21

Follow-Up Materials

06011812

82- SUBMISSIONS FACING SHEET

MICROFICHE CONTROL LABEL

REGISTRANT'S NAME Penn West Energy Trust

*CURRENT ADDRESS

**FORMER NAME

PROCESSED
MAR 2 2 2006
THOMSON FINANCIAL

**NEW ADDRESS

FILE NO. 82- 34902 FISCAL YEAR 12-31-05

* *Complete for initial submissions only* ** *Please note name and address changes*

INDICATE FORM TYPE TO BE USED FOR WORKLOAD ENTRY:

12G3-2B	(INITIAL FILING)	☐	AR/S	(ANNUAL REPORT)	☑
12G32BR	(REINSTATEMENT)	☐	SUPPL	(OTHER)	☐
DEF 14A	(PROXY)	☐			

OICF/BY: dlw

DAT : 3/21/06

RECEIVED
2006 MAR 21 P 3:01
OFFICE OF INTERNATIONAL CORPORATE FINANCE

ARIS
12-31-05

Management's Report

The consolidated financial statements of Penn West Energy Trust were prepared by management in accordance with accounting principles generally accepted in Canada. In preparing the consolidated financial statements, management has made estimates because a precise determination of certain assets and liabilities is dependent on future events. The financial and operating information presented in this report is consistent with that shown in the consolidated financial statements.

Management maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to facilitate the preparation of relevant, reliable and timely financial records for the preparation of statements.

The consolidated financial statements have been examined by the external auditors and approved by the Board of Directors. The Board of Director's financial statement related responsibilities are fulfilled through the Audit Committee. The Audit Committee is composed entirely of independent directors. The Audit Committee recommends appointment of the external auditors to the Board of Directors, ensures their independence, and approves their fees. The Audit Committee meets regularly with management and the external auditors to discuss reporting and control issues and to ensure each party is properly discharging its responsibilities. The auditors have full and unrestricted access to the Audit Committee to discuss their audit and their related findings as to the integrity of the financial reporting process.

Todd H. Takeyasu
Vice President, Finance

Derek W. Loomer
Controller

William E. Andrew
President

February 27, 2006

Auditors' Report to Unitholders

We have audited the consolidated balance sheets of Penn West Energy Trust as at December 31, 2005 and 2004 and the consolidated statements of income and accumulated earnings and cash flow for the years then ended. These consolidated financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada
February 27, 2006

Consolidated Balance Sheets

YEARS ENDED DECEMBER 31, ($ millions)	2005	2004
ASSETS		
Current		
Accounts receivable	$ 214.4	$ 160.5
Future income taxes	–	25.3
Risk management (note 10)	8.5	–
Other	29.0	19.8
	251.9	205.6
Property, plant and equipment (note 3)	3,715.2	3,661.8
	$ 3,967.1	$ 3,867.4

LIABILITIES AND UNITHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	$ 304.1	$ 306.6
Taxes payable	11.8	11.2
Distributions/dividends payable	50.6	6.7
Stock-based compensation (note 8)	–	71.0
Deferred gain on financial instruments (note 10)	11.9	–
	378.4	395.5
Bank loan (note 4)	542.0	503.1
Asset retirement obligations (note 5)	192.4	180.7
Stock-based compensation (note 8)	–	20.9
Future income taxes	682.1	858.2
	1,416.5	1,562.9
Unitholders' Equity		
Unitholders' capital (note 7)	561.0	515.3
Contributed surplus (note 7)	5.5	–
Accumulated earnings	1,927.2	1,393.7
Accumulated cash distributions (note 9)	(321.5)	–
	2,172.2	1,909.0
	$ 3,967.1	$ 3,867.4

See accompanying notes to the consolidated financial statements

Approved on behalf of the Board

John A. Brussa
Chairman

James C. Smith
Director

Consolidated Statements of Income and Accumulated Earnings

YEARS ENDED DECEMBER 31, ($ millions, except per unit amounts)	2005	2004
Revenues		
Oil and natural gas	$ 1,919.0	$ 1,521.3
Royalties	(355.0)	(296.1)
	1,564.0	1,225.2
Expenses		
Operating	327.4	300.4
Transportation	22.7	25.6
General and administrative	23.1	16.1
Interest on long term debt	23.2	17.0
Depletion, depreciation and accretion	437.6	413.1
Equity-based compensation (note 8)	77.2	84.1
Foreign exchange (gain) loss	4.5	(40.4)
Risk management activities (note 10)	3.4	–
	919.1	815.9
Income before Taxes	644.9	409.3
Taxes		
Capital	14.7	10.1
Current income	54.1	17.8
Future income (recovery)	(1.1)	109.6
	67.7	137.5
Net Income	$ 577.2	$ 271.8
Net Income per Unit [1]		
Basic	$ 3.55	$ 1.68
Diluted	$ 3.48	$ 1.65
Accumulated Earnings, Beginning of Period	$ 1,393.7	$ 1,148.7
Net income	577.2	271.8
Plan of arrangement (note 13)	(32.9)	–
Dividends	(10.8)	(26.8)
Accumulated Earnings, End of Period	$ 1,927.2	$ 1,393.7

See accompanying notes to the consolidated financial statements

[1] The 2004 comparative figures have been restated to reflect the conversion ratio of three trust units issued for each Penn West common share pursuant to the plan of arrangement.

Consolidated Statements of Cash Flow

YEARS ENDED DECEMBER 31, ($ millions)	2005	2004
Operating Activities		
Net income	$ 577.2	$ 271.8
Depletion, depreciation and accretion	437.6	413.1
Future income taxes (recovery)	(1.1)	109.6
Foreign exchange (gain) loss	4.5	(40.4)
Equity-based compensation (note 8)	77.2	84.1
Risk management activities (note 10)	3.4	–
Payments for surrendered options	(141.6)	(15.6)
Environmental expenditures	(22.6)	(29.5)
Decrease (increase) in non-cash working capital	(1.8)	23.7
	932.8	816.8
Investing Activities		
Additions to property, plant and equipment, net	(456.7)	(865.6)
Decrease (increase) in non-cash working capital	(63.2)	50.0
	(519.9)	(815.6)
Financing Activities		
(Decrease) increase in bank loan	(51.4)	72.6
Issue of equity	23.7	5.2
Realized foreign exchange gain	85.8	28.5
Distributions/dividends paid	(288.4)	(107.6)
Plan of arrangement costs (note 13)	(36.3)	–
Settlement of future income tax liabilities on conversion	(146.3)	–
Decrease in non-cash working capital	–	0.1
	(412.9)	(1.2)
Change in Cash	–	–
Cash, Beginning of Period	–	–
Cash, End of Period	$ –	$ –
Interest paid	$ 22.9	$ 17.0
Income and capital taxes paid (recovered)	$ 241.2	$ (9.5)

See accompanying notes to the consolidated financial statements

Notes to the Consolidated Financial Statements

(ALL TABULAR AMOUNTS IN $ MILLIONS, EXCEPT UNIT AND PER UNIT AMOUNTS)

1. Structure of the Trust

On May 31, 2005, Penn West Petroleum Ltd. (the "Company") was reorganized into Penn West Energy Trust (the "Trust") under a plan of arrangement (the "Plan") entered into by the Trust and the Company and its shareholders. Shareholders received three trust units for each common share held. On June 2, 2005, the trust units commenced trading on the TSX under the symbol "PWT.UN". The Trust was created pursuant to a trust indenture dated April 22, 2005 with CIBC Mellon Trust Company appointed trustee.

The Trust is an open-ended, unincorporated investment trust governed by the laws of the Province of Alberta. The purpose of the Trust is to indirectly explore for, develop and hold interests in petroleum and natural gas properties, through investments in securities of subsidiaries and royalty interests in oil and natural gas properties. The Trust owns 100 percent of the common shares of the Company which carries on the business of the Trust. The activities of the Company are financed through interest bearing notes from the Trust and third-party debt as described in the notes to these consolidated financial statements.

Pursuant to the terms of an NPI agreement (the "NPI"), the Trust is entitled to payments from the Company equal to essentially all of the proceeds of the sale of production, less certain specified deductions. Under the terms of the NPI, the deductions are discretionary and include the requirement to fund capital expenditures.

Under the terms of the trust indenture, the Trust is required to make distributions to unitholders in amounts equal to the income of the Trust earned from interest on certain notes, the NPI, and any dividends paid on the common shares of the Company, less any expenses of the Trust.

2. Summary of significant accounting policies

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles.

a) Principles of consolidation

The consolidated financial statements, prior to the Plan, included the Company and its subsidiaries. Upon completion of the Plan, the consolidated financial statements have been prepared on a continuity of interests basis with the Trust as the successor to the Company.

The 2005 consolidated financial statements reflect the results of operations and cash flows of the Company and its subsidiaries for the period January 1, 2005 to May 31, 2005 and the results of operations of the Trust and its subsidiaries for the period from June 1, 2005 to December 31, 2005. As a result of the conversion into a trust, certain information included in the consolidated financial statements for prior periods may not be comparable. The consolidated financial statements include the accounts of the Trust and all its wholly owned subsidiaries and partnerships.

b) Other current assets

Other current assets include deposits, prepayments and inventory. Inventories are valued at the lower of cost and net realizable value.

c) Property, plant and equipment

I) CAPITALIZED COSTS

The full cost method of accounting for oil and natural gas operations is followed whereby all costs of acquiring, exploring and developing oil and natural gas reserves are capitalized. These costs include lease acquisition, geological and geophysical, exploration and development and related equipment costs. Proceeds from the disposition of oil and natural gas properties are accounted for as a reduction of capitalized costs, with no gain or loss recognized unless such disposition results in a significant change in the depletion and depreciation rate.

II) DEPLETION AND DEPRECIATION

Depletion and depreciation of resource properties is calculated using the unit-of production method based on production volumes before royalties in relation to total proved reserves as estimated by independent petroleum engineers. Natural gas volumes are converted to equivalent oil volumes based upon the relative energy content of six thousand cubic feet of natural gas to one barrel of oil. In determining its depletion base, the Trust includes estimated future costs to be incurred in developing proved reserves and excludes estimated facility and equipment salvage values and the cost of unevaluated properties. Significant natural gas processing facilities, net of estimated salvage values, are depreciated using the declining balance method over the estimated useful lives of the facilities.

III) CEILING TEST

The recoverability of accumulated costs in a cost center is assessed based on undiscounted future cash flows from proved reserves, using forecast prices, and the cost of unproven properties. If accumulated costs are assessed to be not fully recoverable, the cost centre is written down to its fair value estimated as the present value of expected future cash flows, using forecast prices, from proved and probable reserves and the value of unproved properties. Expected future cash flows are discounted at the Trust's estimated risk free rate.

IV) ASSET RETIREMENT OBLIGATIONS

The fair value of legal obligations for property abandonment and site restoration are recognized as a liability on the balance sheet as incurred with a corresponding increase to the carrying amount of the related asset. The recorded liability increases over time to its future amount through accretion charges included in depletion, depreciation and accretion. Revisions to the estimated amount or timing of the obligations are reflected as increases or decreases to the recorded liability. Asset retirement expenditures, up to the recorded liability at the time, are charged to the liability. Amounts capitalized to the related assets are amortized to income consistent with the depletion or depreciation of the underlying asset.

The estimates in ii) and iii) and iv) are based on volumes and reserves calculated based on forecast sales prices, costs and regulations expected at the end of the fiscal year.

d) Joint ventures

Some of the Trust's exploration and development activities are conducted jointly with others. The accounts reflect only the Trust's proportionate interest in such activities.

e) Financial instruments

The Trust has policies and procedures in place with respect to the required documentation and approvals for the use of derivative financial instruments and their use is limited to mitigating market price risk associated with expected cash flows.

The Trust elected to discontinue hedge accounting in 2005. Effective July 1, all financial instruments are accounted for using the fair value method. These financial instruments are recognized on the balance sheet at inception and changes in the fair value of these instruments are recognized in income.

Prior to July 1, 2005 financial instruments that were determined to be hedges were accounted for as a component of the hedged item such as oil prices, natural gas prices, electricity costs or interest. The changes in market values of financial instruments accounted for as hedges were not recognized in the financial statements until the underlying oil or natural gas production, power or interest was realized. Changes in market value of financial instruments determined not to be hedges, not qualifying as a hedge, or no longer effective as a hedge were fully recognized in the financial statements.

f) Enhanced oil recovery

The value of proprietary injectants is not recognized as revenue until reproduced and sold to third parties. The cost of injectants purchased from third parties for miscible flood projects is included in property, plant and equipment. Deferred injectant costs are amortized as depletion and depreciation over the period of expected future economic benefit on a straight-line basis. Costs associated with the production of proprietary injectants are expensed.

g) Foreign currency translation

Monetary items, such as receivables and borrowings, are translated to Canadian dollars at the rate of exchange in effect at the balance sheet date. Non-monetary items, such as property, plant and equipment, are translated to Canadian dollars at the rates of exchange in effect when the transaction occurred. Revenues and expenses denominated in foreign currencies are translated at the average exchange rates in effect during the period. Foreign exchange gains or losses on translation are included in income.

h) Equity-based compensation

The Trust has a new trust unit rights incentive plan that was implemented during the second quarter of 2005. Compensation expense for the plan is based on the fair value of rights issued and amortized over the remaining vesting periods on a straight-line basis. The Black-Scholes option pricing model was used to determine the fair value of rights granted.

The Company had a stock option plan in effect until May 31, 2005. As the plan included a cash settlement alternative, stock-based compensation cost was measured for stock options outstanding at intrinsic value and recognized as an expense over the vesting period. Provision was made for all vested options at the period end plus the portion of future option vestings attributable to the current period. Changes in intrinsic value of outstanding options between the grant date and the measurement date were reflected as stock-based compensation cost. Cash payments made on option exercises were charged against the stock-based compensation liability to the extent that prior provision was made for the payment. Payments in excess of the recorded liability were charged to stock-based compensation cost.

Compensation costs in excess of the recorded liability that were realized due to the cancellation of outstanding stock options as a result of the trust conversion were charged to income as the stock option plan contained a cash settlement alternative.

Costs in respect to the employee trust unit savings plan are expensed as incurred.

i) Revenue recognition

Revenues from the sale of crude oil, natural gas liquids and natural gas are recognized when title passes from the Company to the purchaser. Sales below or in excess of the Company's working interest share of production are recorded as inventory or deferred revenue, respectively.

j) Income taxes

The corporate subsidiaries of the Trust use the liability method of accounting for future income taxes. Timing differences are calculated assuming that the financial assets and liabilities will be settled at their carrying amount. Future income taxes are computed on temporary differences using income tax rates that are expected to apply when future income tax assets and liabilities are realized or settled.

The Trust entity is taxable on income in excess of distributions to unitholders. In accordance with its trust indenture, no provision for future income taxes has been made for timing differences in the Trust as the Trust is required to distribute all of its taxable income to unitholders.

3. Property, plant and equipment

DECEMBER 31,	2005	2004
Oil and natural gas properties, and production and processing equipment	$ 5,710.4	$5,241.8
Other	14.0	12.7
	$ 5,724.4	$5,254.5
Accumulated depletion and depreciation	(2,009.2)	(1,592.7)
Net book value	$ 3,715.2	$3,661.8

Other than the Trust's net share of capital overhead recoveries, no G&A is capitalized. The cost of unevaluated property excluded from the depletion base as at December 31, 2005 was $259 million (2004 – $284 million). The depletion and depreciation calculation includes future capital costs to develop proved reserves of $413 million (2004 – $397 million).

A ceiling test calculation was performed on the Trust's oil and natural gas property interests at December 31, 2005, which determined that the estimated undiscounted future net cash flows associated with proved reserves, based on forecast prices and escalated costs, exceeded the carrying amount of the Trust's oil and natural gas property interests. Average prices of $8.46 per mcf for gas and $54.95 per bbl for liquids were used to calculate the future net revenues.

4. Bank loan

DECEMBER 31,	2005	2004
Bankers' acceptances	$ 542.0	$ 154.1
LIBOR advances (2004 – US$290 million)	–	349.0
	$ 542.0	$ 503.1

As at December 31, 2005, the Company had an unsecured, extendable, three year revolving syndicated credit facility with an aggregate borrowing limit of $1,170 million that expires May 31, 2008, plus a $50 million operating credit facility. The credit facility contains provision for stamping fees on Bankers' Acceptances and LIBOR loans, and standby fees on lines that vary depending on certain consolidated financial ratios. Letters of credit totaling $9 million (2004 – $9 million), that reduced the amount otherwise available to be drawn on the operating facility, were outstanding at the end of the year.

In 2005, the Company converted its U.S. denominated borrowings to Canadian dollar loans realizing a foreign exchange gain of $85.8 million.

5. Asset retirement obligations

Total asset retirement obligations are based upon the present value of the Trust's net share of estimated future costs to abandon and reclaim all wells and facilities. The estimates were made by management and external consultants assuming current technology and enacted legislation.

The total undiscounted, uninflated amount required to settle the asset retirement obligations at December 31, 2005 was $777 million (2004 – $737 million). The asset retirement obligation was determined by applying an inflation factor of 1.7 percent (2004 – 1.5 percent) and discounting the inflated amount using a credit adjusted rate of 7.5 percent (2004 – 7.5 percent) over the expected useful life of the underlying assets, which currently extends up to 50 years into the future with an average life of 22 years.

Changes to asset retirement obligations were as follows:

	2005	2004
Asset retirement obligations at January 1	$ 180.7	$ 172.8
Liabilities incurred during the period	9.8	18.6
Liabilities settled during the period	(22.6)	(29.5)
Increase in liability due to change in estimates	3.4	–
Accretion	21.1	18.8
Asset retirement obligations at December 31	$ 192.4	$ 180.7

6. Income taxes

As at December 31, future income tax assets (liabilities) arose from temporary differences as follows:

	2005	2004
Property, plant and equipment	$ (753.7)	$ (914.0)
Asset retirement obligations	67.0	64.4
Other	4.6	–
Bank loan	–	(16.1)
Stock-based compensation	–	32.8
Capital losses	–	10.7
Valuation allowance on capital losses	–	(10.7)
	$ (682.1)	$ (832.9)
Current future income tax assets	$ –	$ 25.3
Future income tax liability	(682.1)	(858.2)
	$ (682.1)	$ (832.9)

The Trust maintains an income tax status that permits it to deduct distributions to unitholders in addition to other items. Accordingly, no future income tax provision or recovery was made for temporary differences in the Trust. As at December 31, 2005, the book amount of the Trust's assets and liabilities exceed their tax basis by $86 million.

The provision for (recovery of) income taxes reflects an effective tax rate that differs from the combined federal and provincial statutory tax rate as follows:

YEARS ENDED DECEMBER 31,	2005	2004
Income before taxes	$ 644.9	$ 409.3
Corporate income tax rate	38.4%	39.4%
Computed income tax provision	$ 247.6	$ 161.3
Increase (decrease) resulting from:		
Net income attributable to the Trust	(154.3)	–
Non-deductible Crown payments, net	71.0	72.6
Resource allowance	(75.9)	(74.2)
Tax rate reductions	(31.1)	(20.2)
Non-taxable foreign exchange	0.8	(7.5)
Other	(5.1)	(4.6)
Total income taxes	$ 53.0	$ 127.4
Current	54.1	17.8
Future (recovery)	(1.1)	109.6
	$ 53.0	$ 127.4

7. Unitholders' capital

a) Authorized

i) An unlimited number of voting Trust units, which are redeemable at the option of the unitholder.

ii) An unlimited number of Special Voting Units, which enable the Trust to provide voting rights to holders of any exchangeable shares that may be issued by any direct or indirect subsidiaries of the Trust. Except for the right to vote, the Special Voting Units do not confer any other rights.

Trust units are redeemable at any time at the option of the unitholder. The redemption price is equal to the lesser of 95 percent of the closing market price on the date the units were tendered for redemption, 95 percent of the market price for the 10 days immediately after the date the units were tendered for redemption, or 95 percent of the closing market price on the date of redemption. Total redemptions are limited to $250,000 in any calendar month, subject to waiver at the discretion of the administrator. If the limitation is not waived, the amount payable in excess of the $250,000 will be settled by the distribution of redemption notes to the redeeming unitholders by the Trust.

The Trust has a Distribution Reinvestment and Optional Trust Unit Purchase Plan (the "DRIP") that provides eligible unitholders the opportunity to reinvest monthly cash distributions into additional units at a potential discount. Units are issued from treasury at 95 percent of the average market price when available. When units are not available from treasury they are acquired in the open market at prevailing market prices.

Unitholders who participate in the DRIP may also purchase additional units, subject to a monthly maximum of $5,000 and a minimum of $500. Optional cash purchase units are acquired, without a discount, in the open market at prevailing market prices or issued from treasury at the average market price.

b) Issued

Penn West shareholders received three trust units for each common share held resulting in the issuance of 163,137,018 trust units in exchange for the common shares of Penn West pursuant to the plan of arrangement. No special voting units were issued.

Common shares of Penn West	Shares	Amount
Balance, December 31, 2003	53,692,290	$ 505.6
Issued on excerise of stock options	176,455	5.2
Liability settlement on stock options excercised for shares	–	4.5
Balance, December 31, 2004	53,868,745	$ 515.3
Issued on exercise of stock options	488,399	17.0
Issued to employee stock savings plan	21,905	1.8
Cancellation of certificates	(43)	–
Liability settlements on stock options exercised for shares	–	22.0
Balance, May 31, 2005 prior to plan of arrangement	54,379,006	$ 556.1
Exchanged for trust units	(54,379,006)	(556.1)
Balance as at May 31, 2005	–	$ –

Trust units of Penn West Energy Trust	Units	Amount
Issued to settlor for cash, April 22, 2005	1,250	$ -
Exchanged for Penn West shares, May 31, 2005	163,137,018	556.1
Issued to employee trust unit savings plan	151,745	4.9
Balance as at December 31, 2005	163,290,013	$ 561.0

c) Contributed surplus

	2005	2004
Balance, January 1	$ –	$ –
Unit-based compensation expense	5.5	–
Balance as at December 31	$ 5.5	$ –

8. Equity-based compensation

a) Stock option plan

Until May 31, 2005, the Company had a stock option plan (the "Stock Option Plan") for the benefit of its employees and directors. Stock options vested over a five-year period and, if unexercised, expired six years from the date of grant. The stock option plan included a cash payment alternative and stock-based compensation costs were recorded based on changes to the share price at the end of each quarter and any changes to the number of outstanding options. Pursuant to the plan of arrangement, all stock options outstanding on the date of conversion were settled for cash of $84.77 per share or by issuing shares. The continuity of the compensation liability and outstanding options to the date of cancellation was as follows:

	2005	2004
Liability, January 1	$ 91.9	$ 27.9
Compensation expense provision	71.7	84.1
Cash payments on exercise of stock options	(141.6)	(15.6)
Liability settlements on stock options exercised for shares	(22.0)	(4.5)
Liability, December 31	–	91.9
Current portion	–	71.0
Long term portion	–	20.9
	$ –	$ 91.9

Penn West stock options	Number of Stock Options	Weighted Average Excercise Price
Outstanding, January 1, 2005	3,728,980	$ 39.00
Granted	82,600	79.51
Exercised for common shares	(488,399)	34.72
Settled for cash	(3,212,931)	40.51
Forfeited	(110,250)	44.26
Outstanding, May 31, 2005	–	$ –

b) Trust unit rights incentive plan

In May 2005, the Trust implemented a unit rights incentive plan that allows the Trust to issue rights to acquire trust units to directors, officers, employees and service providers. The number of trust units reserved for issuance shall not at any time exceed ten percent of the aggregate number of issued and outstanding trust units of the Trust. Unit right exercise prices are equal to the market price for the trust units based on the five-day weighted average market price prior to the date the unit rights are granted. If certain conditions are met, the exercise price per unit is reduced by deducting from the grant price the aggregate of all distributions, on a per unit basis, paid by the Trust after the grant date. Rights granted under the plan vest over a five-year period and expire six years after the date of the grant.

Trust unit rights	Number of unit rights	Weighted average exercise price
Granted	10,045,325	$ 29.73
Forfeited	(597,700)	28.46
Balance before reduction of exercise price	9,447,625	$ 29.81
Reduction of exercise price for distributions paid	–	(1.36)
Outstanding, December 31, 2005	9,447,625	$ 28.45
Exercisable, December 31, 2005	–	$ –

The Trust recorded compensation expense of $5.5 million for the period from implementation to December 31, 2005. The compensation expense is based on the fair value of rights issued and is amortized over the remaining vesting periods on a straight-line basis. The Black-Scholes option pricing model was used to determine the fair value of trust unit rights granted with the following weighted average assumptions:

SEVEN MONTHS ENDED DECEMBER 31,	2005
Average fair value of trust unit rights granted (PER UNIT)	
Directors and officers	$ 6.50
Other employees	$ 6.13
Expected life of trust unit rights (years)	
Directors and officers	5.0
Other employees	4.5
Expected volatility (average)	16%
Risk free rate of return (average)	3.4%
Expected distribution rate	*Nil

* The expected distribution rate is assumed to be nil as it is expected that future distributions will result in a reduction to the exercise price of trust unit rights.

c) Employee trust unit savings plan

The Trust has an employee trust unit savings plan (the "Savings Plan") for the benefit of all employees. Under the Savings Plan, employees may elect to contribute up to 10 percent of their salary and contributions are used to fund the acquisition of trust units. The Trust matches employee contributions at a rate of $1.50 for each $1.00 contributed. Trust units may be issued from treasury at the five-day weighted average month end market price or purchased in the open market. No units have been purchased in the open market subsequent to the conversion.

Prior to the trust conversion, the Company had a stock savings plan with essentially the same terms as the Plan. During 2005, 20,355 employer contribution shares (equivalent to 61,065 trust units) were purchased in the open market at an average price of $81.48 per share ($27.16 per equivalent trust unit) and a total cost of $1.7 million and 21,905 shares (equivalent to 65,715 trust units) were issued from treasury. In 2004, all employee contribution shares and 87,787 employer contribution shares (equivalent to 263,361 trust units) were purchased in the open market. The employer contribution shares were purchased at an average price of $66.90 per share ($22.30 per equivalent trust unit) and a total cost of $5.9 million.

9. Distributions payable to unitholders

Under the terms of the Trust indenture, the Trust is required to make distributions to unitholders in amounts equal to the income of the Trust earned from interest on certain notes, the NPI, and any dividends paid on the common shares of the Company, less any expenses of the Trust. Distributions may be monthly or special and in cash or in trust units at the discretion of the Board of Directors. Distributions payable to unitholders is the amount declared and payable by the Trust.

Accumulated cash distributions

	2005
Accumulated cash distributions, beginning of period	$ –
Distributions declared	321.5
Accumulated cash distributions, end of period	$ 321.5
Distributions per unit [1]	$ 1.97
Accumulated cash distributions per unit, beginning of period	–
Accumulated cash distributions per unit, end of period	$ 1.97

[1] Distributions per unit are the sum of the per unit amounts declared monthly to unitholders.

10. Financial instruments

Financial instruments, included in the balance sheets, consist of accounts and taxes receivable, current liabilities and the bank loan. The fair values of these financial instruments approximate their carrying amounts due to the short-term maturity of the instruments and the market rate of interest and exchange rates applied to the bank loan.

All of the accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risk. The Trust, from time to time, uses various types of financial instruments to reduce its exposure to fluctuating oil and natural gas prices, electricity costs, exchange rates and interest rates. The use of these instruments exposes the Trust to credit risks associated with the possible non-performance of counterparties to derivative instruments. The Trust limits this risk by transacting only with financial institutions with high credit ratings and by obtaining security in certain circumstances.

The Trust's revenue from the sale of crude oil, natural gas liquids and natural gas are directly impacted by changes to the underlying commodity prices. To ensure that cash flows are sufficient to fund planned capital programs and distributions, costless collars, or other financial instruments, may be utilized. Collars ensure that commodity prices realized will fall into a contracted range for a contracted sales volume. Forward power contracts fix a portion of future electricity costs at levels determined to be economic by management.

Variations in interest rates directly impact interest costs. From time to time, the Trust may increase the certainty of future interest rates using financial instruments to swap floating interest rates to fixed rates.

Crude oil sales and certain bank loans are referenced to or denominated in U.S. dollars. Accordingly, realized crude oil prices and debts in Canadian dollars are directly impacted by CAD/USD exchange rates. From time to time, the Trust may use financial instruments to fix future exchange rates.

As at December 31, 2005, the Trust had the following financial instruments outstanding:

	Notional Volume	Remaining Term	Pricing	Market Value ($ millions)
Crude Oil				
WTI Costless Collars	20,000 bbls/d	Jan/06 – Dec/06	$US 47.50 to $67.86/bbl	$ (22.1)
Natural Gas				
AECO Costless Collars	46,300 mcf/d	Jan/06 – Mar/06	$8.64 to $16.69/mcf	0.2
AECO Costless Collars	46,300 mcf/d	Jan/06 – Oct/06	$8.64 to $16.25/mcf	2.1
AECO Costless Collars	18,500 mcf/d	Jan/06 – Oct/06	$9.72 to $17.28/mcf	3.3
AECO Costless Collars	23,100 mcf/d	Apr/06 – Sept/06	$9.07 to $15.12/mcf	0.7
AECO Costless Collars	9,300 mcf/d	Apr/06 – Sept/06	$9.18 to $15.39/mcf	0.8
AECO Costless Collars	13,400 mcf/d	Oct/06 – Dec/06	$9.18 to $17.39/mcf	0.2
Electricity				
Alberta Power Pool Swaps	60 MW	2006	$42.25 to $43.15/MWh	16.6
Alberta Power Pool Swaps	35 MW	2007	$46.00/MWh	6.7

Effective July 1, 2005, the Trust elected to discontinue the designation of commodity and power financial instruments as hedges, choosing to account for these instruments using the fair value method. In accordance with the accounting recommendations, the fair value of power contracts at July 1, 2005 in the amount of $16.7 million was recorded as a deferred gain and will be recognized into income over the life of the contracts. Future changes in the fair value of commodity and power contracts will be recorded on the balance sheet with a corresponding unrealized gain or loss in income.

The following table reconciles the changes in the fair value of financial instruments no longer designated as hedges:

Risk Management:	December 31, 2005
Balance June 30, 2005	$ –
Deferred gain at June 30	16.7
Unrealized gain on financial instruments	(8.2)
Fair value, end of period	$ 8.5
Deferred Gain on Financial Instruments:	
Balance June 30, 2005	$ –
Deferred gain at June 30	(16.7)
Amortization	4.8
Ending balance	$ (11.9)

11. Per unit amounts

The Trust follows the treasury stock method to compute the dilutive impact of unit rights. The treasury stock method assumes that the proceeds received from the pro-forma exercise of in-the-money trust unit rights are used to purchase trust units at average market prices.

The Trust adopted the new earnings per share ("EPS") accounting recommendations effective January 1, 2005. The number of incremental shares included in diluted EPS is computed using the average market price of common shares for the year-to-date period. In addition, contracts that could be settled in cash or common shares are assumed settled in common shares if share settlement is more dilutive. Shares to be issued upon conversion of convertible instruments with a mandatory conversion feature would be included in the basic weighted average EPS calculation from the date when conversion becomes mandatory. These changes did not materially impact the Trust's reported diluted EPS amounts.

The weighted average number of trust units used to calculate per unit amounts was:

YEARS ENDED DECEMBER 31,	2005	2004
Basic	**162,632,127**	161,458,452
Diluted	**165,878,364**	164,408,871

12. Change in non-cash working capital

Changes in non-cash working capital items increased (decreased) cash and cash equivalents as follows:

YEARS ENDED DECEMBER 31,	2005	2004
Accounts receivable	**$ (53.9)**	$ (18.9)
Taxes receivable	**–**	26.3
Other current assets	**(9.2)**	(3.3)
Accounts payable and accrued liabilities	**(2.5)**	58.5
Taxes payable	**0.6**	11.2
	$ (65.0)	$ 73.8
Operating activities	**$ (1.8)**	$ 23.7
Investing activities	**(63.2)**	50.0
Financing activities	**–**	0.1
	$ (65.0)	$ 73.8

13. Plan of arrangement costs

Effective May 31, 2005, the Company commenced operations as an oil and gas income trust pursuant to a plan of arrangement approved by the shareholders on May 27, 2005. Certain amounts, related to the plan of arrangement, were charged to accumulated earnings:

	Amount
Rate differences on income taxes paid	$ 13.3
Incremental capital taxes	13.4
Financial advisor fees	5.6
Filing fees, communication, professional fees and other	4.0
Tax benefit on fees	(3.4)
	$ 32.9

In addition, the Trust conversion resulted in a short income tax year that accelerated $146.3 million of cash income taxes as a significant amount of Penn West's taxable income was earned in a partnership.

14. Related party transactions

The Trust incurred $2.1 million (2004 – $0.8 million) of legal expenses with a law firm, at which one of its partners is a director of the Trust.

Summary Information – Five Year Summary

YEARS ENDED DECEMBER 31,	2005	2004	2003	2002	2001
FINANCIAL					
($ millions, except unit and per unit [1] amounts)					
Gross revenues	**$ 1,919.0**	$ 1,521.3	$ 1,394.2	$ 1,008.4	$ 1,096.6
Cash flow	**1,184.6**	866.7	812.8	463.5	612.9
Basic per unit	**7.28**	5.37	5.04	2.90	3.91
Diluted per unit	**7.14**	5.28	4.97	2.83	3.79
Net income	**577.2**	271.8	446.6	165.2	248.1
Basic per unit	**3.55**	1.68	2.77	1.03	1.58
Diluted per unit	**3.48**	1.65	2.73	1.01	1.53
Capital expenditures	**456.7**	865.6	608.1	573.3	633.5
Total assets	**3,967.1**	3,867.4	3,309.6	2,933.3	2,507.8
Bank indebtedness	**542.0**	503.1	442.4	598.4	556.3
Unitholders' equity	**2,172.2**	1,909.0	1,654.3	1,314.6	1,128.9
Distributions declared	**321.5**	–	–	–	–
Dividends declared					
Quarterly	**10.8**	26.8	6.7	–	–
Special	**–**	–	80.7	–	–
Total	**$ 10.8**	$ 26.8	$ 87.4	$ –	$ –
Trust units outstanding at year end (000s):					
Basic	**163,290**	161,607	161,076	161,199	158,169
Basic plus rights	**172,738**	172,794	173,757	176,214	174,327
Market value per trust unit					
High	**$ 38.53**	$ 27.33	$ 16.50	$ 14.91	$ 15.08
Low	**25.23**	15.86	11.92	10.92	10.10
Close	**$ 37.99**	$ 26.42	$ 16.05	$ 13.67	$ 11.80
OPERATING					
Production					
Light oil and natural gas liquids production (bbls/day)	**33,137**	34,943	35,479	33,822	29,375
Light oil and natural gas liquids price ($/bbl)	**$ 62.59**	$ 42.04	$ 38.40	$ 34.81	$ 34.92
Conventional heavy oil production (bbls/day)	**18,705**	18,136	10,853	10,211	9,509
Conventional heavy oil price ($/bbl)	**$ 35.71**	$ 31.73	$ 28.70	$ 26.10	$ 20.24
Total liquids production (bbls/day)	**51,842**	53,079	46,332	44,033	38,884
Total liquids price ($/bbl)	**$ 52.89**	$ 38.52	$ 36.13	$ 32.79	$ 31.33
Natural gas production (mmcf/day)	**287.8**	316.3	331.3	332.7	330.3
Natural gas price ($/mcf)	**$ 8.74**	$ 6.68	$ 6.48	$ 3.97	$ 5.41
Reserves (proved plus probable)					
Oil and liquids (mmbbls)	**241**	240	222	249	229
Natural gas (bcf)	**698**	761	813	1,013	1,071
Wells drilled (gross)					
Natural gas	**150**	209	307	209	274
Oil	**119**	195	337	112	118
Dry	**18**	35	106	44	61
Total wells drilled	**287**	439	750	365	453
UNDEVELOPED LAND HOLDINGS					
Western Canada (000 acres)					
Gross	**4,390**	6,058	5,538	4,402	3,672
Net	**4,142**	5,767	5,313	4,158	3,381
Average working interest (%)	**94**	95	96	94	92

(1) The 2004 and prior years comparative figures have been restated to reflect the conversion ratio of three trust units issued for each Penn West common share pursuant to the Plan of Arrangement.

Summary Information – Quarterly Summary

THREE MONTHS ENDED	2005 Mar 31	2005 June 30	2005 Sept 30	2005 Dec 31	2004 Mar 31	2004 June 30	2004 Sept 30	2004 Dec 31
FINANCIAL								
($ millions, except per unit amounts)								
Gross revenues	$ 405.3	$ 424.2	$ 535.0	$ 554.5	$ 346.1	$ 390.4	$ 384.3	$ 400.5
Cash flow[1]	260.1	257.0	334.9	332.6	181.2	211.2	236.5	237.8
Basic per unit	1.61	1.58	2.06	2.03	1.13	1.31	1.46	1.47
Diluted per unit	1.58	1.49	2.04	2.03	1.11	1.29	1.44	1.44
Net income	66.9	59.7	209.5	241.1	61.0	65.5	76.7	68.6
Basic per unit	0.41	0.37	1.29	1.48	0.38	0.41	0.48	0.42
Diluted per unit	$ 0.41	$ 0.34	$ 1.27	$ 1.46	$ 0.37	$ 0.40	$ 0.47	$ 0.42
OPERATING								
Light oil and natural gas liquids production (bbls/day)	34,219	32,011	33,101	33,227	37,277	34,624	33,370	34,524
Light oil and natural gas liquids price ($/bbl)	$ 56.00	$ 59.05	$ 70.94	$ 64.28	$ 37.72	$ 39.80	$ 42.37	$ 48.57
Conventional heavy oil production (bbls/day)	18,943	18,622	18,533	18,726	13,968	19,692	19,596	19,257
Conventional heavy oil price ($/bbl)	$ 28.06	$ 31.22	$ 48.60	$ 34.95	$ 28.50	$ 30.17	$ 37.37	$ 29.89
Total liquids production (bbls/day)	53,162	50,633	51,634	51,953	51,245	54,316	52,966	53,781
Total liquids price ($/bbl)	$ 46.04	$ 48.81	$ 62.92	$ 53.71	$ 35.21	$ 36.30	$ 40.52	$ 41.88
Natural gas production (mmcf/day)	289.1	295.7	289.0	277.5	312.0	329.8	316.0	307.4
Natural gas price ($/mcf)	$ 7.11	$ 7.41	$ 8.88	$ 11.66	$ 6.41	$ 7.03	$ 6.43	$ 6.83

[1] Cash flow, cash flow per unit-basic and cash flow per unit-diluted are non-GAAP measures. Refer to the calculation of cash flow in the MD&A.

FEE RULE

FORM 13-502F1
ANNUAL PARTICIPATION FEE FOR REPORTING ISSUERS

Reporting Issuer Name: Penn West Energy Trust

Financial Year Ending, used in calculating the participation fee: December 31, 2005

Complete Only One of 1, 2 or 3:

1. Class 1 Reporting Issuers (Canadian Issuers – Listed in Canada and/or the U.S.)

Market value of equity securities:
Total number of equity securities of a class or series outstanding at the end of the issuer's most recent financial year 163,290,013

Simple average of the closing price of that class or series as of the last trading day of each of the months of the financial year (under paragraph 2.5(a)(ii)(A) or (B) of the Rule) X 37.99

Market value of class or series = 6,203,387,594

____ (A)

(Repeat the above calculation for each class or series of equity securities of the reporting issuer that are listed and posted for trading, or quoted on a marketplace in Canada or the United States of America at the end of the financial year)

____ (A)

Market value of corporate debt or preferred shares of Reporting Issuer or Subsidiary Entity referred to in Paragraph 2.5(b)(ii):
[Provide details of how determination was made.]

(Repeat for each class or series of corporate debt or preferred shares) ____ (B)

Total Capitalization (add market value of all classes and series of equity securities and market value of debt and preferred shares) (A) + (B) = 6,203,387,594

Total fee payable in accordance with Appendix A of the Rule $65,000.00

Reduced fee for new Reporting Issuers (see section 2.8 of the Rule) ____

Total Fee Payable x Number of entire months remaining in the issuer's financial year / 12

Late Fee, if applicable
(please include the calculation pursuant to section 2.9 of the Rule) ____
1.

Management's Discussion and Analysis

Management's discussion and analysis ("MD&A") of financial conditions and results of operations should be read in conjunction with the audited consolidated financial statements and accompanying notes of Penn West Energy Trust (the "Trust") for the year ended December 31, 2005. Penn West Petroleum Ltd. ("Penn West") converted to an income trust on May 31, 2005, and to facilitate meaningful comparisons, the financial results of the Trust are presented on a continuity of interest basis as if it historically carried on the business of Penn West. The date of this MD&A is February 27, 2006. For additional information, including the Trust's audited financial statements and Annual Information Form (when filed), go to the Trust's website at www.pennwest.com or SEDAR at www.sedar.com.

References to cash flow, cash flow per unit-basic, cash flow per unit-diluted, and netbacks included in this MD&A are considered non-GAAP measures and may not be comparable to similar measures provided by other issuers. Management utilizes cash flow and netbacks to assess financial performance and the capacity of the Trust to fund distributions to unitholders and future capital projects. The reconciliation of cash flow to cash flow from operating activities is as follows:

Calculation of Cash Flow *($ millions, except per unit amounts)*

	Three months ended December 31		Years ended December 31	
	2005	2004	**2005**	2004
Cash flow from operating activities	**$ 368.7**	$ 206.2	**$ 932.8**	$ 816.8
Increase (decrease) in non-cash working capital	**(42.4)**	10.0	**1.8**	(23.7)
Payments for surrendered options	**–**	5.2	**141.6**	15.6
Environmental expenditures	**6.3**	16.4	**22.6**	29.5
Realized foreign exchange gains	**–**	–	**85.8**	28.5
Cash flow	**$ 332.6**	$ 237.8	**$ 1,184.6**	$ 866.7
Basic, per unit	**$ 2.03**	$ 1.47	**$ 7.28**	$ 5.37
Diluted, per unit	**$ 2.03**	$ 1.44	**$ 7.14**	$ 5.28

Notes to Reader

This document contains forward-looking statements (forecasts) under applicable securities laws. Forward-looking statements are necessarily based upon assumptions and judgements 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. For a discussion of other factors, please refer to "Notice Regarding Forward-Looking Statements" later in this MD&A. 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 actual results to differ materially from those anticipated or implied in the forward-looking statements. The Trust assumes no responsibility to publicly update or revise any forward-looking statements.

All dollar amounts contained in this document are expressed in millions of Canadian dollars unless noted otherwise.

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. This could be misleading if used in isolation as it is based on energy equivalency at the burner tip and might not represent a value equivalency at the wellhead.

Quarterly Financial Summary ($ millions, except per unit and production amounts)

Three months ended	2005 Dec 31	Sept 30	Jun 30	Mar 31	2004 Dec 31	Sept 30	Jun 30	Mar 31
Gross revenues	**$ 554.5**	**$ 535.0**	**$ 424.2**	**$ 405.3**	$ 400.5	$ 384.3	$ 390.4	$ 346.1
Cash flow	**$ 332.6**	**$ 334.9**	**$ 257.0**	**$ 260.1**	$ 237.8	$ 236.5	$ 211.2	$ 181.2
Basic per unit (1)	**2.03**	**2.06**	**1.58**	**1.61**	1.47	1.46	1.31	1.13
Diluted per unit (1)	**2.03**	**2.04**	**1.49**	**1.58**	1.44	1.44	1.29	1.11
Net income	**$ 241.1**	**$ 209.5**	**$ 59.7**(2)	**$ 66.9**	$ 68.6	$ 76.7	$ 65.5	$ 61.0
Basic per unit (1)	**1.48**	**1.29**	**0.37**	**0.41**	0.42	0.48	0.41	0.38
Diluted per unit (1)	**1.46**	**1.27**	**0.34**	**0.41**	0.42	0.47	0.40	0.37
Distributions declared	**$ 151.8**	**$ 127.3**	**$ 42.4**	**$ –**	$ –	$ –	$ –	$ –
Distributions per unit (1)	**0.93**	**0.78**	**0.26**	**–**	–	–	–	–
Dividends declared	**$ –**	**$ –**	**$ –**	**$ 10.8**	$ 6.7	$ 6.7	$ 6.7	$ 6.7
Dividends per unit (1)	**–**	**–**	**–**	**0.07**	0.04	0.04	0.04	0.04
Production								
Liquids (bbls/d)	**51,953**	**51,634**	**50,633**	**53,162**	53,781	52,966	54,316	51,245
Natural gas (mmcf/d)	**277.5**	**289.0**	**295.7**	**289.1**	307.4	316.0	329.8	312.0
Total (boe/d)	**98,205**	**99,802**	**99,910**	**101,343**	105,007	105,639	109,280	103,237

(1) Per unit figures for the periods prior to June 30, 2005 have been restated to reflect the conversion of Penn West common shares to trust units using an exchange ratio of three trust units per share pursuant to the plan of arrangement.

(2) Net income in the second quarter of 2005 contained stock-based compensation charges related to the trust conversion and current income tax provisions related to the pre-conversion period. Higher commodity prices and lower tax provisions, due to income allocations to the Trust, are reflected in the third and fourth quarter of 2005 net income amounts.

Business Environment

Increased demand for commodities from growing economies such as China, political instability in parts of the world and the occurrence of natural disasters, resulted in strong energy prices in 2005. The price of West Texas Intermediate ("WTI"), the benchmark for light crude oil, averaged US$56.70 per barrel in 2005, up 37 percent compared to 2004.

Heavy oil differentials increased in 2005 as a significant portion of 2005 incremental supply, especially from the Organization of Petroleum Exporting Countries, was heavy oil and there was a continuing shortage of upgrading capacity. The average 2005 heavy/light crude oil differential was $24.16 per barrel, an increase of 58 percent from $15.32 per barrel in 2004.

AECO natural gas prices continued to be strong in 2005 increasing 34 percent to $8.81 per mcf compared to $6.59 per mcf in 2004. Concerns about overall North American supply/demand balance and interruptions in supply from the Gulf of Mexico 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 generally based on WTI prices denominated in U.S. dollars; therefore the strengthening Canadian dollar reduces Canadian dollar prices. The average exchange rate increased from $0.769 CAD/USD in 2004 to $0.825 CAD/USD in 2005. Strong commodity prices increased operating costs due to increases in the demand for energy, steel, services and other costs.

Penn West has proven management, dedicated employees and a business plan appropriate for an energy trust. In terms of production, cash flow, reserves and market capitalization, Penn West progressed from a very small explorer and producer in 1992 to the top ranks of independent oil and natural gas producers in Western Canada. This year, Penn West converted into the largest conventional oil and natural gas trust by production in Canada. We believe 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, but also to acquire and optimize producing fields. 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 goal is to create and protect unitholder value by:

> Pursuing an active program of internal development, focusing on low-risk opportunities to maintain production or reduce operating costs and resource plays such as our CO_2 enhanced oil recovery project at Pembina and our Seal conventional oil sands project;

> Participating in exploration, without the requirement to fund capital expenditures, through the farmout of undeveloped lands;

> Rationalizing our asset base with the aim of maintaining distributions over the long-term, including asset acquisitions and dispositions that are accretive or strategic; and

> Maintaining a strong balance sheet.

Using our established business plan, we achieved record cash flow and net income in 2005.

Unitholder Value Measures

YEARS ENDED DECEMBER 31,	2005	2004	2003
Cash flow per unit ($)	**7.28**	5.37	5.04
Distributions per unit ($)	**1.97**	–	–
Dividends per unit ($)	**0.07**	0.16	0.54
Ratio of year-end bank debt to annual cash flow	**0.5**	0.6	0.5

We have an extensive base of undeveloped land (4.1 million net acres at December 31, 2005) and a strong balance sheet. These attributes, plus strong in-house professional and technical staff, give us the ability to pursue a strategy of both organic growth and optimization through acquisitions, dispositions and farmout of undeveloped land. We believe that the application of financial discipline is also a key factor in achieving superior returns on investment for our unitholders.

Performance Indicators

YEARS ENDED DECEMBER 31	2005	2004	2003
Return on capital employed	**36.2%**	8.4%	15.9%
Total assets ($ millions)	**3,967**	3,867	3,310
Return on equity	**28.3%**	15.3%	30.1%

Cash Flow and Net Income

A 57 percent increase in Q4 2005 operating netbacks resulted in a 40 percent increase in cash flow and a 251 percent increase in net income compared to Q4 2004. Operating netbacks were higher mainly due to increased prices received for crude oil and natural gas. Prices received for crude oil and NGL are related to world markets and the quality of crude oil produced. The Trust's liquids production is 64 percent light oil and NGL that receives prices close to Edmonton par price. This benchmark price increased over 24 percent in Q4 2005 compared to Q4 2004.

Natural gas prices in North America are more significantly impacted by regional supply and demand factors. The geographic constraints can result in volatility due to the supply and demand imbalances that occur from time to time. Benchmark AECO prices for natural gas were 73 percent higher in the current quarter than Q4 2004.

Cash flow and net income before taxes in 2005 increased mainly due to the increases in the sales prices of crude oil and natural gas. The impact of higher prices during 2005 was partially offset by a reduction in pre-tax income of $53 million to reflect the payout of outstanding stock options in accordance with the plan of arrangement in respect of the trust conversion and the terms of the stock option plan. After-tax net income was further impacted by future income tax recoveries in the period since converting to a trust.

Production and Netbacks

	Three months ended December 31			Years ended December 31		
	2005	2004	% Change	2005	2004	% Change
Natural gas: MMcf per day	**277.5**	307.4	(10)	**287.8**	316.3	(9)
Operating netback ($ per mcf):						
Sales price	**$ 11.66**	$ 6.81	71	**$ 8.68**	$ 6.68	30
Hedging gain	**–**	0.02	–	**0.06**	–	–
Royalties	**(2.67)**	(1.51)	77	**(1.86)**	(1.43)	30
Operating costs	**(0.87)**	(0.71)	23	**(0.85)**	(0.69)	23
Netback	**$ 8.12**	$ 4.61	76	**$ 6.03**	$ 4.56	32
Light oil and NGL: Barrels per day	**33,227**	34,524	(4)	**33,137**	34,943	(5)
Operating netback ($ per bbl):						
Sales price	**$ 64.28**	$ 52.67	22	**$ 62.59**	$ 48.09	30
Hedging loss	**–**	(4.10)	–	**–**	(6.05)	–
Royalties	**(11.46)**	(9.47)	21	**(10.17)**	(7.86)	29
Operating costs	**(15.17)**	(13.14)	15	**(14.43)**	(12.80)	13
Netback	**$ 37.65**	$ 25.96	45	**$ 37.99**	$ 21.38	78
Conventional heavy oil: Barrels per day	**18,726**	19,257	(3)	**18,705**	18,136	3
Operating netback ($ per bbl):						
Sales price	**$ 34.95**	$ 29.89	17	**$ 35.71**	$ 31.73	13
Royalties	**(5.67)**	(4.42)	28	**(5.41)**	(4.62)	17
Operating costs	**(9.64)**	(8.32)	16	**(9.30)**	(8.49)	10
Netback	**$ 19.64**	$ 17.15	15	**$ 21.00**	$ 18.62	13
Total liquids: Barrels per day	**51,953**	53,781	(3)	**51,842**	53,079	(2)
Operating netback ($ per bbl):						
Sales price	**$ 53.71**	$ 44.51	21	**$ 52.89**	$ 42.50	24
Hedging loss	**–**	(2.63)	–	**–**	(3.98)	–
Royalties	**(9.38)**	(7.67)	22	**(8.45)**	(6.75)	25
Operating costs	**(13.18)**	(11.41)	16	**(12.58)**	(11.33)	11
Netback	**$ 31.15**	$ 22.80	37	**$ 31.86**	$ 20.44	56

Production and Netbacks (CONTINUED)

	Three months ended December 31			Years ended December 31		
	2005	2004	% Change	2005	2004	% Change
Combined totals: Barrels of oil equivalent[1]						
Daily production	**98,205**	105,007	(6)	**99,807**	105,788	(6)
Operating netback ($ per boe):						
Sales price	**$ 61.38**	$ 42.73	44	**$ 52.50**	$ 41.27	27
Hedging gain (loss)	**–**	(1.28)	–	**0.18**	(1.98)	–
Royalties	**(12.52)**	(8.33)	50	**(9.74)**	(7.65)	27
Operating costs	**(9.44)**	(7.94)	19	**(8.99)**	(7.75)	16
Netback	**$ 39.42**	$ 25.18	57	**$ 33.95**	$ 23.89	42

(1) Barrels of oil equivalent (boe) are based on six mcf of natural gas equals one barrel of oil (6:1).

Production of 98,205 boe per day in the fourth quarter of 2005 was down slightly compared to the third quarter of 2005 due to minor asset dispositions. Production levels in 2005 were impacted by wet weather that limited access and product hauling. Unanticipated production interruptions, normal production declines and a 47 percent reduction in capital spending also impacted 2005 production levels compared to 2004.

For the year ended December 31, 2005, the Trust received an average light oil and liquids netback of $37.99 per barrel, an average conventional heavy oil netback of $21.00 per barrel, and a natural gas netback of $6.03 per mcf. The light oil and liquids netback was up 78 percent from $21.38 per barrel for the year ended December 31, 2004 due to higher average commodity prices in 2005 and a 2004 hedging loss of $6.05 per barrel compared to no realized gain or loss in 2005. The increase was partially offset by higher royalties and operating expenses experienced in 2005. The heavy oil netback was up 13 percent from $18.62 per barrel in 2004 mainly due to higher benchmark oil prices, partially offset by the larger light/heavy oil price differential and higher royalties and operating costs. The natural gas netback was up 32 percent from $4.56 per mcf in 2004 due to higher prices, partially offset by higher royalties and operating expenses in 2005.

In Q4 2005, the Trust achieved an overall netback of $39.42 per boe consisting of a light oil and liquids netback of $37.65 per barrel, a conventional heavy oil netback of $19.64 per barrel, and a natural gas netback of $8.12 per mcf. All products contributed to the 57 percent overall increase from $25.18 per boe in 2004. The Q4 2005 light oil and liquids netback increased 45 percent from $25.96 per barrel in Q4 2004, the netback for conventional heavy oil increased 15 percent from $17.15 per barrel in Q4 2004, and the natural gas netback increased 76 percent from $4.61 per mcf in Q4 2004. The increased netbacks in the quarter were the result of higher commodity prices in Q4 2005 and hedging losses in the 2004 period, partially offset by increased royalties and increased operating expenses.

Oil and Natural Gas Revenues

($ millions)	2005	2004	2003
	Years ended December 31		
Light oil and natural gas liquids	**$ 757.0**	$ 537.7	$ 497.3
Conventional heavy oil	**243.8**	210.6	113.7
Total liquids	**1,000.8**	748.3	611.0
Natural gas	**918.2**	773.0	783.2
Total	**$ 1,919.0**	$ 1,521.3	$ 1,394.2

Increases (Decreases) in Gross Revenues, before Royalties

($ millions)	
Gross revenues – 2004	$ 1,521.3
Decrease in light oil and NGL production	(29.2)
Increase in light oil and NGL prices	248.5
Increase in conventional heavy oil production	6.0
Increase in conventional heavy oil prices	27.2
Decrease in natural gas production	(71.5)
Increase in natural gas prices	216.7
Gross revenues – 2005	$ 1,919.0

Oil Revenues and Marketing

The Trust's overall quality of crude oil remains high, averaging 28 degrees API in 2005. Light and medium oil and NGL made up 33 percent of the Trust's total production, with an average quality of 37 degrees API. Conventional heavy oil, at an average of 15 degrees API, accounted for 19 percent of the Trust's production. The Trust's light and heavy oil netbacks remained strong throughout 2005 despite larger differentials between light/heavy oil prices. Most of the Trust's production is sold at the field level to various refiners and marketing companies.

Revenues from light oil and liquids increased 41 percent to $757 million for the year ended December 31, 2005 from $538 million in 2004. This increase was attributable to higher average prices in 2005. The Trust's average light oil and liquids price increased 30 percent to $62.59 per barrel for the year ended December 31, 2005 from $48.09 per barrel in 2004. The average daily production of light oil and liquids decreased five percent to 33,137 barrels per day in 2005 from 34,943 barrels per day in 2004. Hedging reduced the net price received in 2004 by $6.05 to $42.04 per barrel. At December 31, 2005, the Trust had hedged 20,000 barrels per day for 2006 using collars with a floor price of US$47.50 and a ceiling price of US$67.86. The Trust maintains an active hedging program.

Light oil and liquids revenues in the fourth quarter of 2005 were $197 million, an increase of 28 percent over Q4 2004 revenues of $154 million. This increase was due to significantly higher average prices in the 2005 quarter. The Trust's average light oil and liquids price for Q4 2005 was $64.28 per barrel, an increase of 22 percent over the Q4 2004 average price of $52.67 per barrel. Hedging reduced the net price received in Q4 2004 by $4.10 to $48.57 per barrel. Production of 33,227 barrels per day of light oil and liquids was down four percent from production of 34,524 in Q4 of 2004.

Revenues from conventional heavy oil for the year ended December 31, 2005 increased 16 percent to $244 million from $211 million in the same period of 2004. This increase was attributable to higher average prices in the year. The Trust's average conventional heavy oil price increased 13 percent to $35.71 per barrel in 2005 from $31.73 in 2004, and the average production of conventional heavy oil increased three percent to 18,705 barrels per day in 2005 from 18,136 barrels per day in 2004.

In the fourth quarter of 2005, conventional heavy oil revenues increased 13 percent to $60 million compared to $53 million in Q4 2004. This increase was also due to higher average prices in the quarter. Conventional heavy oil prices were $34.95 per barrel in Q4 2005, an increase of 17 percent over Q4 2004 prices of $29.89 per barrel. Production in Q4 was down three percent to 18,726 barrels per day in 2005 compared to 19,257 barrels per day in 2004.

Natural Gas Revenues and Marketing

The Trust maintained significant weighting to the Alberta natural gas market in 2005, as this market continued to offer a premium netback relative to other indices. At December 31, 2005, the Trust marketed approximately 89 percent of its natural gas sales directly, with the remaining 11 percent marketed by aggregators.

For the year ended December 31, 2005, Penn West received an average natural gas sales price of $8.68 per mcf, an increase of 30 percent from $6.68 per mcf in 2004. Revenues from natural gas increased 19 percent in the year ended December 31, 2005 to $918 million from $773 million in 2004. The increased revenue in 2005 over 2004 was due to pricing, as natural gas production of 288 mmcf per day in 2005 was nine percent less than production of 316 mmcf per day in 2004. The decrease in natural gas production in 2005 was attributable to minor asset dispositions, natural reservoir declines and a reduced capital program.

Natural gas revenues in the fourth quarter of 2005 increased 54 percent to $298 million from $193 million in the same period in 2004. This was the result of higher natural gas prices in Q4 2005 partially offset by lower production volumes. Q4 2005 natural gas prices of $11.66 per mcf were 71 percent higher than Q4 2004 prices of $6.81 per mcf, and natural gas production of 278 mmcf per day in Q4 2005 was 10 percent lower than the 307 mmcf per day in Q4 2004.

The Trust makes use of financial instruments at various times in the commodity price cycle to manage downside risk. On average, the Trust hedged approximately 20 percent of its natural gas production in 2005. For the year ended December 31, 2005, natural gas hedging increased the sales price received by $0.06 per mcf and had no impact in 2004. The Trust currently has a number of AECO collars in place for 2006. For details on financial instruments outstanding at December 31, 2005 see note 10 to the audited consolidated financial statements.

Royalty Expenses

YEARS ENDED DECEMBER 31,	2005	2004	2003
Royalties, net of Alberta Royalty Tax Credit ($ millions)	**$ 355.0**	$ 296.1	$ 265.1
Average rate ($/boe)	**$ 9.74**	$ 7.65	$ 7.15
Percentage of gross revenues	**19%**	20%	19%

The average royalty rate incurred was 19 percent for the year ended December 31, 2005 compared to 20 percent for the same period in 2004. The royalty rate comprises an oil and liquids royalty rate of 16 percent compared to 18 percent in 2004 and a natural gas royalty rate of 21 percent in both 2005 and 2004. The decrease in the oil and liquids royalty rate was mainly attributable to 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 quarters of 2005 and 2004, the average royalty rate incurred was 20 percent. The oil and liquids royalty component was 18 percent in Q4 of both 2005 and 2004. The natural gas royalty was 23 percent in Q4 2005 compared to 22 percent in Q4 2004.

Operating Expenses

YEARS ENDED DECEMBER 31,	2005	2004	2003
Operating expenses ($ millions)	$ 327.4	$ 300.4	$ 245.6
Average cost ($/boe)	$ 8.99	$ 7.75	$ 6.63
Percentage of gross revenues	17%	20%	18%

For the year ended December 31, 2005, operating costs averaged $8.99 per boe, a 16 percent increase from the average cost of $7.75 per boe achieved in 2004. The average production decline between 2004 and 2005 accounted for 10 percent of the increase in unit operating costs. In addition, operating costs are higher for oil properties, and in 2005 liquids production increased to 52 percent of total production compared to 50 percent in 2004. A significant portion of the Trust's liquids production is light oil that commands a premium price; therefore, the Trust is well positioned to absorb operating cost increases and still maintain economic operating netbacks. Operating costs were impacted by higher energy and fuel costs, planned facility maintenance projects, increased natural gas compression costs and lower natural gas production. Higher industry activity and commodity prices also impacted operating costs by increasing the demand for services, thus increasing input costs resulting in higher rates charged by our service providers.

Light oil and liquids operating costs increased 13 percent to $14.43 per barrel in the year ended December 31, 2005 from $12.80 per barrel in the same period of 2004. Operating costs for conventional heavy oil increased 10 percent to $9.30 per barrel during 2005 from $8.49 per barrel in 2004. Operating costs for natural gas in 2005 were $0.85 per mcf, an increase of 23 percent from $0.69 per mcf in 2004.

Q4 2005 operating costs were $9.44 per boe, 19 percent higher than Q4 2004 operating costs of $7.94 per boe. This increase was the result of the higher liquids production as a percentage of total production, higher energy and fuel costs, increased industry demand for oilfield services, and lower total production in the 2005 quarter. The overall production decline between Q4 2005 and Q4 2004 accounted for 13 percent of the increase in unit operating costs.

Light oil and liquids operating costs in Q4 2005 increased 15 percent to $15.17 per barrel from $13.14 per barrel in Q4 2004 and natural gas operating costs increased 23 percent to $0.87 per mcf in Q4 2005 from $0.71 per mcf in Q4 2004.

General and Administrative Expenses

YEARS ENDED DECEMBER 31, ($ millions)	2005	2004	2003
Gross expenses	$ 45.0	$ 41.3	$ 34.0
Operator recoveries	(21.9)	(25.2)	(21.5)
Net expenses	$ 23.1	$ 16.1	$ 12.5
Gross general and administrative expenses – average cost ($/boe)	$ 1.24	$ 1.07	$ 0.92
Percentage of gross revenues	2%	3%	2%
Net general and administrative expenses – average cost ($/boe)	$ 0.64	$ 0.42	$ 0.34
Percentage of gross revenues	1%	1%	1%

Gross general and administrative expenses increased due to higher compensation costs to retain staff. On a unit of production basis, the gross general and administrative costs increased 16 percent to $1.24 per boe for the year ended December 31, 2005 from $1.07 per boe in 2004. Net general and administrative expenses on a per unit basis increased 52 percent to $0.64 per boe in 2005 from $0.42 per boe in 2004. The reduction in operator recoveries resulted from the planned reduction in capital spending due to the trust conversion. Q4 2005 net general and administrative expenses were up 36 percent on a per unit basis to $0.75 per boe from $0.55 per boe in Q4 2004.

Equity-Based Compensation Provision

YEARS ENDED DECEMBER 31,	2005	2004	2003
Unit-based compensation ($ millions)	$ 77.2	$ 84.1	$ 48.0
Average cost ($/boe)	$ 2.12	$ 2.17	$ 1.30
Percentage of gross revenues	4%	6%	3%

Upon conversion to a Trust, unvested stock options were vested in accordance with the terms of the stock option plan and the plan of arrangement. Option-holders had several alternatives including a cash payment, purchasing Penn West shares at the option exercise price or carrying the option forward. Of the total unit-based compensation charge of $77 million in 2005, $53 million represented the cash paid to option-holders in the second quarter of 2005 in excess of the previously recorded stock-based compensation liability. Penn West paid $81 million at the end of May 2005 to option-holders who elected to receive cash for surrendering stock options that were outstanding at the time of the trust conversion. The impact of these payments was expensed in Q2 2005.

In May 2005, the Trust implemented a unit rights incentive plan. Compensation expense related to this plan is based on the fair value of trust unit rights granted and determined using the Black-Scholes option pricing model. The resulting expense is amortized over the remaining vesting periods on a straight-line basis. Compensation expense of $6 million relating to the unit rights incentive plan was expensed in the year ended December 31, 2005.

Financing Expenses

YEARS ENDED DECEMBER 31,	2005	2004	2003
Interest ($ millions)	$ 23.2	$ 17.0	$ 11.9
Cash flow times interest coverage	52.1	51.9	69.5
Average cost ($/boe)	$ 0.63	$ 0.45	$ 0.32
Percentage of gross revenues	1%	1%	1%

Interest expense for the year ended December 31, 2005 amounted to $23 million, an increase of 35 percent from $17 million in 2004. This increase was due to higher 2005 short-term interest rates and average debt levels that resulted from the payment of over $200 million in income taxes and $142 million for the surrender of stock options. With 2005 cash flows and the planned capital program reductions, the Trust repaid the majority of this debt prior to the end of 2005.

Q4 2005 interest expense of $7 million is 75 percent higher than Q4 2004 interest expense of $4 million as a result of higher average debt levels in the 2005 quarter and higher short-term interest rates.

Capital Expenditures ($ millions)

	Three months ended December 31		Year ended December 31		
	2005	2004	2005	2004	2003
Property (dispositions) acquisitions, net	$ (91.3)	$ 101.4	$ (5.8)	$ 332.3	$ 0.3
Land acquisition and retention	3.7	3.9	13.5	18.4	47.4
Drilling and completions	61.0	89.4	277.1	301.5	349.6
Facilities and well equipping	30.0	27.1	155.2	191.3	191.4
Geological and geophysical	0.8	4.6	7.4	16.3	18.1
Pembina CO_2 Pilot project	1.9	2.3	8.1	4.9	–
Administrative	0.2	0.3	1.2	0.9	1.3
Capital expenditures	$ 6.3	$ 229.0	$ 456.7	$ 865.6	$ 608.1

The decrease in 2005 capital expenditures compared to 2004 reflects planned reductions due to the trust conversion, the February 2004 acquisition of oil and natural gas assets and undeveloped land in southwest Saskatchewan for $234 million, and $91 million of net property dispositions in Q4 2005 versus the $101 million in net acquisitions in Q4 2004.

The Pembina CO_2 Pilot project represents capital expenditures, including injectants, for which no reserves have been booked. Capital expenditures exclude the impact of property, plant and equipment adjustments for asset retirement obligations and future income taxes. For details of these adjustments, see notes 3 and 5 to the audited consolidated financial statements.

Depletion, Depreciation and Accretion

YEARS ENDED DECEMBER 31,	2005	2004	2003
Depletion and depreciation ($ millions)	$ 416.5	$ 394.3	$ 291.9
Accretion ($ millions)	21.1	18.8	11.8
	$ 437.6	$ 413.1	$ 303.7
Average rate ($/boe)	$ 12.01	$ 10.67	$ 8.19
Percentage of gross revenues	23%	27%	22%

The increase in the 2005 depletion, depreciation and accretion provision compared to 2004 reflects a rate increase of 13 percent that was partially offset by lower production. The rate increase was due to a higher portion of the capital program being allocated to infill drilling and other production optimization activities, consistent with the Trust's mandate that focuses on capital efficiency. Generally, a lower amount of reserve additions are assigned to these activities than conventional exploration and development company activities; however, production is added or maintained at a lower capital cost per flowing barrel of production.

Foreign Exchange

YEARS ENDED DECEMBER 31, ($ millions)	2005	2004	2003
Foreign exchange loss (gain)	$ 4.5	$ (27.7)	$ (95.6)
Loss (gain) from written Canadian dollar calls	–	(12.7)	12.7
Net foreign exchange loss (gain)	$ 4.5	$ (40.4)	$ (82.9)
Average loss (gain) ($/boe)	$ 0.12	$ (1.04)	$ (2.24)
Percentage of gross revenues	–	3%	6%

During Q1 2005, the Trust converted US$205 million of its US denominated borrowings to Canadian dollars at an average exchange rate of $0.829 CAD/USD resulting in a realized foreign exchange gain of $63 million. In May 2005, the Trust converted its remaining US$85 million of US denominated borrowings to Canadian dollars at an average exchange rate of $0.803 CAD/USD and realized an additional $23 million foreign exchange gain. As at December 31, 2005, the Trust had no foreign currency denominated debt versus the $290 million of US denominated debt outstanding at December 31, 2004.

Taxes

YEARS ENDED DECEMBER 31,	2005	2004	2003
Current income taxes ($ millions)	$ 54.1	$ 17.8	$ 9.9
Future income taxes (recovery) ($ millions)	(1.1)	109.6	97.3
	$ 53.0	$ 127.4	$ 107.2
Effective tax rate	8%	31%	19%
Capital taxes ($ millions)	$ 14.7	$ 10.1	$ 10.1

In Q4 2005, no current income tax provision was required compared to a recovery of $13 million in the same period of 2004. The cash income tax provision for 2005 was $54.1 million compared to $18 million in the 2004 period due to higher cash flow in 2005. The trust conversion on May 31, 2005 resulted in a short income tax year that accelerated $214 million of cash income taxes as a significant amount of Penn West's taxable income was earned in a partnership. Of this amount, $54 million was expensed as current income taxes to May 31, 2005, $146 million was reflected as a reduction to the future income tax liability and $13 million, being the tax rate differential, was recorded as a restructuring charge.

The trust conversion also impacted capital taxes in Q2 2005. Part of the plan of arrangement consisted of the conveyance of properties from a partnership to a corporation. This transaction increased taxable capital for Large Corporations Tax in the corporation for the tax year ended December 31, 2005; however, this increase will not apply in subsequent taxation years.

In Q4 2005, a $51 million future tax recovery was recorded compared to a $48 million provision in Q4 2004. There was a future income tax recovery in 2005 of $1 million compared to a future income tax provision of $110 million in 2004. The 2005 future income tax provisions reflect future tax reductions related to 2005 income allocations to the Trust and lower tax rates. Interest and royalty payments, by the operating corporation to the Trust, are accounted for as a reduction of accumulated timing differences and accordingly lowers the future income tax provision.

In the fourth quarter of 2005, a $28 million general future tax rate reduction was recorded to reflect lower scheduled future tax rates resulting from timing differences, reversing in later taxation years under current legislation. In the third quarter of 2005, a $3 million tax rate reduction was recorded to reflect British Columbia's 1.5 percent general tax rate reduction. In the first quarter of 2004, a $20 million future income tax recovery was recorded to reflect the 2004 tax rate reduction enacted by the Government of Alberta.

Tax Pools

AS AT DECEMBER 31, ($ millions)	2005	2004	2003
Undepreciated Capital Cost (UCC)	$ 519.0	$ 276.4	$ 270.1
Cumulative Canadian Oil and Gas Property Expense (CCOGPE)	707.6	611.5	679.2
Cumulative Canadian Development Expense (CDE)	329.8	95.4	136.6
Cumulative Canadian Exploration Expense (CEE)	–	–	–
Total tax pools	$ 1,556.4	$ 983.3	$ 1,085.9

Items Affecting Cash Flow and Net Income

YEARS ENDED DECEMBER 31,	2005		2004		2003	
	$/boe	%	$/boe	%	$/boe	%
Oil and natural gas revenues	$ 52.68	100.0	$ 39.29	100.0	$ 37.62	100.0
Net royalties	(9.74)	(18.5)	(7.65)	(19.5)	(7.15)	(19.0)
Operating expenses	(8.99)	(17.1)	(7.75)	(19.7)	(6.63)	(17.6)
Transportation	(0.62)	(1.1)	(0.66)	(1.7)	(0.71)	(1.9)
Net operating income	33.33	63.3	23.23	59.1	23.13	61.5
General and administrative expenses	(0.64)	(1.2)	(0.42)	(1.1)	(0.34)	(0.9)
Interest	(0.63)	(1.2)	(0.45)	(1.1)	(0.32)	(0.9)
Realized foreign exchange gain	2.35	4.4	0.74	1.9	–	–
Current and capital taxes	(1.89)	(3.6)	(0.71)	(1.8)	(0.54)	(1.4)
Cash flow	32.52	61.7	22.39	57.0	21.93	58.3
Unrealized foreign exchange gain (loss)	(2.48)	(4.7)	0.30	0.8	2.24	6.0
Unit-based compensation	(2.12)	(4.0)	(2.17)	(5.5)	(1.30)	(3.5)
Risk management activities	(0.09)	(0.2)	–	–	–	–
Depletion, depreciation and accretion	(12.01)	(22.8)	(10.67)	(27.2)	(8.19)	(21.8)
Future income taxes	0.03	–	(2.83)	(7.2)	(2.63)	(7.0)
Net income	$ 15.85	30.0	$ 7.02	17.9	$ 12.05	32.0

Cash flow increased by 37 percent to $1.2 billion for the year ended December 31, 2005 from $867 million in the same period of 2004. Basic cash flow per unit rose by 36 percent to $7.28 per unit in 2005, compared to $5.37 per unit in 2004.

Q4 2005 cash flow was $333 million, an increase of 40 percent from $238 million in Q4 2004. Basic cash flow per unit increased 38 percent to $2.03 per unit in Q4 2005 compared to $1.47 per unit in Q4 2004.

Net income for the year ended December 31, 2005 increased by 112 percent to $577 million from $272 million in 2004. Basic net income per unit increased by 111 percent in 2005 to $3.55 per unit from $1.68 per unit in 2004.

Net income in Q4 2005 increased 251 percent to $241 million from $69 million in Q4 2004. Basic net income per unit increased 252 percent to $1.48 per unit in Q4 2005 from $0.42 per unit in Q4 2004.

Market Risk Management

The Trust 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 Trust, from time to time, attempts to minimize exposure to these risks using financial instruments.

Credit Risk

Credit risk is the risk of loss if purchasers or counterparties do not fulfill their contractual obligations. All of the Trust'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 Trust transacts only with financial institutions with high credit ratings and by obtaining security in certain circumstances.

Commodity Price Risk

Commodity price risk is the Trust'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 policy, the Trust may, from time to time, manage these risks through the use of costless collars or other financial instruments up to a maximum of 50 percent of sales volumes.

The Trust maintains an active hedging program. Other financial instruments include Alberta electricity contracts with positive mark-to-market values. For details of the financial instruments outstanding on December 31, 2005, see note 10 to the audited consolidated financial statements.

Interest Rate Risk

The Trust maintains its debt in floating-rate bank facilities resulting in exposure to fluctuations in short-term interest rates. From time to time, the Trust may increase the certainty of future interest rates using financial instruments to swap floating interest rates for fixed rates or to collar interest rates. The Trust had no financial instruments in place at December 31, 2005 that affected its future interest rate exposure.

Foreign Currency Rate Risk

Prices received for sales of crude oil and certain bank loans are referenced to, or denominated in, US dollars. Accordingly, realized oil prices, interest costs and debt levels may be impacted by CAD/USD exchange rates. When considered appropriate, the Trust may use financial instruments to fix or collar future exchange rates. At December 31, 2005 the Trust had no financial instruments outstanding related to foreign exchange rates.

Liquidity and Capital Resources

Capitalization

AS AT DECEMBER 31,	2005		2004		2003	
	$ millions	%	$ millions	%	$ millions	%
Trust unit equity, at market	**$ 6,203**	**90.5**	$ 4,269	86.0	$2,586	81.0
Bank loan	**542**	**7.9**	503	10.2	442	13.8
Working capital deficiency [1]	**127**	**1.6**	190	3.8	165	5.2
Total enterprise value	**$ 6,872**	**100.0**	$ 4,962	100.0	$ 3,193	100.0

[1] Current assets less current liabilities.

Penn West's closing market price on the Toronto Stock Exchange was $37.99 per unit in 2005. The closing market price in the prior years, after accounting for the conversion ratio of three trust units issued for each common share, was $26.42 per unit in 2004 and $16.05 per unit in 2003. Total enterprise value was $6.9 billion at December 31, 2005 compared to $5.0 billion at year end 2004.

Dividends paid to shareholders prior to the trust conversion of $18 million, distributions paid to unitholders after the conversion of $270 million, and the 2005 capital program were funded using a portion of internally generated 2005 cash flow. Distributions declared subsequent to the trust conversion represented 43 percent of cash flow and 66 percent of net income. The remaining cash flow was used to repay bank debt which, at December 31, 2005, was $542 million compared with $503 million at December 31, 2004 after the payment of cash taxes and stock options related to the trust conversion in 2005.

In the second quarter of 2005, the Trust entered into an unsecured, extendible, three year revolving syndicated credit facility with an aggregate borrowing limit of $1,170 million plus a $50 million operating facility. The credit facility contains provision for stamping fees on Bankers' Acceptances and LIBOR loans, and standby fees on lines not drawn depending on certain consolidated bank debt to earnings before interest, taxes and depreciation and depletion ("EBITDA") ratios. The Trust is in compliance with all financial covenants relating to the facility.

Under the terms of its trust indenture, the Trust is required to distribute all of its taxable income to unitholders. Distributions may be monthly or special and in cash or in trust units at the discretion of the Board of Directors. To the extent that additional cash distributions are paid and capital programs are not adjusted, debt levels may increase. In the event that a special distribution in the form of trust units is declared, the terms of the Trust Indenture require that the outstanding units be consolidated immediately subsequent to the distribution. The number of outstanding trust units would remain at the number outstanding immediately prior to the distribution of trust units and that portion of the Trust's taxable income would be allocated to the unitholders.

The philosophy of the Trust is to retire approximately 10 percent to 15 percent of its opening asset retirement obligations annually from cash flow. Due to the extent of its environmental programs, the Trust believes little or no benefit would result from the initiation of a reclamation fund. The Trust believes its program is sufficient to meet or exceed existing environmental regulations and best industry practices. In the event of significant changes to the environmental regulations or the cost of environmental activities, a higher portion of cash flow will be required to fund these expenditures.

Reconciliation of Cash Flow to Distributions

($ millions, except indicators and per unit amounts)	Three months ended December 31, 2005	Seven months ended December 31, 2005[1]
Cash flow from operating activities	$ 368.7	$ 696.5
(Decrease) increase in non-cash working capital	(42.4)	34.6
Payments for surrendered options	–	0.6
Environmental expenditures	6.3	12.6
Cash flow	$ 332.6	$ 744.3
Funding of capital expenditures	(6.3)	(203.3)
Environmental expenditures	(6.3)	(12.6)
Debt repayments	(168.2)	(206.9)
Cash distributions	$ 151.8	$ 321.5
Accumulated cash distributions, beginning of period	169.7	–
Accumulated cash distributions, end of period	$ 321.5	$ 321.5
Net income	$ 241.1	$ 485.6
Cash distributions as a percentage of net income	63%	66%
Cash distributions as a percentage of cash flow	46%	43%
Cash distributions per unit	$ 0.93	$ 1.97

(1) Includes the operations of the Trust subsequent to the effective date of the trust conversion, May 31, 2005.

During 2005, Penn West paid dividends of $18 million (2004 – $108 million) and distributions of $270 million. The first monthly cash distribution of the Trust, in the amount of $42 million or $0.26 per trust unit, was paid on July 15, 2005 to unitholders of record on June 30, 2005. On October 17, 2005, the Trust announced an increased monthly distribution of $0.31 per trust unit, a 19 percent increase, that was payable on November 15, 2005 to unitholders of record on October 31, 2005. On February 2, 2006, a further 10 percent or $0.03 per trust unit distribution increase was announced effective for the February distribution payable March 15, 2006. The distribution increases were made considering expected commodity prices that exceed those initially forecasted, hedging contracts put in place to increase the likelihood of achieving price expectations, strong industry interest in the Trust's undeveloped land base, and the level of projected capital requirements for 2006 and beyond.

The Trust's 2005 distributions, for both Canadian and U.S. unitholders, were 100 percent taxable with no return of capital.

Plan of Arrangement

On May 27, 2005, the shareholders approved the proposed reorganization of Penn West into an income trust as described in the plan of arrangement dated April 22, 2005. Court approval was obtained on the effective date of the conversion, May 31, 2005. Penn West shareholders received three units of the Trust for each Penn West share. The Trust commenced operations on May 31, 2005 with a new business mandate and legal structure pursuant to the trust indenture dated April 22, 2005. The Trust assumed all assets and liabilities previously held by Penn West.

Prior to the trust conversion, the audited consolidated financial statements included the accounts of the Penn West and its subsidiaries and partnerships. The audited consolidated financial statements of the Trust have been prepared on a continuity of interest basis, as if the Trust historically carried on the business of Penn West, and include the financial results of Penn West to May 31, 2005 and the Trust for the subsequent months. Per unit figures of comparative periods have been restated to reflect the conversion ratio of three units of the Trust for each share of Penn West.

Reorganization costs of $36 million, pre-tax, relating to financial advisors, legal fees, short-year tax rate differences and additional capital taxes associated with the plan of arrangement were charged to accumulated earnings in the second quarter of 2005. In addition, as Penn West's stock option plan contained a cash payment alternative, $53 million related to canceling outstanding options was expensed in the second quarter of 2005. At the end of May 2005, Penn West made cash payments of $81 million for the surrender of the remaining vested and unvested stock options pursuant to the plan of arrangement and the terms of the stock option plan.

In addition, the Trust conversion resulted in a short income tax year that accelerated $146 million of cash income taxes as a significant amount of Penn West's taxable income was earned in a partnership.

Business Risks

The Trust's exploration, development, production and asset acquisition/disposition 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 potential instability of commodity prices, exchange rates and interest rates, and other factors discussed under "Notice Regarding Forward-Looking Statements."

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

- Balancing the production portfolio between oil and natural gas;
- Pursuing low risk development and production optimization projects and implementing a phased approach to significant projects such as the Pembina/Swan Hills CO_2 enhanced oil recovery project and the Seal oilsands project;
- Pursuing strategic acquisitions, dispositions and the farmout of undeveloped land; and,
- Maintaining high average capital efficiency and low operating and general and administrative costs.

The Trust's management team believes that these principles, validated through Penn West's thirteen-year track record of growth and profitability, will continue to apply under the Trust's business model.

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, 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 Trust is committed to meeting its responsibilities to minimize its impact on 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. The Trust's plan is to retire approximately 10 percent to 15 percent of its opening ARO annually from cash flow. All activities that have or could have an environmental impact and all environmental regulations are regularly monitored by the Trust.

Outlook

The outlook for oil and natural gas prices remains strong. For 2006, we are forecasting net capital expenditures of $400 to $500 million which will fund 250 to 300 net wells. Estimated average 2006 production is forecast between 94,000 and 98,000 boe per day. Based on a forecast WTI oil price of US$58.00 per barrel and an $8.75 per mcf natural gas price with an exchange rate of $0.850 CAD/USD for 2006, forecast after-tax cash flow for 2006 is between $1.0 billion and $1.1 billion.

Sensitivity Analysis

This MD&A includes forward-looking statements (forecasts) under applicable securities laws. These statements are based on assumptions related to, but not limited to, commodity prices, the capital markets, the performance of producing wells and reservoirs, and the regulatory and legal environment. Forward-looking statements are subject to known or unknown risks and uncertainties that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements. The Trust assumes no responsibility to publicly update or revise any forward-looking statements. Sensitivities to selected key assumptions, excluding hedging impacts, are outlined in the table below.

Change of:	Impact on Cash Flow[1]	Impact on Net Income[1]
$1.00 per barrel of liquids price	16.0	10.4
Per trust unit, basic	0.10	0.06
1,000 barrels per day in liquids production	16.1	7.3
Per trust unit, basic	0.10	0.04
$0.10 per mcf of natural gas price	7.5	4.9
Per trust unit, basic	0.05	0.03
10 mmcf per day in natural gas production	24.7	10.7
Per trust unit, basic	0.15	0.07
$0.01 in $CAD/$US exchange rate	15.4	10.0
Per trust unit, basic	0.09	0.06

(1) $ millions, except per unit amounts. Cash flow and net income impacts are computed based on 2006 forecast commodity prices and production volumes. The net income impact further assumes that income allocations to the Trust are not adjusted for changes in cash flow, thus impacting the incremental tax rate.

Commitments

We are committed to certain payments over the next five calendar years as follows:

($ millions)	2006	2007	2008	2009	2010	Thereafter
Transportation	15.4	8.3	6.4	4.4	1.3	-
Transportation ($US)	3.4	1.7	1.6	1.6	1.6	7.7
Electricity	3.9	3.9	3.9	3.9	3.9	6.5
Office lease	5.4	4.5	4.2	4.2	2.1	1.4

Equity Instruments

Trust units issued	
As at December 31, 2005[1]	163,290,013
Issued to distribution reinvestment plan	222,037
Issued to employee savings plan	43,742
As at February 27, 2006	163,555,792
Trust unit rights outstanding	
As at December 31, 2005[1]	9,447,625
Granted	154,250
Forfeited	(24,000)
As at February 27, 2006	9,577,875

[1] See notes 7 and 8 to the audited consolidated financial statements

Evaluation of Disclosure Controls

The Trust maintains a Disclosure Committee (the "Committee") that is responsible for ensuring that all public and regulatory disclosures are sufficient, timely and appropriate, and that disclosure controls and procedures are operating effectively. The Committee includes select members of senior management, including the Chief Executive Officer, the Chief Operating Officer and the Vice-President, Finance. As at the end of the period covered by this report, under the supervision of the Committee, the design and operating effectiveness of the Trust's disclosure controls were evaluated. According to this evaluation, we have concluded the Trust's disclosure controls and procedures are effective to ensure that any material, or potentially material, information is made known to a member of the Committee and is appropriately included in this report.

Critical Accounting Estimates

The Trust's significant accounting policies are detailed in note 2 to the audited consolidated financial statements. In the determination of financial results, the Trust must make certain significant accounting estimates as follows:

Full Cost Accounting

The Trust uses the full cost method of accounting for oil and natural gas properties. 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 using forecast pricing.

All Trust reserves were evaluated by GLJ Petroleum Consultants Ltd., an independent engineering firm. In both 2005 and 2004, 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

The Trust applies the "Asset Retirement Obligations" ("ARO") accounting recommendations. The discounted, expected future cost 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 to its future amount 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 audited consolidated financial statements details the impact these accounting recommendations had on the audited consolidated financial statements.

Financial Instruments

Financial instruments, included in the balance sheets, consist of accounts and taxes receivable, current liabilities and the bank loan. The fair values of these financial instruments approximate their carrying amounts due to the short-term maturity of the instruments and the market rate of interest and exchange rates applied to the bank loan.

All of the accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risk. The Trust, from time to time, uses various types of financial instruments to reduce its exposure to fluctuating oil and natural gas prices, electricity costs, exchange rates and interest rates. The use of these instruments exposes the Trust to credit risks associated with the possible non-performance of counterparties to derivative instruments. The Trust limits this risk by transacting only with financial institutions with high credit ratings and by obtaining security in certain circumstances.

The Trust's revenue from the sale of crude oil, natural gas liquids and natural gas are directly impacted by changes to the underlying commodity prices. To ensure that cash flows are sufficient to fund planned capital programs and distributions, costless collars, or other financial instruments, may be utilized. Collars ensure that commodity prices realized will fall into a contracted range for a contracted sales volume. Forward power contracts fix a portion of future electricity costs at levels determined to be economic by management.

Accounting Changes

Earnings per Share

Effective January 1, 2005, this accounting pronouncement requires the number of incremental shares included in year-to-date diluted earnings per share calculations be computed using the average market price of shares for the year-to-date period. It also stipulates that contracts that could be settled in cash or shares be assumed settled in shares if share settlement is more dilutive. Shares to be issued upon conversion of convertible instruments with mandatory conversion features would be included in the basic weighted average earnings per share calculation from the date of mandatory conversion. These changes did not materially impact the Trust's reported diluted earnings per unit amounts.

Financial Instruments

Future changes in the fair value of derivative financial instruments will be recorded on the balance sheet with a corresponding unrealized gain or loss in income. For a summary of financial instruments outstanding on December 31, 2005 see note 10 to the audited consolidated financial statements.

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, but are not limited to, the following:

- > Changes in general economic, market and business conditions which will impact demand for and market prices of the Trust's products;
- > The ability of the Trust to implement its business strategy;
- > Availability and cost of borrowing;
- > The ability of the Trust to complete its capital programs;
- > The ability of the Trust 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 Trust 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. The Trust assumes no responsibility to publicly update or revise any forward-looking statements.

Accounting Pronouncements

Financial Instruments, Other Comprehensive Income

This pronouncement, effective for fiscal year ends beginning on or after October 1, 2006, 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 as an equity item with the related mark-to-market gain or loss recognized in other comprehensive income. Consistent with current practice, financial instruments not designated as hedges will be valued at market with any related gains and losses recognized in net income of the period. As the Trust no longer designates financial instruments as hedges, and immediately recognizes changes in their fair value in net income, this pronouncement is not expected to impact reported results.

Non-Monetary Transactions

Effective January 1, 2006, this accounting pronouncement requires that non-monetary transactions be measured at fair value unless certain conditions apply and is not expected to affect the Trust's reported results.

FORM 52-109F1

CERTIFICATION OF ANNUAL FILINGS

I, WILLIAM E. ANDREW, President and Chief Executive Officer of Penn West Petroleum Ltd., on behalf of Penn West Energy Trust, certify that:

1. I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52- 109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of Penn West Energy Trust (the issuer) for the period ending December 31, 2005;

2. Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings;

3. Based on my knowledge, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures for the issuer, and we have:

   (a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared; and

   (b) evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation.

Date: February 27, 2006

signed *"William E. Andrew"*
William E. Andrew
President and Chief Executive Officer

G:\040302\0190\Annual Certificate (Modified) (CEO).doc

FORM 52-109F1

CERTIFICATION OF ANNUAL FILINGS

I, TODD TAKEYASU, Vice President, Finance acting in the capacity of Chief Financial Officer of Penn West Petroleum Ltd., on behalf of Penn West Energy Trust, certify that:

1. I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52- 109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of Penn West Energy Trust (the issuer) for the period ending December 31, 2005;

2. Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings;

3. Based on my knowledge, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures for the issuer, and we have:

   (a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared; and

   (b) evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation.

Date: February 27, 2006

signed *"Todd Takeyasu"*
Todd Takeyasu
Vice President, Finance

PENN WEST
ENERGY TRUST

NEWS RELEASE

Penn West Energy Trust Files Audited Consolidated Financial Statements

FOR IMMEDIATE RELEASE, Wednesday, March 8, 2006

PENN WEST ENERY TRUST (TSX – PWT.UN) files Financial Disclosure Statements

(Calgary, March 8, 2006) /CNW/ - Penn West Energy Trust (the "Trust") announced today that it has filed with Canadian securities authorities its audited consolidated financial statements and accompanying notes for the year ended December 31, 2005 and related Management's Discussion and Analysis. Copies of the filed documents may be obtained through SEDAR at www.sedar.com, through the Trust's website at www.pennwest.com, or by contacting our investor relations group.

Penn West Energy Trust is a senior oil and natural gas energy trust based in Calgary, Alberta that trades on the Toronto Stock Exchange under the symbol PWT.UN.

For further information, please contact:

PENN WEST ENERGY TRUST
Suite 2200, 425 - First Street S.W.
Calgary, Alberta T2P 3L8

Phone: (403) 777-2500
Toll-free: 1-866-693-2707
Fax: (403) 777-2699
Website: www.pennwest.com
E-mail: investor_relations@pennwest.com

William Andrew, President and CEO
Phone: (403) 777-2502