**20.16**	–	–	–	–	–	–
	Operating costs	**6.84**	**4.30**	**12.24**	**4.07**	**6.23**	–	–	–	–	–	–
		10.76	**14.77**	**4.68**	**11.68**	**9.54**	–	–	–	–	–	–
Sudan	Oil ($/bbl)											
	Sales price	**43.89**	–	–	–	**43.89**	37.79	46.30	38.33	36.64	29.35	32.66
	Hedging (gain)	–	–	–	–	–	0.07	0.37	0.52	0.11	(0.75)	(0.13)
	Royalties	**20.34**	–	–	–	**20.34**	14.94	21.74	12.45	13.96	11.32	12.78
	Operating costs	**3.73**	–	–	–	**3.73**	3.82	3.72	4.07	4.55	2.89	3.40
		19.82	–	–	–	**19.82**	18.96	20.47	21.29	18.02	15.89	16.61
Total Company	Oil and liquids ($/bbl)											
	Sales price	**38.93**	**37.53**	**37.15**	**34.87**	**44.85**	37.20	41.47	39.64	36.46	31.27	33.99
	Hedging (gain)	**2.05**	**2.08**	**2.01**	**0.65**	**3.14**	0.09	0.37	0.63	0.11	(0.75)	(0.16)
	Royalties	**5.59**	**5.13**	**4.20**	**3.83**	**8.53**	6.83	8.85	6.66	6.32	5.52	6.22
	Operating costs	**9.63**	**9.51**	**9.89**	**9.87**	**9.36**	7.99	8.53	8.89	7.17	7.38	7.15
		21.66	**20.81**	**21.05**	**20.52**	**23.82**	22.29	23.72	23.46	22.86	19.12	20.78
	Natural gas ($/mcf)											
	Sales price	**6.03**	**5.02**	**5.59**	**6.09**	**7.48**	4.03	5.20	3.32	4.02	3.55	5.22
	Hedging (gain)	**0.08**	**(0.03)**	**0.02**	**0.10**	**0.25**	(0.22)	(0.09)	(0.30)	(0.16)	(0.33)	0.02
	Royalties	**1.14**	**0.93**	**0.98**	**1.28**	**1.40**	0.67	0.89	0.51	0.65	0.63	1.14
	Operating costs	**0.70**	**0.70**	**0.74**	**0.65**	**0.72**	0.69	0.80	0.72	0.62	0.61	0.63
		4.11	**3.42**	**3.85**	**4.06**	**5.11**	2.89	3.60	2.39	2.91	2.64	3.43

1 Includes operations in Indonesia and Malaysia/Vietnam.

Netbacks do not include synthetic oil or pipeline operations.

Historical Operations Summary

Years ended December 31	**2003**	2002	2001	2000	1999	1998	1997	1996	1995	1994
Daily Average Production										
Crude oil (bbls/d)										
North America	**44,456**	46,287	50,424	51,005	44,806	45,103	40,627	34,169	31,019	29,801
North Sea	**110,613**	124,965	108,163	109,096	57,267	54,988	48,065	30,675	16,987	7,114
Southeast Asia [1]	**23,159**	21,925	20,326	19,627	28,286	31,684	28,458	22,621	18,121	5,919
Algeria	**6,594**	–	–	–	–	–	–	–	–	–
Sudan	**13,039**	60,109	53,257	45,869	11,726	–	–	–	–	–
Other	**–**	–	–	–	–	–	–	–	–	473
Natural gas liquids (bbls/d)										
North America	**12,473**	13,521	12,851	12,829	10,918	9,818	8,054	7,598	7,097	5,512
North Sea	**2,462**	2,521	2,665	2,806	1,989	2,492	2,437	2,363	1,791	538
Southeast Asia [1]	**1,271**	544	547	579	566	–	–	–	–	–
Synthetic oil (Canada) (bbls/d)	**2,649**	2,868	2,781	2,540	2,765	2,664	2,536	2,534	2,527	2,425
Total oil and liquids	**216,716**	272,740	251,014	244,351	158,323	146,749	130,177	99,960	77,542	51,782
Natural gas (mmcf/d)										
North America	**864**	820	809	755	681	631	558	557	581	481
North Sea	**109**	122	108	122	115	104	100	90	69	15
Southeast Asia [1]	**117**	94	93	111	108	13	–	–	–	–
Total natural gas	**1,090**	1,036	1,010	988	904	748	658	647	650	496
Total (mboe/d)	**398**	445	419	409	309	271	240	208	186	134
WTI (average US$/bbl)	**30.99**	26.15	25.92	30.26	19.30	14.37	20.61	22.02	18.40	17.19
NYMEX gas (average US$/mmbtu)	**5.44**	3.25	4.38	4.30	2.27	2.08	2.48	2.67	1.71	1.91
$C/$US exchange rate (year end)	**0.7738**	0.6331	0.6279	0.6666	0.6887	0.6511	0.6987	0.7298	0.7331	0.7129

1 Includes operations in Indonesia and Malaysia/Vietnam.

Reserves

Continuity of Proved Gross Reserves

	North America[1]	North Sea	Southeast Asia[2]	Algeria	Sudan	Trinidad	Total
Crude Oil and Liquids (mmbbls)							
Total Proved							
Proved reserves at December 31, 2000	199.3	246.0	25.5	20.3	140.7	–	631.8
Discoveries, additions and extensions	21.3	54.9	22.6	14.9	30.2	–	143.9
Purchase of reserves	10.7	20.4	14.7	–	–	–	45.8
Sale of reserves	(3.9)	(5.2)	–	–	–	–	(9.1)
Net revisions and transfers	8.0	(1.1)	4.1	–	4.8	–	15.8
2001 Production	(23.1)	(40.5)	(7.6)	–	(19.4)	–	(90.6)
Proved reserves at December 31, 2001	212.3	274.5	59.3	35.2	156.3	–	737.6
Discoveries, additions and extensions	13.0	13.5	9.6	2.6	32.3	19.2	90.2
Purchase of reserves	1.4	7.5	–	–	–	–	8.9
Sale of reserves	(4.6)	(2.8)	–	–	–	–	(7.4)
Net revisions and transfers	(1.2)	3.5	–	(10.4)	(5.8)	–	(13.9)
2002 Production	(21.8)	(46.5)	(8.3)	–	(21.9)	–	(98.5)
Proved reserves at December 31, 2002	199.1	249.7	60.6	27.4	160.9	19.2	716.9
Discoveries, additions and extensions	**16.0**	**8.2**	**25.2**	**3.9**	**–**	**–**	**53.3**
Purchase of reserves	**1.3**	**21.1**	**–**	**–**	**–**	**–**	**22.4**
Sale of reserves	**(5.3)**	**–**	**–**	**–**	**(156.1)**	**–**	**(161.4)**
Net revisions and transfers	**(0.1)**	**18.7**	**7.6**	**0.1**	**–**	**–**	**26.3**
2003 Production	**(20.8)**	**(41.3)**	**(9.0)**	**(2.4)**	**(4.8)**	**–**	**(78.3)**
Proved reserves at December 31, 2003	**190.2**	**256.4**	**84.4**	**29.0**	**–**	**19.2**	**579.2**
Proved Developed							
December 31, 2000	192.7	182.4	21.6	–	117.9	–	514.6
December 31, 2001	203.0	215.7	20.4	–	120.4	–	559.5
December 31, 2002	190.0	212.6	19.7	4.8	143.4	–	570.5
December 31, 2003	**186.4**	**213.0**	**29.5**	**25.5**	**–**	**–**	**454.4**
Natural Gas (bcf)							
Total Proved							
Proved reserves at December 31, 2000	2,216.8	286.0	769.5	–	–	–	3,272.3
Discoveries, additions and extensions	374.1	14.2	657.5	–	–	–	1,045.8
Purchase of reserves	365.0	57.1	173.9	–	–	–	596.0
Sale of reserves	(57.0)	(1.6)	–	–	–	–	(58.6)
Net revisions and transfers	(6.6)	(14.0)	30.6	–	–	–	10.0
2001 Production	(295.5)	(39.5)	(34.0)	–	–	–	(369.0)
Proved reserves at December 31, 2001	2,596.8	302.2	1,597.5	–	–	–	4,496.5
Discoveries, additions and extensions	374.2	15.4	19.7	–	–	223.5	632.8
Purchase of reserves	37.7	0.4	–	–	–	–	38.1
Sale of reserves	(34.9)	–	–	–	–	–	(34.9)
Net revisions and transfers	(80.3)	(11.3)	(54.4)	–	–	–	(146.0)
2002 Production	(300.1)	(44.6)	(34.5)	–	–	–	(379.2)
Proved reserves at December 31, 2002	2,593.4	262.1	1,528.3	–	–	223.5	4,607.3
Discoveries, additions and extensions	**351.5**	**1.0**	**107.0**	**–**	**–**	**–**	**459.5**
Purchase of reserves	**107.1**	**14.4**	**–**	**–**	**–**	**–**	**121.5**
Sale of reserves	**(14.3)**	**–**	**–**	**–**	**–**	**–**	**(14.3)**
Net revisions and transfers	**(77.0)**	**17.5**	**(20.6)**	**–**	**–**	**–**	**(80.1)**
2003 Production	**(315.8)**	**(39.9)**	**(42.7)**	**–**	**–**	**–**	**(398.4)**
Proved reserves at December 31, 2003	**2,644.9**	**255.1**	**1,572.0**	**–**	**–**	**223.5**	**4,695.5**
Proved Developed							
December 31, 2000	1,972.3	227.0	170.9	–	–	–	2,370.2
December 31, 2001	2,281.8	247.4	358.5	–	–	–	2,887.7
December 31, 2002	2,278.7	232.8	723.8	–	–	–	3,235.3
December 31, 2003	**2,404.0**	**220.1**	**920.9**	**–**	**–**	**–**	**3,545.0**

1 North American gross proved reserves exclude synthetic crude oil reserves: 2001 – 43.4 mmbbls; 2002 – 43.2 mmbbls; 2003 – 42.3 mmbbls.

2 Includes operations in Indonesia and Malaysia/Vietnam.

Historical Proved Reserves[1]

	1994	1995	1996	1997	1998	1999	2000	2001	2002	**2003**
Crude Oil and Liquids (mmbbls)										
Opening balance	95.0	167.8	167.9	225.9	300.3	416.5	557.1	631.8	737.6	**716.9**
Discoveries, additions and extensions	8.8	15.4	33.8	68.7	83.3	62.0	72.5	143.9	90.2	**53.3**
Dispositions and acquisitions	69.9	0.9	35.6	29.0	67.3	111.3	57.2	36.7	1.5	**(139.0)**
Net revisions and transfers	12.2	11.2	24.3	23.2	18.2	24.1	33.5	15.8	(13.9)	**26.3**
Production	(18.1)	(27.4)	(35.7)	(46.5)	(52.6)	(56.8)	(88.5)	(90.6)	(98.5)	**(78.3)**
Closing balance	167.8	167.9	225.9	300.3	416.5	557.1	631.8	737.6	716.9	**579.2**
Natural Gas (bcf)										
Opening balance	1,267.9	1,852.1	1,901.8	2,301.7	2,663.5	2,834.4	3,221.0	3,272.3	4,496.5	**4,607.3**
Discoveries, additions and extensions	186.0	195.3	263.9	407.6	396.0	301.0	472.3	1,045.8	632.8	**459.5**
Dispositions and acquisitions	564.1	9.5	34.2	289.6	(51.7)	368.6	(53.9)	537.4	3.2	**107.2**
Net revisions and transfers	15.1	82.0	338.7	(95.2)	100.2	47.4	(5.0)	10.0	(146.0)	**(80.1)**
Production	(181.0)	(237.1)	(236.9)	(240.2)	(273.6)	(330.4)	(362.1)	(369.0)	(379.2)	**(398.4)**
Closing balance	1,852.1	1,901.8	2,301.7	2,663.5	2,834.4	3,221.0	3,272.3	4,496.5	4,607.3	**4,695.5**
BOE[2] (mmboe)										
Opening balance	306.3	476.5	485.0	609.5	744.2	888.8	1,094.0	1,177.2	1,487.0	**1,484.7**
Discoveries, additions and extensions	39.8	47.9	77.7	136.6	149.2	112.0	151.1	318.2	195.7	**129.8**
Dispositions and acquisitions	163.9	2.5	41.3	77.3	58.7	172.8	48.1	126.2	2.1	**(121.1)**
Net revisions and transfers	14.8	25.0	80.7	7.4	34.9	32.2	32.8	17.5	(38.4)	**13.2**
Production	(48.3)	(66.9)	(75.2)	(86.6)	(98.2)	(111.8)	(148.8)	(152.1)	(161.7)	**(144.7)**
Closing balance	476.5	485.0	609.5	744.2	888.8	1,094.0	1,177.2	1,487.0	1,484.7	**1,361.9**

1 Gross reserves, excluding sulphur and synthetic oil.
2 Six mcf of natural gas equals one boe.

Over the past two years, Talisman has played a leading role in the Alberta Securities Commission process to develop new disclosure standards for reserves. The Company supports the objective of fostering investor confidence in reserves and has advocated uniformity with its North American peer group. In response to the recommendations, Talisman undertook a thorough review of its procedures for evaluating and booking reserves. The Company also established a Board committee to review the reserves process and disclosure and has established the position of an internal qualified reserves evaluator (IQRE). The IQRE provides a report to the Reserves Committee and a regulatory certificate regarding proved reserves and their related cash flows.

Talisman continues to do a complete internal evaluation of proved reserves annually, supported by external audits. Over the past three years, 90% of the Company's reserves have been independently audited. As a result of these reviews, the Company is confident that its reserves booking procedures and internal controls accurately capture and report its reserves. The empirical evidence for this is the Company's continued production growth, low and positive level of historical reserve revisions and low percentage of proved undeveloped reserves (PUD) in North America.

Talisman replaced 150% of production from all sources in 2003 (including proved and probable discoveries, revisions and net acquisitions excluding Sudan). On the basis of proved reserves, the Company replaced 127% of production from all sources and 102% through drilling, excluding Sudan.

Year end proved reserves were 1,362 mmboe, a 3% increase over 2002, excluding Sudan, largely due to increases in Malaysia/Vietnam and the US. Proved reserves per share increased by 5%, excluding Sudan. Overall revisions and transfers were positive, adding 13 mmboe. Probable reserves increased 4% to 873 mmboe, excluding Sudan.

Proved natural gas reserves increased 2% to 4,696 bcf. Approximately 57% of Talisman's proved reserves are natural gas, of which 56% (2,645 bcf) are situated in North America. Proved oil reserves increased by 4%, excluding Sudan, to 579 mmbbls. Virtually all of these reserves are high quality, medium-light crude oil and natural gas liquids.

PUDs account for only 7% of Talisman's North American total proved reserves. While international PUDs are higher at 37%, these are reserves with a high degree of certainty in well defined projects. Talisman's North Sea PUDs are in projects under development and for which near term development drilling is scheduled. Southeast Asia PUDs relate to the South Angsi development oil and gas reserves (under contract) in the PM-3 CAA in Malaysia and in the Corridor Block in Indonesia. These are long life gas contracts backstopped by proved reserves. Trinidad PUDs are associated with the Greater Angostura development, which is currently under construction.

At year end 2003 (based on 2003 production excluding Sudan), Talisman had a reserve life index of 9.7 years for proved reserves and 16 years based on proved plus probable reserves.

Probable Reserves[1]

	North America	North Sea	Southeast Asia[2]	Algeria	Sudan	Trinidad	Total
Crude Oil and Liquids (mmbbls)							
Probable reserves at December 31, 2002	86.3	141.9	56.7	40.4	52.3	19.3	396.9
Discoveries, additions and extensions	0.1	17.0	7.1	(3.9)	–	–	20.3
Dispositions and acquisitions	(1.3)	17.0	–	–	(52.3)	–	(36.6)
Net revisions and transfers	1.7	(3.6)	(0.5)	3.7	–	–	1.3
Probable reserves at December 31, 2003	**86.8**	**172.3**	**63.3**	**40.2**	**–**	**19.3**	**381.9**
Natural Gas (bcf)							
Probable reserves at December 31, 2002	1,398.3	101.3	1,388.5	–	–	92.0	2,980.1
Discoveries, additions and extensions	86.9	12.3	(13.7)	–	–	39.9	125.4
Dispositions and acquisitions	(2.2)	16.0	–	–	–	–	13.8
Net revisions and transfers	(123.4)	5.0	(54.6)	–	–	–	(173.0)
Probable Reserves at December 31, 2003	**1,359.6**	**134.6**	**1,320.2**	**–**	**–**	**131.9**	**2,946.3**
BOE[3] (mmboe)							
Probable reserves at December 31, 2002	319.3	158.7	288.1	40.4	52.3	34.6	893.4
Discoveries, additions and extensions	14.6	19.0	4.8	(3.9)	–	6.7	41.2
Dispositions and acquisitions	(1.6)	19.7	–	–	(52.3)	–	(34.2)
Net revisions and transfers	(18.9)	(2.7)	(9.5)	3.7	–	–	(27.4)
Probable reserves at December 31, 2003	**313.4**	**194.7**	**283.4**	**40.2**	**–**	**41.3**	**873.0**

1 Gross probable reserves, excluding sulphur and synthetic oil.
2 Includes operations in Indonesia and Malaysia/Vietnam.
3 Six mcf of natural gas equals one boe.

Finding and Development Costs

Talisman's finding and development (F&D) costs averaged $14.28/boe (US$11.71/boe net) in 2003.

Based on 2003 drilling results, Talisman's North American F&D costs averaged $13.72/boe. Approximately half of the increase over 2002 can be attributed to higher spending on land, geological and geophysical expenses (G&G) and, to a lesser extent, plant and equipment. Land and G&G represent an investment in potential future reserve additions. Timing was also an issue in 2003, where money spent in some areas (e.g. Appalachia and Monkman) will result in reserves additions in 2004.

Talisman also drilled more wells in 2003 to capitalize on higher gas prices and although this resulted in lower reserve adds per well, the investments were highly profitable at prevailing prices.

Including net revisions, North American F&D costs were $16.62/boe in 2003. Revisions and transfers in 2003 had the net effect of lowering North American proved reserves by 13 mmboe (less than 1% of Company total). The main reason for the revision was a detailed internal review of properties acquired by Talisman several years ago. For these reasons, the Company believes that three-year F&D costs are a better reflection of underlying performance.

International F&D costs were $12.52/boe in 2003, although again Talisman believes the three-year average of $7.03/boe is more representative. At year end, Talisman had over 100 mmboe of probable reserves (in Corridor gas in Indonesia and the J1/J5 oil discoveries in the North Sea), which will be transferred to proved, pending gas sales contracts and final project approvals in 2004. Had these reserves been booked in 2003, Talisman's international F&D costs would have been $5.62/boe.

Finding, development and acquisition (FD&A) costs were $14.67/boe in 2003 and largely reflect Talisman's asset acquisitions in Appalachia and Norway. Sudan has been excluded from the FD&A calculations because the sale of such a large property distorts the results so much that meaningful comparisons are not possible.

Finding, Development and Acquisition Costs (gross before royalties)

	1999	2000	2001	2002	**2003**	3-year	5-year
Proved Reserves Additions (mmboe)[1]							
North America	55.1	93.2	90.6	60.7	**61.6**	212.9	361.2
International	89.1	90.7	245.1	96.6	**81.5**	423.2	603.0
Total	144.2	183.9	335.7	157.3	**143.1**	636.1	964.2
Proved Net Acquisitions (mmboe)[2]							
North America	95.2	(6.0)	58.1	(2.7)	**11.5**	66.9	156.1
International	77.6	54.1	68.1	4.8	**23.5**	96.4	228.1
Total	172.8	48.1	126.2	2.1	**35.0**	163.3	384.2
Capital Spending (millions of dollars)[3]							
Exploration and development							
North America	300.5	658.7	821.2	753.9	**1,023.6**	2,598.7	3,557.9
International	621.1	459.6	971.1	980.7	**1,019.7**	2,971.5	4,052.2
Total Company	921.6	1,118.3	1,792.3	1,734.6	**2,043.3**	5,570.2	7,610.1
Net acquisitions and divestitures	1,581.5	209.5	1,478.1	203.4	**568.4**	2,249.9	4,040.9
Total Capital	2,503.1	1,327.8	3,270.4	1,938.0	**2,611.7**	7,820.1	11,651.0
Proved F&D Cost ($/boe)[4]							
North America	5.45	7.07	9.06	12.42	**16.62**	12.20	9.85
International	6.97	5.06	3.96	10.15	**12.52**	7.03	6.72
Total	6.39	6.08	5.34	11.03	**14.28**	8.76	7.89
Proved FD&A Cost ($/boe)[5]							
North America	8.35	7.39	11.75	15.00	**19.09**	14.34	11.43
International	7.49	4.72	4.86	10.53	**11.59**	7.33	6.91
Total	7.90	5.72	7.08	12.15	**14.67**	9.79	8.64

1 Proved discoveries and revisions only, excluding acquisitions, conventional oil only.

2 Reserve purchases less dispositions, includes asset sales, dispositions, swaps and corporate acquisitions. Excludes the impacts of the sale of the Sudan operations in 2003.

3 Exploration and development spending excludes indirect exploration expenses, synthetic oil operations capital, enhanced oil recovery, Chauvin pipeline, Canadian midstream and capitalized interest.

4 F&D costs have been calculated by dividing finding and development (excluding net acquisition costs) in Canadian dollars by proved gross before royalties reserves additions including revisions but excluding net acquired proved gross after royalty reserves.

5 FD&A costs have been calculated by dividing finding and development costs (including net acquisition costs) in Canadian dollars by proved gross before royalties reserves additions including revisions and net acquired proved gross before royalty reserves.

No amount of future capital has been included in the FD&A calculation, which is consistent with calculations performed in prior years.

Six mcf of natural gas equals one boe.

Recycle Ratio[1]

	1999	2000	2001	2002	**2003**	3-Year	5-Year
Netback ($/boe) – average annual	11.87	20.73	20.70	20.34	**23.00**	21.30	19.71
Finding and development	1.9	3.4	3.9	1.8	**1.6**	2.4	2.5
Finding, development and acquisition	1.5	3.6	2.9	1.7	**1.6**	2.2	2.3

1 Average annual netback divided by finding, development and acquisition costs.

Reconciliation of Costs included in F&D Calculations (gross before royalties)

(C$ millions)	1999	2000	2001	2002	**2003**	3-Year	5-Year
Exploration and development expenditures	996	1,179	1,882	1,848	**2,180**	5,910	8,085
Less:							
Midstream capital	–	(1)	(27)	(21)	**(27)**	(75)	(76)
Indirect costs	(23)	(33)	(34)	(41)	**(52)**	(127)	(183)
Capitalized interest	(41)	(16)	(19)	(25)	**(24)**	(68)	(125)
Synthetic oil operations capital	(9)	(8)	(8)	(24)	**(30)**	(62)	(79)
Enhanced recovery expenditures	(1)	(3)	(2)	(2)	**(4)**	(8)	(12)
	922	1,118	1,792	1,735	**2,043**	5,570	7,610

Detailed Property Reviews

2003 Landholdings

(thousands of acres)	Developed Gross	Developed Net	Undeveloped Gross	Undeveloped Net	Total Gross	Total Net
Canada						
Western Canada	2,844	1,493	5,128	3,443	7,972	4,936
Ontario	366	238	836	588	1,202	826
Other[1]	–	–	3,930	331	3,930	331
United States	11	11	1,038	884	1,049	895
Total North America	3,221	1,742	10,932	5,246	14,153	6,988
North Sea	412	140	2,117	1,036	2,529	1,176
Southeast Asia						
Indonesia	293	127	2,798	817	3,091	944
Malaysia and Vietnam	224	93	3,582	1,238	3,806	1,331
Papua New Guinea	–	–	187	90	187	90
Total Southeast Asia	517	220	6,567	2,145	7,084	2,365
Algeria	77	5	751	263	828	268
Trinidad	–	–	323	136	323	136
Other[2]	–	–	2,422	1,578	2,422	1,578
Total International	1,006	365	12,180	5,158	13,186	5,523
Total Worldwide	4,227	2,107	23,112	10,404	27,339	12,511
Synthetic Oil	9	1	410	39	419	40

1 Includes Yukon Territory, Northwest Territories, Arctic Islands and Scotia Slope.
2 Includes Colombia, Qatar and Falkland Islands.

2003 Drilling

Year Ended December 31, 2003		Exploration Oil	Exploration Gas	Exploration Dry	Exploration Total	Development Oil	Development Gas	Development Dry	Development Total	Total Oil	Total Gas	Total Dry	Total Total
North America													
Canada	Gross	14	147.0	22.0	183.0	190.0	225.0	21.0	436.0	204.0	372.0	43.0	619.0
	Net	9.4	100.9	15.9	126.2	101.0	132.7	18.2	251.9	110.4	233.6	34.1	378.1
United States	Gross	–	6.0	–	6.0	–	–	–	–	–	6.0	–	6.0
	Net	–	4.2	–	4.2	–	–	–	–	–	4.2	–	4.2
North Sea	Gross	3.0	–	2.0	5.0	12.0	2.0	3.0	17.0	15.0	2.0	5.0	22.0
	Net	2.2	–	1.1	3.3	5.5	0.2	0.9	6.6	7.7	0.2	2.0	9.9
Southeast Asia													
Indonesia	Gross	–	1.0	2.0	3.0	6.0	–	–	6.0	6.0	1.0	2.0	9.0
	Net	–	0.4	0.5	0.9	2.6	–	–	2.6	2.6	0.4	0.5	3.5
Malaysia	Gross	2.0	4.0	1.0	7.0	12.0	9.0	–	21.0	14.0	13.0	1.0	28.0
and Vietnam	Net	0.9	1.6	0.4	2.9	4.9	3.6	–	8.5	5.8	5.2	0.4	11.4
Algeria	Gross	1.0	–	–	1.0	11.0	–	–	11.0	12.0	–	–	12.0
	Net	0.4	–	–	0.4	0.6	–	–	0.6	1.0	–	–	1.0
Sudan	Gross	2.0	–	–	2.0	1.0	–	–	1.0	3.0	–	–	3.0
	Net	0.5	–	–	0.5	0.3	–	–	0.3	0.8	–	–	0.8
Trinidad	Gross	1.0	2.0	–	3.0	–	–	–	–	1.0	2.0	–	3.0
	Net	0.4	0.6	–	1.0	–	–	–	–	0.4	0.6	–	1.0
Total	Gross	23.0	160.0	27.0	210.0	232.0	236.0	24.0	492.0	255.0	396.0	51.0	702.0
	Net	13.8	107.7	17.9	139.4	114.9	136.5	19.1	270.5	128.7	244.2	37.0	409.9

Water injection, source and disposal wells are not included.

Five Year Drilling Results

	2003	2002	2001	2000	1999
North America					
Total oil wells	**204**	146	258	282	88
Total gas wells	**378**	223	241	256	178
Drilling success (%)	**93**	87	90	88	90

	2003	2002	2001	2000	1999
International					
Total oil wells	**51**	59	131	96	89
Total gas wells	**18**	11	7	7	8
Drilling success (%)	**90**	77	83	87	87

Property Review:
North America[1]

Property		Average WI (%)	2003	2002[2]	2001[2]
Greater Arch					
Production:	Oil & Liquids (bbls/d)	82	**7,734**	8,842	10,347
	Natural Gas (mmcf/d)	75	**152.4**	166.9	204.2
	Total Production (boe/d)		**33,131**	36,654	44,379
Drilling:	Number of wells		**72**	79	96
	Success Rate (%)		**75**	71	76
Capital Expenditures:	(C$ million)		**119**	114	136
Alberta Foothills					
Production:	Oil & Liquids (bbls/d)		**169**	167	139
	Natural Gas (mmcf/d)	86	**129.9**	121.1	102.4
	Total Production (boe/d)		**21,812**	20,353	17,210
Drilling:	Number of wells		**32**	22	21
	Success Rate (%)		**94**	95	100
Capital Expenditures:	(C$ million)		**163**	118	142
Chauvin					
Production:	Oil & Liquids (bbls/d)	97	**15,334**	14,265	12,578
	Natural Gas (mmcf/d)		**17.2**	18.3	16.7
	Total Production (boe/d)		**18,195**	17,312	15,361
Drilling:	Number of wells		**79**	60	90
	Success Rate (%)		**99**	93	99
Capital Expenditures:	(C$ million)		**53**	48	76
Northern Plains					
Production:	Oil & Liquids (bbls/d)	88	**1,456**	1,642	2,810
	Natural Gas (mmcf/d)	65	**30.8**	33.0	43.1
	Total Production (boe/d)		**6,595**	7,142	9,988
Drilling:	Number of wells		**5**	6	8
	Success Rate (%)		**63**	50	75
Capital Expenditures:	(C$ million)		**29**	25	18
Ontario					
Production:	Oil & Liquids (bbls/d)	98	**2,257**	2,664	3,056
	Natural Gas (mmcf/d)	91	**17.9**	20.2	18.9
	Total Production (boe/d)		**5,242**	6,034	6,198
Drilling:	Number of wells		**20**	29	35
	Success Rate (%)		**70**	79	94
Capital Expenditures:	(C$ million)		**20**	41	43
Monkman-BC Foothills					
Production:	Oil & Liquids (bbls/d)		**–**	–	11
	Natural Gas (mmcf/d)	68	**86.6**	82.7	90.0
	Total Production (boe/d)		**14,430**	13,770	15,016
Drilling:	Number of wells		**5**	2	5
	Success Rate (%)		**100**	100	80
Capital Expenditures:	(C$ million)		**51**	44	17
Carlyle					
Production:	Oil & Liquids (bbls/d)	85	**7,199**	7,657	9,421
	Natural Gas (mmcf/d)		**1.0**	1.0	0.9
	Total Production (boe/d)		**7,369**	7,824	9,576
Drilling:	Number of wells		**15**	13	17
	Success Rate (%)		**93**	100	89
Capital Expenditures:	(C$ million)		**14**	13	15
Edson Area (includes West Whitecourt, Bigstone/Wild River)					
Production:	Oil & Liquids (bbls/d)	89	**4,022**	4,189	3,449
	Natural Gas (mmcf/d)	85	**197.8**	199.7	162.7
	Total Production (boe/d)		**36,995**	37,465	30,565
Drilling:	Number of wells		**130**	79	95
	Success Rate (%)		**96**	96	85
Capital Expenditures:	(C$ million)		**281**	192	169

Property Review:
North America[1] (continued)

Property		Average WI (%)	**2003**	2002[2]	2001[2]
Lac La Biche					
Production:	Natural Gas (mmcf/d)	84	**49.2**	56.3	63.9
	Total Production (boe/d)		**8,208**	9,383	10,647
Drilling:	Number of wells		**24**	12	17
	Success Rate (%)		**83**	83	100
Capital Expenditures:	(C$ million)		**12**	6	19
Central Alberta (includes Acme)					
Production:	Oil & Liquids (bbls/d)	92	**2,112**	2,632	2,981
	Natural Gas (mmcf/d)	78	**17.4**	19.2	22.2
	Total Production (boe/d)		**5,015**	5,832	6,676
Drilling:	Number of wells		**8**	6	11
	Success Rate (%)		**100**	100	100
Capital Expenditures:	(C$ million)		**16**	18	35
Southern Alberta Foothills					
Production:	Oil & Liquids (bbls/d)	83	**2,422**	2,264	2,105
	Natural Gas (mmcf/d)	94	**10.9**	10.3	6.8
	Total Production (boe/d)		**4,242**	3,978	3,231
Drilling:	Number of wells		**17**	4	5
	Success Rate (%)		**100**	100	100
Capital Expenditures:	(C$ million)		**67**	22	23
Shaunavon					
Production:	Oil & Liquids (bbls/d)	84	**3,624**	3,724	3,813
Drilling:	Number of wells		**34**	7	4
	Success Rate (%)		**100**	86	100
Capital Expenditures:	(C$ million)		**17**	4	6
Other					
Production:	Oil & Liquids (bbls/d)		**8,865**	10,198	11,384
	Natural Gas (mmcf/d)		**41.8**	53.1	58.7
	Total Production (boe/d)		**15,819**	19,050	21,048
Drilling:	Number of wells		**115**	65	115
	Success Rate (%)		**99**	87	60
Capital Expenditures:	(C$ million)		**118**	130	133
Syncrude	Synthetic oil (bbls/d)	1.25	**2,649**	2,868	2,781
Deep Basin					
Production:	Oil & Liquids (bbls/d)		**1,735**	1,564	1,181
	Natural Gas (mmcf/d)	83	**50.9**	38.2	18.5
	Total Production (boe/d)		**10,212**	7,937	4,264
Drilling:	Number of wells		**60**	40	37
	Success Rate (%)		**97**	100	97
Capital Expenditures:	(C$ million)		**91**	47	44
United States:					
Appalachia					
Production:	Natural Gas (mmcf/d)	100	**59.9**	–	–
	Total Production (boe/d)		**9,984**	–	–
Drilling:	Number of wells		**6**	–	–
	Success Rate (%)		**100**	–	–
Capital Expenditures:	(C$ million)		**58**	–	–
Total Production:	Oil & Liquids (bbls/d)		**59,578**	62,676	66,056
	Natural Gas (mmcf/d)		**863.7**	820.0	809.0
	(boe/d)		**203,522**	199,326	200,753
Total Capital Expenditures:	(C$ million)		**1,109**	822	876

1 All production volumes are shown before royalties.
2 Prior year drilling statistics have been revised as necessary, such that all reported numbers are stated within the definitions used for 2003.

Property Review:
North Sea[1]

Property		Average WI (%)	**2003**	2002[2]	2001[2]
Mid-North Sea					
Clyde/Orion/Halley		13-95			
Production:	Oil & Liquids (bbls/d)		**13,014**	14,688	15,112
	Natural Gas (mmcf/d)		**4.4**	4.5	7.1
	Total Production (boe/d)		**13,742**	15,446	16,297
Drilling:	Number of wells		**2**	2	2
Capital Expenditures:	(C$ million)		**132**	94	77
Buchan/Hannay		86			
Production:	Oil & Liquids (bbls/d)		**8,526**	8,062	5,990
	Natural Gas (mmcf/d)		**0.4**	0.7	1.0
	Total Production (boe/d)		**8,598**	8,178	6,165
Drilling:	Number of wells		**2**	4	3
Capital Expenditures:	(C$ million)		**55**	89	89
Ross/Blake		54-69			
Production:	Oil & Liquids (bbls/d)		**22,437**	27,017	16,029
	Natural Gas (mmcf/d)		**7.0**	7.7	3.0
	Total Production (boe/d)		**23,601**	28,294	16,524
Drilling:	Number of wells		**3**	–	4
Capital Expenditures:	(C$ million)		**125**	4	163
Beatrice		100			
Production:	Oil & Liquids (bbls/d)		**5,603**	7,406	2,160
Drilling:	Number of wells		**–**	1	3
Capital Expenditures:	(C$ million)		**4**	16	104
Flotta Catchment Area		20-100			
Production:	Oil & Liquids (bbls/d)				
	Tartan/Highlander/Petronella		**6,706**	10,008	9,447
	Piper		**11,862**	16,009	19,070
	MacCulloch		**6,045**	6,184	4,761
	Claymore		**18,692**	20,045	17,496
	Natural Gas (mmcf/d)				
	MacCulloch and Piper		**0.7**	1.4	0.9
	Total Production (boe/d)		**43,414**	52,488	50,926
Drilling:	Number of wells		**6**	8	5
Capital Expenditures:	(C$ million)		**121**	186	145
Norway (Gyda)		61			
Production:	Oil & Liquids (bbls/d)		**2,574**	–	–
	Natural Gas (mmcf/d)		**1.3**	–	–
	Total Production (boe/d)		**2,788**	–	–
Drilling:	Number of wells		**–**	–	–
Capital Expenditures:	(C$ million)		**12**	–	–
Non-Operated					
Brae		13-18			
Production:	Oil & Liquids (bbls/d)		**7,883**	8,801	9,221
	Natural Gas (mmcf/d)		**83.6**	93.2	79.3
	Total Production (boe/d)		**21,816**	24,330	22,440
Drilling:	Number of wells		**2**	1	4
Capital Expenditures:	(C$ million)		**15**	4	11
Netherlands		4-20			
Production:	Oil & Liquids (bbls/d)		**132**	199	176
	Natural Gas (mmcf/d)		**9.8**	12.4	13.8
	Total Production (boe/d)		**1,764**	2,269	2,482
Drilling:	Number of wells		**2**	2	3
Capital Expenditures:	(C$ million)		**4**	13	6

Property Review:
North Sea[1] (continued)

Property		Average WI (%)	2003	2002[2]	2001[2]
Other		2-60			
Production:	Oil & Liquids (bbls/d)		**9,601**	9,067	11,366
	Natural Gas (mmcf/d)		**1.9**	2.3	3.0
	Total Production		**9,932**	9,436	11,848
Drilling:	Number of wells		**5**	5	9
Capital Expenditures:	(C$ million)		**28**	25	38
Total Production:	Oil & Liquids (bbls/d)		**113,075**	127,486	110,828
	Natural Gas (mmcf/d)		**109.1**	122.2	108.1
	(boe/d)		**131,258**	147,847	128,842
Total Capital Expenditures:	(C$ million)		**496**	431	633

1 All production volumes are shown before royalties.
2 Prior year drilling statistics have been revised as necessary, such that all reported numbers are stated within the definitions used for 2003.

Southeast Asia[1]

Property		Average WI (%)	2003	2002[2]	2001[2]
Corridor					
Production:	Oil & Liquids (bbls/d)				
	Corridor Technical Assistance Contract	40	**3,368**	4,329	5,344
	Corridor Production Sharing Contract	36	**2,543**	2,031	2,081
	Natural Gas (mmcf/d)				
	Corridor Production Sharing Contract	36	**105.3**	89.4	93.3
	Total Production (boe/d)		**23,453**	21,254	22,971
Drilling:	Number of wells		**1**	1	41
Capital Expenditures:	(C$ million)		**20**	59	65
Tanjung Raya		100			
Production:	Oil & Liquids (bbls/d)		**6,338**	6,617	6,414
Drilling:	Number of wells			2	3
Capital Expenditures:	(C$ million)		**7**	8	8
Ogan Komering		50			
Production:	Oil & Liquids (bbls/d)		**2,443**	2,721	3,340
	Natural Gas (mmcf/d)		**6.8**	5.0	–
	Total Production (boe/d)		**3,590**	3,563	3,340
Drilling:	Number of wells		**2**	6	12
Capital Expenditures:	(C$ million)		**4**	3	7
Jambi		40			
Production:	Oil & Liquids (bbls/d)		**1,066**	1,154	1,420
Drilling:	Number of wells		**4**	–	9
Capital Expenditures:	(C$ million)		**2**	0.5	3
Malaysia/Vietnam		41			
Production:	Oil & Liquids (bbls/d)		8,672	5,617	2,273
	Natural Gas (mmcf/d)		5.0	–	–
	Total Production (boe/d)		9,502	5,617	2,273
Drilling:	Number of wells		28	6	3
Capital Expenditures:	(C$ million)		275	161	56
Other		25-60			
Drilling:	Number of wells		2	2	–
Capital Expenditures:	(C$ million)		8	37.5	2
Total Production:	Oil & Liquids (bbls/d)		24,430	22,469	20,872
	Natural Gas (mmcf/d)		117.1	94.4	93.3
	(boe/d)		43,949	38,205	36,419
Total Capital Expenditures:	(C$ million)		316	269	141

1 All production volumes are shown before royalties.
2 Prior year drilling statistics have been revised as necessary, such that all reported numbers are stated within the definitions used for 2003.

Property Review:

Algeria [1]		Average WI (%)	2003	2002 [2]	2001 [2]
Production:	Oil & Liquids (bbls/d)	35	6,594		
Drilling:	Number of wells		12	8	14
Capital Expenditures:	(C$ million)		34	107	62
Sudan [1]					
Production:	Oil & Liquids (bbls/d)	25	13,039	60,109	53,257
Drilling:	Number of wells		3	30	44
Capital Expenditures:	(C$ million)		2	98	117
Exploration Areas					
Trinidad		25-65			
Drilling:	Number of wells		3	5	3
Capital Expenditures:	(C$ million)		130	78	31
Colombia		30-70			
Drilling:	Number of wells		–	–	–
Capital Expenditures:	(C$ million)		21	22	7
Other					
Drilling:	Number of wells		–	–	–
Capital Expenditures:	(C$ million)		72	21	15

1 All production volumes are shown before royalties.

2 Prior year drilling statistics have been revised as necessary, such that all reported numbers are stated within the definitions used for 2003.

Investor Information

Common Shares

Transfer agent:	Computershare Trust Company of Canada Calgary, Toronto, Montreal, Vancouver
Co-transfer agent:	Computershare Investor Services, LLC
Authorized:	Unlimited number of common shares and unlimited number of first and second preferred shares
Issued:	127,998,728 common shares at December 31, 2003

Preferred Securities

Trustee:	JP Morgan Chase Bank, New York
Issued:	TLM PrB 6,000,000 8.9% Preferred Securities each having principal amount of US$25

Stock Exchange Listings

Common Shares

Symbol:	**TLM**
Canada:	The Toronto Stock Exchange
United States:	New York Stock Exchange

Preferred Securities

Symbol:	**TLM PrB**
United States:	New York Stock Exchange

Public Debt

Trustee: Computershare Trust Company of Canada
7.125% (US$) unsecured debentures
9.80% unsecured debentures, Series B
7.25% (US$) unsecured debentures
8.06% unsecured medium term notes
5.80% unsecured medium term notes

Trustee: JP Morgan Chase, London
6.625% (£) unsecured notes

Talisman's commercial paper is currently rated as:
Moody's – P-2

Talisman's public long-term debt is currently rated as:
Dominion Bond Rating Service – BBB (high);
Moody's – Baa1; S&P – BBB+

Private Debt

6.71% (US$) unsecured notes, Series A
6.96% (US$) unsecured notes
6.89% (US$) unsecured notes, Series B
6.68% (US$) unsecured notes

Dividends

In June 2003, the Company paid a semi-annual dividend of $0.30 per share on Talisman's common shares. In December 2003, the Company paid a semi-annual dividend of $0.40 per share on Talisman's common shares.

Market Information

Common Shares		**2003**		2002		2001	
		TSX (C$)	**NYSE (US$)**	TSX (C$)	NYSE (US$)	TSX (C$)	NYSE (US$)
Share Price (dollars)	High	**73.80**	**56.98**	70.09	45.70	65.77	42.30
	Low	**55.12**	**35.30**	51.30	32.10	46.51	29.76
	Close	**73.52**	**56.60**	56.85	36.17	60.50	37.85
Shares Traded (millions)	First quarter	**38.3**	**10.1**	26.4	7.9	42.2	7.9
	Second quarter	**26.2**	**8.3**	28	8.6	44.5	9.4
	Third quarter	**23.8**	**7.9**	29.7	10.8	35.3	8.5
	Fourth quarter	**26.6**	**8.6**	51.3	15.4	39.2	10.8
	Year	**114.9**	**34.9**	135.4	42.7	161.2	36.7
Year end shares outstanding (millions)		**128**		131		134	
Weighted average shares outstanding (millions)		**129**		134		135	
Year end stock options outstanding (millions)		**7.9**		7.4		7.5	

Corporate Information

Executive Office

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Facsimile: (974) 435-0980

Investor Relations Contacts

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Executive Vice-President,
Corporate and Legal,
and Corporate Secretary
(403) 237-1183

David W. Mann
Senior Manager, Corporate and
Investor Communications
(403) 237-1196

Christopher LeGallais
Manager, Investor Relations
(403) 237-1957

Annual Meeting

The annual meeting of shareholders of Talisman Energy Inc. will be held at 10:30 a.m. on Tuesday, May 4, 2004 in the Exhibition Hall, North Building of the Telus Convention Center, 136 Eighth Avenue S.E., Calgary, Alberta. Shareholders are encouraged to attend the meeting, but those who are unable to do so are requested to participate by voting, using one of the three available methods: (i) by telephone, (ii) by internet, or (iii) by signing and returning the form of proxy or voting instruction form mailed with this report.

Directors and Executive

Board of Directors

Douglas D. Baldwin[2,3,4,6]
Calgary, Alberta
Chairman, Talisman Energy Inc.

James W. Buckee[2]
Calgary, Alberta
President and Chief Executive Officer
Talisman Energy Inc.

Kevin S. Dunne[3,5,6]
London, England
Corporate Director

Al L. Flood, C.M.[1,4]
Thornhill, Ontario
Corporate Director

Dale G. Parker[1,5]
Vancouver, British Columbia
Public Administration and Financial Institution Advisor

Roland Priddle[3,5]
Victoria, British Columbia
Consultant

Lawrence G. Tapp[3,4]
Langley, British Columbia
Principal, Tapp Technologies

Stella M. Thompson[4,5]
Calgary, Alberta
Principal, Governance West Inc.
President, Stellar Energy Ltd.

Robert G. Welty[1,2]
Calgary, Alberta
Director and Chief Executive Officer,
Sterling Resources Ltd.

Charles W. Wilson[1,2,6]
Evergreen, Colorado
Corporate Director

1 Member of Audit Committee
2 Member of Executive Committee
3 Member of Governance and Nominating Committee
4 Member of Management Succession and Compensation Committee
5 Member of Pension Funds Committee
6 Member of Reserves Committee

Executive

James W. Buckee
President and Chief Executive Officer

Ronald J. Eckhardt
Executive Vice-President, North American Operations

T. Nigel D. Hares
Executive Vice-President, Frontier and International Operations

Joseph E. Horler
Executive Vice-President, Marketing

Michael D. McDonald
Executive Vice-President, Finance and Chief Financial Officer

Robert M. Redgate
Executive Vice-President, Corporate Services

M. Jacqueline Sheppard
Executive Vice-President, Corporate and Legal, and Corporate Secretary

John 't Hart
Executive Vice-President, Exploration

Advisory – Forward-Looking Statements

This Annual Report contains statements that constitute forward-looking statements within the meaning of the United States Private Securities Litigation Reform Act of 1995.

Identifying Forward-Looking Statements

Forward-looking statements are included throughout this Annual Report, including among other places, under the headings "President's Message", "Business Environment", "Objectives and Performance", "2004 Outlook" and "Management's Discussion and Analysis". These statements include, among others, statements regarding:

- anticipated cash flow and cash flow per share;
- estimates of future sales, production and operations or financial performance;
- business plans for drilling, exploration and development;
- the estimated amounts and timing of capital expenditures;
- estimates of operating costs;
- business strategy and plans or budgets,
- outlook for oil and gas prices,
- anticipated liquidity, capital resources and debt levels;
- royalty rates and exchange rates;
- the merits or anticipated outcome of pending litigation; and
- other expectations, beliefs, plans, goals, objectives, assumptions, information and statements about possible future events, conditions, results of operations or performance.

Statements concerning oil and gas reserves contained in this Annual Report may be deemed to be forward-looking statements as they involve the implied assessment that the resources described can be profitably produced in the future, based on certain estimates and assumptions.

Often, but not always, forward-looking statements use words or phrases such as: "expects", "does not expect" or "is expected", "anticipates" or "does not anticipate", "plans" or "planned", "estimates" or "estimated", "projects" or "projected", "forecasts" or "forecasted", "believes", "intends", "likely", "possible", "probable", "scheduled" or "positioned", or state that certain actions, events or results "may", "could", "would", "might" or "will" be taken, occur or be achieved.

Material factors that could cause actual results to differ materially from those in forward-looking statements

Forward-looking statements are based on current expectations, estimates and projections that involve a number of risks and uncertainties, which could cause actual results to differ materially from those anticipated by Talisman Energy Inc. and described in the forward-looking statements. These risks and uncertainties include:

- the risks of the oil and gas industry, such as operational risks in exploring for, developing and producing crude oil and natural gas, and market demand;
- risks and uncertainties involving geology of oil and gas deposits;
- the uncertainty of reserves estimates and reserves life;
- the uncertainty of estimates and projections relating to production, costs and expenses;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- fluctuations in oil and gas prices, foreign currency exchange rates and interest rates;
- health, safety and environmental risks;
- uncertainties as to the availability and cost of financing;
- uncertainties related to the litigation process, such as possible discovery of new evidence or acceptance of novel legal theories and the difficulties in predicting the decisions of judges and juries;
- risks in conducting foreign operations (for example, political and fiscal instability or the possibility of civil unrest or military action);
- general economic conditions;
- the effect of acts of, or actions against international terrorism; and
- the possibility that government policies or laws may change or governmental approvals may be delayed or withheld.

We caution that the foregoing list of risks and uncertainties is not exhaustive. Additional information on these and other factors which could affect the Company's operations or financial results are included under the headings "Management's Discussion and Analysis – Risks and Uncertainties" and "– Outlook for 2004" and elsewhere in this Annual Report. Additional information may also be found in the Company's other reports on file with Canadian securities regulatory authorities and the United States Securities and Exchange Commission.

No obligation to update forward-looking statements

Forward-looking statements are based on the estimates and opinions of the Company's management at the time the statements are made. The Company assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change.

Advisory – Reserves Data and Other Oil and Gas Information

Talisman's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to Talisman by Canadian securities regulatory authorities, which permits Talisman to provide disclosure in accordance with US disclosure requirements. The information provided by Talisman may differ from the corresponding information prepared in accordance with Canadian disclosure standards under National Instrument 51-101 (NI 51-101). The proved reserves disclosed in this annual report have been calculated using the standards contained in Regulation S-X of the US Securities and Exchange Commission (SEC). The probable reserves disclosed in this annual report have been calculated using the definition for probable reserves set out by the Society of Petroleum Engineers/World Petroleum Congress. Further information on the differences between the US requirements and the NI 51-101 requirements is set forth under the heading "Note Regarding Reserves Data and Other Oil and Gas Information" in Talisman's Annual Information Form.

The exemption granted to Talisman also permits it to disclose internally evaluated reserves data. While Talisman annually obtains an independent audit of a portion of its reserves, no independent qualified reserves evaluator or auditor was involved in the preparation of the reserves data disclosed in this Annual Report.

Throughout this Annual Report, the calculation of barrels of oil equivalent (BOE) is calculated at a conversion rate of six thousand cubic feet (mcf) of natural gas for one barrel of oil and is based on an energy equivalence conversion method. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf:1 bbl is based on an energy equivalence conversion method primarily applicable at the burner tip and does not represent a value equivalence at the wellhead.

The finding, development and acquisition cost per BOE is calculated by dividing total capital expended on finding, development and acquisition activities by additions to proved reserves.

Advisory – Non-GAAP Financial Measures

Included in this Annual Report are references to financial measures commonly used in the oil and gas industry such as cash flow and cash flow per share. These financial measures have no standardized meaning and are not defined by Generally Accepted Accounting Principles in either Canada or the US. Consequently these are referred to as non-GAAP measures. Cash flow, as commonly used, appears as a separate caption on the Company's cash flow statement and is reconciled to both net income and cash flow from operations. Cash flow is used by the Company to assess operating results between years and between peer companies with different accounting policies. Our reported amounts may not be comparable to similarly titled measures reported by other companies. Cash flow should not be considered an alternative to, or more meaningful than, cash provided by operating, investing and financing activities or net income as determined in accordance with Canadian GAAP as an indicator of the Company's performance or liquidity.

Abbreviations

API	American Petroleum Institute
bbls	barrels
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
C$	Canadian dollars
FPSO	Floating, Production, Storage and Offloading Vessel
FSO	Floating, Storage and Offloading Vessel
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbbls	million barrels
mmboe	million barrels of oil equivalent
mmbtu	million British thermal units
mmcf	million cubic feet
Moody's	Moody's Investor Service
NYMEX	New York Mercantile Exchange
OECD	Organization of Economic Cooperation and Development
OPEC	Organization of Petroleum Exporting Countries
S&P	Standard & Poor's Ratings Group
tcf	trillion cubic feet
UK	United Kingdom
US	United States of America
US$	United States dollars
WTI	West Texas Intermediate
£	pound sterling

Conversion & Equivalency Factors

Imperial		**Metric**
1 ton	=	0.907 tonnes
1 acre	=	0.40 hectares
1 barrel	=	0.159 cubic metres
1 cubic foot	=	0.0282 cubic metres

Creative Development by Rivard Communications Inc. Printed in Canada by Quebecor World Calgary.

alisman has published a separate Corporate
esponsibility Report, which can be obtained
y contacting the Company. Talisman's Annual
nd Corporate Responsibility reports can also
e viewed on our website.

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NERGY

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