Management's Discussion and Analysis

For the year ended December 31, 2004

Management's Discussion and Analysis ("MD&A') should be read in conjunction with the audited consolidated financial statements and accompanying notes, prepared in accordance with Canadian generally accepted accounting principles (GAAP). All dollar amounts are in thousands of Canadian dollars unless otherwise indicated. The calculations of barrels of oil equivalent (boe) are based on a conversion ratio of six thousand cubic feet of natural gas to one barrel of crude oil, however this could be misleading if used in isolation. A boe conversion ratio of 6 mcf: 1bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Unless otherwise indicated, all production volumes quoted are the Company's working interest share before royalties. This MD&A is dated March 22, 2005.

References to cash flow; cash flow per share – basic; cash flow per share – diluted; and netbacks included in the MD&A are considered non-GAAP measures and may not be comparable to similar measures provided by other issuers. Cash flow represents cash flow from operating activities before changes in non-cash working capital, cash option payments and expenditures on abandonments. Management utilizes cash flow as a key measure to assess financial performance and the ability of the Company to finance future capital expenditures.

Certain 2003 and 2002 comparative financial information has been restated for a change in accounting policy and accounting reclassifications. For details of the change in accounting policy, please refer to *Critical Accounting Estimates, Asset Retirement Obligations* later in this MD&A. Certain comparative financial information was reclassified to conform with 2004 financial statement presentation. Certain transportation costs, previously reported as an offset to revenues, are now a separate expense item, and future income tax assets related to the current portion of stock-based compensation are now presented as a current future income tax asset rather than a component of the long term future income tax liability.

This MD&A contains forward-looking statements (forecasts) under applicable securities laws. Forward-looking statements are necessarily based upon assumptions and judgments with respect to the future including, but not limited to, the outlook for commodity prices and capital markets, the performance of producing wells and reservoirs, and the regulatory and legal environment. Many of these factors can be difficult to predict. As a result, the forward-looking statements are subject to known or unknown risks and uncertainties that could cause the actual results to differ materially from those anticipated or implied in the forward-looking statements.

Business Environment

Increased demand for commodities from growing economies such as China, and political instability in parts of the world, resulted in strong energy prices in 2004. The price of West Texas Intermediate ("WTI"), a benchmark for light crude oil, averaged $41.47 per barrel in 2004 up 34 percent compared to 2003.

Increased heavy oil differentials in 2004 were due to the fact that a significant portion of 2004 incremental supply, especially from the Organization of Petroleum Exporting Countries (OPEC), was heavy oil and there was a shortage of upgrading capacity. The average 2004 heavy/light crude oil differential was $15.32 per barrel, an increase of 41 percent from $10.84 per barrel in 2003.

AECO natural gas prices were stable in 2004 averaging $6.59 per mcf compared to $6.67 per mcf in 2003. Concerns about overall North American inventory levels and the tight balance between supply and demand factors were the main contributors to this price level.

The benefit of the strength in commodity prices was partially offset by the strength of the Canadian dollar relative to the U.S. dollar and wider heavy oil differentials. Oil marketing contracts are based on WTI prices, therefore, the strengthening Canadian dollar reduces netbacks realized in Canadian dollars. The average exchange rate increased by eight percent to $0.769 CAD/USD in 2004 compared to $0.715 CAD/USD in 2003. The Canadian dollar's strength was the result of numerous factors, including differences between Canadian and U.S. interest rates and relatively large U.S. current account deficits. Strong commodity prices also impacted operating costs due to increases in energy, steel and other costs.

Penn West has a proven management team, dedicated employees and an established business plan. In terms of production, cash flow, reserves and market capitalization, the Company has progressed from a very small producer in 1992 to the top ranks of independent oil and natural gas producers in western Canada. We have a disciplined approach to business that stresses cost control and product balance. Using this discipline, we have shown the ability not only to explore for and develop reserves of crude oil and natural gas, but also to acquire and optimize producing fields of crude oil and natural gas. We have a diverse asset base in the western Canada sedimentary basin divided into five core areas ranging from southern Saskatchewan to regions bordering the Northwest Territories. Our vision is to create shareholder value by:

- *Maintaining a strong balance sheet;*
- *Developing a portfolio of profitable exploration, development and research projects; and*
- *Effectively managing our diversified production base of light oil and medium crude, natural gas and heavy oil.*

Using our established business plan, we achieved record annual production and cash flow in 2004, as illustrated in the table below.

5. SHAREHOLDER VALUE MEASURES

Years ended December 31

	2004	2003	2002
Daily production per thousand shares (boe)	**2.0**	1.9	1.9
Cash flow per share ($)	**16.10**	15.11	8.70
Ratio of year end bank debt to annual cash flow	**0.6**	0.5	1.3

One component of our business plan is to maintain a strong balance sheet and thus provide the Company with the flexibility to take advantage of opportunities to create shareholder value. On February 18, 2004, the Company closed the acquisition of certain properties with production of 10,000 boe per day of conventional heavy oil and natural gas. These properties were an excellent fit with our existing southwest Saskatchewan core area properties and we are optimistic they will provide strong returns for our shareholders.

The factors that contribute to our success include an extensive land base of undeveloped land (5.8 million net acres at December 31, 2004), highly trained and motivated in house professional and technical staff, and a strong balance sheet that provides the flexibility to pursue a strategy of either organic growth or growth through cost effective acquisitions. The application of financial discipline has also been a key factor in achieving strong returns on investment.

The Company's three year financial returns are summarized in the table below:

6. PERFORMANCE INDICATORS

Years ended December 31

	2004	2003	2002
Return on capital employed (%)	**8.4**	15.9	6.6
Return on equity (%)	**15.3**	30.1	13.5

Review of Strategic Alternatives

The key item on Penn West's agenda in 2004 was the review of strategic alternatives to maximize value for the Company's shareholders. On August 20, 2004, the Company announced that the Board of Directors had recommended Penn West's assets be converted into an income trust. The conversion was contingent on receiving a satisfactory advance tax ruling from the Canada Revenue Agency.

At this date, the ruling remains pending. Upon receipt of a satisfactory ruling, Penn West intends to submit a Plan of Arrangement to shareholders for approval to effect the conversion. While this process has been lengthier than first hoped, feedback from shareholders suggests that a trust conversion remains their preference.

7. OIL AND NATURAL GAS REVENUES

Years ended December 31

($000s)	2004	2003	2002
Light oil and natural gas liquids	**$ 537,681**	$ 497,287	$ 429,695
Conventional heavy oil	**210,617**	113,707	97,276
Total liquids	**748,298**	610,994	526,971
Natural gas	**772,964**	783,188	481,426
Total	**$ 1,521,262**	$ 1,394,182	$ 1,008,397

8. 2004 INCREASES (DECREASES) IN GROSS REVENUES

($000s)	
Gross revenues – 2003	$ 1,394,182
Decrease in light oil and liquids production	(6,168)
Increase in light oil and liquids price	46,574
Increase in conventional heavy oil production	76,814
Increase in conventional heavy oil price	20,083
Decrease in natural gas production	(33,458)
Increase in natural gas price	23,235
Gross revenues – 2004	**$ 1,521,262**

Oil Revenues and Marketing

The Company's overall quality of crude oil remained high, averaging 28.5 degrees API in 2004. Light and medium oil and NGLs made up 33 percent of the Company's total production, with an average quality of 37 degrees API. Heavy oil, at 15 degrees API, accounted for 17 percent of the Company's production. The Company's light and heavy oil netbacks remained strong throughout 2004 despite wider differentials between WTI and Canadian heavy oil postings. Most of the Company's production is sold at the field level to various refiners and marketing companies.

Revenues from light oil and liquids increased eight percent to $538 million for the year ended December 31, 2004 from $497 million in 2003. This increase was attributable to higher average prices in 2004. The Company's average light oil and liquids price increased nine percent to $42.04 per barrel for the year ended December 31, 2004 from $38.40 per barrel in 2003, and the average daily production of light oil and liquids decreased two percent to 34,943 barrels per day in 2004 from 35,479 barrels per day in 2003.

Light oil and liquids revenues in the fourth quarter ("Q4') of 2004 were $154 million, an increase of 27 percent over Q4 2003 revenues of $121 million. This increase was due to significantly higher average prices in the 2004 quarter. The Company's average light oil and liquids price for Q4 2004 was $48.57 per barrel, an increase of 31 percent over the Q4 2003 average price of $36.94 per barrel. Production of 34,524 barrels per day of light oil and liquids was down three percent compared to production of 35,633 in Q4 of 2003.

For the year ended December 31, 2004, the Company received an average price of $48.09 per barrel for its light oil and NGL production before hedging (2003 – $39.84). Hedges reduced the netback price by $6.05 per barrel in 2004 compared to $1.44 per barrel in 2003. On average, the Company hedged approximately 40 percent of its liquid production in 2004. At December 31, 2004, and at the date of this MD&A, no crude oil volumes were hedged.

Hedging reduced the light oil and liquids price by $4.10 per barrel in Q4 2004 compared to a reduction of $0.12 per barrel in the same period in 2003. The price before hedging in Q4 2004 was $52.67 (2003 – $37.06).

Revenues from conventional heavy oil for the year ended December 31, 2004 increased 85 percent to $211 million from $114 million in the same period of 2003. This increase was attributable to the 2004 acquisition of conventional heavy oil properties and higher average prices. The Company's average conventional heavy oil price increased 11 percent to $31.73 per barrel in 2004 from $28.70 in 2003, and the average production of conventional heavy oil increased 67 percent to 18,136 barrels per day in 2004 from 10,853 barrels per day in 2003.

In the fourth quarter of 2004, conventional heavy oil revenues increased 112 percent to $53 million compared to $25 million in Q4 2003. This increase was also due to higher average prices in the quarter and increased production as a result of the acquisition of heavy oil properties. Conventional heavy oil prices were $29.89 per barrel in Q4 2004, an increase of 25 percent over Q4 2003 prices of $23.96 per barrel. Production in Q4 was up 68 percent to 19,257 barrels per day in 2004 compared to 11,446 barrels per day in 2003.

Natural Gas Revenues and Marketing

The Company maintains a significant weighting to the Alberta natural gas market, as this market offers a premium netback relative to other indices. As at December 31, 2004, the Company marketed approximately 86 percent of its natural gas sales directly, with the remaining 14 percent marketed by aggregator pools.

For the year ended December 31, 2004, Penn West received an average natural gas sales price of $6.68 per mcf, an increase of three percent from $6.48 per mcf in 2003. Revenues from natural gas decreased one percent in the year ended December 31, 2004 to $773 million from $783 million in 2003. Although pricing was higher in 2004 than in 2003, natural gas production of 316 mmcf per day in 2004 was five percent less than production of 331 mmcf per day in 2003, resulting in an overall reduction of natural gas revenue. The decrease in natural gas production in 2004 was attributable to natural reservoir declines.

Natural gas revenues in the fourth quarter of 2004 increased 18 percent to $193 million from $164 million in the same period in 2003. This was the result of higher natural gas prices in Q4 2004 partially offset by lower production volumes. Q4 2004 natural gas prices of $6.83 per mcf were 20 percent higher than Q4 2003 prices of $5.68 per mcf, and natural gas production of 307 mmcf per day in Q4 2004 was two percent lower than the 314 mmcf per day in Q4 2003.

The Company makes use of short term financial instruments at various times in the commodity price cycle to manage downside risk. On average, the Company hedged approximately 20 percent of its natural gas production in 2004. For the year ended December 31, 2004, natural gas hedging did not impact the sales price received compared to a $0.06 per mcf hedging loss in 2003. At December 31, 2004, the Company had an AECO costless collar in place hedging 75,000 GJ per day, representing approximately one-quarter of natural gas production, for the period January 2005 to March 2005 with a floor price of $7.30 per GJ and a ceiling price of $13.10 per GJ.

9. ROYALTY EXPENSES

Years ended December 31

	2004	2003	2002
Royalties, net of Alberta Royalty Credit ($000s)	**$ 296,054**	$ 265,132	$ 188,898
Average rate ($/boe)	**$ 7.65**	$ 7.15	$ 5.20
Percentage of gross revenues	**20%**	19%	19%

The average royalty rate incurred was 20 percent for the year ended December 31, 2004 compared to 19 percent for the same period in 2003. The royalty rate comprises an oil and liquids royalty rate of 18 percent compared to 16 percent in 2003 and a natural gas royalty rate of 21 percent in both 2004 and 2003. The increase in the oil and liquids royalty rate is mainly attributable to larger hedging losses in 2004. The year-to-year royalty rates also vary with commodity prices and the proportion of oil production relative to natural gas production.

For the fourth quarter of 2004, the average royalty rate incurred was 20 percent compared to 18 percent in Q4 2003. The oil and liquids royalty component increased to 18 percent in Q4 2004 compared to 14 percent in Q4 2003 as a result of increased hedging losses in Q4 2004 and higher prices. The natural gas royalty was 22 percent in Q4 2004 compared to 21 percent in Q4 2003.

10. OPERATING EXPENSES

Years ended December 31

	2004	2003	2002
Operating expenses ($000s)	**$ 300,278**	$ 245,572	$ 210,932
Average cost ($/boe)	**$ 7.75**	$ 6.63	$ 5.81
Percentage of gross revenues	**20%**	18%	21%

For the year ended December 31, 2004, operating costs averaged $7.75 per boe, a 17 percent increase from the average cost of $6.63 per boe achieved in 2003. Operating costs are generally higher for oil properties, and in 2004 liquids production increased to 50 percent of total production compared to 46 percent in 2003. A significant portion of the Company’s liquid production is light oil that commands a premium price, therefore, with increased light oil prices the Company is well positioned to absorb operating cost increases and still maintain high operating netbacks. Operating costs were impacted by increases in the costs of steel and energy, and the elevation of general oilfield service costs due to increased industry demand.

Light oil and liquids operating costs increased 10 percent to $12.80 per barrel in the year ended December 31, 2004 from $11.68 per barrel in the same period of 2003. Operating costs for conventional heavy oil increased 14 percent to $8.49 per barrel during 2004 from $7.48 per barrel in 2003. Operating costs for natural gas in 2004 were $0.69 per mcf, an increase of 30 percent from $0.53 per mcf in 2003.

Q4 2004 operating costs were $7.94 per boe, eight percent higher than Q4 2003 operating costs of $7.35 per boe. This increase was the result of the higher liquids production as a percentage of total production, higher steel and energy costs and increased industry demand for oilfield services.

Light oil and liquids operating costs in Q4 2004 increased six percent to $13.14 per barrel from $12.35 per barrel in Q4 2003 and natural gas operating costs increased 11 percent to $0.71 per mcf in Q4 2004 from $0.64 per mcf in Q4 2003.

11. NETBACKS

Years ended December 31

	2004	2003	2002
Light oil and natural gas liquids			
Production (bbls/day)	**34,943**	35,479	33,822
Price ($/bbl)	**$ 48.09**	$ 39.84	$ 36.26
Hedging loss ($/bbl)	**(6.05)**	(1.44)	(1.45)
Royalties ($/bbl)	**(7.86)**	(6.39)	(6.17)
Operating expenses ($/bbl)	**(12.80)**	(11.68)	(10.29)
Netback ($/bbl)	**$ 21.38**	$ 20.33	$ 18.35
Conventional heavy oil			
Production (bbls/day)	**18,136**	10,853	10,211
Price ($/bbl)	**$ 31.73**	$ 28.70	$ 26.10
Royalties ($/bbl)	**(4.62)**	(3.84)	(3.31)
Operating expenses ($/bbl)	**(8.49)**	(7.48)	(7.30)
Netback ($/bbl)	**$ 18.62**	$ 17.38	$ 15.49
Natural gas			
Production (mmcf/day)	**316.3**	331.3	332.7
Price ($/mcf)	**$ 6.68**	$ 6.54	$ 4.06
Hedging loss ($/mcf)	**–**	(0.06)	(0.09)
Royalties ($/mcf)	**(1.43)**	(1.38)	(0.83)
Operating expenses ($/mcf)	**(0.69)**	(0.53)	(0.46)
Netback ($/mcf)	**$ 4.56**	$ 4.57	$ 2.68

For the year ended December 31, 2004, the Company received an average light oil and liquids netback of $21.38 per barrel, an average conventional heavy oil netback of $18.62 per barrel, and a natural gas netback of $4.56 per mcf. The light oil and liquids netback was up five percent from $20.33 per barrel for the year ended December 31, 2003 due to higher average commodity prices, partially offset by higher royalties, hedging losses and operating expenses experienced in the year. The heavy oil netback was up seven percent from $17.38 per barrel in 2003 mainly due to higher prices, partially offset by the wider light/heavy oil price differential and higher royalties and operating costs. The netback for natural gas was relatively unchanged as the impact of higher royalties and operating costs were offset by higher prices in 2004.

In Q4 2004, the Company achieved an overall netback of $25.18 per boe comprised of an average light oil and liquids netback of $25.96 per barrel, an average conventional heavy oil netback of $17.15 per barrel, and an average natural gas netback of $4.61 per mcf. All products contributed to the 23 percent overall increase from $20.50 per boe in 2003. The Q4 2004 light oil and liquids netback increased 35 percent from $19.17 per barrel in Q4 2003, the netback for conventional heavy oil increased 33 percent from $12.85 per barrel in Q4 2003, and the natural gas netback increased 20 percent from $3.85 per mcf in Q4 2003. The increased netbacks in the quarter were the direct result of higher commodity prices partially offset by increased royalties and operating expenses.

12. GENERAL AND ADMINISTRATIVE EXPENSES

Years ended December 31

	2004	2003	2002
Gross expenses ($000s)	**$ 41,272**	$ 33,967	$ 26,182
Operator recoveries ($000s)	**(25,183)**	(21,463)	(15,859)
Net expenses ($000s)	**$ 16,089**	$ 12,504	$ 10,323
Gross general and administrative expenses – average cost ($/boe)	**$ 1.07**	$ 0.92	$ 0.72
Percentage of gross revenues	**3%**	2%	3%
Net general and administrative expenses – average cost ($/boe)	**$ 0.42**	$ 0.34	$ 0.28
Percentage of gross revenues	**1%**	1%	1%

Gross general and administrative expenses increased due to growth in staff levels required to manage the Company's larger asset base. Expressed on a unit of production basis, the gross general and administrative costs increased 16 percent to $1.07 per boe for the year ended December 31, 2004 from $0.92 per boe in 2003. Net general and administrative expenses on a per unit basis increased 24 percent to $0.42 per boe in 2004 from $0.34 per boe in 2003.

Q4 2004 net general and administrative expenses were up 34 percent on a per unit basis to $0.55 per boe from $0.41 per boe in Q4 2003.

13. STOCK-BASED COMPENSATION PROVISION

Years ended December 31

	2004	2003	2002
Stock-based compensation ($000s)	**$ 84,136**	$ 48,002	–
Average cost ($/boe)	**$ 2.17**	$ 1.30	–
Percentage of gross revenues	**6%**	3%	–

The Company's Stock Option Plan provides option holders the right to receive cash on the exercise of stock options. As a result, stock-based compensation costs of $84 million were recorded in 2004 (2003 – $48 million). Cash payments of $15.6 million (2003 – $13.6 million) were made during 2004 on the exercise of 523,305 stock options (2003 – 741,820 stock options). These payments were charged to the stock-based compensation liability.

Stock-based compensation of $22 million in Q4 2004 was up 214 percent from $7 million in Q4 2003. The increase was due to a $9.30 increase in the closing market price of Company common shares during Q4 2004 compared to an increase of $2.43 during Q4 2003.

14. FINANCING EXPENSES

Years ended December 31

	2004	2003	2002
Interest ($000s)	**$ 17,012**	$ 11,870	$ 20,310
Cash flow times interest coverage	**51.9**	69.5	23.8
Average cost ($/boe)	**$ 0.45**	$ 0.32	$ 0.57
Percentage of gross revenues	**1%**	1%	2%

Interest expense for the year ended December 31, 2004 amounted to $17.0 million, an increase of 43 percent from $11.9 million in 2003. This increase reflects higher relative debt levels due to the acquisition of properties producing approximately 10,000 boe per day in February 2004 for $234 million, and the payment of a special one time dividend of $1.50 per share and quarterly dividends of $0.125 per share for total cash payments to shareholders of $108 million in 2004 (2003 – nil).

Q4 2004 interest expense of $4.3 million is 48 percent higher than Q4 2003 interest expense of $2.9 million as a result of higher average debt levels in the current quarter.

15. DEPLETION, DEPRECIATION AND ACCRETION

Years ended December 31

	2004	2003	2002
Depletion and depreciation ($000s)	**$ 394,324**	$ 291,867	$ 237,954
Accretion ($000s)	**18,750**	11,795	10,082
	$ 413,074	$ 303,662	$ 248,036
Average rate ($/boe)	**$ 10.67**	$ 8.19	$ 6.83
Percentage of gross revenues	**27%**	22%	25%

The depletion, depreciation and accretion provision increased by 36 percent to $413 million in 2004 from $304 million in 2003, and by 29 percent in Q4 2004 to $116 million from $90 million in Q4 2003. These increases are the result of an increase in the fourth quarter 2004 depletion rate to $11.19 per boe (fourth quarter 2003 – $9.45). The average depletion and depreciation rate, excluding accretion, for the year increased by 29 percent to $10.18 per boe in 2004 from $7.87 per boe in 2003.

16. FOREIGN EXCHANGE

Years ended December 31

	2004	2003	2002
Foreign exchange (gain) loss ($000s)	**$ (27,708)**	$ (95,574)	$ 4,482
(Gain) loss from written Canadian dollar calls ($000s)	**(12,686)**	12,686	–
Net foreign exchange (gain) loss ($000s)	**$ (40,394)**	$ (82,888)	$ 4,482
Average (gain) loss ($/boe)	**$ (1.04)**	$ (2.24)	$ 0.12
Percentage of gross revenues	**3%**	6%	0.4%

As at December 31, 2004, the Company had $290 million of USD denominated debt (2003 – US$340 million). The translation of the outstanding U.S. dollar bank loans to Canadian dollars, using exchange rates in effect at year end, resulted in an unrealized foreign exchange gain of $12 million for 2004, versus an unrealized foreign exchange gain of $96 million in 2003. The unrealized gain in 2003 was reduced by the unrealized loss of $13 million on Canadian dollar calls outstanding at December 31, 2003. These calls expired in 2004 with no cost to the Company, which totally eliminated the unrealized loss recorded in 2003.

In July 2004, the Company converted US$150 million of its U.S. denominated borrowings to Canadian dollars at an exchange rate of $0.755 CAD/USD resulting in a realized foreign exchange gain of $28.5 million. In January 2005, the Company converted US$80 million of U.S. denominated debt to Canadian dollars at an exchange rate of $0.831 CAD/USD and realized an additional foreign exchange gain of $24.9 million.

17. TAXES

Years ended December 31

	2004	2003	2002
Current income taxes ($000s)	**$ 17,834**	$ 9,898	$ 82,021
Future income taxes ($000s)	**109,568**	97,343	45,737
	$ 127,402	$ 107,241	$ 127,758
Effective tax rate	**31%**	19%	42%
Capital taxes ($000s)	**$ 10,146**	$ 10,150	$ 11,031

The provision for income taxes increased by 19 percent for the year ended December 31, 2004 to $127 million from $107 million in 2003. A non-recurring future income tax benefit of $20 million was recorded in 2004 reflecting a tax rate reduction enacted by the Government of Alberta in May 2004. This compares to a non-recurring future tax benefit of $100 million recorded in the prior year ended December 31, 2003 due to a reduction in both the federal and provincial tax rates. The 2003 provision was also impacted by larger foreign exchange gains. These gains are 50 percent taxable. The larger tax recovery and capital gains in 2003 are the main contributors to the lower 2003 tax provision even though income before taxes of $564 million in 2003 was 38 percent higher than 2004 income before taxes of $409 million.

The provision for income taxes in 2004 includes current taxes payable of $18 million, which was up 80 percent from $10 million in 2003 as a result of increased taxable income in the current year.

The Q4 2004 income tax provision of $35 million was 22 percent lower than the Q4 2003 income tax provision of $45 million.

18. TAX POOLS

At December 31

($ millions)	2004	2003	2002
Undepreciated capital cost (UCC)	**$ 276.4**	$ 270.1	$ 440.6
Cumulative Canadian oil and gas property expense (COGPE)	**611.5**	679.2	852.7
Cumulative Canadian development expense (CDE)	**95.4**	136.6	128.5
Cumulative Canadian exploration expense (CEE)	**–**	–	1.4
Other	**–**	–	0.7
Total tax pools	**$ 983.3**	$ 1,085.9	$ 1,423.9

19. ITEMS AFFECTING CASH FLOW AND NET INCOME

Years ended December 31

	2004		2003		2002	
	$/boe	**%**	$/boe	%	$/boe	%
Oil and natural gas revenues	**$ 39.29**	**100**	$ 37.62	100.0	$ 27.77	100
Net royalties	**(7.65)**	**(19.5)**	(7.15)	(19.0)	(5.20)	(18.7)
Operating expenses	**(7.75)**	**(19.7)**	(6.63)	(17.6)	(5.81)	(20.9)
Net operating income	**23.89**	**60.8**	23.84	63.4	16.76	60.4
Transportation	**(0.66)**	**(1.7)**	(0.71)	(1.9)	(0.59)	(2.1)
General and administrative expenses	**(0.42)**	**(1.1)**	(0.34)	(0.9)	(0.28)	(1.0)
Interest	**(0.45)**	**(1.1)**	(0.32)	(0.9)	(0.57)	(2.1)
Realized foreign exchange gain	**0.74**	**1.9**	–	–	–	–
Current and capital taxes	**(0.71)**	**(1.8)**	(0.54)	(1.4)	(2.56)	(9.2)
Cash flow from operations	**22.39**	**57.0**	21.93	58.3	12.76	46.0
Unrealized foreign exchange gain (loss)	**0.30**	**0.8**	2.24	6.0	(0.12)	(0.4)
Stock-based compensation	**(2.17)**	**(5.5)**	(1.30)	(3.5)	–	–
Depletion, depreciation and accretion	**(10.67)**	**(27.2)**	(8.19)	(21.8)	(6.83)	(24.6)
Future income taxes	**(2.83)**	**(7.2)**	(2.63)	(7.0)	(1.26)	(4.6)
Net income	**$ 7.02**	**17.9**	$ 12.05	32.0	$ 4.55	16.4

Cash flow increased by seven percent to $867 million for the year ended December 31, 2004 from $813 million in the same period of 2003. Basic cash flow per share rose by seven percent to $16.10 per share in 2004, compared to $15.11 per share in 2003.

Q4 2004 cash flow was $238 million, an increase of 23 percent from $194 million in Q4 2003. Basic cash flow per share increased 23 percent to $4.41 per share in Q4 2004 compared to $3.60 per share in Q4 2003.

Net income for the year ended December 31, 2004 decreased by 39 percent to $272 million from $447 million in 2003. Basic net income per share decreased by 39 percent in 2004 to $5.05 per share from $8.30 per share in 2003.

Net income in Q4 2004 increased 77 percent to $69 million from $39 million in Q4 2003. Basic net income per share increased 76 percent to $1.27 per share in Q4 2004 from $0.72 per share in Q4 2003.

Market Risk Management

The Company is exposed to normal market risks inherent in the oil and natural gas business, including credit risk, commodity price risk, interest rate risk and foreign currency risk. The Company, from time to time, attempts to minimize exposure to these risks using financial instruments. Financial instruments are not used by the Company for trading or speculative purposes.

Credit Risk

Credit risk is the risk of loss if purchasers or counterparties do not fulfill their contractual obligations. All of the Company's receivables are with customers in the oil and natural gas industry and are subject to normal industry credit risk. In order to limit the risk of non-performance of counterparties to derivative instruments, the Company transacts only with financial institutions with high credit ratings and by obtaining security in certain circumstances.

Commodity Price Risk

Commodity price risk is the Company's most significant exposure. Crude oil prices are influenced by worldwide factors such as OPEC actions, supply and demand fundamentals, and political events. Natural gas prices are generally influenced by oil prices and North American natural gas supply and demand factors. Pursuant to Company policy, the Company may from time to time attempt to manage these risks through the use of costless collars up to a maximum of 50 percent of sales volumes.

Interest Rate Risk

The Company maintains its debt in floating-rate bank facilities resulting in exposure to fluctuations in short term interest rates. From time to time, the Company may increase the certainty of interest rates using financial instruments to swap floating interest rates to fixed interest rates.

Foreign Currency Rate Risk

Prices received for sales of crude oil and certain bank loans are referenced to, or denominated in, U.S. dollars. Accordingly, realized oil prices, interest costs and debt levels are impacted by CAD/USD exchange rates. When considered appropriate, the Company may use financial instruments to fix future exchange rates.

Liquidity and Capital Resources

20. CAPITALIZATION

At December 31

	2004		2003		2002	
	$ millions	**%**	$ millions	%	$ millions	%
Common share equity, at market	**$ 4,269**	**86.0**	$ 2,586	81.0	$ 2,203	75.4
Bank loan	**503**	**10.2**	442	13.8	598	20.5
Working capital deficiency	**190**	**3.8**	165	5.2	120	4.1
	$ 4,962	**100.0**	$ 3,193	100.0	$ 2,921	100.0

Penn West's closing market price on the Toronto Stock Exchange was $79.25 per share in 2004, $48.17 per share in 2003 and $41.00 per share in 2002. Total capitalization was $5.0 billion at December 31, 2004 compared to $3.2 billion at year end 2003.

The Company ended the year 2004 with increased annual average production and only slightly increased debt levels compared to year end 2003. The Company maintained its strong balance sheet during 2004 even though it paid $108 million in special and quarterly dividends during the 2004 year. The strong balance sheet provides the Company flexibility to pursue a variety of opportunities for 2005.

Penn West had an aggregate borrowing limit of $840 million on its loan facility with a syndicate of chartered banks. The Company had drawn $503 million at year end 2004. This loan facility is subject to an annual review by the lenders and requires no principal repayments provided that tangible net worth and cash flow coverage tests are met. Penn West believes it has ample coverage under these tests and anticipates that the loan facility will be renewed.

The Company announced a Normal Course Issuer Bid through the facilities of the Toronto Stock Exchange effective March 8, 2004. For a period not to exceed one year, a maximum of five percent of the issued and outstanding common shares of the Company, being 2,689,796 shares, could be purchased for cancellation. No share purchases were made under this bid.

Business Risks

The Company's exploration, development, production and acquisition activities are conducted in the Western Canada Sedimentary Basin and involve a number of business risks. These risks include the uncertainty of replacing annual production and finding new reserves on an economic basis, the instability of commodity prices, exchange rates and interest rates, and other factors discussed under *Notice Regarding Forward-Looking Statements*.

To the extent practical, the Company mitigates these risks by employing highly trained and competent management and staff who manage these risks by:

- *Balancing the production portfolio between oil and natural gas;*
- *Pursuing numerous investing opportunities, including;*
  - *Low risk development projects;*
  - *Moderate risk exploration plays;*
  - *Strategic acquisitions; and,*
- *Maintaining low finding, operating and general and administrative costs.*

The Company's management team believes that these principles, validated through Penn West's twelve year track record of growth and profitability, will continue to apply under the current or alternative business models.

The oil and natural gas industry is subject to extensive government influence through taxation policies and environmental legislation. While taxation policy has remained relatively stable recently, there is always the potential for change.

The industry is also subject to extensive regulations imposed by governments related to the protection of the environment. Environmental legislation in western Canada has undergone major revisions that have resulted in environmental standards and compliance becoming more stringent. The Company is committed to meeting its responsibilities to protect the environment wherever it operates, and has instituted a series of controls and procedures with respect to environmental protection that meet the standards of the Environmental Code of Practice published by the Canadian Association of Petroleum Producers.

Future Prospects and Outlook

Focusing on its five core areas, the Company continues to generate economic prospects through acquisitions, exploration, exploitation and development. The Company believes its extensive undeveloped land base and high quality, long life reserves, provide opportunities to add both reserves and production at relatively low risk.

Penn West has provided positive earnings in each quarter for the last twelve years. Fiscal responsibility has always played a major role in the timing of actions taken by our management team. With commodity prices presently at relatively high levels and market expectations that they will remain high, the Company believes it has a variety of capital reinvestment options to achieve strong returns for shareholders.

Penn West will continue to plan conservatively while emphasizing low costs and maximum efficiencies in its operations. Penn West's asset base, control of infrastructure and efficient operations provide a solid foundation to generate superior future rates of return with low risk.

Our capital expenditure program in the first quarter of 2005 is based on a "business as usual" approach and is estimated in the $190 – $220 million range. These expenditures will cover a drilling program of between 140 – 170 net wells, versus 180 net wells drilled in the first quarter of 2004. For the balance of the year, our plans will vary with the timing of any potential change in strategic direction. Average annual production is forecast at 103,000 to 109,000 boe per day. Our current plans and budget are based on assumed average 2005 commodity prices of US$39 per barrel of WTI crude oil and US$6.25 per MMBTU of NYMEX gas, and a currency exchange rate of $0.80 CAD/USD.

Under these assumptions, Penn West is expected to generate 2005 pre-tax cash flow of between $800 million to $850 million.

The results of operations and the forecasts noted above are sensitive to changes in production, commodity prices, foreign exchange rates and interest rates. The table below summarizes those sensitivities.

21. SENSITIVITIES

($ millions, except per share amounts)	Impact on 2005 Cash Flow	Impact on 2005 Net Income
Change of:		
$1.00 per barrel in liquids price	$ 18.4	$ 11.6
Per common share	0.34	0.21
1,000 barrels per day in daily liquids production	11.7	4.6
Per common share	0.22	0.08
$0.10 per mcf in natural gas price	8.1	5.1
Per common share	0.15	0.09
10 mmcf per day in daily natural gas production	17.3	6.2
Per common share	0.32	0.11
$0.01 in CAD/USD exchange rate	15.0	9.5
Per common share	0.28	0.17
1% in prime interest rate	6.0	3.8
Per common share	$ 0.11	$ 0.07

(Sensitivities exclude hedging impacts).

22. COMMITMENTS

The Company has committed to certain payments over the next five years, in addition to regular payments under the Company's credit facilities, as follows:

($ millions)	2005	2006	2007	2008	2009	Thereafter
Transportation	$ 21.8	$ 11.4	$ 8.8	$ 6.7	$ 3.3	$ 2.5
Transportation (US$)	3.4	3.4	1.7	1.6	1.6	9.3
Electricity	2.1	2.1	2.1	2.1	2.1	2.8
Office lease	4.0	4.2	4.2	4.2	4.2	3.5

23. EQUITY INSTRUMENTS

Common shares issued	
As at December 31, 2004*	53,868,745
Issued on exercise of stock options	61,200
As at March 22, 2005	53,929,945
Stock options outstanding	
As at December 31, 2004*	3,728,980
Granted	48,700
Exercised for common shares	(61,200)
Exercised for cash	(130,075)
Forfeited	(34,450)
As at March 22, 2005	3,551,955

* See Note 7 to the consolidated financial statements.

Critical Accounting Estimates

The Company's significant accounting policies are detailed in Note 1 to the consolidated financial statements. In the determination of financial results, the Company must make certain significant accounting estimates as follows:

Full Cost Accounting

The Company uses the full cost method of accounting for oil and natural gas properties. The Company has used this methodology consistently since the existing management team assumed responsibility for the Company in 1992. Generally, all costs of exploring and developing oil and natural gas reserves are capitalized and depleted against associated oil and natural gas production using the unit-of-production method based on the estimated proved reserves.

The Company adopted the new oil and natural gas full cost accounting guideline effective January 1, 2004. The guideline changed the determination of the ceiling amount for ascertaining the recoverability of accumulated costs in a cost center. The ceiling amount for a cost center is based on the undiscounted cash flows from proved reserves, using future prices, and the cost of unproven properties. If the costs are determined to be not fully recoverable, they are written down to fair value. Fair value is estimated as the present value of expected future cash flows from proven and probable reserves, using future prices, and the value of unproved properties. The Company's estimated risk-free rate is used to determine present values.

The Company used a weighted average price of $41.07 per barrel for oil and natural gas liquids and $6.40 per mcf for natural gas in the determination of the ceiling amount at December 31, 2004. There was no impact on reported results due to the application of this guideline.

Oil and Natural Gas Reserves

All of the Company's reserves were evaluated by the independent petroleum engineering consultant Gilbert Laustsen Jung Associates Ltd. In both 2004 and 2003, reserves were determined in compliance with National Instrument 51-101. The evaluation of oil and natural gas reserves are, by their nature, based on complex extrapolations and models as well as other significant engineering, capital, pricing and cost assumptions. Reserve estimates are a key component in the calculation of depletion. In addition, reserves are a key component of value in the ceiling test. To the extent that the ceiling amount is less than the carrying amount of property, plant and equipment, a write down against income must be made.

Asset Retirement Obligations

Effective January 1, 2004, the Company retroactively adopted the new Asset Retirement Obligations ("ARO') accounting recommendations. The fair value of statutory, contractual or legal obligations to retire long-lived assets are recorded as an ARO liability with a corresponding increase to the carrying amount of the related asset. The recorded ARO liability increases over time for changes in its fair value through accretion charges to earnings. Revisions to the estimated amount or timing of the obligations are reflected as increases or decreases to the ARO liability. Actual asset retirement expenditures are charged to the ARO liability to the extent of the then recorded liability. Amounts capitalized to the related assets are amortized to income consistent with the depletion or depreciation of the underlying asset. Note 5 to the consolidated financial statements details the impact of adopting these accounting recommendations on the comparative financial statements.

Stock-Based Compensation

The Company has recognized the potential liability that could arise if option holders elected the cash settlement alternative at the period end share price. Provision is made for all vested options at the period end plus the portion of future option vestings attributable to the period. The stock-based compensation expense of future periods will vary with share prices and changes in outstanding options.

Financial Instruments

Financial instruments contracted by the Company and determined to be hedges are accounted for as a component of the hedged item such as oil price, natural gas price, electricity or interest costs. The change in market value of a financial instrument accounted for as a hedge is not recognized in the financial statements until the underlying oil or natural gas production, power or interest is realized. Net income could change if these impacts were immediately recognized in the financial statements. Market value changes of financial instruments determined not to be hedges, not qualifying as a hedge, or no longer effective as hedgers, are fully recognized in the financial statements. There are, for certain financial instruments, several acceptable methods for determining a mark-to-market value at a point in time. These differences can directly impact reported results.

Accounting Changes

Effective January 1, 2004, the Company began accounting for certain transportation costs as expenses in the consolidated statements of income and retained earnings. This change had no impact on net income as it was a reclassification between revenue and expenses. Previously, these costs were netted against revenue. Comparative periods have been restated to conform with the current year presentation. Future income taxes related to the current portion of the stock-based compensation liability were reclassified to a current future income tax asset from a component of the long term futures income tax liability.

Notice Regarding Forward-Looking Statements

This document contains certain forward-looking statements that can generally be identified as such because of the context of the statements. Forward-looking statements may contain words such as forecasts, expects, anticipates, plans, intends, projects, estimates, or words of a similar nature. Results may differ materially from those expressed or implied by the forward-looking statements as a result of known and unknown risks, uncertainties and other factors.

Such factors include, among others:

- *Changes in general economic, market and business conditions which will impact demand for and market prices of the Company's products;*
- *The ability of the Company to implement its business strategy;*
- *Availability and cost of borrowing;*
- *The ability of the Company to complete its capital programs;*
- *The ability of the Company to transport its products to market;*
- *Potential delays or changes in plans with respect to exploration or development projects;*
- *The success of exploration and development activities;*
- *The accuracy of reserve estimates;*
- *Actions by governmental authorities, government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations);*
- *Competitive actions of other entities, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; and,*
- *The occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events directly affecting assets, and/or daily operations.*

Readers are cautioned that the foregoing list of important factors is not exhaustive. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available on the date the statements are made, events or circumstances could cause actual results to differ materially from those estimated or projected and expressed in, or implied by, these forward-looking statements.

Future Accounting Pronouncements

Earnings Per Share

Effective January 1, 2005, this accounting pronouncement will require the number of incremental shares included in the year-to-date diluted earnings per share calculation be computed using the average market price of common shares for the year-to-date period. It also stipulates that contracts which could be settled in cash or common shares would be settled in common shares, if share settlement is more dilutive. Shares to be issued upon conversion of a mandatorily convertible instruments would be included in the basic weighted average earnings per share calculation from the date when conversion becomes mandatory. These changes will not materially impact the Company's diluted earnings per share calculations.

Consolidation of Variable Interest Entities

Effective January 1, 2005, this accounting guideline addresses the circumstances where an entity has control of another entity through arrangements other than share ownership. The accounting guideline requires an enterprise to consolidate the entity when that enterprise has a variable interest that will absorb a majority of the entity's returns or losses. As the Company does not currently have any such arrangements, no impact is expected from the implementation of this guideline.

Financial Instruments, Other Comprehensive Income

This exposure draft addresses when to recognize, and how to measure, a financial instrument on the balance sheet and how gains and losses are to be presented. An additional financial statement, other comprehensive income, will be required. Once implemented, the fair value of financial instruments, designated as hedges, will be included on the balance sheet with the related gain or loss recognized in other comprehensive income. Consistent with current practice, financial instruments not designated as hedges will be valued at market with the related gains and losses recognized in net income.