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THOMSON FINANCIAL

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ENERGY TRUST

12-21-05
AR/S

NOTICE OF ANNUAL GENERAL MEETING

The Annual General Meeting of unitholders will be held at 3:00 p.m. on Wednesday, May 17, 2006 at the Westin Hotel,

[illegible]20 – 4th Avenue S.W., Calgary, Alberta.

All unitholders are invited to attend.

FORWARD-LOOKING INFORMATION

Certain information set forth in this document, including management's assessment of Focus' future plans and operations, contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond Focus' control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Focus' actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do, what benefits Focus will derive therefrom. Focus disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. Readers are cautioned that net present value of reserves does not represent fair market value of reserves.

FOCUS ENERGY TRUST IS A NATURAL GAS WEIGHTED ENERGY TRUST. FOCUS IS COMMITTED TO MAINTAINING ITS EMPHASIS ON OPERATING HIGH-QUALITY OIL AND GAS PROPERTIES, DELIVERING CONSISTENT DISTRIBUTIONS TO UNITHOLDERS, AND ENSURING FINANCIAL STRENGTH AND SUSTAINABILITY.

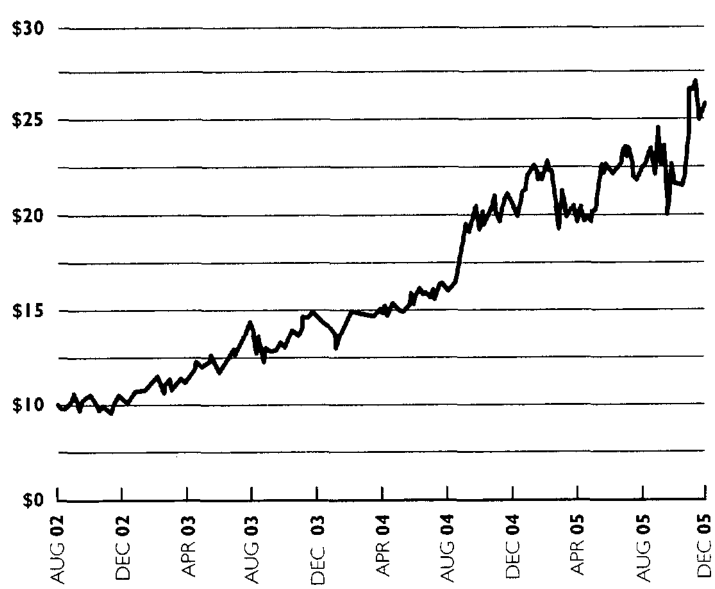
FOCUS ENERGY TRUST UNITS TRADE ON THE TSX UNDER THE SYMBOL **FET.UN**, AND THE EXCHANGEABLE SHARES OF FET RESOURCES LTD. TRADE ON THE TSX UNDER THE SYMBOL **FTX**.

PRODUCTION OF NATURAL GAS AND LIGHT OIL IS APPROXIMATELY 10,000 BOE/D AND IS PRODUCED FROM SIX MAIN AREAS IN BRITISH COLUMBIA AND ALBERTA. PRODUCTION IS WEIGHTED 74% TO NATURAL GAS, AND FOCUS OPERATES APPROXIMATELY 89% OF ITS PRODUCTION.

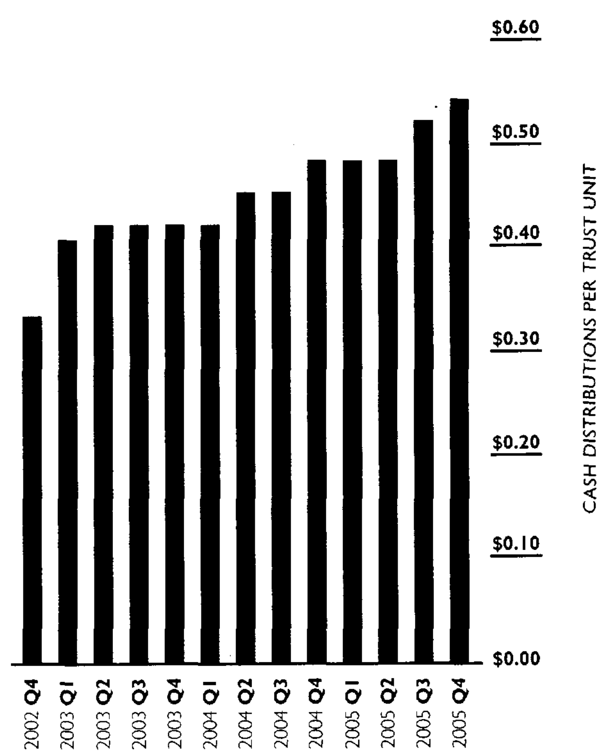
CONTENTS

STRENGTH.
PERFORMANCE.
SUSTAINABILITY.

FET.UN EQUITY



FET.UN DISTRIBUTIONS
PER QUARTER



2005 HIGHLIGHTS

(thousands of dollars, except where indicated)	Three Months Ended December 31, 2005	2004	Years Ended December 31, 2005	2004	Year Over Year Change
FINANCIAL					
Oil and gas revenues, before transportation system charges and royalties	**52,315**	39,233	**191,669**	150,173	28%
Funds flow from operations (1)	**32,350**	23,241	**116,368**	89,567	30%
Per unit (2) (4)	**$ $0.86**	$ 0.63	**$ 3.12**	$ 2.49	25%
Cash distributions per trust unit					
Per unit	**$ 0.54**	$ 0.48	**$ 2.02**	$ 1.80	12%
Payout ratio (per-unit basis)	**63%**	77%	**65%**	72%	(7%)
Net income (3)	**17,858**	14,545	**63,464**	51,080	24%
Per unit (3)	**$ 0.49**	$ 0.41	**$ 1.74**	$ 1.52	15%
Capital expenditures and acquisitions	**10,832**	12,515	**53,398**	154,855	(66%)
Long-term debt less working capital	**92,518**	81,157	**92,518**	81,157	14%
Total Trust Units – outstanding (000's) (4)	**37,456**	37,223	**37,456**	37,223	1%
Weighted average Total Trust Units (000's) (5)	**37,442**	37,163	**37,344**	35,903	4%
OPERATIONS					
Average daily production					
Crude oil (bbls/d)	**1,714**	1,903	**1,765**	1,996	(12%)
NGLs (bbls/d)	**762**	724	**777**	669	16%
Natural gas (mcf/d)	**42,629**	43,080	**44,526**	42,706	4%
Barrels of oil equivalent (@ 6:1)	**9,582**	9,807	**9,963**	9,782	2%
Average product prices realized, net of transportation system charges (6)					
Crude oil (CDN$/bbl)	**$ 59.20**	$ 41.28	**$ 56.61**	$ 40.43	40%
NGLs (CDN$/bbl)	**$ 60.64**	$ 48.48	**$ 57.50**	$ 43.73	31%
Natural gas (CDN$/mcf)	**$ 9.24**	$ 6.64	**$ 7.92**	$ 6.41	24%
Field netback per BOE					
Revenue (6)	**$ 56.61**	$ 40.82	**$ 49.97**	$ 39.27	27%
Royalties, net of ARTC	**$ (13.41)**	$ (9.36)	**$ (11.98)**	$ (9.52)	26%
Production expenses	**$ (4.61)**	$ (3.76)	**$ (4.11)**	$ (3.29)	25%
Field netback	**$ 38.58**	$ 27.71	**$ 33.88**	$ 26.46	28%
Wells drilled					
Gross	**6**	8	**37**	24	54%
Net	**4.8**	5.8	**29.4**	14.6	101%
Success rate	**100%**	100%	**100%**	96%	4%
TRUST UNIT TRADING STATISTICS					
Unit prices					
High	**$ 26.74**	$ 21.39	**$ 26.74**	$ 21.39	–
Low	**$ 19.72**	$ 18.08	**$ 18.60**	$ 12.90	–
Close	**$ 25.72**	$ 19.97	**$ 25.72**	$ 19.97	29%
Daily average trading volume	**103,540**	139,144	**100,967**	112,677	(10%)
RESERVES					
Proved plus probable (7)					
Crude oil (mbbls)			**5,608**	5,697	(2%)
NGLs (mbbls)			**3,420**	3,387	1%
Natural gas (Mmcf)			**187,506**	194,462	(4%)
Barrels of oil equivalent (@6:1)			**40,279**	41,495	(3%)
Reserve life index of proved plus probable (8)			**10.5**	10.6	(1%)
Gas weighting of proved plus probable reserves			**78%**	78%	0%
Proved reserves/proved plus probable reserves			**77%**	76%	1%

(1) FUNDS FLOW FROM OPERATIONS ("FUNDS FLOW" BEFORE CHANGES IN NON-CASH WORKING CAPITAL AND RECLAMATION COSTS) IS USED BY MANAGEMENT TO ANALYZE OPERATING PERFORMANCE AND LEVERAGE. FUNDS FLOW AS PRESENTED DOES NOT HAVE ANY STANDARDIZED MEANING PRESCRIBED BY CANADIAN GAAP AND THEREFORE IT MAY NOT BE COMPARABLE WITH THE CALCULATION OF SIMILAR MEASURES OF OTHER ENTITIES. FUNDS FLOW AS PRESENTED IS NOT INTENDED TO REPRESENT OPERATING CASH FLOW OR OPERATING PROFITS FOR THE PERIOD NOR SHOULD IT BE VIEWED AS AN ALTERNATIVE TO CASH FLOW FROM OPERATING ACTIVITIES, NET EARNINGS OR OTHER MEASURES OF FINANCIAL PERFORMANCE CALCULATED IN ACCORDANCE WITH CANADIAN GAAP. ALL REFERENCES TO FUNDS FLOW THROUGHOUT THIS REPORT ARE BASED ON FUNDS FLOW FROM OPERATIONS BEFORE CHANGES IN NON-CASH WORKING CAPITAL AND RECLAMATION COSTS.

(2) BASED ON THE WEIGHTED AVERAGE TOTAL TRUST UNITS OUTSTANDING FOR THE PERIOD.

(3) NET INCOME HAS BEEN RESTATED. SEE NOTES 2 AND 3 OF THE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS. PER-UNIT AMOUNTS ARE BASED ON WEIGHTED AVERAGE UNITS OUTSTANDING FOR THE PERIOD, EXCLUDING EXCHANGEABLE SHARES.

(4) TOTAL TRUST UNITS BEING TRUST UNITS AND EXCHANGEABLE SHARES CONVERTED AT THE EXCHANGE RATIO PREVAILING AT THE TIME. TOTAL TRUST UNITS AS PRESENTED DOES NOT HAVE ANY STANDARDIZED MEANING PRESCRIBED BY CANADIAN GAAP AND THEREFORE IT MAY NOT BE COMPARABLE WITH THE CALCULATION OF SIMILAR MEASURES OF OTHER ENTITIES. THE EXCHANGE RATIO WAS 1.37265 AT DECEMBER 31, 2005 AND 1.27833 AT DECEMBER 31, 2004.

(5) WEIGHTED AVERAGE TOTAL TRUST UNITS INCLUDING TRUST UNITS AND EXCHANGEABLE SHARES CONVERTED AT THE AVERAGE EXCHANGE RATIO.

(6) NET OF SETTLEMENTS FOR FINANCIAL HEDGING INSTRUMENTS AND NET OF TRANSPORTATION SYSTEM CHARGES.

(7) RESERVE NUMBERS ARE TOTAL PROVED PLUS PROBABLE COMPANY GROSS RESERVES (BEFORE DEDUCTION OF ROYALTIES PAYABLE, NOT INCLUDING ROYALTIES RECEIVABLE) AS DEFINED IN NATIONAL INSTRUMENT 51-101.

(8) RESERVE LIFE INDEX IS CALCULATED BY DIVIDING YEAR-END RESERVES BY THE FORWARD YEAR PRODUCTION ESTIMATE FROM THE RESERVE REPORTS.

MESSAGE TO THE UNITHOLDERS

2005 was a very successful year for Focus. We continued to execute our sustainable business model, add to our inventory of internally developed opportunities and acquire strategic assets that are reflective of our tight gas initiatives. All the while, we enjoyed a strong commodity price environment that allowed us to increase distributions during the year.

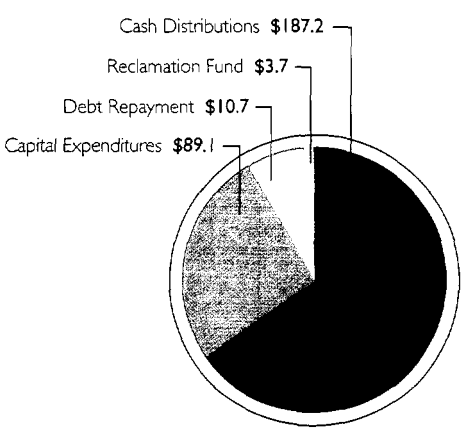
HIGHLIGHTS

- Focus units realized a 39 percent total annualized return in 2005. Total return since the Trust's inception in 2002 is 228 percent.
- Monthly distributions increased from $0.16 per unit at the start of the year to $0.18 per unit in August 2005. Distribution increases were driven primarily by extremely strong commodity prices.
- Funds flow from operations per unit increased 25 percent on a year-over-year basis, primarily driven by high natural gas prices.
- In 2005 our drilling program doubled in size as we continued to utilize our inventory of internally-generated drilling opportunities to replace production.
- Drilling success was 100 percent on the expanded program.
- Through a series of three land deals, we effectively doubled our land position at Tommy Lakes, building our inventory of internally-generated drilling opportunities.
- On a per-unit basis, proved plus probable reserves decreased by three percent in 2005. Proved plus probable reserves per unit have increased by 13 percent since Trust inception.
- Our reserve life index, on a proved plus probable basis, has essentially held constant at 10.5 years, even in the absence of a major acquisition.
- Net asset value per unit increased 49 percent on a year-over-year basis to $16.50, based on the Paddock Price Forecast and a 10 percent discount rate. Using a Constant Price Forecast and a 10 percent discount rate, the net asset value per unit is $19.74.
- Three-year average proved plus probable, finding, development and acquisition costs of $12.60 per BOE (including future capital) represent a recycle ratio of 2.2 times.
- Over the past four years, funds flow from operations has fully funded all capital expenditures, reclamation fund contributions, cash distributions, as well as reducing debt by $10.7 million.
- Our 2005/2006 Tommy Lakes winter drilling program is complete. Ten gross (10 net) development wells were drilled, completed and tied in. In addition, two gross (1 net) exploration wells were drilled and completed.
- In 2006 we have approximately 50 percent of gas production price protected at $10.06 per mcf.

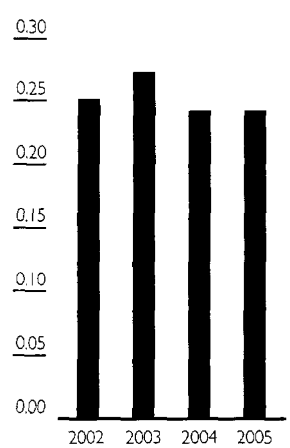
SUSTAINABILITY

In 2002, we set out to create a Trust with a strong operational focus that utilized the drill bit to create value and focused on sustainability. The four main elements that we believe define sustainability are production per unit, reserves per unit, capital use versus funds flow, and inventory. Each of these measures is reported on below.

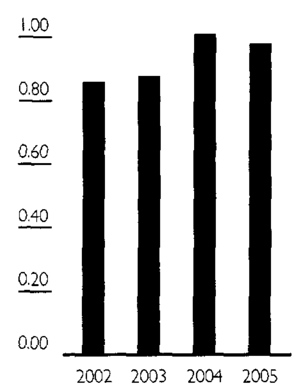
Funds Flow from Operations Q3 2002 – Q4 2005 (millions)



Production – BOE/d per Thousand Units (Debt Adjusted)



Reserves – BOE per Unit (Debt Adjusted)



2005 production per unit, on a debt adjusted basis, is down approximately two percent versus 2004 and has decreased by approximately five percent since the Trust's inception in 2002.

2005 reserves per unit, on a debt adjusted basis, are down approximately three percent to 2004 and have increased by approximately 12 percent since the Trust's inception.

One of the key tenets of our sustainability concept is that the sum of capital expenditures, distributions, and reclamation fund contribution, should not exceed 100 percent of funds flow.

Over the past four years, funds flow from operations has fully funded all capital expenditures, reclamation fund contributions, cash distributions, as well as reducing debt by $10.7 million. In 2005 we exceeded 100 percent of funds flow for the first time on a yearly basis with a $1.8 million increase in debt. This was as a result of the acceleration of our Tommy Lakes winter program in late 2005.

The fourth dimension of sustainability is inventory. At the inception of the Trust, we had one property with approximately 18 months of drilling inventory. At the end of 2005, we have over two years drilling inventory on five out of our six core areas. The expansion of our inventory has been driven by our technical team's continued ability to generate new drilling ideas on our existing asset base. The majority of our natural gas inventory has a recycle ratio of two times or better at a $5.50/mcf gas price.

As our history details, we are a selective acquirer of assets. Although we continue to evaluate both property and corporate acquisition opportunities, there is little by way of public offering that fits our strategic requirements and that, historically, we can be competitive on from a price perspective.

Accordingly, we have focused our attention on generating ideas on our existing land base. In addition, we have spent considerable time looking at increasing our land base in and around our core areas. In the third quarter, we reported on three separate deals in the Tommy Lakes area that, in aggregate, have effectively doubled our land position. These lands play an important role in continuing to build inventory at Tommy, not only in terms of extending the existing Halfway pool to the south and west, but also in providing exposure to exploratory upside on these lands, in secondary zones and, potentially, new Halfway gas accumulations.

We believe our focus on building on our land position around our core areas is the most effective way for us to create value for our unitholders in this high-priced/high-risk acquisition market.

OUTLOOK

In 2006, our drilling and development will occur in all core areas with the majority of our $45 million capital program being spent at Tommy Lakes, Pouce Coupe and Medicine Hat. We remain disciplined, focused and committed to increasing unitholder value. We are not going to spend more capital to do less, and are prepared to delay or cancel projects where operational or execution cost efficiencies do not exist. We anticipate that our capital program will result in average production of 9,750 to 10,250 BOE per day in 2006 and that our operating cost structure will be in the range of $4.25 to $4.75 per BOE.

Our hedging program, with approximately 50 percent of our 2006 natural gas volumes price protected at $10.06 per mcf, provides excellent protection in a very volatile natural gas market. As we have no crystal ball to provide clarity on future commodity prices, we will continue to focus our attention on the parts of our business in which we can have an impact, primarily the control of our operating costs and our capital reinvestment efficiencies.

Current industry activity levels continue to create significant challenges with respect to sourcing equipment, services and, most importantly, people to undertake projects. We are working diligently to ensure our drilling programs are delivered on time and on budget and are attempting to reduce cost pressures through innovation, planning and execution efficiencies.

The Trust is in excellent financial position with a low debt to funds flow ratio of 0.8 times, sufficient funds after distributions to fund our capital program, and the financial flexibility to execute on a material acquisition should a quality opportunity arise.

We would like to thank our unitholders for investing in Focus and for their continued support.

We would also like to thank our Board of Directors for their continued guidance and our Focus team for their tireless efforts and continued enthusiasm.

On behalf of the Board,

Derek W. Evans
President and Chief Executive Officer

OPERATIONS REVIEW

All of Focus' producing properties are located in six main areas in Alberta and British Columbia. These include the natural gas producing areas of Tommy Lakes, Kotcho-Cabin, Pouce Coupe, and Medicine Hat, the light oil producing area of Red Earth, and Sylvan Lake, which produces both natural gas and light oil.

In 2005, production of the Trust was weighted 74 percent to natural gas, with the remaining 26 percent consisting of light sweet crude and natural gas liquids. Our average working interest is approximately 70 percent, and we operate approximately 89 percent of our production.

TOMMY LAKES, NE BRITISH COLUMBIA

The Trust's largest single asset and main natural gas producing property is the Tommy Lakes area in northeastern British Columbia. The main producing zone at Tommy Lakes is the areally extensive blanket sand of the Triassic Halfway formation. Total pool original gas in place is in excess of 600 Bcf, of which approximately 31 percent has been produced to date. Although the reservoir is thick (more than 10 meters) and continuous, permeability is low, requiring all wells to be fracture stimulated to achieve stabilized rates of 600 to 800 mcf per day, with natural gas liquids recovered at 20 barrels per million cubic feet.

During 2005, Focus' gross production from the Tommy Lakes property averaged 33.1 Mmcf per day of natural gas and 681 bbls per day of natural gas liquids from 96 (91.0 net) wells. The base decline rate on the existing production is approximately 12 percent per year. Production at the property is compressed at four Focus-operated facilities and delivered into the Duke (Westcoast) system for further processing and delivery to markets. At December 31, 2005, Tommy Lakes represented approximately 67 percent of the Trust's reserves.

Focus invested $10.2 million in Q3 2005 to acquire production and undeveloped land immediately to the south of its Tommy Lakes property. The acquired production of approximately 0.9 Mmcf per day and 19 bbls per day of associated natural gas liquids is 100 percent working interest and is tied in to the Focus owned and operated gathering system and facilities. The acquisition also included 33,550 gross acres of undeveloped land, the evaluation of which will lead to expansion of the Trust's drilling inventory at Tommy Lakes over the coming years. The Trust also acquired additional crown lands at Tommy during the year, and entered into a farm-in commitment with rolling options on a block of prospective lands to the northwest of our existing Halfway production. Combined, these three transactions have approximately doubled our acreage position at Tommy Lakes.

Subsequent to year end, the Trust successfully completed its 12-well (11.0 net) winter drilling program at Tommy Lakes. Ten of these wells (10.0 net) were development wells drilled within the existing Tommy Lakes Halfway pool. All of these wells were cased and have been placed on production. Two wells (1.0 net) were exploratory tests drilled on the farm-in lands described above, which lie to the northwest of the existing Halfway pool. Both of these wells were cased and completed. Specific information concerning the results of these two wells is confidential.

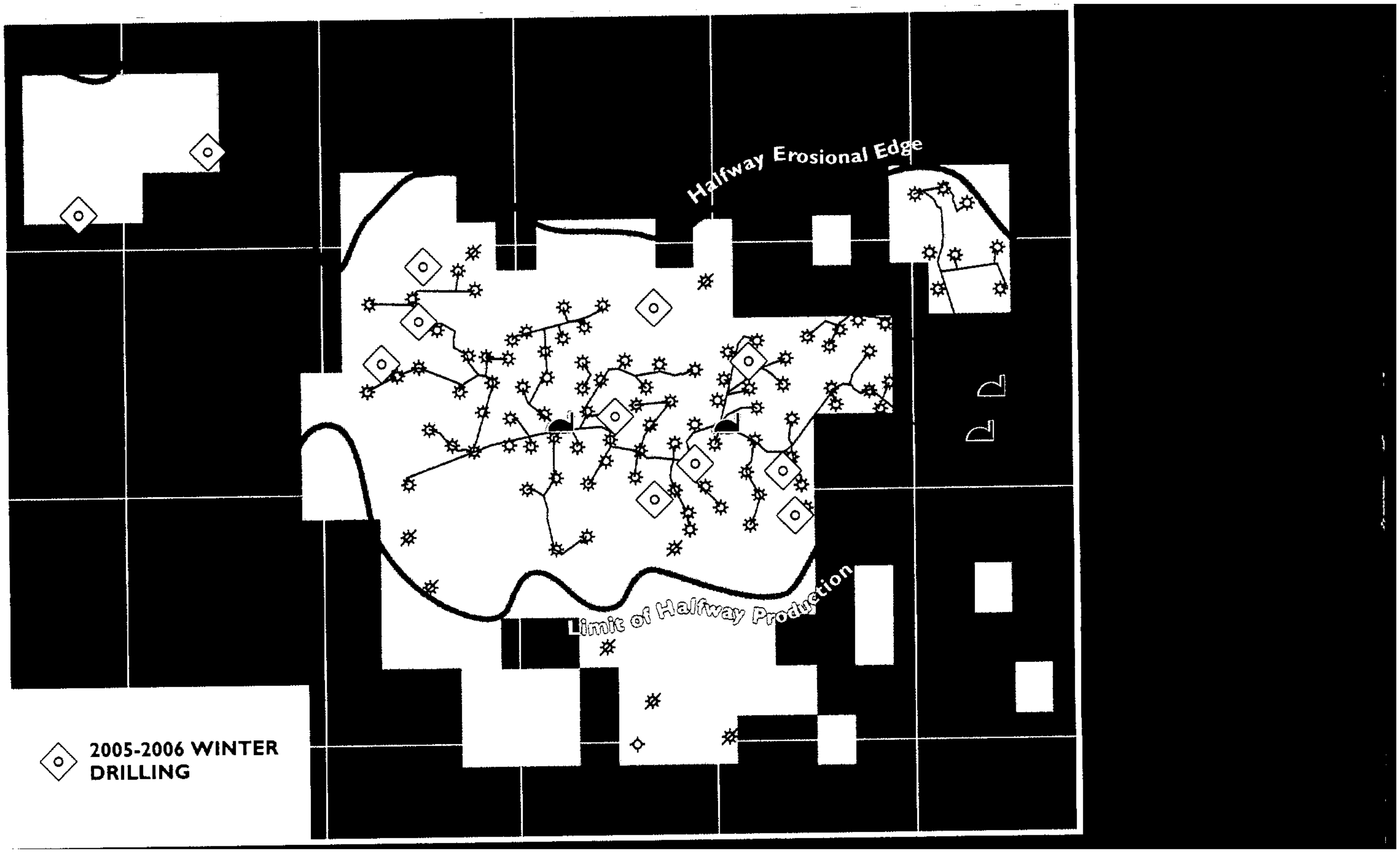
This year's 10-well development program set out to achieve three main objectives:

- the continued efficient infill development of the Halfway A Pool;
- selective Halfway step-out drilling to continue to extend the economic boundaries of the main pool;
- the continued implementation of well design and program execution initiatives designed to maximize our cost efficiencies.

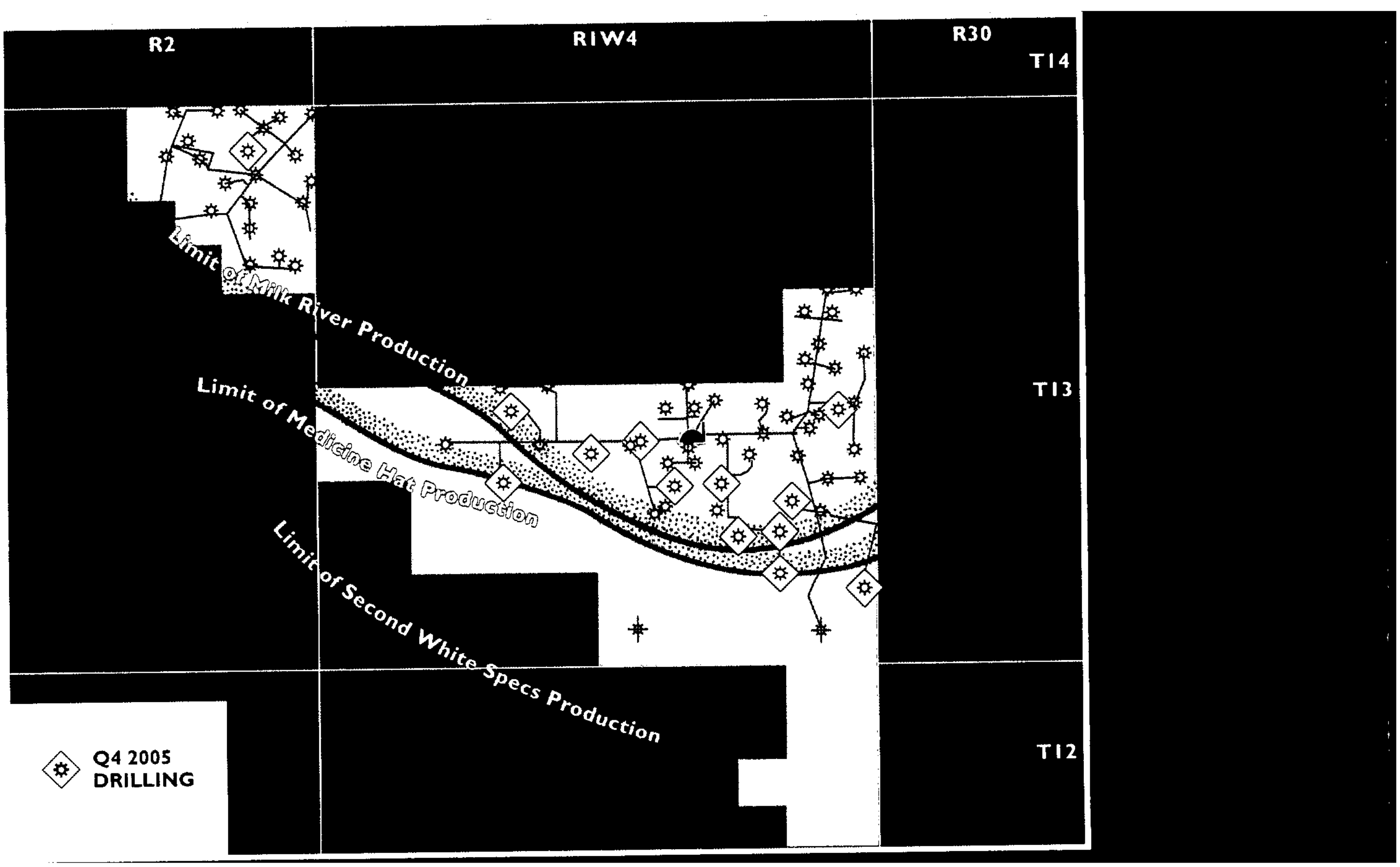
The program was successful in achieving all of these objectives and the overall winter program at Tommy Lakes came in as per our expectations. Based upon this continued success, Focus anticipates that the Tommy Lakes property will continue to be the main development area for the Trust, with several more years of similar sized development programs.


KOTCHO-CABIN
FORT NELSON
TOMMY LAKES
RED EARTH
FORT ST. JOHN
POUCE COUPE
British Columbia
Alberta
EDMONTON
SYLVAN LAKE
CALGARY
MEDICINE HAT
OIL PRODUCING
GAS PRODUCING

ommy Lakes



Medicine Hat



RED EARTH, ALBERTA

The Trust's light oil production is concentrated in the Red Earth area, within which the main producing properties are Golden, Loon Lake, Loon Lake North, Evi and Kitty. In 2005 Focus' gross production from the Red Earth area averaged 1,688 bbls per day of 38° API light sweet crude. Approximately 47 percent of the Red Earth production is operated by Focus.

The majority of the Trust's development activity within the Red Earth area is concentrated at Loon Lake, which was acquired in June 2003. The main productive horizon at Loon Lake is the Slave Point G pool, which is a light oil reservoir under active waterflood. During 2005, the Trust drilled four (1.6 net) wells into the Slave Point G pool, and also converted four wells to water injection to optimize the waterflood pattern. Activities in 2006 will include further infill and step-out drilling.

KOTCHO-CABIN, NE BRITISH COLUMBIA

At Kotcho and Cabin the Trust is producing from two sour high-pressure gas pools along a dolomitized reef edge in the Devonian Slave Point formation. Production from both properties is processed through 100 percent Focus-owned dehydration and water disposal facilities and delivered to the Duke (Westcoast) system.

During 2005, Focus' gross production from this area averaged 4.1 Mmcf per day of natural gas. At Kotcho, volumes have continued to decrease over the course of the year due to increasing water production from the pool. We continue to monitor production closely and pursue the appropriate strategies to ensure that recovery from the pool is maximized. In the first quarter of 2005 the Trust participated in the drilling of one (0.4 net) well at Kotcho targeting the Slave Point. The well was completed in the Slave Point and placed on production, however well performance has been disappointing with high water gas ratios and correspondingly lower gas rates. In the first quarter of 2006 the Trust has tied in one (0.8 net) standing Slave Point gas well to a third party facility. This well is in a separate Slave Point pool from the main Kotcho production. Also in Q1 2006 the Trust added compression to our Kotcho facility to ensure that the wells will efficiently produce the remaining reserves in the main Slave Point pool.

POUCE COUPE, ALBERTA

At Pouce Coupe the Trust produces natural gas and associated NGLs from the Triassic Montney and Doig formations. Focus' gross production from this property in 2005 averaged 3.4 Mmcf per day of natural gas and 38 bbls per day of natural gas liquids. The majority of production is compressed at a 100 percent Focus-owned facility and then delivered to a third party plant for further processing and delivery onto the TransCanada pipeline system.

Activity at Pouce Coupe has been concentrated on downspacing within the Montney reservoir. Offsetting operators have commonly downspaced the Montney to four wells per section and in specific cases are testing the economics of eight-well-per-section spacing. Focus drilled two wells into the Montney in 2005 with good success, bringing the spacing on our lands to four wells per section. In 2006 we plan to drill two more wells to test the viability of tighter well spacing.

SYLVAN LAKE, ALBERTA

Sylvan Lake is a multi-zone area which produces both gas and light oil from a number of formations ranging in depth from 400 to 2,200 metres. The primary producing zones are the Shunda, Pekisko, Lower Mannville and Edmonton. In 2005, Focus' gross production from the area averaged 2.1 Mmcf per day of natural gas, and 123 bbls per day of oil and natural gas liquids. Production at Sylvan Lake is processed through the Focus-operated Sylvan Lake gas plant, in which the Trust holds an average working interest of 60 percent. The Trust owns excess capacity in this plant which generates significant third party processing income.

In 2005 the Trust participated in the drilling of four (2.0 net) wells at Sylvan Lake, all targeting the Edmonton sand. All of these wells were successfully completed for gas and placed on production, and the Trust anticipates a similar sized drilling program for 2006.

MEDICINE HAT, ALBERTA

The Medicine Hat property, which was acquired in late 2004, produces sweet natural gas from the Milk River, Medicine Hat and Second White Specks formations. In 2005 Focus' gross production from the property averaged 1.8 Mmcf per day of natural gas. Production is compressed at two Focus-operated facilities and delivered to the TransCanada and TransGas pipeline systems.

In 2005 the Trust commenced the first round of infill drilling on this property, which consisted of a 13-well (12.0 net) development program targeting Milk River, Medicine Hat and Second White Specks pools. In Q4 2005 all of these wells were successfully completed and tied in. Overall, the Medicine Hat program has met our expectations, and as a result we anticipate a similar sized program of infill drilling will occur on this property in the second half of 2006.

DRILLING

During 2005, the Trust participated in the drilling of 37 wells (29.4 net) with excellent drilling results and a success rate of 100 percent. The 2005 development program was strongly weighted towards natural gas with 91 percent of net wells and 83 percent of capital expenditures in the field directed towards gas targets. Focus was the operator of 34 of the 37 wells drilled in 2005.

Approximately 58 percent of the Trust's capital expenditures for 2005 were invested at Tommy Lakes for the drilling of 11 (10.3 net) natural gas wells. Of the 11 wells, six were drilled and tied in during the first quarter of 2005, five were drilled in the fourth quarter of 2005, and four of these were tied in during the first quarter of 2006.

Additional activity in 2005 took place at Pouce Coupe with the drilling of two (2.0 net) natural gas wells in the Montney zone. At Medicine Hat, Focus drilled 13 (12.0 net) wells targeting Milk River, Medicine Hat and Second White Specks gas. At Sylvan Lake, the Trust participated in the drilling of four (2.0 net) Edmonton Sand gas wells. Six oil wells (2.7 net) were drilled in the Red Earth project area, primarily at Loon Lake. Finally, at Kotcho, the Trust drilled one (0.4 net) Slave Point gas well.

	2005				2004			
Drilling (Gross Wells)	Oil	Gas	Abandoned	Total	Oil	Gas	Abandoned	Total
Tommy Lakes	–	11	–	11	–	15	1	16
Red Earth	6	–	–	6	1	–	–	1
Pouce Coupe	–	2	–	2	–	2	–	2
Medicine Hat	–	13	–	13	–	–	–	–
Kotcho	–	1	–	1	–	–	–	–
Sylvan Lake	–	4	–	4	–	5	–	5
	6	31	–	37	1	22	1	24

	2005				2004			
Drilling (Net Wells)	Oil	Gas	Abandoned	Total	Oil	Gas	Abandoned	Total
Tommy Lakes	–	10.3	–	10.3	–	9.1	0.8	9.9
Red Earth	2.7	–	–	2.7	0.5	–	–	0.5
Pouce Coupe	–	2.0	–	2.0	–	2.0	–	2.0
Medicine Hat	–	12.0	–	12.0	–	–	–	–
Kotcho	–	0.4	–	0.4	–	–	–	–
Sylvan Lake	–	2.0	–	2.0	–	2.2	–	2.2
	2.7	26.7	–	29.4	0.5	13.3	0.8	14.6

UNDEVELOPED LAND

At December 31, 2005 Focus had undeveloped land of 57,051 net acres with an average working interest of 85 percent. Net undeveloped land is concentrated in Tommy Lakes (78 percent), Medicine Hat (10 percent), and Red Earth (eight percent).

	December 31, 2005		December 31, 2004	
Undeveloped Acres	**Gross**	**Net**	Gross	Net
Alberta	**16,807**	**11,573**	16,729	11,645
British Columbia	**50,207**	**45,478**	18,027	15,231
	67,014	**57,051**	34,756	26,876

PRODUCTION

Focus had average production in 2005 of 9,963 BOE per day, with a weighting of 74 percent towards natural gas. Focus has had a very active drilling program at Tommy Lakes this past winter and 10 natural gas wells have been brought on stream in the first quarter of 2006. With the significance of winter drilling operations, Focus will continue to have its highest production volumes in the second quarter of the year as a result of flush production. For 2006, Focus is expecting to average between 9,750 and 10,250 BOE per day.

	2005				2004			
Production by Area	**Oil**	**Natural Gas**	**NGLs**		Oil	Natural Gas	NGLs	
	bbls/d	**mcf/d**	**bbls/d**	**BOE/d**	bbls/d	mcf/d	bbls/d	BOE/d
Tommy Lakes (1)	**–**	**33,123**	**681**	**6,201**	–	29,391	569	5,468
Red Earth	**1,688**	**–**	**12**	**1,700**	1,913	–	–	1,913
Kotcho-Cabin	**–**	**4,118**	**–**	**686**	–	8,156	–	1,359
Pouce Coupe	**11**	**3,352**	**27**	**597**	9	2,865	20	507
Sylvan Lake	**66**	**2,111**	**57**	**475**	74	1,679	80	433
Medicine Hat (2)	**–**	**1,822**	**–**	**304**	–	615	–	102
	1,765	**44,526**	**777**	**9,963**	1,996	42,706	669	9,782

(1) INCLUDES APRIL 1, 2004 AND AUGUST 12, 2005 ACQUISITIONS OF ADDITIONAL INTERESTS AT TOMMY LAKES.
(2) THE MEDICINE HAT PROPERTY WAS ACQUIRED EFFECTIVE SEPTEMBER 1, 2004.

	2005				2004			
Production by Quarter	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Oil (bbls/d)	**1,714**	**1,718**	**1,779**	**1,850**	1,903	1,932	2,027	2,122
Natural gas (mcf/d)	**42,629**	**44,910**	**46,997**	**43,575**	43,080	44,903	50,913	31,902
NGL (bbls/d)	**762**	**833**	**770**	**743**	724	776	703	472
BOE/d	**9,582**	**10,036**	**10,382**	**9,856**	9,807	10,191	11,215	7,911

YEAR-END RESERVES REVIEW

YEAR-END RESERVES

Based on independent engineering evaluations conducted by Paddock Lindstrom and Associates Ltd. ("Paddock") and McDaniel and Associates Consultants Ltd. ("McDaniel") effective December 31, 2005, Focus had proved plus probable reserves of 40.3 MMBOE, a decrease of three percent from the 41.5 MMBOE recorded at December 31, 2004. Year-end reserves were evaluated in accordance with National Instrument 51-101 ("NI 51-101").

Paddock and McDaniel evaluated 100 percent of the Trust's reserves. The portion of the evaluation conducted by Paddock represented 86 percent of the proved plus probable reserves and 83 percent of the associated future net revenue discounted at 10 percent. The remainder of the reserves and associated future net revenue were evaluated by McDaniel. The Paddock December 31, 2005 price forecast was used in the future net revenue determinations for both evaluations. The Trust's Reserves Committee, made up of independent and qualified directors of the Trust, has reviewed and approved the reports prepared by Paddock and McDaniel and other pertinent reserves data.

Proved developed producing reserves represent 53 percent of proved plus probable reserves, while total proved reserves represent 77 percent of total proved plus probable reserves. On a BOE basis, total proved plus probable reserves consist of 78 percent natural gas, 14 percent light crude oil and eight percent natural gas liquids. On a proved basis, technical revisions were positive 1.8 MMBOE, or approximately six percent of the opening balance. On a proved plus probable basis, technical revisions were positive 0.7 MMBOE, or two percent of the opening balance.

NET PRESENT VALUE OF FUTURE NET REVENUE

The estimated net present value of Focus' crude oil, natural gas and natural gas liquids reserves was evaluated using Paddock's December 31, 2005 price forecast prior to provision for income taxes, interest, debt service charges and general and administrative expenses. At a 10 percent discount rate, the net present value of the Trust's proved plus probable reserves was $705 million. Proved producing and total proved reserves make up respectively 66 percent and 85 percent of the total proved plus probable value.

RESERVE LIFE INDEX

Focus' proved plus probable RLI at year-end 2005 is 10.5 years, essentially flat to the year-end 2004 RLI of 10.6 years. Similarly, the Trust's proved year-end 2005 RLI is 8.3 years as compared to 8.4 years at year-end 2004. These RLIs are calculated using period-end reserves and forward-year forecast production from the reserves report.

RESERVE ADDITION COSTS

Under NI 51-101, the methodology to be used to calculate FD&A costs includes incorporating changes in future development capital ("FDC") required to bring the proved undeveloped and probable reserves to production. On a proved basis, Focus' 2005 reserve addition costs were $21.84 per BOE including acquisitions and divestitures or $21.85 per BOE excluding acquisitions and divestitures. On a proved plus probable basis, 2005 reserve addition costs were $29.87 per BOE including acquisitions and divestitures or $36.15 per BOE excluding acquisitions and divestitures. This year's reserve addition costs were impacted by reserve revisions, increases in estimated FDC, and the large portion of Focus overall capital program that is directed towards the development of proved undeveloped reserves. At year end, total estimated FDC was $61.7 million for proved reserves and $82.7 million for proved plus probable reserves.

Three-year average reserve addition costs, including acquisitions and divestitures, are $16.49 per BOE on a proved basis and $12.60 per BOE on a proved plus probable basis. The Trust believes that these three-year average costs are the most accurate reflection of our ongoing reserve addition costs. Using a three-year average mitigates the impact of year-to-year variability in factors such as acquisition activity, the timing of the development of proved undeveloped reserves, reserve revisions, and changes to capital costs and estimates for future development capital.

RESERVES INFORMATION

The following cautionary statements are specifically required by NI 51-101.

1. It should not be assumed that the estimates of future net revenues presented in the tables represent the fair market value of the reserves. There is no assurance that the constant price and cost assumptions and forecast prices and costs assumptions will be attained and variances could be material.

2. Disclosure provided herein in respect of BOE may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio of 6 mcf:1 bbl has been used in all cases in this disclosure. This BOE conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

3. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during the year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

4. Estimates of reserves and future net revenues for individual properties may not reflect the same confidence level as estimates of reserves and future net revenues for all properties due to the effects of aggregation.

5. In all cases, the F&D or FD&A cost is calculated by dividing the identified capital expenditures by the applicable reserves additions.

2005 RESERVES SUMMARY

Company Gross Reserves at December 31, 2005

(before deduction of royalties payable, not including royalties receivable) (based on Forecast Prices and Costs)	Light Crude Oil (mbbl)	Natural Gas (Mmcf)	NGLs (mbbl)	Oil Equivalent (MBOE)
Proved producing	3,380	95,853	1,841	21,196
Proved non-producing	148	13,186	171	2,516
Total proved developed	**3,527**	**109,039**	**2,012**	**23,713**
Proved undeveloped	560	36,789	619	7,310
Total proved	**4,087**	**145,828**	**2,631**	**31,023**
Probable additional	1,521	41,678	789	9,256
Total proved + probable	**5,608**	**187,506**	**3,420**	**40,279**

Company Net Reserves at December 31, 2005

(after deduction of royalties payable, including royalties receivable) (based on Forecast Prices and Costs)	Light Crude Oil (mbbl)	Natural Gas (Mmcf)	NGLs (mbbl)	Oil Equivalent (MBOE)
Proved producing	2,980	76,212	1,455	17,137
Proved non-producing	136	10,168	137	1,968
Total proved developed	**3,116**	**86,380**	**1,592**	**19,105**
Proved undeveloped	514	29,273	496	5,889
Total proved	**3,630**	**115,653**	**2,088**	**24,994**
Probable additional	1,375	32,953	628	7,496
Total proved + probable	**5,005**	**148,606**	**2,716**	**32,489**

(1) NUMBERS MAY NOT ADD DUE TO ROUNDING.

NET ASSET VALUE (BEFORE TAX) DECEMBER 31, 2005

The following net asset value ("NAV") table shows what is commonly referred to as a "produce out" NAV calculation before tax. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time.

NAV at December 31, 2005	Discounted at 10%		Discounted at 5%	
($ thousands except per-unit amounts)	Paddock Price Forecast	Constant Price Forecast	Paddock Price Forecast	Constant Price Forecast
Value of proved plus probable reserves	704,777	825,830	903,175	1,078,254
Undeveloped lands	5,120	5,120	5,120	5,120
Net debt including working capital	(92,518)	(92,518)	(92,518)	(92,518)
Reclamation fund	2,711	2,711	2,711	2,711
Abandonment and reclamation liability (1)	(2,085)	(1,599)	(1,831)	(1,267)
Net asset value	618,005	739,544	816,657	992,300
Total Trust Units outstanding (thousands)	37,456	37,456	37,456	37,456
Per unit	$16.50	$19.74	$21.80	$26.49

(1) IN ADDITION TO ABANDONMENT AND RECLAMATION LIABILITY ALREADY INCLUDED IN RESERVE REPORTS.

Net asset value per unit, based on the Paddock Price Forecast and a 10 percent discount rate, increased 49 percent on a year-over-year basis, driven primarily by a stronger commodity price forecast.

2005 RESERVE RECONCILIATION

Company Gross Reserves

(before deduction of royalties payable, not including royalties receivable)	Light Crude Oil (mbbl)	Natural Gas (Mmcf)	NGLs (mbbl)	Oil Equivalent (MBOE)
TOTAL PROVED				
December 31, 2004	4,237	148,370	2,601	31,567
Discoveries	26	3,594	64	688
Extensions	82	0	0	82
Improved recovery	0	0	0	0
Technical revisions	382	7,530	200	1,837
Economic factors	0	0	0	0
Acquisitions	0	2,585	54	485
Dispositions	0	0	0	0
Production	(640)	(16,252)	(288)	(3,636)
December 31, 2005	**4,087**	**145,828**	**2,631**	**31,023**
PROBABLE				
December 31, 2004	1,460	46,092	786	9,928
Discoveries	4	526	8	100
Extensions	31	0	0	31
Improved recovery	0	0	0	0
Technical revisions	27	(6,568)	(39)	(1,107)
Economic factors	0	0	0	0
Acquisitions	0	1,629	34	306
Dispositions	0	0	0	0
Production	0	0	0	0
December 31, 2005	**1,521**	**41,678**	**789**	**9,256**
PROVED PLUS PROBABLE				
December 31, 2004	5,697	194,462	3,387	41,495
Discoveries	30	4,120	71	788
Extensions	113	0	0	113
Improved recovery	0	0	0	0
Technical revisions	409	962	161	730
Economic factors	0	0	0	0
Acquisitions	0	4,214	88	790
Dispositions	0	0	0	0
Production	(640)	(16,252)	(288)	(3,636)
December 31, 2005	**5,608**	**187,506**	**3,420**	**40,279**

(1) ALL RESERVES ARE BASED ON FORECAST PRICES AND COSTS.
(2) NUMBERS MAY NOT ADD DUE TO ROUNDING.

NET PRESENT VALUE SUMMARY

Net Present Value of Future Net Revenue Before Income Taxes – Forecast Prices and Costs

(including ARTC)

($ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	716,015	558,523	465,078	403,170	358,914
Proved non-producing	77,992	60,407	50,043	43,169	38,237
Total proved developed	**794,007**	**618,930**	**515,120**	**446,339**	**397,152**
Proved undeveloped	190,425	122,248	85,618	63,449	48,797
Total proved	**984,432**	**741,178**	**600,738**	**509,789**	**445,948**
Probable additional	297,249	161,997	104,039	74,074	56,389
Total proved + probable	**1,281,681**	**903,175**	**704,777**	**583,862**	**502,337**

(1) NUMBERS MAY NOT ADD DUE TO ROUNDING.

December 31, 2005 Price Forecast – Paddock Lindstrom and Associates Ltd.

	WTI Crude Oil $US/bbl	Edmonton Light Crude Oil $CDN/bbl	Henry Hub Natural Gas $US/Mmbtu	AECO C Natural Gas $CDN/Mmbtu	Westcoast Station 2 Natural Gas $CDN/Mmbtu	Exchange Rate $US/$CDN
2006	60.00	69.57	9.85	10.54	10.52	0.85
2007	57.50	66.61	9.00	9.52	9.50	0.85
2008	55.00	63.64	8.00	8.32	8.30	0.85
2009	52.50	60.68	7.50	7.71	7.69	0.85
2010	50.00	57.72	7.00	7.10	7.08	0.85
2011	47.50	54.76	7.14	7.24	7.22	0.85
2012	48.45	55.85	7.28	7.39	7.37	0.85
Escalate thereafter at	2%/yr	2%/yr	2%/yr	2%/yr	2%/yr	0%/yr

Net Present Value of Future Net Revenue Before Income Taxes – Constant Prices and Costs

(including ARTC)

($ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	854,403	648,073	526,570	446,970	390,817
Proved non-producing	92,617	69,941	56,576	47,783	41,552
Total proved developed	**947,020**	**718,015**	**583,146**	**494,753**	**432,368**
Proved undeveloped	245,197	158,489	111,488	82,864	63,885
Total proved	**1,192,217**	**876,504**	**694,634**	**577,617**	**496,253**
Probable additional	363,106	201,751	131,196	93,907	71,509
Total proved + probable	**1,555,323**	**1,078,254**	**825,830**	**671,524**	**567,763**

(1) NUMBERS MAY NOT ADD DUE TO ROUNDING.

Constant Prices at December 31, 2005

	Edmonton Light Crude Oil $CDN/bbl	AECO C Natural Gas $CDN/Mmbtu	Westcoast Station 2 Natural Gas $CDN/Mmbtu
2006 and thereafter	68.05	9.50	9.28

FINDING AND DEVELOPMENT COSTS

Company Gross Reserves Excluding the Effect of Acquisitions and Dispositions (1)

	2005	2004	2003	Three-Year Total
Capital expenditures – $M	**43,035**	25,156	16,589	84,780
Net change in future development capital – $M				
Proved	**13,941**	9,469	(2,506)	20,904
Proved plus probable	**15,885**	3,599	(921)	18,563
Total capital including change in future development capital – $M				
Proved	**56,976**	34,625	14,083	105,684
Proved plus probable	**58,920**	28,755	15,668	103,343
Reserve additions – BOE				
Proved	**2,607**	1,882	(1,153)	3,336
Proved plus probable	**1,630**	1,798	2,143	5,571
Finding and development cost – $/BOE				
Proved	**$21.85**	$18.40	n/a	$31.68
Proved plus probable	**$36.15**	$15.99	$7.31	$18.55

(1) RESERVES ARE BASED ON FORECAST PRICES AND COSTS.

FINDING, DEVELOPMENT AND ACQUISITION COSTS

Company Gross Reserves Including the Effect of Acquisitions and Dispositions (1)

	2005	2004	2003	Three-Year Total
Capital expenditures – $M	**53,398**	154,825	36,805	245,028
Net change in future development capital – $M				
Proved	**14,141**	18,594	(94)	32,641
Proved plus probable	**18,885**	21,360	1,579	41,824
Total capital including change in future development capital – $M				
Proved	**67,539**	173,419	36,711	277,669
Proved plus probable	**72,283**	176,185	38,384	286,852
Reserve additions – BOE				
Proved	**3,092**	12,501	1,247	16,840
Proved plus probable	**2,420**	15,480	4,869	22,769
Finding and development cost – $/BOE				
Proved	**$21.84**	$13.87	$29.44	$16.49
Proved plus probable	**$29.87**	$11.38	$ 7.88	$12.60

(1) RESERVES ARE BASED ON FORECAST PRICES AND COSTS.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is a discussion and analysis of the operating and financial results of Focus for the three months and year ended December 31, 2005 compared with the prior year, as well as information and opinions concerning the Trust's future outlook based on currently available information. **This discussion is dated March 6, 2006 and should be read in conjunction with the Trust's audited consolidated financial statements for the years ended December 31, 2005 and 2004, together with accompanying notes.**

Throughout this Management's Discussion and Analysis, we use the term funds flow from operations ("funds flow" before changes in non-cash working capital and reclamation costs). Funds flow is used by management to analyze operating performance and leverage. Funds flow, as presented, does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures of other entities. Funds flow, as presented, is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to funds flow throughout this report are based on funds flow from operations before changes in non-cash working capital and reclamation costs.

Per barrel of oil equivalent ("BOE") amounts have been calculated using a conversion of six thousand cubic feet of natural gas to one barrel of oil *(6 mcf = 1 bbl).*

OVERALL 2005 PERFORMANCE

Strong performance continued in 2005 driven by record high commodity prices, successful development programs in several of our core areas and the execution of our business strategy. Focus' strategy is to surface value on our existing assets, maintain cost efficiencies, maintain financial strength and acquire quality assets.

Production of the Trust in 2005 increased two percent primarily through development programs at our key natural gas properties at Tommy Lakes, Pouce Coupe, Medicine Hat and Sylvan Lake. In a year of escalating costs within the sector and extreme competition for acquisitions, we continue to expand our operational focus and utilize the drill bit to replace production and reserves. In 2005 we increased field expenditures by 71 percent and increased the number of net wells drilled by 101 percent. Natural gas continues to be the primary focus of the Trust, with 91 percent of net wells drilled targeting natural gas. Our land position and inventory of drilling opportunities were increased in natural gas areas, especially Tommy Lakes where three deals effectively doubled our land position.

Focus continued its strong financial performance during 2005 and maintained its financial strength. Funds from operations increased 30 percent due to a 27 percent increase in revenue per BOE and a two percent increase in volumes. Production expenses per BOE increased 25 percent during 2005 as a result of increased cost of services and energy used in field operations. The $116.4 million of funds flow from operations plus $1.8 million of debt was used to fund distributions, reclamation fund contributions and field capital expenditures.

Funds flow from operations increased 25 percent to $3.12 per unit and cash distributions declared were increased to $2.02 per unit. The distribution policy is aimed at achieving consistency of distributions and sustainability through balancing funds flow compared to distributions and capital programs.

	Three Months Ended Dec. 31,		Years Ended Dec. 31,		Year Over
OPERATIONS SUMMARY	**2005**	2004	**2005**	2004	Year Change
Average daily production					
Barrels of oil equivalent (@ 6:1)	**9,582**	9,807	**9,963**	9,782	2%
% Natural gas	**74%**	73%	**74%**	73%	1%
Average product prices realized[1]					
Crude oil sales (CDN$/bbl)	**$ 68.95**	$ 56.33	**$ 66.81**	$ 51.43	30%
Financial hedging settlements (CDN$/bbl)	**$ (9.75)**	$ (15.05)	**$ (10.20)**	$ (11.01)	(7%)
Realized price (CDN$/bbl)	**$ 59.20**	$ 41.28	**$ 56.61**	$ 40.43	40%
NGLs (CDN$/bbl)	**$ 60.64**	$ 48.48	**$ 57.50**	$ 43.73	31%
NGL price/crude oil price	**88%**	86%	**86%**	85%	1%
Natural gas sales (CDN$/mcf)	**$ 10.20**	$ 7.25	**$ 8.64**	$ 7.02	23%
Transportation system charges (CDN$/mcf)	**$ (0.62)**	$ (0.61)	**$ (0.61)**	$ (0.61)	–
Financial hedging settlements (CDN$/mcf)	**$ (0.34)**	$ –	**$ (0.11)**	$ –	100%
Realized price (CDN$/mcf)	**$ 9.24**	$ 6.64	**$ 7.92**	$ 6.41	24%
Reference prices & differential to price, net of transportation					
Crude oil (Edm. Light Price CDN$/bbl)	**$ 71.17**	$ 57.74	**$ 68.50**	$ 52.62	30%
Differential (CDN$/bbl)	**$ (2.22)**	$ (1.41)	**$ (1.69)**	$ (1.18)	43%
Natural gas (AECO daily CDN$/mcf)	**$ 11.43**	$ 6.57	**$ 8.77**	$ 6.55	34%
Differential (CDN$/mcf)	**$ (1.85)**	$ 0.07	**$ (0.74)**	$ (0.14)	414%
Barrels of oil equivalent (@ 6:1)	**$ 69.26**	$ 44.34	**$ 56.67**	$ 42.93	32%
Differential (including NGLs vs crude oil)	**$ (9.38)**	$ (0.60)	**$ (4.40)**	$ (1.42)	210%
Production revenue, before transportation system charges ($ thousands)					
Crude oil, before hedging settlements	**10,925**	9,891	**43,182**	37,704	15%
Financial hedging settlements	**(1,538)**	(2,634)	**(6,573)**	(8,040)	(18%)
NGLs	**4,255**	3,233	**16,321**	10,715	52%
Natural gas, before transportation system charges	**40,017**	28,743	**140,516**	109,793	28%
Financial hedging settlements	**(1,345)**	–	**(1,777)**	–	–
	52,315	39,233	**191,669**	150,173	28%
Funds flow from operations ($ thousands)					
Cash flow from operating activities	**36,818**	28,117	**114,744**	91,385	26%
Reclamation costs	**34**	124	**632**	124	410%
Net change in non-cash working capital items	**(4,502)**	(5,000)	**992**	(1,942)	(151%)
	32,350	23,241	**116,368**	89,567	30%
Funds flow from operations per BOE					
Production revenue	**$ 62.62**	$ 46.40	**$ 55.00**	$ 44.19	24%
Financial hedging settlements	**(3.27)**	(2.92)	**(2.30)**	(2.25)	2%
Transportation system charges	**(2.74)**	(2.66)	**(2.73)**	(2.68)	2%
Realized price[1]	**56.61**	40.82	**49.97**	39.27	27%
Royalties, net of ARTC	**(13.41)**	(9.36)	**(11.98)**	(9.52)	26%
Production expenses	**(4.61)**	(3.76)	**(4.11)**	(3.29)	25%
Field netback	**38.58**	27.71	**33.88**	26.46	28%
Facility income	**0.44**	0.58	**0.54**	0.73	(26%)
Interest income	**0.01**	0.05	**0.01**	0.06	(83%)
General and administrative, cash portion	**(1.27)**	(1.21)	**(1.22)**	(1.13)	8%
Interest and financing and other	**(1.07)**	(0.93)	**(0.97)**	(0.70)	39%
Current and large corporations tax	**0.01**	(0.44)	**(0.24)**	(0.40)	(40%)
	$ 36.70	$ 25.76	**$ 32.00**	$ 25.02	28%
Funds flow from operations/field netback	**95%**	93%	**94%**	95%	(1%)
Royalty rate (before hedging settlements and net of transportation system charges)	**22%**	21%	**23%**	23%	–

(1) NET OF SETTLEMENTS FOR FINANCIAL HEDGING INSTRUMENTS AND TRANSPORTATION SYSTEM CHARGES

SEASONALITY OF OPERATIONS

Many of Focus' natural gas properties are in areas of British Columbia which are only accessible by road in the winter. This includes Tommy Lakes and Kotcho-Cabin. These areas represent approximately 70 percent of our production. The majority of the Trust's capital program is conducted at Tommy Lakes in the first and fourth quarters when winter conditions allow us to access the area. Capital expenditures at Tommy Lakes represented 58 percent of the total field capital expenditures during 2005 and 64 percent in 2004.

The significance of the winter access issues, especially for the Tommy Lakes winter development program, impacts the operating results of Focus. This seasonality of operations and results is reflected in the following areas:

- Capital expenditures are highest in the first and fourth quarters of the year. The Tommy Lakes winter development program commences as soon as there is access and is completed as soon as possible.
- Natural gas wells drilled during the winter development program are brought on-stream from January to March. Production volumes for natural gas and natural gas liquids are highest at the end of the first quarter and into the second quarter. These wells have strong flush production and then drop down to their stabilized production rate within 12 months.
- Higher production volumes during these initial months of flush production result in a corresponding increase in the revenue, royalties and operating expenses reported.
- Fluctuations in the utilization of credit facilities will result from the pattern of capital expenditures and funds flow from operations.
- Production expenses per BOE are the highest in the first and fourth quarters when these properties are accessible for maintenance and the restocking of supplies.
- As the operator of these properties, the Trust recovers general and administrative expenses from joint venture capital programs based on a percentage of the total capital program managed. As a result, most of the recovery of general and administrative expenses will be in the first and fourth quarters of the year.

PRODUCTION

2005 Q4:

- Overall production on a BOE basis during the fourth quarter declined 4.5 percent from the previous quarter. Oil and NGL volumes decreased three percent and natural gas volumes were five percent lower. This pattern of fourth quarter production levels being the lowest of the year is consistent with prior years and expectations. The natural gas wells at Tommy Lakes from last winter's drilling program continued to transition from the flush production phase.
- Natural gas volumes added through development activities in the fourth quarter were delayed due to issues associated with weather and the availability of services in the Medicine Hat area. Ultimately, all 13 wells drilled in the third quarter were successfully completed and tied in during the fourth quarter. Focus' share of production from these new wells is expected to average approximately 1.2 Mmcf per day in the first quarter of 2006.
- Compared with the fourth quarter of 2004, production of crude oil was down 10 percent and natural gas production decreased one percent. Natural gas production increased in all operating areas except Kotcho-Cabin where decline rates are higher and there has been limited reinvestment.
- Production continues to be weighted towards natural gas with 74 percent of overall production consisting of natural gas and another eight percent of natural gas liquids.

2005 compared with 2004:

- Overall average production was two percent higher in 2005 compared with 2004, with a four percent increase in natural gas, a 16 percent increase in NGL's and a 12 percent decline in crude oil. These results reflect the emphasis of reinvestment on longer life natural gas properties. The increase in NGL production reflects the decline of leaner gas at Kotcho-Cabin and the increase in more liquids-rich gas primarily at Tommy Lakes.

- Focus continued to replace production volumes through successful drilling programs in the natural gas areas of Tommy Lakes, Pouce Coupe, Medicine Hat and Sylvan Lake.

- The majority of our oil properties have experienced natural declines in production rates. Capital expenditures for the oil properties have been directed towards our operated properties at Loon Lake and Golden.

- The production pattern for 2004 and 2005 is consistent with higher volumes of natural gas and NGLs peaking in the second quarter. This pattern is expected to continue for 2006 as the 2005-2006 winter drilling program at Tommy Lakes commenced in November 2005 and the new production is coming on stream in the first quarter of 2006.

PRICING AND PRICE RISK MANAGEMENT

Natural Gas

- Focus has a differential between the realized price compared to the AECO average daily reference price resulting from:

  a) higher than standard heat content of our natural gas;

  b) a high proportion of natural gas delivered to British Columbia markets;

  c) transportation system charges in British Columbia and Alberta;

  d) the difference between how the physical gas is sold during the period versus the AECO daily average.

- Realized natural gas price compared to AECO daily reference price:

	Three Months Ended December 31,		Years Ended December 31,	
Realized Price Per Mcf	**2005**	2004	**2005**	2004
AECO daily average (CDN$/mcf)	**$ 11.43**	$ 6.57	**$ 8.77**	$ 6.55
Plus: heat content adjustment (1)	**1.29**	0.58	**0.83**	0.57
Less: differential to B.C. markets (1)	**(0.02)**	0.02	**(0.16)**	(0.05)
Less: transportation system charges (1)	**(0.62)**	(0.61)	**(0.61)**	(0.61)
Adjust: timing of actual gas sales (1)	**(0.48)**	(0.39)	**(0.13)**	(0.09)
Price before price protection	**11.60**	6.17	**8.71**	6.37
Impact of longer term physical sales contracts (1)	**(2.02)**	0.47	**(0.67)**	0.04
Financial hedging settlements	**(0.34)**	–	**(0.11)**	–
Realized price per mcf	**$ 9.24**	$ 6.64	**$ 7.92**	$ 6.41

(1) INCLUDED IN DIFFERENTIAL REPORTED IN OPERATIONS SUMMARY TABLE

- Focus' realized natural gas price increased 19 percent to $9.24 per mcf in the fourth quarter of 2005 from $7.77 in the third quarter. Realized natural gas prices for the year increased 24 percent in 2005 to $7.92 per mcf compared to $6.41 per mcf in 2004.

- During the quarter, 49 percent of natural gas was sold under forward physical sales contracts and resulted in natural gas sales of $7.9 million lower than if the natural gas had been sold based on the AECO daily reference price.

- During 2005, 58 percent of natural gas production was sold under forward physical sales contracts and resulted in natural gas sales of approximately $10.9 million lower than if the natural gas had been sold based on the AECO daily reference price. This compares with an increase of $0.6 million in 2004.
- The impact of financial instrument settlements for natural gas was $1.8 million in 2005 ($1.3 million in the fourth quarter). There were no settlements of financial instruments for natural gas in 2004.
- At December 31, 2005 the estimated fair market value of the physical and financial contracts related to natural gas price protection was a cost of $6.0 million. This is based on the futures market for natural gas and fluctuates considerably. The current fair market value of these contracts is estimated by management to be an in-the-money value exceeding $14.0 million.

Crude Oil

- The price realized by Focus for crude oil, after settlement of financial hedges, was $59.20 per barrel for the fourth quarter of 2005 versus $41.28 for the comparable period in 2004.
- With continued strong oil prices in 2005, there was a hedging cost of $1.5 million or $9.75 per barrel for the fourth quarter of 2005 and a hedging cost of $6.6 million or $10.20 per barrel for 2005. For the comparable period in 2004, there was a hedging cost of $2.6 million or $15.05 per barrel for the fourth quarter of 2004 and a hedging cost of $8.0 million or $11.01 per barrel for 2004.

PRICE PROTECTION

- Focus uses price protection through longer term physical delivery contracts and financial contracts to reduce the volatility in commodity prices in an effort to help maintain sustainable distributions.
- A full description of the outstanding financial instruments and physical sales contracts and their estimated mark to market values is contained in Notes 13 and 14 of the notes to consolidated financial statements.

Price Protection (volume and reference price)

		2006				2007
		Q1	Q2	Q3	Q4	Q1
Natural gas	Mmcf/d	24.2	22.5	22.5	15.0	11.3
	CDN$/mcf	$9.10-$9.43	$10.08-$10.80	$10.08-$10.80	$11.30-$12.02	$12.54-$13.24
Crude oil	bbls/d	700	700	700	700	–
	CDN$/bbl	$62.73-$68.44	$62.73-$68.44	$62.73-$68.44	$62.73-$68.44	–

CHANGES IN ACCOUNTING POLICY

On January 19, 2005, the CICA issued EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" which requires that exchangeable securities issued by a subsidiary of an income trust should be reflected as either non-controlling interest or debt on the consolidated balance sheet unless they meet certain criteria. EIC-151 states that if the exchangeable shares are transferable to a third party, they should be reflected as non-controlling interest or debt. The exchangeable shares issued by FET Resources Ltd., a corporate subsidiary of the Trust, are publicly traded and therefore must be recorded as non-controlling interest outside of unitholders' equity on the consolidated balance sheet. Previously, the exchangeable shares were reflected as a component of unitholders' equity.

In accordance with EIC-151 and given the circumstances in the Trust's case, each conversion of exchangeable shares into trust units is treated as a step purchase accounted for at market value. This results in an increase in the carrying value of petroleum and natural gas properties and equipment and thus an increase to depletion and depreciation. This increase to petroleum and natural gas properties and equipment is without tax basis and thus creates a future income tax liability. This liability is recognized on the balance sheet as an increase to the future income tax liability and an increase to petroleum and natural gas properties and equipment. As the addition to petroleum and natural gas properties and equipment is depleted, there is a recovery to future income taxes on the income statement.

In accordance with the transitional provisions of EIC-151, retroactive application has been applied with restatement of prior periods. The following tables summarize the results of this change in accounting policy.

Cumulative Change in Balance Sheet Items [increase (decrease)]

(thousands)	**December 31, 2005**	December 31, 2004
Petroleum and natural gas properties and equipment	**$ 111,797**	$ 111,347
Future income taxes	**38,411**	38,612
Non-controlling interest – exchangeable shares	**4,131**	4,934
Unitholders' capital	**102,004**	91,143
Exchangeable shares	**(928)**	(1,547)
Accumulated income, opening adjustment	**(21,795)**	(13,247)
Net income impact of new policy	**(10,026)**	(8,548)

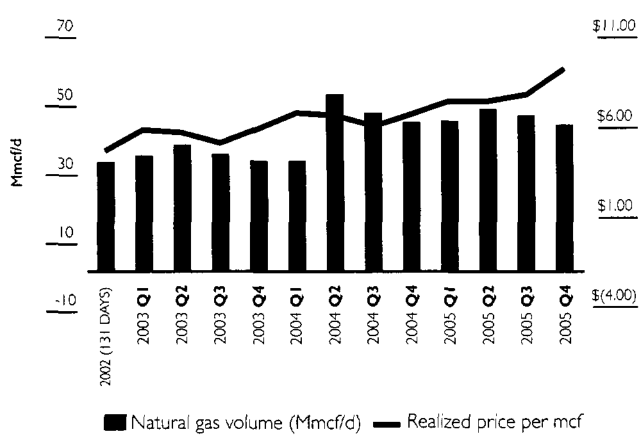
Change in Statements of Income Items	Three Months Ended December 31,		Years Ended December 31,	
(thousands)	**2005**	2004	**2005**	2004
Depletion and depreciation	**$ 3,177**	$ 3,182	**$ 13,762**	$ 11,819
Future income tax expense (reduction)	**(1,509)**	(2,772)	**(5,173)**	(6,291)
Non-controlling interest	**366**	495	**1,437**	3,020
Net income impact of new policy	**$ 2,034**	$ 905	**$ 10,026**	$ 8,548

There was no change to funds flow from operations as a result of this change in accounting policy.

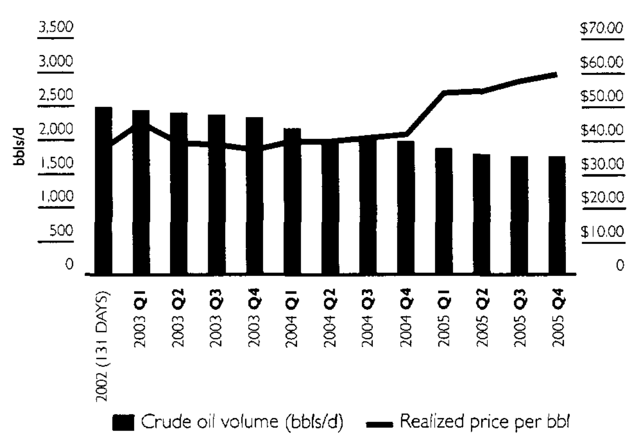
PRODUCTION REVENUE

- Production revenue, before transportation system charges, for the three months ended December 31, 2005 was $52.3 million, consisting of 71 percent natural gas sales, 20 percent crude oil sales, and nine percent from sales of natural gas liquids. Focus has increased its weighting of volumes to natural gas and natural gas liquids through development programs which primarily target natural gas opportunities. Production revenue for the fourth quarter of 2005 is $3.5 million higher than the third quarter of 2005 due to a 14 percent increase in production revenue per BOE offsetting a five percent decrease in production.
- Production revenue, before transportation system charges, for 2005 increased 28 percent to $192 million. Compared with 2004, there was a two percent increase in average daily production and a 25 percent increase in revenue per BOE.

Natural Gas Volumes & Realized Price per mcf



Crude Oil Volumes & Realized Price per Barrel



PRODUCTION EXPENSES

	2005				2004			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production expenses per BOE	**$4.61**	**$3.56**	**$4.10**	**$4.19**	$3.76	$3.31	$2.52	$3.78

- Our main natural gas properties are in winter-only access areas of British Columbia, and production expenses per BOE are typically the highest in the first and fourth quarters when these properties are accessible for maintenance and restocking of supplies.
- Production expenses for 2005 averaged $4.11 per BOE compared with $3.29 per BOE for 2004. Production expenses in 2005 have risen 25 percent in response to high activity levels in the sector, competition for services and higher energy costs.
- Average production expenses for 2006 are forecast to be in the range of $4.25 to $4.75 per BOE.

GENERAL AND ADMINISTRATIVE EXPENSES

	Three Months Ended December 31,		Years Ended December 31,	
(thousands)	**2005**	2004	**2005**	2004
Cash G&A expenses	**$ 1,941**	$ 1,557	**$ 6,898**	$ 5,713
Overhead recoveries	**(822)**	(464)	**(2,470)**	(1,667)
Total cash G&A expenses	**1,119**	1,093	**4,428**	4,046
Non-cash G&A expense (1)	**348**	276	**1,455**	1,174
Trust Unit Rights Plan expense (2)	**266**	125	**885**	306
Net G&A reported	**$ 1,733**	$ 1,494	**$ 6,768**	$ 5,526
Cash based G&A per BOE	**$ 1.27**	$ 1.21	**$ 1.22**	$ 1.13
Net reported G&A per BOE	**$ 1.97**	$ 1.66	**$ 1.86**	$ 1.54

(1) GROSS GENERAL AND ADMINISTRATIVE EXPENSES FOR 2005 INCLUDED $2.9 MILLION ASSOCIATED WITH THE EXECUTIVE BONUS PLAN (2004 - $2.3 MILLION). HALF OF THIS AMOUNT IS NON-CASH AND SETTLED THROUGH THE ISSUANCE OF UNITS FROM TREASURY AT A PRICE EQUAL TO THE AVERAGE OF THE LAST FIVE TRADING DAYS OF THE MONTH FOR WHICH THE BONUS RELATES.

(2) TRUST UNIT RIGHTS PLAN COMPENSATION EXPENSE IS CALCULATED USING THE FAIR VALUE METHOD ADOPTED IN 2003 AND REPRESENTS A NON-CASH CHARGE. DETAILS OF THIS COMPENSATION EXPENSE ARE CONTAINED IN NOTE 11 OF THE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS.

Cash-based general and administrative expenses were $1.27 per BOE for the fourth quarter and $1.22 per BOE for 2005. This compares with $1.21 per BOE for the fourth quarter of 2004 and $1.13 per BOE for 2004. Increased general and administrative expenses in 2005 result from increased staff levels and office expenses as part of the organic growth initiatives and expanded operations offset by higher overhead recoveries as well as expenses related to ensuring compliance with new internal control over financial reporting and disclosure regulations.

INTEREST AND FINANCING EXPENSES

Interest and financing expenses increased $1.0 million to $3.5 million in 2005 compared to $2.5 million in 2004 commensurate with higher average debt balances and higher interest rates. Long-term debt was $87.5 million at December 31, 2005 compared to $74.5 million at December 31, 2004.

DEPLETION AND DEPRECIATION

The depletion and depreciation rate is impacted by the change in policy for accounting for exchangeable shares ("EIC-151") which was described earlier under "Changes in Accounting Policy."

The depletion and depreciation rate, excluding the impact of exchangeable share conversions, for the three months ended December 31, 2005 increased to $11.47 per BOE ($15.08 per BOE, including the exchangeable share impact) compared to $10.42 per BOE ($13.98 per BOE, including the exchangeable share impact) in the fourth quarter of 2004. The increase reflects actual capital expenditures and updated estimates of proved reserves. The depletion rate of $11.47 per BOE in the fourth quarter of 2005 includes $0.32 per BOE related to the estimated asset retirement obligation compared to $0.22 per BOE in the fourth quarter of 2004. The depletion rate in the fourth quarter of 2005 was impacted by higher industry costs incurred for drilling and development activities and by future development cost estimates.

ASSET RETIREMENT OBLIGATION

The asset retirement obligation increased $3.6 million to $15.1 million at December 31, 2005 from $11.5 million at December 31, 2004. The increase reflects additional liabilities associated with new drilling activity, properties acquired during the year and accretion expense net of actual reclamation expenditures. Accretion expense increased by $0.2 million to $0.9 million in 2005 from $0.7 million in 2004 commensurate with the increase in the asset retirement obligation liability. See Note 6 of the notes to consolidated financial statements for more information.

INCOME AND OTHER TAXES

The future income tax provision and liability is impacted by the change in policy for accounting for exchangeable shares ("EIC-151") which was described earlier in this document under "Changes in Accounting Policy."

Income and other taxes include a future income tax recovery of $5.7 million in 2005 compared to a recovery of $10.5 million in 2004. The recovery of future income tax results from a reduction in corporate income tax rates in 2005, distributions to unitholders which transfers taxable income from the Trust to individual unitholders and from the depletion associated with accounting for exchangeable shares.

Large corporations tax, predominantly based on year-end debt and equity levels, in 2005 was $0.8 million compared to $1.1 million in 2004 reflecting a reduction of the large corporations tax rate.

CAPITAL EXPENDITURES

Capital expenditures for field operations were $10.9 million in the fourth quarter of 2005, as Focus completed and tied in the wells drilled at Medicine Hat in Q3 and initiated the winter development program at Tommy Lakes. The Trust drilled six wells during the quarter, including five wells (4.5 net) at Tommy Lakes and one well (0.3 net) at Loon Lake.

For 2005, total capital expenditures for field operations were $43.0 million, excluding the amount recorded for asset retirement obligations. Fifty-eight percent of this capital was spent at Tommy Lakes, 10 percent at Medicine Hat, 10 percent at Pouce Coupe, seven percent on other gas properties and 15 percent on our Red Earth oil properties, predominately at Loon Lake. During 2005 Focus continued to maximize the value of our existing asset base and acquired properties through the drill bit.

Focus invested $10.2 million in 2005 to acquire production and undeveloped land immediately to the south of its Tommy Lakes property. The acquired production of approximately 0.9 Mmcf/d and 19 bbls/d of associated natural gas liquids is 100% working interest and is tied in to the Focus owned and operated gathering system and facilities. The acquisition also included 33,550 gross acres of undeveloped land, the evaluation of which may lead to expansion of the Trust's drilling inventory at Tommy Lakes over the coming years.

Focus will be drilling actively in 2006 with a capital budget for field operations of approximately $45 million. Development is expected to continue at Tommy Lakes, Pouce Coupe, Loon Lake, Sylvan Lake and Medicine Hat. We continue to work diligently to ensure that our capital dollars are spent as effectively as possible and that we do everything we can to minimize the impact of rising service costs. There will be a continued emphasis on natural gas development and on those projects that we operate and control.

LIQUIDITY AND CAPITAL RESOURCES

As at December 31, 2005 Focus had a working capital deficit of $5.0 million compared with a working capital deficit of $6.7 million at December 31, 2004. The working capital deficit has increased from the $0.8 million at September 30, 2005, largely due to the winter development program which commenced in the fourth quarter of 2005 at Tommy Lakes. On a monthly basis, there are fluctuations in accounts receivable and accounts payable reflecting the extent of capital programs, distributions to unitholders after month-end and accrued revenue and royalties for the current month.

Long-term debt at December 31, 2005 was $87.5 million compared with $74.5 million at December 31, 2004 and $93.5 million at September 30, 2005. Focus had a $130 million revolving syndicated credit facility among four financial institutions and a $10 million operating facility at December 31, 2005. The credit facility revolves until May 24, 2006, whereupon it may be renewed for a further 364-day term subject to a review by the lenders.

Long-term debt less working capital increased $11.4 million during 2005. This change primarily resulted from the following factors:

- Funds flow from operations of $116.4 million plus $1.8 million of debt were used to fund $73.7 million in distributions declared to unitholders, $43.0 million invested in capital expenditures for field operations and $1.3 million of net contributions to the reclamation fund.
- The Tommy Lakes acquisition and other minor acquisitions were financed with bank credit facilities for $10.4 million.
- Proceeds were $0.8 million from the issuance of equity pursuant to the exercise of Unit Appreciation Rights.

Focus plans to finance its program for development drilling and enhancement of production primarily through investing approximately 30 to 35 percent of funds flow. Capital expenditures, including acquisitions, above this level will be financed through a combination of funds flow, debt and equity by issuing units from treasury.

Capitalization Table (thousands, except per-unit amounts)	**December 31, 2005**	December 31, 2004
Long-term debt	**$ 87,500**	$ 74,500
Plus: working capital deficiency	**5,018**	6,657
Total debt	**$ 92,518**	$ 81,157
Units outstanding and issuable for exchangeable shares	**37,456**	37,223
Market price	**$ 25.72**	$ 19.97
Market capitalization	**$ 963,368**	$ 743,343
Total capitalization	**$ 1,055,886**	$ 824,501
Total debt as a percentage of total capitalization	**8.8%**	9.8%
Funds flow from operations	**$ 116,368**	$ 89,567
Total debt to funds flow	**0.8**	0.9

CASH DISTRIBUTIONS

We announce our distribution policy on a quarterly basis. The actual amount of the cash distribution is determined by the Board of Directors and is dependent upon the commodity price environment, production levels, and the amount of capital expenditures to be funded from funds flow. Our distribution policy incorporates the withholding of approximately 30 to 35 percent of funds flow for the financing of capital expenditures to provide more sustainable distributions. Cash distributions are essentially taxed to the unitholders as ordinary income.

Focus declared distributions of $2.02 per unit in respect of 2005 production. Monthly distributions were increased from $0.16 per month to $0.18 per month beginning with the September 15th distribution in 2005.

On January 13, 2006, Focus announced an increase in monthly distributions to $0.19 per unit per month for the first quarter of 2006.

The exchangeable shares of FET Resources Ltd. are convertible into trust units of Focus based on the exchange ratio, which is adjusted monthly to reflect the distribution paid on the trust units. Cash distributions are not paid on the exchangeable shares and the cash flow related to the exchangeable shares is retained by the Trust for reduction of debt or for additional capital expenditures. The initial exchange ratio was one trust unit for one exchangeable share. The exchange ratio at December 31, 2005 was 1.37265. Effective March 15, 2006 the exchange ratio is 1.39579 trusts units for one exchangeable share.

Payout Ratio	**Three Months Ended December 31, 2005**	**Year Ended December 31, 2005**	Year Ended December 31, 2004
Funds flow from operations (thousands)	**$ 32,350**	**$ 116,368**	$ 89,567
Funds flow from operations per Total Unit (weighted average Total Trust Units, including exchangeable shares converted at the average exchange ratio)	**$ 0.86**	**$ 3.12**	$ 2.49
Distributions per unit declared	**$ 0.54**	**$ 2.02**	$ 1.80
Payout ratio – per-unit basis	**63%**	**65%**	72%
Cash distributions declared to unitholders; exchangeable shares do not receive cash distributions (thousands)	**$ 19,799**	**$ 73,677**	$ 61,439
Payout ratio – dollar basis	**61%**	**63%**	69%

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Trust has contractual obligations in the normal course of operations including purchase of assets and services, operating agreements, transportation commitments and sales commitments. These obligations are of a recurring and consistent nature and impact cash flow in an ongoing manner. See Note 17 of the notes to consolidated financial statements for further details.

OFF BALANCE SHEET ARRANGEMENTS

The Trust has certain lease agreements that are entered into in the normal course of operations. All leases are treated as operating leases whereby the lease payments are included in operating expenses or general and administrative expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases in the balance sheet as at December 31, 2005.

Focus has not entered into any guarantee or off balance sheet arrangements other than in the normal course of operations.

TAXATION OF CASH DISTRIBUTIONS

Focus Energy Trust, for purposes of the Canadian Income Tax Act, is treated as a mutual fund trust and each year the Trust files an income tax return with the taxable income allocated to the unitholders. Distributions paid to the unitholders may be both a return on capital (income) and a return of capital. The allocation between these two streams is dependent upon the income tax deductions that the Trust is able to claim against the income it earns. The return of capital portion reduces the adjusted cost base of the trust units held. The Trust has net income for each year that is required to be calculated on an accrual basis of accounting. Net income includes all interest income from FET and other income that accrues to the Trust to the end of the year. Under the Trust Indenture, net income of the Trust for each year will be paid or payable by way of cash distributions to the unitholders. Taxable income of the Trust includes a deduction for the allocation of taxable income to unitholders, which is paid or becomes payable in the year and a deduction relating to income tax pools residing at the Trust level. The Trust Indenture provides that an amount at least equal to the taxable income of the Trust must be paid or payable each year to unitholders in order to reduce the Trust's taxable income to zero. Such taxable income is allocated to unitholders. Any taxable income relating to a payable amount is allocated to unitholders of record at December 31, 2005, and each unitholder receives a pro rata share of that payable amount on January 16, 2006.

For 2005, cash distributions will be 99 percent taxable income (return on capital) and one percent tax deferred (return of capital). For a more detailed breakdown, as well as tax information for U.S. investors, please visit our website at www.focusenergytrust.com.

2005 CANADIAN TAX INFORMATION

The following information is intended to assist Canadian holders of trust units of Focus Energy Trust (FET.UN – TSX) in the preparation of their 2005 T1 Income Tax Return. This summary is directed to a unitholder who, for purposes of the Income Tax Act (Canada), is a resident of Canada and holds the units as capital property. Other unitholders are advised to consult with their tax advisor concerning their circumstances.

- Trust Units held within an RRSP, RRIF or DPSP - NO AMOUNTS are to be reported on the 2005 income tax return where trust units are held within a Registered Retirement Savings Plan (RRSP), Registered Retirement Income Fund (RRIF), Deferred Profit Savings Plan (DPSP), or any other such registered plans.
- Trust Units held outside of an RRSP, RRIF or DPSP - If the trust unit is held through a broker or other intermediary then the unitholder will receive a T3 Supplementary slip directly from the broker or intermediary, not from the transfer agent (Valiant Trust Company) or from Focus, no later than March 31, 2006.
- If the unitholder is a registered holder then the unitholder will receive a T3 Supplementary slip directly from Valiant Trust Company.
- The amount reported in Box (26) on the T3 Supplementary slip, "Other Income", should be reported on the 2005 T1 Income Tax Return. The amount reported in Box (42) on the T3 Supplementary slip, "Return of Capital", will, in most circumstances, reduce the unitholder's adjusted cost base of their Focus Energy Trust units. This is discussed in more detail below.

Taxable Income Allocated to Unitholders for 2005 and Taxation Treatment

- Focus Energy Trust, for purposes of the Canadian Income Tax Act, is treated as a mutual fund trust and each year the Trust files an income tax return with the taxable income allocated to the unitholders. Distributions paid to the unitholders may be both a return on capital (income) and a return of capital. The allocation between these two streams is dependent upon the income tax deductions that the Trust is able to claim against the income it earns.
- For those unitholders who held their Focus Energy Trust units outside of a registered plan, the return on capital or income portion is reported in Box (26) of the T3 Supplementary slip, "Other Income", and should be reported on the 2005 T1 Income Tax Return.
- The following table outlines the breakdown of cash distributions per unit paid by Focus Energy Trust with respect to record dates for the period January 31 to December 31, 2005.

Record Date	Payment Date	Distribution Paid	Taxable Income (Box 26 Other Income)	Tax Deferred Amount (Box 42 Return of Capital)
January 31, 2005	February 15, 2005	$0.16	$0.1584	$0.0016
February 29, 2005	March 15, 2005	$0.16	$0.1584	$0.0016
March 31, 2005	April 15, 2005	$0.16	$0.1584	$0.0016
April 30, 2005	May 16, 2005	$0.16	$0.1584	$0.0016
May 31, 2005	June 15, 2005	$0.16	$0.1584	$0.0016
June 30, 2005	July 15, 2005	$0.16	$0.1584	$0.0016
July 31, 2005	August 15, 2005	$0.16	$0.1584	$0.0016
August 31, 2005	September 15, 2005	$0.18	$0.1782	$0.0018
September 30, 2005	October 17, 2005	$0.18	$0.1782	$0.0018
October 31, 2005	November 15, 2005	$0.18	$0.1782	$0.0018
November 30, 2005	December 15, 2005	$0.18	$0.1782	$0.0018
December 31, 2005	January 16, 2006	$0.18	$0.1782	$0.0018
Total		$2.02	$1.9998	$0.0202

Adjusted Cost Base

In most circumstances, the return of capital portion will reduce the unitholder's adjusted cost base of their Focus Energy Trust units. The adjusted cost base of the units is required in the calculation of a capital gain or capital loss (if capital property to the unitholder) upon the disposition of the units.

Should a unitholder's adjusted cost base ever be reduced below zero, that negative amount is deemed to be a capital gain and the adjusted cost base is deemed to be nil. The capital gain is reported on Schedule 3 of the T1 Income Tax Return.

2005 UNITED STATES TAX INFORMATION

The following information is being provided to assist U.S. individual unitholders of Focus Energy Trust in reporting distributions received from Focus during 2005 on their Internal Revenue Service ("IRS") Form 1040 – U.S. Individual Income Tax Return ("Form 1040") for 2005.

Focus has not obtained a legal or tax opinion, nor has it requested a ruling from the IRS on these matters.

- **Trust Units Held Outside of a Qualified Retirement Plan**

  For distributions relating to 2005, 100 percent of the distributions should be considered taxable as dividends to the unitholder for U.S. federal income tax purposes. After consulting with its tax advisors, Focus believes that its distributions should be considered "Qualified Dividends" under the Jobs and Growth Tax Relief Reconciliation Act of 2003 and should be eligible for the reduced U.S. dividend tax rate. However, the individual taxpayer's situation must be considered before making this determination. Qualified Dividends should be reported on Line 9(b) of the IRS Form 1040 unless the facts of the U.S. individual unitholder determine otherwise. Page 23 of the IRS 2005 Form 1040 instruction booklet provides examples of individual situations where the distributions would not be "Qualified Dividends". Where the distributions are not considered "Qualified Dividends" due to an individual's situation, the amount should be reported on Schedule B, Part II – Ordinary Dividends and Line 9(a) of your IRS Form 1040.

  For the non-taxable portion of distributions, if any ("Non-Taxable Return of Capital"), a taxpayer must reduce the cost (or other basis) by the amount of non-taxable distributions in calculating the gain or loss on sale of Focus units. If the amount of "Non-Taxable Return of Capital" exceeds your cost (or other basis), report the excess as a capital gain.

  U.S. unitholders are encouraged to utilize the Qualified Dividends and Capital Gain Tax Worksheet provided by the IRS to determine the amount of tax applicable.

  Canadian withholding taxes that have been withheld from the taxable portion of your distributions (as computed under Canadian tax principles) should be reported on Form 1116 "Foreign Tax Credit (Individual, Estate or Trust)". Amounts over-withheld should be claimed as a refund from the Canada Revenue Agency and should not be claimed as a credit against your U.S. federal income tax liability. Information regarding the amount of Canadian tax withheld relating to 2005 distributions should be available through your investment advisor or other intermediary and is not available from Focus.

- **Trust Units Held Within a Qualified Retirement Plan**

  There should be no amount that is required to be reported as income on an IRS Form 1040 where the Focus trust units are held in a Qualified Retirement Plan.

  The information in this release is not meant to be an exhaustive discussion of all possible income tax considerations, but a general guideline and is not intended to be legal or tax advice to any particular holder or potential holder of Focus Energy Trust units. Holders or potential holders of trust units should consult their tax advisors as to their particular tax consequences of holding Focus trust units.

CRITICAL ACCOUNTING ESTIMATES

Focus' financial and operating results incorporate certain estimates including:

- estimated revenues, royalties and operating expenses on production as at a specific reporting date but for which actual revenues and expenses have not yet been received;
- estimated capital expenditures on projects that are in progress;
- estimated depletion, depreciation and accretion that are based on estimates of oil and gas reserves that the Trust expects to recover in the future, estimated future salvage values, and estimated future capital costs;
- estimated fair values of derivative contracts and physical sales contracts that are subject to fluctuation depending upon the underlying commodity prices and foreign exchange rates;
- estimated value of asset retirement obligations that are dependent upon estimates of future costs and timing of expenditures.

The Trust has hired individuals and consultants who have the skill sets to make such estimates and ensures that the individuals and departments with the most knowledge of an activity are responsible for the estimates. Past estimates are reviewed and compared to actual results in order to make more informed decisions on future estimates. The management team's mandate includes ongoing development of procedures, standards and systems to allow the Trust to make the best estimates possible.

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

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 consists of the Chief Executive Officer and each of the Vice Presidents. As at the end of the period covered by this report, the design and operating effectiveness of the Trust's disclosure controls were evaluated by the Chief Executive Officer and the Chief Financial Officer. According to this evaluation, the Trust's disclosure controls and procedures are effective to ensure that any material, or potentially material, information is made known to the Committee and is properly included in this report. This evaluation took into consideration Focus' Disclosure, Confidentiality & Trading Policy and the functioning of its senior management, board of directors and board committees.

UPDATE ON FINANCIAL REPORTING AND REGULATORY MATTERS

The following new accounting policy impacted the Trust in 2005:

- EIC-151, Exchangeable Securities Issued by Subsidiaries of Income Trusts

  In 2005, the Trust adopted the recommendations contained in EIC-151, Exchangeable Securities Issued by Subsidiaries of Income Trusts. The abstract requires the Trust to reclassify the amounts recorded as exchangeable shares from unitholders' capital to non-controlling interests. The revision is effective for periods on or after June 30, 2005. This accounting policy change has been applied retroactively with restatement of prior periods. The impact of this change in accounting policy has been described in Note 3 of the notes to consolidated financial statements.

Other future possible accounting policy changes include:

- Non-Monetary Transactions

  In June 2005, the Accounting Standards Board ("AcSB") issued Section 3831, Non-Monetary Transactions, which replaces Section 3830 and requires all non-monetary transactions to be measured at fair value unless certain conditions are met. The new requirements apply to non-monetary transactions initiated in periods beginning on or after January 1, 2006. Earlier adoption is permitted beginning on or after July 1, 2005.

  This pronouncement is not expected to effect the Trust's financial statements.

- Financial Instruments - Recognition and Measurement, Hedges, and Comprehensive Income

  The CICA has issued three exposure drafts on financial instruments which will apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006. It will require the following:

  – all trading financial instruments will be recognized on the balance sheet and will be fair valued through the income statement;

  – all remaining financial assets will be recorded at cost and amortized through the financial statements;

  – a new statement for comprehensive income that will include certain gains and losses on translation of assets and liabilities; and

  – an update to Accounting Guideline 13 to incorporate the fair value changes not recorded in the income statement to be recorded through the comprehensive income statement.

The Trust has not assessed the future impact on the financial statements at this time.

- Changes in Accounting Policies and Estimates and Errors

  The CICA has proposed a new Handbook section 1506 "Changes in Accounting Policies and Estimates, and Errors" to provide guidance around when and how an entity is permitted to change an accounting policy as well as establish appropriate disclosures to explain the effects of changes in accounting policy, estimates and corrections of errors.

SUMMARY OF QUARTERLY RESULTS

The following table provides a summary of results for each of the last eight quarters. Significant factors and trends which have impacted these results include:

- Revenue and royalties are directly related to fluctuations in the underlying commodity prices and the extent to which price protection has been achieved through financial hedges and forward physical sales contracts.
- Many of Focus' natural gas areas are only accessible by road in the winter. This includes the Tommy Lakes area, which is very significant from a production and development program perspective. Please refer to the "Seasonality of Operations" section for additional information.
- Focus completed major acquisitions at Tommy Lakes in April 2004 and Medicine Hat in September 2004. The Tommy Lakes acquisition was financed by the issuance of equity from treasury and use of existing bank credit facilities. The acquisition in September 2004 was financed with the use of existing bank credit facilities.
- Focus was created in August 2002 and has continually been developing its organization with the addition of professional and technical staff.

Quarter Ended	2005				2004			
(thousands of dollars, except per-unit amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Oil and gas revenues, before royalties	**52,315**	**48,790**	**46,583**	**43,981**	39,233	37,979	42,284	30,677
Net income	**17,858**	**17,573**	**14,682**	**13,351**	14,545	10,508	14,877	11,150
Per Unit – basic	**$0.49**	**$0.48**	**$0.40**	**$0.37**	$0.41	$0.30	$0.44	$0.38
– diluted	**$0.48**	**$0.47**	**$0.40**	**$0.36**	$0.40	$0.29	$0.43	$0.37

ASSESSMENT OF BUSINESS RISKS

Following are the primary risks associated with the business of the Trust. These risks are similar to those affecting others in the conventional oil and gas income trust sector. The Trust's financial position, results of operations and distributions to unitholders are directly impacted by these factors:

1. operational risk associated with the production of oil and natural gas;
2. reserve risk in respect to the quantity and quality of recoverable reserves;
3. market risk relating to the availability of transportation systems to move the product to market;
4. commodity risk as crude oil and natural gas prices fluctuate due to market forces;
5. financial risk such as the Canadian/U.S. dollar exchange rate, interest rates and debt service obligations;
6. environmental and safety risk associated with well operations and production facilities;
7. change in laws, regulation and administrative practice of governmental authorities relating to the oil and natural gas industry and the trust sector, particularly with respect to operations, environmental controls, royalties and income taxes, including changes in foreign ownership rules and changes to the taxation of trusts.

Focus seeks to mitigate these risks by:

1. acquiring mature properties to reduce technical uncertainty;
2. acquiring long-life reserves to ensure more stable production and to reduce the economic risks associated with commodity price cycles;
3. maintaining a low-cost structure to maximize product netbacks and reduce impact of commodity price cycles;
4. diversifying properties to mitigate individual property and well risk;
5. maintaining a product mix to balance exposure to commodity prices;
6. conducting rigorous reviews of all property acquisitions;
7. monitoring pricing trends and developing a mix of contractual arrangements for the marketing of products with creditworthy counterparties;
8. maintaining a hedging program to hedge commodity prices and foreign exchange currency rates with creditworthy counterparties;
9. ensuring strong third-party operators for non-operated properties;
10. adhering to the Trust's safety program and keeping abreast of current operating best practices;
11. keeping informed of proposed change in regulations and laws to properly respond to and plan for the effects that these changes may have on our operations;
12. carrying insurance to cover losses and business interruption;
13. establishing and building cash resources to fund future site reclamation costs.

OUTLOOK

The Trust's operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by demand and supply factors, including weather and general economic conditions as well as conditions in other oil and natural gas producing regions.

The following chart summarizes Focus' 2006 outlook. No acquisitions are assumed for the purposes of these forecasts.

In 2006, Focus will continue its active drilling and development programs on the significant development opportunities on its major properties. It is anticipated that these development activities will maintain production by offsetting production declines.

We do not attempt to forecast commodity prices, and as a result, we do not forecast funds flow from operations or future cash distributions to unitholders.

Summary of 2006 Expectations	
Average annual production	9,750 - 10,250 BOE/D
Weighting to natural gas	75%
Production expenses per BOE	\$4.25 - \$4.75
Cash G&A expenses per BOE	\$1.55 - \$1.70
Capital expenditures - field	\$45 million
Average annual payout ratio	65% - 70%
Approximate taxable portion of distributions	100%
Funds from operations/net debt	Under 1x

The table below shows the potential impact on the Trust's funds flow (before price protection) resulting from changes to the business environment or operations.

		Change to Funds Flow	
Business Environment	Change	$000's	$/Unit
Price per barrel of crude oil (US$ WTI)	$ 1.00	772	0.021
Price per mcf of natural gas (CDN$ AECO)	$ 0.25	3,073	0.083
US/CDN exchange rate	$ 0.01	1,526	0.041
Interest rate on debt	1%	828	0.022
Operations			
Oil production - bbls/d	100	1,767	0.047
Gas production - mcf/d	1,000	2,459	0.066
Operating expenses ($ per BOE)	$ 0.25	935	0.025
Cash G&A expenses ($ per BOE)	$ 0.25	935	0.025

Focus is committed to increasing the long term value of the Trust to unitholders. The following goals are the foundation of our commitment to value creation:

- Maximize the value of existing assets;
- Attract and retain the best value creation team in the business;
- Pursue quality acquisitions that are strategic and accretive;
- Protect margins and improve profitability;
- Surface value through operational expertise and control; and
- Maintain financial flexibility and strength.

MANAGEMENT'S RESPONSIBILITY

Management is responsible for the preparation of the accompanying consolidated financial statements and for the consistency therewith of all other financial and operating data. The consolidated financial statements have been prepared in accordance with the accounting policies detailed in the notes thereto. In management's opinion, the consolidated financial statements are in accordance with Canadian generally accepted accounting principles and have been prepared within acceptable limits of materiality.

Management maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely information. Where estimates are used in the preparation of these financial statements, management has ensured that careful judgment has been made and that these estimates are reasonable, based on all information known at the time the estimates are made.

Independent auditors appointed by the Trustee have examined and expressed their opinion on the consolidated financial statements of the Trust. The Audit Committee, consisting of independent directors of FET Resources Ltd., has reviewed these consolidated financial statements with management and the auditors, and has recommended them to the Board of Directors for approval. The Board has approved the consolidated financial statements of the Trust.

Derek W. Evans
President and Chief Executive Officer

William D. Ostlund
Vice President, Finance and Chief Financial Officer

March 6, 2006

AUDITORS' REPORT

To the Unitholders of Focus Energy Trust:

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

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 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

March 6, 2006

CONSOLIDATED BALANCE SHEETS

(thousands)	December 31, 2005	December 31, 2004
ASSETS		(Restated – Note 3)
Current assets		
Cash and cash equivalents	$ 4,696	$ 44
Accounts receivable	**21,065**	20,221
Prepaid expenses and deposits	**1,952**	1,698
	27,713	21,963
Petroleum and natural gas properties and equipment [note 4]	**430,865**	413,800
Goodwill	**5,100**	5,100
Reclamation fund [note 7]	**2,711**	1,923
	$ 466,389	$ 442,786
LIABILITIES		
Current		
Accounts payable and accrued liabilities	**$ 26,127**	$ 22,864
Cash distributions payable	**6,604**	5,756
	32,731	28,620
Long-term debt [note 8]	**87,500**	74,500
Asset retirement obligation [note 6]	**15,090**	11,461
Future income taxes [note 16]	**81,634**	82,339
	216,955	196,920
NON-CONTROLLING INTEREST		
Exchangeable shares [note 9]	**4,131**	4,934
UNITHOLDERS' EQUITY		
Unitholders' capital [note 10]	**244,426**	230,478
Contributed surplus [note 11]	**1,135**	499
Accumulated income [note 12]	**(258)**	9,955
	245,303	240,932
Commitments and contingencies [note 17]		
	$ 466,389	$ 442,786

SEE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Approved on behalf of the Board:

Stuart G. Clark
Director

James H. McKelvie
Director

CONSOLIDATED STATEMENTS OF INCOME AND ACCUMULATED INCOME

(thousands, except per-unit amounts)	December 31, 2005	December 31, 2004
Revenue		(Restated – Note 3)
Production revenue	$ 191,669	$ 150,173
Royalties	(44,067)	(34,551)
Alberta Royalty Tax Credit	490	475
Facility income	1,950	2,597
Interest income	40	229
	150,082	118,923
Expenses		
Transportation system charges	9,931	9,584
Production	14,948	11,789
General and administrative	6,768	5,526
Interest and financing	3,531	2,516
Depletion and depreciation [note 4]	53,916	43,826
Accretion on asset retirement obligation [note 6]	889	664
	89,983	73,905
Income before income taxes	60,099	45,018
Income and other taxes [note 16]		
Future income tax reduction	(5,678)	(10,503)
Current and large corporations tax	876	1,421
	(4,802)	(9,082)
Non-controlling interest – exchangeable shares	1,437	3,020
Net income for the period	63,464	51,080
Accumulated income, beginning of period		
As previously reported	31,750	33,561
Retroactive adjustment for changes in accounting policies [note 3]	(21,795)	(13,247)
As restated	9,955	20,314
Cash distributions	(73,677)	(61,439)
Accumulated income, end of period	(258)	9,955
Net income per unit [note 15]		
Basic	$ 1.74	$ 1.52
Diluted	$ 1.71	$ 1.49

SEE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands)		December 31, 2005		December31, 2004
Operating activities				(Restated – Note 3)
Net income for the period	$	**63,464**	$	51,080
Add non-cash items:				
Non-controlling interest – exchangeable shares		**1,437**		3,020
Non-cash general and administrative expenses [notes 10 & 11]		**2,340**		1,480
Depletion and depreciation		**53,916**		43,826
Accretion on asset retirement obligation		**889**		664
Future income tax recovery		**(5,678)**		(10,503)
Reclamation costs		**(632)**		(124)
Net change in non-cash working capital items		**(992)**		1,942
		114,744		91,385
Financing activities				
Proceeds from issue of trust units (net of costs)		**–**		70,419
Proceeds from exercise of unit appreciation rights		**813**		854
Increase (decrease) in long-term debt		**13,000**		53,163
Cash distributions paid		**(72,829)**		(59,608)
		(59,016)		64,828
Investing activities				
Capital asset additions		**(43,035)**		(25,156)
Acquisition expenditures [note 5]		**(10,363)**		(130,182)
Reclamation fund contributions, net of costs		**(788)**		(893)
Net change in non-cash working capital items		**3,110**		62
		(51,076)		(156,169)
Increase in cash and cash equivalents during the period		**4,652**		44
Cash and cash equivalents, beginning		**44**		–
Cash and cash equivalents, ending	**$**	**4,696**	$	44

SEE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. STRUCTURE OF THE TRUST

Focus Energy Trust (the "Trust") was established on August 23, 2002 under a Plan of Arrangement involving the Trust, Storm Energy Inc., FET Resources Ltd., and Storm Energy Ltd. The Trust is an open-end unincorporated investment trust governed by the laws of the Province of Alberta and created pursuant to a trust indenture (the "Trust Indenture"). Valiant Trust Company has been appointed Trustee under the Trust Indenture. The beneficiaries of the Trust are the holders of the trust units (the "unitholders").

Pursuant to the terms of a net profits interest agreement (the "NPI Agreement"), the Trust is entitled to a payment from FET Resources Ltd. each month essentially equal to the amount by which the gross proceeds from the sale of production exceed certain deductible expenditures (as defined). Under the terms of the NPI Agreement, deductible expenditures may include amounts, determined on a discretionary basis, to fund capital expenditures, to repay third party debt and to provide for working capital required to carry out the operations of FET Resources Ltd.

Under the Trust Indenture, the Trust may declare payable to unitholders all or any part of the income of the Trust. The income of the Trust consists primarily of interest earned on promissory notes issued to FET Resources Ltd. and Focus BC Trust, wholly owned by the Trust, distributions paid on subordinated units from Focus BC Trust units owned by the Trust, as well as amounts attributed to the NPI Agreement.

The taxable income of the Trust includes a deduction for the allocation of taxable income to unitholders, which is paid or becomes payable in the year. The Trust Indenture provides that an amount at least equal to the taxable income of the Trust must be paid or payable each year to unitholders in order to reduce the Trust's taxable income to zero. Such taxable income relating to the payable amount is allocated to unitholders of record at the end of the year, and each unitholder at the distribution record date receives a pro rata share of the payable amount.

FET Resources Ltd. (the "Company") is a subsidiary of the Trust. Under the Plan of Arrangement, the Company became the successor company to Storm Energy Inc. through amalgamation on August 23, 2002. The Company is actively engaged in the business of oil and natural gas exploitation, development, acquisition and production.

2. SUMMARY OF ACCOUNTING POLICIES

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP"). The preparation of these consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingencies at the date of the financial statements, and revenues and expenses during the reporting period. Correspondingly, actual results could differ from estimated amounts. These consolidated financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below.

In particular, the amounts recorded for depletion and depreciation of the petroleum and natural gas properties and equipment and for asset retirement obligations are based on estimates of reserves and future costs. The cost impairment test is based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements of future periods could be material.

a) Principles of Consolidation

The consolidated financial statements of the Trust include the accounts of Focus Energy Trust, its subsidiaries FET Resources Ltd. and FET Gas Production Ltd. and Focus B.C. Trust, and its share of two partnerships. All inter-entity transactions and balances have been eliminated.

b) Petroleum and Natural Gas Properties and Equipment

The Trust follows the full cost method of accounting for petroleum and natural gas properties, whereby all costs of acquiring petroleum and natural gas properties and related development costs, whether productive or unproductive, are capitalized and accumulated in one Canadian cost centre, including asset retirement costs. Such costs include acquisition, drilling, geological, geophysical, and equipment costs and overhead expenses related to the properties and development activities. Costs of acquiring and evaluating unproved properties are excluded from depletion calculations until it is determined in the period that proved reserves are attributable to the properties or impairment has occurred. Maintenance and repairs are charged against income, and renewals and enhancements which extend the economic life of the properties and equipment are capitalized. Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion by 20 percent or more.

Depletion of petroleum and natural gas properties and depreciation of equipment are provided for using the unit-of-production method based on estimated proved petroleum and natural gas reserves, before royalties, as determined by independent engineers calculated in accordance with National Instrument 51-101. Production and reserves of natural gas are converted to equivalent barrels of crude oil based on the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil. The depletion and depreciation cost base includes total capitalized costs, less prior depletion and depreciation charges, less costs of unproved properties, less the estimated future net realizable value of production equipment and facilities, plus provision for future development costs and future asset retirement costs of proved undeveloped reserves.

c) Cost Impairment Test

The Trust places a limit on the aggregate carrying value of petroleum and natural gas properties and equipment, which may be amortized against revenues of future periods (the "cost impairment test"). The cost impairment test requires an evaluation of petroleum and natural gas assets in each reporting period to determine that the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre.

Cost impairment is recognized if the carrying amount of the petroleum and natural gas properties exceeds the sum of the undiscounted cash flows expected to result from the Trust's proved reserves. Cash flows are calculated based on third party quoted forward prices, adjusted for the Trust's contract prices and quality differentials.

Upon recognition of impairment, the Trust would then measure the amount of impairment by comparing the carrying amounts of the petroleum and natural gas properties to an amount equal to the estimated net present value of future cash flows from proved plus risked probable reserves. The Trust's risk-free interest rate is used to arrive at the net present value of the future cash flows. Any excess carrying amount above the net present value of the Trust's future cash flows would be recognized as a permanent impairment.

The cost of unproved properties is excluded from the cost impairment test calculation and subject to a separate impairment test.

d) Asset Retirement Obligation

The Trust uses the asset retirement obligation method of recording the future cost associated with removal, site restoration and asset retirement costs. The fair value of the liability for the Trust's asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using the credit-adjusted risk-free interest rate and the corresponding amount recognized by increasing the carrying amount of property, plant and equipment. The asset recorded is depleted on a unit-of-production basis over the life of the reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost could also result in an increase or decrease to the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

e) Goodwill

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value for accounting purposes of the net identifiable assets and liabilities of the acquired business. Net identifiable liabilities of the acquired business include an estimate of future income taxes. The goodwill balance is assessed for impairment annually at year end or more frequently if events change and circumstances indicate that the asset might be impaired. The test for impairment is the comparison of the carrying amount to the fair value of the reporting entity. If the fair value of the consolidated Trust is less than the book value, impairment is measured by allocating the fair value of the consolidated Trust to the identifiable assets and liabilities at their fair values. The excess of this allocation is the fair value of goodwill. Any excess of the book value of goodwill over this implied value is the impairment amount. Impairment is charged to income in the period in which it occurs.

Goodwill is stated at cost less impairment and is not amortized.

An impairment test of goodwill was completed at December 31, 2005 resulting in no impairment amount.

f) Financial Instruments

The Trust uses financial instruments to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. The Trust's policy is not to use financial instruments for speculative or trading purposes. Gains and losses on contracts which constitute effective hedges are recognized in production income at the time of sale of the related production. Financial instruments which do not qualify as hedges are recorded on a mark-to-market basis at the balance sheet date with the resulting gains or losses being taken into income in the period.

g) Income Taxes

Income taxes are calculated using the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the consolidated financial statements of the Trust and their respective tax base, using substantively enacted income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs. Temporary differences arising on acquisitions result in future income tax assets and liabilities.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. As the Trust allocates all of its taxable income to the unitholders in accordance with the Trust Indenture, and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for income tax expense or liability has been made in the Trust.

In the Trust structure, payments are made between the Company and the Trust which result in the transferring of taxable income from the Company to individual unitholders. These payments may reduce future income tax liabilities previously recorded by the Company which would be recognized as a recovery of income tax in the period incurred.

h) Unit-Based Compensation Plan

The Trust has a unit-based compensation plan (the "Plan") for employees, directors and consultants of the Trust and its subsidiaries which are described in Note 11. Compensation expense associated with rights granted under the Plan is deferred and recognized in earnings over the vesting period of the Plan with a corresponding increase or decrease in contributed surplus. Compensation expense is based on the fair value of the unit-based compensation at the date of grant using a modified Black Scholes option pricing model. The fair value method has been adopted prospectively with rights granted in 2003. The pro forma impact for rights granted for the period from August 23, 2002 to December 31, 2002 using the fair value method is disclosed in Note 11.

Consideration paid upon the exercise of the rights together with the amount previously recognized in contributed surplus is recorded as an increase in unitholders' capital.

The Trust has not incorporated an estimated forfeiture rate for rights that will not vest, rather, the Trust accounts for actual forfeitures as they occur.

i) Per-Unit Amounts

Net income per unit is calculated using the weighted average number of units outstanding during the year. Diluted net income per unit includes additional trust units for the dilutive impact of the Rights Plan and exchangeable shares converted at the average exchange rate. The treasury stock method is used to determine the dilutive effect of unit-based compensation. The treasury stock method assumes that the proceeds received from the exercise of in-the-money trust unit rights are used to repurchase units at the average market rate during the period. The weighted average number of units outstanding is then adjusted by the net change. Net income is also increased for the net income attributable to the exchangeable shareholders in calculating dilutive per-unit amounts.

j) Revenue Recognition

Revenue associated with sales of crude oil, natural gas, and natural gas liquids is recognized when title passes to the purchaser, normally at the pipeline delivery point for natural gas and at the wellhead for crude oil.

k) Joint Operations

Certain of the Trust's exploration and production activities are conducted jointly with others. The accounts of the Trust reflect its proportionate interest in such activities.

l) Cash and Cash Equivalents

The Trust considers all highly liquid investments with a maturity of three months or less at the time of purchase to be cash equivalents. These cash equivalents consist primarily of funds on deposit for various terms. Cash and cash equivalents are stated at cost which approximates fair value.

m) Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at the balance sheet date. Revenues and expenses are translated at the monthly average rates of exchange. Translation gains and losses are included in income in the period in which they arise.

n) Transportation System Charges

The Trust records revenue gross of transportation system charges and a transportation system charge on the income statement.

o) Comparative Figures

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

The Trust's most significant properties in terms of production and capital expenditures are only accessible by road in the winter. This restricted access typically results in higher capital expenditures in the first and fourth quarters. Production is typically higher due to flush production from the winter drilling program at the end of the first quarter and beginning of the second quarter. Production from the new wells stabilizes within 12 months.

3. CHANGES IN ACCOUNTING POLICY

a) Non-Controlling Interest – Exchangeable Shares

On January 19, 2005, the CICA issued EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" which requires that exchangeable securities issued by a subsidiary of an income trust should be reflected as either non-controlling interest or debt on the consolidated balance sheet unless they meet certain criteria. EIC-151 states that if the exchangeable shares are transferable to a third party, they should be reflected as non-controlling interest or debt. The exchangeable shares issued by FET Resources Ltd., a corporate subsidiary of the Trust, are publicly traded and therefore must be recorded as non-controlling interest outside of unitholders' equity on the consolidated balance sheet. Previously, the exchangeable shares were reflected as a component of unitholders' equity.

In accordance with the transitional provisions of EIC-151, retroactive application has been applied with restatement of prior periods. As a result of this change in accounting policy, the Trust has presented non-controlling interest of $4.1 million and $4.9 million, respectively, in the Trust's consolidated balance sheet as at December 31, 2005 and 2004. Net income has been reduced for net income attributable to the non-controlling interest of $1.4 million and $3.0 million, respectively, for the years ended December 31, 2005 and 2004. Net income per trust unit-basic decreased $0.23 and $0.14, respectively, for the years ended December 31, 2005 and 2004. Net income per trust unit-diluted decreased $0.23 and $0.16, respectively, for the years ended December 31, 2005 and 2004.

In accordance with EIC-151 and given the circumstances in the Trust's case, each conversion of exchangeable shares into trust units is treated as a step purchase accounted for at market value. This resulted in an increase in petroleum and natural gas properties and equipment of $111.8 million and $111.3 million respectively, an increase to unitholders' capital of $102.0 million and $91.1 million respectively, and an increase in the future income tax liability of $38.4 million and $38.6 million respectively at December 31, 2005 and 2004.

Opening accumulated income for 2005 and 2004 was decreased by $21.8 million and $13.2 million respectively for the cumulative impact of this change in accounting policy. The new accounting policy also resulted in a change in the calculation of weighted average trust units. Previously, weighted average trust units included outstanding exchangeable shares at the period end exchange ratio whereas under the new accounting policy, the weighted average trust units excludes trust units issuable for exchangeable shares.

There was no change to cash flow from operations as a result of this change in accounting policy.

b) Accumulated Income

Effective January 1, 2005 the Trust has presented accumulated income net of accumulated cash distributions paid or payable to unitholders on the balance sheet.

4. PETROLEUM AND NATURAL GAS PROPERTIES AND EQUIPMENT

(thousands)	2005	2004
Petroleum and natural gas properties and equipment, at cost	**$ 655,693**	$ 584,712
Accumulated depletion and depreciation	**(224,828)**	(170,912)
Petroleum and natural gas properties and equipment, at cost, net	**$ 430,865**	$ 413,800

The calculation of depletion and depreciation in 2005 included an estimate of $61.6 million (2004 - $47.5 million) for future development costs and $3.4 million (2004 – $4.1 million) for future asset retirement costs associated with proved undeveloped reserves. Unproved property costs of $4.7 million (2004 - $3.1 million) and estimated net realizable value of production equipment and facilities of $25.0 million (2004 - $21.9 million) were excluded from the depletion calculation.

The Trust performed a cost impairment test at December 31, 2005 to assess the recoverable amount of the net carrying value of petroleum and natural gas properties and equipment. Future prices for crude oil and natural gas were obtained for the period 2006 to 2010 inclusive from the Trust's year-end independent reserve evaluations and then escalated based on escalation factors in the same evaluations. Based on these assumptions, the present value of future net revenues from the Trust's proved plus probable reserves exceeded the carrying value of the Trust's net carrying value of the petroleum and natural gas properties and equipment.

The future prices used for the cost impairment test for December 31, 2005 are as follows:

Consultant's Price Forecasts	2006	2007	2008	2009	2010
Crude Oil - WTI ($U.S/bbl)	$ 60.00	$ 57.50	$ 55.00	$ 52.50	$ 50.00
Natural Gas - AECO ($CDN/Mmbtu)	$ 10.54	$ 9.52	$ 8.32	$ 7.71	$ 7.10

5. ACQUISITION EXPENDITURES

(thousands) Area	Effective	Year ended December 31, 2005	Year ended December 31, 2004
Tommy Lakes, B.C.	April 1, 2004	$ –	$ 110,075
Medicine Hat, Alberta	September 1, 2004	–	19,090
Medicine Hat, Alberta	October 1, 2004	–	1,145
Tommy Lakes, B.C.	May 1, 2005	10,215	–
Other		148	(128)
		$ 10,363	$ 130,182

6. ASSET RETIREMENT OBLIGATION

The Trust's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Trust estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations is approximately $35.8 million which will be incurred between 2006 and 2020. The majority of the costs will be incurred after 2020. A credit-adjusted risk-free rate of 7.0 percent and an inflation rate of 2.0 percent were used to calculate the fair value of the asset retirement obligation.

A reconciliation of the asset retirement obligation is provided below:

(thousands)	December 31, 2005	December 31, 2004
Balance, beginning of period	$ 11,461	$ 7,442
Accretion expense	889	664
Liabilities incurred		
Acquisitions	366	1,939
Development activity and change in estimates	3,006	1,540
Settlement of liabilities	(632)	(124)
Balance, end of period	$ 15,090	$ 11,461

7. RECLAMATION FUND

(thousands)	2005	2004
Balance as at January 1	$ 1,923	$ 1,030
Contributions (net of reclamation costs)	788	893
Balance as at December 31	$ 2,711	$ 1,923

A reclamation fund was established to fund the payment of environmental and site reclamation costs. Annual contributions will be made to the reclamation fund such that the currently estimated future environmental and site reclamation costs will be funded after 20 years. The Company may use the reclamation fund for purposes of funding its environmental and site reclamation costs. The reclamation fund is held on deposit at a Canadian financial institution.

8. LONG-TERM DEBT

The Trust has a $130 million revolving syndicated credit facility among four Canadian financial institutions with an extendible 364-day revolving period and a one-year amortization period. In addition, the Trust has a $10 million demand operating line of credit. At December 31, 2005, the available borrowings under these facilities were reduced by $3.0 million of letters of credit. The credit facilities are secured by a floating charge debenture covering all of the assets of the Trust and a general security agreement.

Advances bear interest at the bank's prime rate, bankers' acceptance rates plus stamping fees, or U.S. LIBOR rates plus applicable margins depending on the form of borrowing by the Trust. Stamping fees and margins vary from zero percent to 1.5 percent dependent upon financial statement ratios and type of borrowing. The effective rate on debt outstanding at December 31, 2005 is approximately 4.3 percent.

The credit facility will revolve until May 24, 2006, whereupon it may be renewed for a further 364-day term subject to review by the lenders. If not extended, principal payments will commence after expiry of the revolving period and will consist of three quarterly payments of five percent and the remaining 85 percent at the end of the term.

9. NON-CONTROLLING INTEREST – EXCHANGEABLE SHARES

The exchangeable shares of FET Resources Ltd. are convertible at any time into trust units (at the option of the holder) based on the exchange ratio. The exchange ratio is increased monthly based on the cash distribution paid on the trust units divided by the ten-day weighted average unit price preceding the record date. During the period of January 1 to December 31, 2005, a total of 417,128 exchangeable shares were converted into 546,473 trust units at exchange ratios prevailing at the time. At December 31, 2005, the exchange ratio was 1.37265 trust units for each exchangeable share. Cash distributions are not paid on the exchangeable shares. On the tenth anniversary of the issuance of the exchangeable shares, subject to extension of such date by the Board of Directors of the Company, the exchangeable shares will be redeemed for trust units at a price equal to the value of that number of trust units based on the exchange ratio as at the last business day prior to the redemption date. The Company may redeem all but not less than all of the outstanding exchangeable shares at any time when the aggregate number of issued and outstanding exchangeable shares is less than 1,000,000. The Company will, at least 45 days prior to any redemption date, provide the registered holders with written notice of the prospective redemption. The redemption price is equal to that described previously. The exchangeable shares of FET Resources Ltd. are listed for trading on the Toronto Stock Exchange under the symbol FTX.

Exchangeable Shares of FET Resources Ltd.	Number of Shares		Consideration (thousands)	
	2005	2004	**2005**	2004
Balance as at January 1	**977,346**	3,245,650	**$ 4,934**	$ 10,539
Net income attributable to non-controlling interest			**1,437**	3,019
Exchanged for trust units	**(417,128)**	(2,268,304)	**(2,240)**	(8,624)
Balance as at December 31	**560,218**	977,346	**$ 4,131**	$ 4,934

For the year ended December 31, 2005 the Trust retroactively adopted EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts". Per EIC-151, if certain conditions are met, the exchangeable shares issued by a subsidiary must be reflected as non-controlling interest on the consolidated balance sheet and in turn, net income must be reduced by the amount of net income attributed to the non-controlling interest.

The non-controlling interest on the consolidated balance sheet consists of the book value of exchangeable shares at the time of the Plan of Arrangement, plus net income attributable to the exchangeable shareholders, less exchangeable shares converted. The net income attributable to the non-controlling interest on the consolidated statement of income and accumulated income represents the cumulative share of net income attributable to the non-controlling interest based on the trust units issuable for exchangeable shares in proportion to total trust units issued and issuable each period end.

10. UNITHOLDERS' CAPITAL

An unlimited number of trust units may be issued pursuant to the Trust Indenture. Each trust unit entitles the holder to one vote at any meeting of the unitholders and represents an equal fractional undivided beneficial interest in any distribution from the Trust and in any net assets in the event of termination or winding up of the Trust. The trust units are redeemable at the option of unitholders up to a maximum of $250,000 per annum. This limitation may be waived at the discretion of the Trust.

Trust Units of Focus Energy Trust	Number of Units		Consideration (thousands)	
	2005	2004	**2005**	2004
Balance as at January 1	**35,973,651**	28,034,233	**$ 230,478**	$ 115,095
Issued on conversion of exchangeable shares (i)	**546,473**	2,760,027	**11,479**	42,930
Issued pursuant to the Executive Bonus Plan (ii)	**67,293**	72,391	**1,408**	1,128
Issued for cash (iii)	**–**	5,000,000	**–**	74,500
Trust unit issue expense	**–**	–	**–**	(4,081)
Exercise of Unit Appreciation Rights (iv)	**99,750**	107,000	**1,061**	906
Balance as at December 31, 2005	**36,687,167**	35,973,651	**$ 244,426**	$ 230,478

(i) Issued on conversion of exchangeable shares to trust units with the consideration recorded being equal to the market value of the trust units received on the date of conversion

(ii) Pursuant to the Executive Bonus Plan, 50 percent of all amounts due under such plan are payable through the issuance of trust units priced at the five day weighted average trading price for the last five trading days of the month for which the bonus relates.

(iii) Issued for cash March 23, 2004 pursuant to a Short Form Prospectus dated March 15, 2004

(iv) Exercise of Unit Appreciation Rights includes cash consideration of $813,123 (2004 - $854,040) and contributed surplus credit of $247,446 (2004 - $52,497).

11. TRUST UNIT RIGHTS PLAN

The Trust Unit Rights Plan (the "Plan") was established August 23, 2002 as part of the Plan of Arrangement. The Trust may grant rights to employees, directors, consultants and other service providers of the Trust and any of its subsidiaries. The Trust is authorized to grant up to 2,025,000 rights, but the number of units reserved for issuance upon the exercise of rights shall not at any time exceed five percent of the aggregate number of issued and outstanding units of the Trust and including the number of units which may be issued on the exchange of the outstanding exchangeable shares. To December 31, 2005 a total of 227,250 units had been issued pursuant to the exercise of rights under the Plan, and 1,797,750 units are reserved for issuance under the Plan. With respect to the 1,797,750 units reserved for issuance under the Plan, a total of 1,311,100 rights have been granted.

The initial exercise price of rights granted under the Plan is equal to the weighted average of the closing price of the trust units on the immediately preceding five trading days. The exercise price per right is calculated by deducting from the grant price the aggregate of all distributions, on a per-unit basis, made by the Trust after the grant date which represents a return of more than 0.833 percent of the Trust's recorded cost of capital assets less depletion, depreciation and amortization charges and any future income tax liability associated with such capital assets at the end of each month. Provided this test is met, then the entire amount of the distribution is deducted from the grant price. The rights have a life of five years and vest equally over a four-year period commencing on the first anniversary of the grant.

	2005		2004	
	Number of Rights	Weighted Average Exercise Price	Number of Rights	Weighted Average Exercise Price
Balance as at January 1	**1,113,100**	**$ 11.78**	665,500	$ 9.74
Granted	**337,750**	**$ 21.68**	571,150	$ 16.31
Exercised	**(99,750)**	**$ 8.15**	(107,000)	$ 7.42
Cancelled	**(40,000)**	**$ 15.10**	(16,550)	$ 14.01
Before reduction of exercise price	**1,311,100**	**$ 14.51**	1,113,100	$ 13.27
Reduction of exercise price	**–**	**$ (1.99)**	–	$ (1.49)
Balance as at December 31	**1,311,100**	**$ 12.52**	1,113,100	$ 11.78

- The average exercise price at the grant date is $15.89 ($13.74 for 2004).
- The average contractual life of the rights outstanding is 3.21 years (3.79 years for 2004).
- The number of rights exercisable at December 31, 2005 is 273,500 (123,250 for 2004).
- The average value at the grant date for the year ended December 31, 2005 is $4.77 ($3.41 for 2004).

The Trust prospectively adopted the fair value method in 2003 for rights granted subsequent to January 1, 2003. The fair value of rights is estimated using a modified Black Scholes option pricing model.

The Trust has recorded non-cash compensation expense of $884,362 for the year ended December 31, 2005. The Trust recorded non-cash compensation expense of $305,489 for the year ended December 31, 2004.

Had the Trust used the fair value method for rights granted between August 23, 2002 and December 31, 2002, pro forma net income would have decreased by $136,759 (2004 - $137,133) which would result in no change to net income per trust unit on a basic and diluted basis in 2005 and 2004.

The fair value of rights granted in 2005 was estimated using a modified Black Scholes option pricing model with the following weighted average assumptions: risk-free interest rate of 3.62 percent, volatility of 35 percent, life of 4.4 years and a dividend yield rate of 9.5 percent. Users are cautioned that the assumptions made are estimates of future events and actual results could differ materially from those estimated.

12. ACCUMULATED INCOME

(thousands)	2005	2004
Accumulated income, before cash distributions	**$ 186,958**	$ 123,495
Accumulated cash distributions	**(187,216)**	(113,540)
Balance as at December 31	**$ (258)**	$ 9,955

13. FINANCIAL INSTRUMENTS

The Company's financial instruments included in the balance sheet consist of accounts receivable, other receivables, accounts payable and accrued liabilities and bank debt.

Credit risk:

The Company's accounts receivable are due from a diverse group of customers and as such are subject to normal credit risks.

Interest rate risk:

The Company is also exposed to interest rate risk to the extent that long-term debt is at a floating rate of interest.

Fair values:

The fair values of short-term financial instruments, being accounts receivable, accounts payable and accrued liabilities and cash distributions payable approximate their carrying values due to their short term to maturity. The fair value of long-term debt approximates its carrying value due to the floating interest rate and the revolving nature of the obligation.

The following financial contracts were outstanding at the date of writing. The fair market value of the contracts outstanding at December 31, 2005, which have no book value, was a cost of $3.3 million.

Financial Contracts	Daily Quantity		Contract Price		Price Index	Term
Crude oil	300 bbls	$	72.97	Cdn	WTI	January 2006 – December 2006
	400 bbls	$	55.05–65.05	Cdn	WTI	January 2006 – December 2006
Natural gas	7,000 GJ	$	8.11-9.26	Cdn	AECO	November 2005 – March 2006
	7,000 GJ	$	7.57-8.60	Cdn	AECO	April 2006 – October 2006
	7,000 GJ	$	8.75-10.02	Cdn	AECO	April 2006 – October 2006
	6,000 GJ	$	10.30	Cdn	AECO	April 2006 – October 2006
	7,000 GJ		11.92	Cdn	AECO	November 2006 – March 2007
	6,000 GJ	$	9.63-10.93	Cdn	AECO	November 2006 – March 2007*

* *contract entered into subsequent to December 31, 2005*

14. PHYSICAL SALES CONTRACTS

In addition to the financial contracts described above, the following physical contracts were outstanding at the date of writing. The fair market value of these contracts at December 31, 2005, which have no book value, was a cost of $3.6 million.

Physical Sales Contracts	Daily Quantity		Contract Price		Term
Natural gas – fixed price	7,000 GJ	$	8.55	Cdn	November 2005 – March 2006
	7,000 GJ	$	7.25	Cdn	November 2005 – March 2006
	7,000 GJ	$	7.62	Cdn	November 2005 – March 2006
	3,000 GJ	$	8.67	Cdn	April 2006 – October 2006*
	3,000 GJ	$	8.30	Cdn	April 2006 – October 2006*

* *contract entered into subsequent to December 31, 2005*

15. PER-UNIT AMOUNTS AND SUPPLEMENTARY CASH FLOW INFORMATION

Basic per-unit calculations are based on the weighted average number of trust units outstanding during the period. Diluted per-unit calculations include additional trust units for the dilutive impact of rights outstanding pursuant to the Rights Plan and include exchangeable shares converted at the average exchange ratio.

Basic per-unit calculations for the year ended December 31 are based on the weighted average number of trust units outstanding in 2005 of 36,432,905 (2004 of 33,605,800).

Diluted calculations for the year ended December 31 include additional trust units for the dilutive impact of the Rights Plan in 2005 of 564,620 (2004 of 327,465) and 910,887 exchangeable shares (2004 of 2,297,247) converted at the average exchange rate. Net income has been increased for the net income attributable to the exchangeable shareholders in calculating dilutive per-unit amounts.

Supplementary cash flow information for the year ended December 31:

(thousands)	2005	2004
Interest paid	$ 3,345	$ 1,986
Interest received	$ 40	$ 76
Taxes paid	$ 791	$ 1,453
Cash distributions paid	$ 72,829	$ 59,608

16. INCOME TAXES

Effective July 1, 2005, the British Columbia government enacted a reduction in corporate income tax rates from 13.5 percent to 12.0 percent and effective April 1, 2004, the Alberta government enacted a reduction in corporate income tax rates from 12.5 percent to 11.5 percent. In 2003, Royal Assent was received legislating the reduction of the general corporate income tax rate on income from resource activities from 28 percent to 21 percent and for the elimination of the existing 25 percent resource allowance deduction and introduced the deductibility of actual provincial and other Crown royalties paid, to be phased in over a five-year period.

The Trust's expected future income tax rate is approximately 34 percent at December 31, 2005 compared to 35 percent at December 31, 2004. The Trust recorded a future income tax recovery of $5.7 million in 2005. This amount includes a recovery of $5.2 million relating to accounting for non-controlling interest – exchangeable shares ($6.3 million in 2004).

The Trust recognized future income tax liabilities of $6.3 million in 2004 related to the acquisitions of the Tommy Lakes partnership interest and of a private company.

Certain of the Trust's assets are held by entities which transfer taxable income to unitholders. The excess of the carrying value of these assets over the tax value is $84.4 million.

The provision for future income taxes is different from the amount computed by applying the combined statutory Canadian Federal and Provincial income tax rate to income for the period before income taxes. The differences are as follows:

(thousands)	2005	2004
Income before income and other taxes and non-controlling interest – exchangeable shares	$ 60,099	$ 45,018
Statutory combined federal and provincial income tax rate	38.08%	39.4%
Expected income tax expense at statutory rates	$ 22,885	$ 17,739
Add (deduct) the income tax effect of:		
Non-deductible crown charges	9,969	9,415
Resource allowance	(8,781)	(7,978)
Alberta Royalty Tax Credit	(121)	(164)
Reduction in corporate tax rate	(1,832)	(3,416)
Income attributable to the Trust, not subject to income tax	(28,779)	(24,178)
Capital tax	836	1,073
Other	1,021	(1,573)
Income and other taxes	$ (4,802)	$ (9,082)

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

(thousands)	2005	2004
Capital assets in excess of tax value	$ 87,973	$ 87,461
Provision for asset retirement obligation	(5,170)	(4,015)
Other	(1,169)	(1,107)
Future income taxes	$ 81,634	$ 82,339

17. COMMITMENTS AND CONTINGENCIES

The Trust is involved in litigation and claims arising in the normal course of operations. Management is of the opinion that any resulting settlements would not materially affect the Trust's financial position or reported results in operations.

The following table is a summary of all contractual obligations and commitments for the next five years:

($ thousands)	Total	2006	2007-2008	2009-2010	2011 and threafter
Office premises	1,898	150	932	816	–
Operating leases	632	284	348	–	–
Mineral and surface leases (2)	3,954	659	1,318	1,318	659
Transportation and processing	27,196	10,733	7,594	2,487	6,382
Asset retirement obligations (3)	15,090	319	470	657	13,644
Total contractual obligations	48,770	12,145	10,662	5,278	20,685

(1) THE TABLE DOES NOT INCLUDE THE TRUST'S OBLIGATIONS FOR FINANCIAL INSTRUMENTS AND PHYSICAL SALES CONTRACTS WHICH ARE FULLY DISCLOSED IN NOTES 13 AND 14.

(2) THE TRUST MAKES PAYMENTS FOR MINERAL AND SURFACE LEASES. THE TABLE INCLUDES PAYMENTS FOR EACH OF THE YEARS 2006 TO 2011 UNDER THESE LEASES, ASSUMING CONTINUATION OF THE LEASES. THE CONTINUATION OF LEASES IS BASED ON DECISIONS BY THE TRUST RELATING TO EACH OF THE UNDERLYING PROPERTIES. PAYMENTS FOR THE PERIOD AFTER 2011 HAVE NOT BEEN INCLUDED IN THE TABLE BUT WOULD CONTINUE AT THE SAME YEARLY RATE IF THERE WERE NO CHANGE TO THE UNDERLYING PROPERTIES.

(3) BASED ON THE ESTIMATED TIMING OF EXPENDITURES TO BE MADE IN FUTURE PERIODS

In addition, the Trust has income and capital tax filings that are subject to audit and potential reassessment. The findings from such audit may impact the tax liability of the Trust. The final results are not reasonably determinable at this time and management believes it has adequately provided for income and capital taxes.

QUARTERLY INFORMATION

Summary of Quarterly Results

	2005				2004			
(thousands of dollars, except as indicated)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
FINANCIAL								
Oil and gas revenues, before royalties (1)	**52,315**	**48,790**	**46,583**	**43,981**	39,233	37,979	42,284	30,677
Funds flow from operations	**32,350**	**29,773**	**27,436**	**26,809**	23,241	21,926	25,961	18,438
Per unit - basic	**$0.86**	**$0.80**	**$0.73**	**$0.72**	$0.63	$0.59	$0.70	$0.57
Cash distributions per trust unit	**$0.54**	**$0.52**	**$0.48**	**$0.48**	$0.48	$0.45	$0.45	$0.42
Payout ratio – per-unit basis	**63%**	**65%**	**65%**	**67%**	77%	76%	64%	74%
Net income (2)	**17,858**	**17,573**	**14,682**	**13,351**	14,545	10,508	14,877	11,150
Per unit - basic (2)	**$0.49**	**$0.48**	**$0.40**	**$0.37**	$0.41	$0.30	$0.44	$0.38
Capital expenditures	**10,865**	**5,658**	**3,962**	**22,475**	11,325	1,529	857	11,445
Acquisition expenditures, net	**(33)**	**10,394**	**0**	**77**	1,190	18,580	109,945	(15)
Long-term debt plus working capital	**92,518**	**94,252**	**88,965**	**94,548**	81,157	75,235	60,690	(39,893)
Per unit - basic	**$2.47**	**$2.52**	**$2.38**	**$2.54**	$2.18	$2.03	$1.64	$(1.08)
Times funds flow from operations (3)	**0.7**	**0.8**	**0.8**	**0.9**	0.9	0.9	0.6	(0.5)
Total Trust Units - outstanding (000's)	**37,456**	**37,418**	**37,339**	**37,290**	37,223	37,094	37,016	36,923
Wtgd average Total Trust Units (000's)	**37,442**	**37,381**	**37,317**	**37,254**	37,163	37,057	36,980	32,386
OPERATIONS								
Average daily production								
Crude oil (bbls/d)	**1,714**	**1,718**	**1,779**	**1,850**	1,903	1,932	2,027	2,122
NGLs (bbls/d)	**762**	**833**	**770**	**743**	724	775	703	472
Natural gas (mcf/d)	**42,629**	**44,910**	**46,997**	**43,575**	43,080	44,903	50,913	31,902
BOE (@6:1)	**9,582**	**10,036**	**10,382**	**9,856**	9,807	10,191	11,215	7,911
Natural gas weighting	**74%**	**75%**	**75%**	**74%**	73%	73%	76%	67%
Product prices realized (4)								
Crude oil (CDN$/bbl)	**$59.20**	**$57.78**	**$54.66**	**$54.94**	$41.28	$40.79	$40.07	$39.66
NGLs (CDN$/bbl)	**$60.64**	**$62.41**	**$55.13**	**$51.08**	$48.48	$45.48	$39.62	$39.59
Natural gas (CDN$/mcf)	**$9.24**	**$7.77**	**$7.40**	**$7.36**	$6.64	$6.01	$6.41	$ 6.65
Netback per BOE								
Revenue, net of transportation (4)	**$56.61**	**$49.87**	**$46.91**	**$46.75**	$40.82	$37.72	$38.85	$39.92
Royalties, net of ARTC	**(13.41)**	**(12.16)**	**(11.90)**	**(10.46)**	(9.36)	(9.22)	(9.45)	(10.20)
Production expenses	**(4.61)**	**(3.56)**	**(4.10)**	**(4.19)**	(3.76)	(3.31)	(2.52)	(3.78)
Netback per BOE	**$38.58**	**$34.15**	**$30.91**	**$32.09**	$27.71	$25.19	$26.88	$25.94
Funds flow from operations per BOE	**$36.70**	**$32.25**	**$29.04**	**$30.22**	$25.76	$23.39	$25.44	$25.61
Wells drilled (gross)	**6**	**16**	**3**	**12**	8	5	–	11
TRUST UNIT TRADING STATISTICS								
Unit prices (based on daily closing price)								
High	**$26.74**	**$24.05**	**$22.40**	**$22.60**	$21.39	$18.50	$15.95	$15.23
Low	**$19.72**	**$20.99**	**$18.99**	**$18.60**	$18.08	$15.37	$14.60	$12.90
Close	**$25.72**	**$24.04**	**$21.60**	**$20.80**	$19.97	$18.08	$15.50	$14.83
Daily average trading volume	**103,540**	**117,859**	**73,020**	**115,824**	139,144	101,752	106,869	112,614

(1) RESTATED AT DECEMBER 31, 2004 TO BREAK OUT THE TRANSPORTATION SYSTEM CHARGES SEPARATELY (INCREASES REVENUE AND RECORDS THIS NEW EXPENSE)

(2) RESTATED AT JUNE 30, 2005 WITH NEW ACCOUNTING POLICY EIC-151 "EXCHANGEABLE SECURITIES ISSUED BY SUBSIDIARIES OF INCOME TRUSTS"

(3) LONG-TERM DEBT PLUS WORKING CAPITAL DIVIDED BY FUNDS FLOW FROM OPERATIONS FOR THE QUARTER ANNUALIZED

(4) REALIZED PRICES ARE NET OF HEDGING SETTLEMENTS AND TRANSPORTATION SYSTEM CHARGES (WHICH ARE REPORTED SEPARATELY STARTING DECEMBER 31, 2004)

SENIOR MANAGEMENT

Derek W. Evans
President and C.E.O.

William D. Ostlund
Vice President, Finance and C.F.O.

Dennis M. Lawrence
Vice President, Engineering

Bryce H. Murdoch
Vice President, Geology

Al S. Pickering
Vice President, Land

David W. Sakal
Vice President, Operations

A. Kim Schoenroth
Controller

Grant A. Zawalsky
Corporate Secretary

DIRECTORS

Matthew J. Brister(3)(4)(5)
John A. Brussa(1)
Stuart G. Clark(1)(2)
Derek W. Evans
James H. McKelvie(2)(3)
Gerry A. Romanzin(2)(4)(5)

(1) CHAIRMAN OF THE BOARD
(2) MEMBER OF THE AUDIT COMMITTEE
(3) MEMBER OF THE COMPENSATION COMMITTEE
(4) MEMBER OF THE RESERVES COMMITTEE
(5) MEMBER OF THE CORPORATE GOVERNANCE COMMITTEE

HEAD OFFICE

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STOCK EXCHANGE LISTING

TSX Listings:
Focus Energy Trust: FET.UN
FET Resources Ltd.: FTX
(Exchangeable Shares)

SOLICITORS

Burnet, Duckworth & Palmer LLP
Calgary, Alberta, Canada

AUDITORS

KPMG LLP
Calgary, Alberta, Canada

BANKERS

Bank Syndicate
Lead Agent: Royal Bank of Canada
Calgary, Alberta

ENGINEERING CONSULTANTS

Paddock Lindstrom & Associates Ltd.
Calgary, Alberta

McDaniel and Associates Consultants Ltd.
Calgary, Alberta

REGISTRAR & TRANSFER AGENT

Valiant Trust Company
Calgary, Alberta

ABBREVIATIONS

api	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
Bcf	Billions of cubic feet
Bcfe	Billions of cubic feet equivalent
BOE	Barrels of oil equivalent @ 6:1
BOE/d	Barrels of oil equivalent per day
bbl	Barrel of oil or natural gas liquids
bbls	Barrels of oil or natural gas liquids
bbls/d	Barrels per day
$CDN	Canadian Dollar
GJ	Gigajoules
GJ/d	Gigajoules per day
Mmbtu	Millions of British Thermal Units
Mmbtu/d	Millions of British Thermal Units per day
mbbl	Thousand barrels
mbbls	Thousands of barrels
Mmbbls	Millions of barrels
Mmcfe/d	Millions of cubic feet equivalent per day
MBOE	Thousands of barrels of oil equivalent
MBOE/d	Thousands of barrels of oil equivalent per day
MMBOE	Millions of barrels of oil equivalent
mcf	Thousands of cubic feet
mcf/d	Thousands of cubic feet per day
Mmcf	Millions of cubic feet
Mmcf/d	Millions of cubic feet per day
Mw	Megawatt
Mw/hr	Megawatt per hour
NGL	Natural gas liquid
OPEC	Organization of Petroleum Exporting Countries
RLI	Reserve Life Index
TSX	Toronto Stock Exchange
WTI	West Texas Intermediate
$US	United States Dollar

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