FORM 6-K
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Report of Foreign Private Issuer

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

For the month of August, 2005

Provident Energy Trust
(Translation of registrant's name into English)
700, 112 - 4th Ave, S.W. ; Calgary, AB; T2P 0H3
(Address of principal executive offices)

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

Form 20-F .... Form 40-F ...X...

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

Yes .... No ...X...

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

SIGNATURE

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

Date: August 08, 2005
Provident Energy Trust

By:

/s/ Mark N. Walker
____
Mark N. Walker
Vice President, Finance, Chief Financial Officer and Corporate Secretary

Provident Energy Announces Second Quarter 2005 Results

NEWS RELEASE NUMBER 19-05 **August 8, 2005**

All values are in Canadian dollars and conversions of natural gas volumes to barrels of oil equivalent (boe) are at 6:1 unless otherwise indicated.

Second quarter 2005 highlights

- Provident generated $64.4 million ($0.41 per unit) in cash flow from operations, and declared distributions of $57.0 million ($0.36 per unit).
- Provident earned $26.8 million ($0.17/unit).
- Provident drilled 16 net operated wells in its Southwest Saskatchewan shallow gas area with test results better than expected.
- Provident completed the redemption of its 10.5 percent convertible unsecured subordinated debentures.
- On June 28, Provident announced the appointment of Dan O'Byrne, Executive Vice President, Operations, and Chief Operating Officer.

CALGARY, ALBERTA - Provident Energy Trust (Provident) (TSX-PVE.UN; AMEX-PVX) reported second quarter 2005 cash flow from operations of $64.4 million ($0.41/unit) compared to $36.5 million ($0.38/unit) generated in the second quarter of 2004, an increase of 76 percent. Distributions declared in the quarter totaled $57.0 million ($0.36/unit) compared to $35.0 million ($0.36/unit) in 2004. For the second quarter of 2005, Provident's payout ratio of cash flow from operations was 88 percent compared to 96 percent in the same period of 2004.

Year-to-date, operating cash flow was $128.6 million ($0.84/unit) compared to $72.8 million ($0.79/unit) for the same period in 2004. For the six months ended June 30, 2005, Provident declared distributions of $108.7 million ($0.72/unit) compared to the $66.1 million

Year-to-date, operating cash flow was $128.6 million ($0.84/unit) compared to $72.8 million ($0.79/unit) for the same period in 2004. For the six months ended June 30, 2005, Provident declared distributions of $108.7 million ($0.72/unit) compared to the $66.1 million ($0.72/unit) during the same period in 2004. For 2005, Provident's payout ratio of cash flow from operations is 85 percent, compared to 91 percent for the same period in 2004. Based on the current distribution level and commodity prices, Provident is forecasting a payout ratio of approximately 80 percent for 2005.

On May 31, 2005, Provident completed the redemption of its 10.5 percent convertible unsecured subordinated debentures. A total of 3.5 million units were issued at the conversion price of $10.70 per unit. A further $3.0 million was paid to the remaining debenture holders who did not convert to trust units at $1,050 per $1,000 of convertible debenture held, plus accrued interest to May 31, 2005.

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“Second quarter and year-to-date results were in line with expectations,” said Provident Chief Executive Officer Tom Buchanan. “At the operations level, our Midstream business unit continued to meet or exceed expectations, however capital programs for our U.S. and Canadian Oil and Gas Production business units were faced with unexpected delays. Our plans to increase drilling activities in the second quarter, particularly at our Lloydminster and Southwest Saskatchewan fields in Canada were delayed due to poor weather, and our West Pico and Santa Fe Spring areas in Los Angeles experienced service access problems.”

On June 28, 2005, Provident announced the appointment of Dan O’Byrne, Executive Vice President, Operations, and Chief Operating Officer. Mr. O’Byrne will be responsible for Provident’s Midstream Services and Marketing, U.S. Oil and Gas Production, and Canadian Oil & Gas Production business units. “I look forward to contributing to Provident’s growth-oriented, balanced portfolio strategy,” said Mr. O’Byrne. “Our focus in the months to come will be on enhancing sustainability, diversifying our asset base and exercising discipline in the management of our assets and capital resources.”

Business Unit Results

Provident owns diversified investments across the energy value chain in Canada and the United States. The company comprises three key business units: Midstream Services and Marketing (Midstream), U.S. Oil and Gas Production (USOGP), and Canadian Oil and Gas Production (COGP). The results for each of these business units are reported below:

Midstream Services and Marketing (Midstream)

Provident’s Midstream business unit generates cash flow by providing fee-based services, such as extraction, transportation, storage, distribution and marketing of natural gas liquids (NGLs), to petroleum producers and refiners, petrochemical companies, and marketing firms. Provident’s Midstream assets include 100 percent ownership of the Redwater

For the second quarter of 2005, Provident’s Midstream business unit generated earnings before interest, taxes, depreciation, accretion, and non-cash revenue (EBITDA) of $11.8 million, a 32 percent increase over the $8.9 million generated in second quarter of 2004. Cash flow from operations increased 52 percent from the second quarter of 2004, rising from $6.9 million to $10.6 million. The increase in EBITDA and cash flow was due to efficient operations, enhanced marketing activities, and increased revenue from NGL storage and distribution services. Throughput at the Redwater fractionation facility averaged 52,175 barrels per day, compared to the 48,452 barrels per day Provident reported for the second quarter of 2004.

Year-to-date, Midstream has generated EBITDA of $28.1 million. This compares with $21.1 million generated in the first half of 2004. Midstream’s year-to-date cash flow for 2005 was $25.8 million, an increase of 53 percent from the $16.8 million cash flow generated during the same period last year.

Provident continues to target previously announced annual EBITDA guidance of $42.0 to $46.0 million.

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U.S. Oil and Gas Production (USOGP)

Provident's USOGP business unit generates cash flow from the production and sale of natural gas and crude oil from basins in Southern California and Wyoming. BreitBurn Energy LP (Breitburn) operates 100 percent of the production, and Provident owns approximately 96 percent of Breitburn. Provident acquired BreitBurn on June 15, 2004 and, therefore, the results for the 15 days ended June 30, 2004 are immaterial. For this reason, comparative discussion and analysis is not included for that period.

In the second quarter of 2005, USOGP generated $13.8 million of cash flow from operations, and production averaged 7,793 boed. Production over the period was weighted 95 percent light/medium crude oil and five percent natural gas. USOGP increased its production in the second quarter of 2005 by 1,801 boed when compared with production during the first quarter of 2005. This increase is primarily due to the addition of the first full quarter of production from the Nautilus properties in Wyoming, which were acquired on March 2, 2005.

Operating netbacks before hedging in the second quarter of 2005 remain strong at $33.65, driven by high commodity prices. Operating costs were $14.00 per barrel of oil equivalent (boe) during the second quarter, compared with $13.77 per boe during the first quarter of 2005. USOGP operations are continuing to return to, or maintain, production on wells with higher operating costs due to persistence of strong crude oil prices. Year-to-date, operating costs at $13.90 per boe were 11 percent lower than the $15.62 reported in the period from June 15 to December 31, 2004. For the remainder of 2005, USOGP operating costs are expected to improve to the $13.00 to $14.00 per boe range, assuming an exchange rate of Cdn$1.25 to US$1.00.

Provident spent $15.3 million on capital expenditures during the second quarter. $10.6 million was directed to drilling, optimization and facility upgrades at its West Pico, Santa Fe Springs, and Orcutt operations, and to its newly-acquired fields in Wyoming. Provident also directed $0.9 million to optimization projects at smaller fields and office equipment, and $3.8 million to the purchase of real estate adjacent to the West Pico operation.

Canadian Oil and Gas Production (COGP)

Provident's COGP business unit generates cash flow from the production and sale of natural gas, light/medium oil, natural gas liquids (NGLs), and heavy oil to energy marketers. Production assets are primarily located in the central and southern regions of Alberta and Saskatchewan.

In the second quarter of 2005, COGP generated $40.1 million in cash flow from operations. This amount compares to $29.6 million that was generated in the second quarter of 2004. Second quarter 2005 production averaged 27,384 boed compared to the 27,000 average boed for the same period last year. The production increase reflects the acquisitions of Olympia and Viracocha in April 2004, as well as drilling and optimization activities offset by natural production declines. Production over the period is weighted 47 percent natural gas, 36 percent medium/light crude oil and NGLs, and 17 percent heavy oil. Year-to-date, Provident's COGP production averaged 28,242 boed, compared to the 25,663 boed average that Provident produced during the same period last year.

Second quarter 2005 operating netback of $24.45 per boe was eight percent above the $22.58 per boe in the same quarter of 2004, as was the year-to-date operating netback of $23.18 compared to $21.39 per boe in the six month period in 2004. The increase in 2005 reflects a higher WTI crude oil benchmark and a significant shift in Provident's production mix.

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Operating costs were $8.94 per boe during the second quarter of 2005, compared to $7.90 per boe during the second quarter of 2004, and $9.77 per boe during the first quarter of 2005. Operating expenses increased in a number of categories, including well servicing, maintenance, power and fuel, and fluid hauling. The increases are a result of the poor weather conditions experienced during the second quarter and higher demand for operating services driven by higher commodity prices. For 2005, Provident is expecting COGP operating costs to average $9.50 to $9.90 per boe, assuming WTI prices are in the range of US$50 to US$55 per barrel.

Provident spent $10.1 million in Southern Saskatchewan, primarily in its shallow gas area in Southwest Saskatchewan. Most of the capital was spent on drilling, completions, equipping, tie-ins and acquiring mineral rights for future development. Sixteen net wells were drilled late in the second quarter and 14 of these are expected to be on production early in the fourth quarter. Test results are better than forecast at approximately four million cubic feet per day (mmcfd) or 660 boed. Two wells were dry and abandoned. Fifteen net wells, drilled in late 2004 and first quarter 2005, commenced production during the second quarter at an initial rate of approximately four mmcf/d (660 boed).

Further development capital of $3.8 million was spent in Southern Alberta on drilling activities, recompletion and facility upgrades, $3.7 million was spent in West Central on non-operated capital, $3.0 million was spent in Lloydminster on workovers and facility, and $0.4 million was spent on office requirements and other costs.

Provident Energy Trust is a Calgary-based, open-ended energy income trust that owns and manages an oil and gas production business and a midstream services business. Provident's energy portfolio is located in some of the most stable and predictable producing regions in Western Canada, Southern California and Wyoming. Provident provides monthly cash distributions to its unitholders and trades on the Toronto Stock Exchange and the American Stock Exchange under the symbols PVE.UN and PVX, respectively.

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Consolidated financial highlights

Consolidated ($000s except per unit data)	Three months ended June 30, 2005	2004 (2)(5)	% Change	Six months ended June 30, 2005 (5)	2004 (2)(5)	% Change
Revenue (net of royalties and financial derivative instruments)	$ **300,504**	$ 218,304	38	$ **622,527**	$ 453,251	37
Cash flow from COGP operations	$ **40,098**	$ 29,593	35	$ **77,667**	$ 55,979	39
Cash flow from USOGP operations (1)	**13,770**	-	-	**25,138**	-	-
Cash flow from midstream services and marketing	**10,567**	6,937	52	**25,767**	16,820	53
Total cash flow from operations	$ **64,435**	$ 36,530	76	$ **128,572**	$ 72,799	77
Per weighted average unit – basic (3)	$ **0.41**	$ 0.38	8	$ **0.84**	$ 0.79	7
Per weighted average unit – diluted (4)	$ **0.40**	$ 0.36	13	$ **0.83**	$ 0.76	10
Declared distributions to unitholders	$ **57,001**	$ 35,039	63	$ **108,735**	$ 66,075	65
Per unit (3)	$ **0.36**	$ 0.36	-	$ **0.72**	$ 0.72	-
Percent of cash flow from operations paid out as declared distributions	**88%**	96%	(8)	**85%**	91%	(8)
Net income (loss)	$ **26,822**	$ (6,873)	-	$ **24,039**	$ (12,868)	-
Per weighted average unit – basic (3)	$ **0.17**	$ (0.07)	-	$ **0.16**	$ (0.14)	-
Per weighted average unit – diluted (4)	$ **0.17**	$ (0.07)	-	$ **0.16**	$ (0.14)	-
Capital expenditures	$ **36,802**	$ 11,607	217	$ **66,088**	$ 23,126	186
Nautilus acquisition	$ **-**	$ -	-	$ **91,420**	$ -	-
Property acquisitions	$ **-**	$ -	-	$ **-**	$ 4,718	-
Property dispositions	$ **-**	$ 705	-	$ **-**	$ 7,114	-
Weighted average trust units outstanding (000s) - Basic (3)	**157,517**	97,267	62	**152,730**	91,800	66
- Diluted (4)	**159,327**	101,829	56	**154,540**	96,362	60

Consolidated ($000s)	As at June 30,2005	As at December 31, 2004	% Change
Long-term debt	$ **417,482**	$ 432,206	(3)
Unitholders' equity	$ **1,134,719**	$ 1,009,048	12

(1) No Q1 2004 comparatives as USOGP operations commenced June 15, 2004.

(2) Restated for the impact of the retroactive implementation of the change in accounting policies for convertible debentures - see note 2

(3) Excludes exchangeable shares

(4) Includes exchangeable shares and unit options

(5) Restated for the impact of the retroactive implementation of change in accounting policies for exchangeable securities - non-controlling interest - see note 2

Operational highlights

Consolidated	Three months ended June 30,					Six months ended June 30,				
		2005		2004	% Change		**2005**		2004	% Change
Oil and Gas Production										
Daily production										
Light/medium crude oil (bpd)		**15,891**		7,861	102		**15,144**		6,913	119
Heavy oil (bpd)		**4,644**		6,537	(29)		**5,093**		6,563	(22)
Natural gas liquids (bpd)		**1,454**		1,267	15		**1,604**		1,198	34
Natural gas (mcfpd)		**79,126**		68,007	16		**79,792**		65,933	21
Oil equivalent (boed)[1]		**35,177**		27,000	30		**35,140**		25,663	37
Average selling price (before hedges)										
Light/medium crude oil ($/bbl)	$	**51.20**	$	42.28	21	$	**50.31**	$	40.86	23
Heavy oil ($/bbl)	$	**26.03**	$	28.26	(8)	$	**25.93**	$	27.55	(6)
Corporate oil blend ($/bbl)	$	**45.50**	$	35.91	27	$	**44.17**	$	34.38	28
Natural gas liquids ($/bbl)	$	**47.75**	$	40.55	18	$	**46.42**	$	38.89	19
Natural gas ($/mcf)	$	**7.29**	$	7.01	4	$	**7.03**	$	6.71	5
Oil equivalent ($/boe)[1]	$	**44.94**	$	38.70	16	$	**43.51**	$	37.11	17
Field netback (before hedges) ($/boe)	$	**26.58**	$	22.59	18	$	**25.41**	$	21.40	19
Field netback (including hedges) ($/boe)	$	**22.16**	$	15.92	39	$	**21.49**	$	15.78	36
Midstream services and marketing										
Redwater throughput (bpd)		**52,175**		48,452	8		**55,322**		58,945	(6)
EBITDA (000s)[2]	$	**11,765**	$	8,945	32	$	**28,145**	$	21,142	33

(1) Provident reports oil equivalent production converting natural gas to oil on a 6:1 basis.

(2) EBITDA is earnings before interest, taxes, depletion, depreciation, accretion and non-cash revenue.

Management's discussion and analysis (MD&A)

The following analysis provides a detailed explanation of Provident's operating results for the quarter and for the six months ended June 30, 2005 compared to same time periods in 2004 and should be read in conjunction with the consolidated financial statements of Provident, found later in the interim report.

This disclosure contains certain forward-looking estimates that involve substantial known and unknown risks and uncertainties, certain of which are beyond Provident's control. These include the impact of general economic conditions in Canada and the United States; industry conditions; changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; increased competition; the lack of availability of qualified personnel or management; fluctuations in commodity prices; foreign exchange or interest rates; stock market volatility and obtaining required approvals of regulatory authorities. Provident's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking estimates and, accordingly, no assurances can be given that any of the events anticipated by the forward-looking estimates will transpire, or if any of them do so, what benefits, including the amounts of proceeds, Provident will derive there from. All amounts are reported in Canadian dollars, unless otherwise stated.

Provident Energy Trust has diversified investments in certain segments of the energy value chain. Provident currently operates in three key business segments: Canadian crude oil and natural gas production and exploitation (COGP), United States crude oil and natural gas production and exploitation, (USOGP) and midstream services and marketing (Midstream). Provident's COGP business produces crude oil and natural gas from five core areas in the western Canadian sedimentary basin. USOGP produces crude oil and natural gas in Southern California and Wyoming, U.S.A. The Midstream business unit processes, markets, transports and offers storage of natural gas liquids at the Redwater facility and surrounding infrastructure located north of Edmonton, Alberta. The unit also markets natural gas liquids, natural gas and crude oil.

This analysis commences with a summary of the consolidated financial and operating results followed by segmented reporting on the COGP business unit, the USOGP business unit and the Midstream business unit. The reporting focuses on the financial and operating

Second quarter and six months ended June 30, 2005 highlights

The second quarter highlights section provides commentary for the second quarter and for the six months ended June 30, 2005. Results are compared to the corresponding periods in 2004.

USOGP comparative discussion and analysis for the 2004 six months and three months ended June 30, 2004 have not been provided within the MD&A. The results of these operations are included in the segmented note to the financial statements but as the USOGP operations were only incorporated into Provident's results from June 15, 2004 to June 30, 2004 the results were immaterial in the quarter and have not been discussed separately.

Consolidated cash flow from operations and cash distributions

Consolidated	Three months ended June 30,			Six months ended June 30,		
($ 000s, except per unit data)	**2005**	2004	% Change	**2005**	2004	% Change
Revenue, Cash Flow and Distributions						
Revenue (net of royalties and financial derivative instruments – see note 9 of the financial statements)	$ **300,504**	$ 218,304	38	**$ 622,527**	$ 453,251	37
Cash flow from operations before changes in working capital and site restoration expenditures	$ **64,435**	$ 36,530	76	**$ 128,572**	$ 72,799	77
Per weighted average unit - basic [1]	$ **0.41**	$ 0.38	9	**$ 0.84**	$ 0.79	6
Per weighted average unit - diluted [2]	$ **0.40**	$ 0.36	13	**$ 0.83**	$ 0.76	10
Declared distributions	$ **57,001**	$ 35,039	63	**$ 108,735**	$ 66,075	65
Per Unit [1]	**0.36**	0.36	-	**0.72**	0.72	-
Percent of cash flow distributed	**88%**	96%	(8)	**85%**	91%	(7)

(1)Excludes exchangeable shares

(2)Includes exchangeable shares and unit options

Second quarter 2005 cash flow was $64.4 million, 76 percent above the $36.5 million of cash flow recorded in the second quarter of 2004. For the six month period ended June 30, 2005 cash flow was $128.6 million, 77 percent above the $72.8 million of cash flow in the same period of 2004. COGP 2005 second quarter cash flow was $40.1 million, a 35 percent improvement above the $29.6 million recorded in the comparable 2004 quarter. The main driver for this increase was the 30 percent increase in production volumes attributed towards 2004 acquisitions and effective drilling programs as well as improved product pricing, product mix and netbacks. For the six month period ended June 30, 2005, COGP cash flow was $77.7 million, a 39 percent improvement above the $56.0 million recorded in the comparable 2004 period. Midstream added $10.6 million to second quarter 2005 cash flow, 52 percent above the $6.9 million recorded in the comparable 2004 quarter. Midstream cash flow benefited from efficient operations, marketing opportunities and increased revenues associated with storage and distribution services. For the six month period ended June 30, 2005, Midstream added $25.8 million to the cash flow, a 53 percent improvement above the $16.8 million recorded in the comparable 2004 period. Cash flow from operations in the second quarter of 2005 also reflects cash flow of $13.8 million from USOGP.

Declared distributions in the second quarter of 2005 totaled $57.0 million compared to $35.0 million of declared distributions in 2004. This represented 88 percent and 96 percent of cash flow from operations respectively.

Net income (loss)

Consolidated		Three months ended June 30,				Six months ended June 30,		
(000s, except per unit data)		**2005**		2004[3]	% Change	**2005**	2004[3]	% Change
Net income (loss)	$	**26,822**	$	(6,873)	-	**$ 24,039**	$ (12,868)	-
Per weighted average unit – basic[1]	$	**0.17**	$	(0.07)	-	**$ 0.16**	$ (0.14)	-
Per weighted average unit – diluted[2]	$	**0.17**	$	(0.07)	-	**$ 0.16**	$ (0.14)	-

[1] Based on weighted average number of trust units outstanding

[2] Based on weighted average number of trust units and trust units that would be issued upon conversion of exchangeable shares and pursuant to the unit option plan

[3] Restated - note 2.

Net income for the second quarter of 2005 improved to $26.8 million, compared to a $6.9 million net loss in the comparable 2004 quarter. Increased income is mainly attributable to a full quarter of production resulting from the late second quarter 2004 acquisitions of Viracocha, Olympia and BreitBurn.

COGP's net income is $7.4 million, comparable to a 2004 second quarter loss of $13.0 million. The COGP business segment's net loss for the six months ended June 30, 2005 is $2.2 million, compared to a $22.8 million net loss in the comparable 2004 period.

Midstream contributed $12.1 million of net income in the second quarter of 2005 as compared to the $4.1 million of net income in the second quarter of 2004. Midstream contributed $24.4 million of net income in the six months ended June 30, 2005 as compared to the $7.8 million of net income in the comparable 2004 period.

In the second quarter of 2005, USOGP net income was $7.3 million and for the six months ended June 30, 2005, USOGP net income was $1.8 million.

Taxes

Consolidated		Three months ended June 30,				Six months ended June 30,		
($ 000s)		**2005**		2004	% Change	**2005**	2004	% Change
Capital taxes	$	**1,533**	$	1,167	31	$ **2,910**	$ 2,172	34
Current and withholding taxes		**2,004**		292	586	**4,371**	292	1,397
Future income tax recovery		**(2,112)**		(3,037)	(30)	**(9,832)**	(17,586)	(44)
	$	**1,425**	$	(1,578)	-	$ **(2,551)**	$ (15,122)	(83)

Capital taxes in the second quarter totaled $1.5 million, an increase of 31 percent above the $1.2 million recorded in the second quarter of 2004, and $2.9 million year-to-date, compared to $2.2 million year-to-date for 2004. The increases reflect the growth in the asset base, increasing paid up capital of Provident as well as the increase in the Saskatchewan resource surcharge that is sensitive to crude oil prices.

The current and withholding taxes total $2.0 million in the second quarter of 2005, an increase of $1.7 million over the comparable 2004 quarter. These taxes arise from Provident's U.S.-based operations and for the second quarter of 2005, represent 11 percent of USOGP EBITDA.

For the six months ended June 30, 2005 current and withholding taxes total $4.4 million. This year-to-date amount includes $0.9 million of taxes related to 2004 operations. The reported taxes in 2005 net of the $0.9 million prior period adjustment constitute 10 percent of year-to-date USOGP EBITDA. Reported taxes for the year ended December 31, 2004 were five percent of USOGP EBITDA. Had the reported 2004 results included the $0.9 million of taxes on 2004 USOGP operations, the tax burden reported would have been 10 percent of USOGP EBITDA for the year ended December 31, 2004.

The 2005 second quarter future tax recovery of $2.1 million on second quarter income before taxes and non-controlling interests of $29.1 million as compared to the expected expense of $11.3 million primarily is a result of interest and royalty charged by the Trust to its incorporated subsidiary, Provident Energy Ltd. These amounts are deductible in computing the income of the subsidiary. The Trust is a taxable entity under Canadian income tax law and is taxable only on income that is not distributed or distributable to the unit holders. If the Trust distributes all of its taxable income to the unitholders, no provision for taxes is required by the Trust. Recoveries of $3.0 million of future taxes in the second quarter of 2004 on losses before tax of $8.5 million exceeds the expected recovery of $3.3 million primarily for the same reasons.

Reconciliation of GAAP

The Trust calculates earnings before interest, taxes, depletion and accretion and non-cash revenue (EBITDA) within its segment disclosure. EBITDA is a non-GAAP measure. Reconciliation between EBITDA and loss before taxes follows:

	Three months ended June 30,		**Six months ended June 30,**	
EBITDA Reconciliation				
(000s, except per unit data)	**2005**	2004	**2005**	2004
EBITDA	$ **75,349**	$ 43,919	$ **150,991**	$ 86,857
Adjusted for:				
Non-cash expenses excluding unrealized loss on financial instruments	**(36,886)**	(61,690)	**(143,210)**	(146,360)
Unrealized loss (gain) on financial instruments	**(9,391)**	9,287	**14,371**	31,331
Income (loss) before taxes and non-controlling interests	$ **29,072**	$ (8,484)	$ **22,152**	$ (28,172)

Interest expens

Consolidated	Three months ended June 30,			Six months ended June 30,		
($ 000s, except per unit data)	**2005**	2004[1]	% Change	**2005**	2004[1]	% Change
Interest on bank debt	$ **1,914**	$ 2,929	(35)	**$ 5,240**	$ 5,073	3
Weighted-average interest rate on bank debt	**3.7%**	4.5%	(18)	**3.9%**	4.2%	(7)
Interest on 10.5% convertible debentures[4]	**1,249**	1,315	(5)	**2,431**	2,621	(7)
Interest on 8.75% convertible debentures	**1,616**	1,644	(2)	**3,215**	3,281	(2)
Interest on 8.0% convertible debentures [2]	**997**	-	-	**2,026**	-	-
Interest on 6.5% convertible debentures [3]	**1,655**	-	-	**2,207**	-	-
Total cash interest	$ **7,431**	5,888	26	**$ 15,119**	10,975	38
Weighted average interest rate on all long-term debt	**6.2%**	8.9%	(30)	**5.5%**	5.0%	10
Non -cash accretion expense - convertible debentures	**964**	641	50	**2,214**	1,747	27
Total interest including accretion on convertible debentures	$ **8,395**	$ 6,529	29	**$ 17,333**	$ 12,722	36

(1) Restated - note 2.

(2) On July 6, 2004 the Trust issued $50.0 million of unsecured subordinated convertible debentures with an 8 percent coupon rate maturing July 31, 2009.

(3)On March 1, 2005 the Trust issued $100.0 million of unsecured subordinated convertible debentures with a 6.5 percent coupon rate maturing August 31, 2012.

(4)On May 31, 2005 the Trust redeemed the entire 10.5 percent unsecured convertible debentures for 3.5 million trust units and $3.0 million in cash

Interest on bank debt decreased in the second quarter of 2005 compared to the second quarter in 2004 as the Trust applied the proceeds from the March 1, 2005 issue of $100 million in subordinated convertible debentures towards paying down bank debt and did not draw on its bank facilities to finance corporate acquisitions.

Cash interest expense on debentures increased for the quarter and year-to-date as compared to the same periods in 2004. This increase reflects the March 1, 2005 issue of $100 million of 6.5 percent subordinated convertible debentures partly offset by the May 31 redemption of approximately $45.7 million of 10.5 percent subordinated convertible debentures. Accretion and amortization on convertible debentures is the result of Provident adopting the revised CICA Handbook section 3860 and reclassifying the bulk of its subordinated convertible debentures to long-term debt and an additional portion to equity.

Commodity price risk management program

Provident continues to execute a commodity price risk management program that is designed to limit exposure to downturns in commodity prices and to protect monthly cash distributions at target payout ratios. Our hedging strategy uses structures that provide a floor price while allowing upside participation in a rising price market.

In accordance with the Trust’s credit policy, the Trust partially mitigates associated credit risk by limiting financial derivative transactions to counterparties with investment grade credit ratings.

Activity in the second quarter:

Provident's second quarter crude oil activity included fixed swaps for 1,000 barrels per day (bpd) at a fixed price of US$58.50 per barrel for the period July 1 to July 31, 2005, and 440 bpd at a fixed price of US$55.00 per barrel for the period May 1 to October 31, 2005. Provident also purchased crude oil put options for 750 bpd at a strike price of US$52.00 per barrel for the period January 1 to December 31, 2006. In addition, Provident entered into crude oil participating swaps for 1,250 bpd at an average floor level of US$50.00 per barrel, with participating percentages up to 90 percent above the floor price, for the period January 1 to December 31, 2006.

Provident's second quarter natural gas activity included natural gas participating swaps for 5,000 gigajoules (gj) per day at a floor level of $7.00 per gj, with participation percentages up to 80 percent above the floor price, for the period November 1 to December 31, 2005. Provident also entered into a natural gas fixed price swap (purchase) for 4,000 gj per day at a fixed price of $7.54 per gj for the period May 1 to October 31, 2005.

Provident's second quarter natural gas liquids activity included a propane swap for 27,720 US gallons per day (gpd) at a fixed price of US$0.85 per US gallon for the period May 1 to October 31, 2005 and 34,239 US gpd at a fixed price of US$0.87375 for the period October 1 to December 31, 2005. During the quarter Provident also entered into a condensate swap for a total of 3,000 barrels for the period July 1 to July 31, 2005 at a fixed price of US$59.55 per barrel. This contract is settled against the monthly calendar average for WTI.

The following is a summary of the net cash flow to settle commodity contracts during the second quarter of 2005 as well as the 2004 second quarter amounts.

a) Crude oil

For the second quarter of 2005, Provident paid out $13.0 million on an aggregate volume of 0.7 million barrels to settle various oil market based contracts. For the quarter ended June 30, 2004, Provident paid out $11.8 million to settle various oil market based contracts on an aggregate volume of 0.7 million barrels. The estimated value of contracts for the second quarter in place if settled at market prices at June 30, 2005 would have resulted in an opportunity cost of $36.6 million (June 30, 2004-$21.2 million)

For the six months ended June 30, 2005, Provident paid out $23.6 million on an aggregate volume of 1.3 million barrels to settle various oil market based contracts. For the comparable period in 2004, Provident paid out $21.2 million to settle various oil market based contracts on an aggregate volume of 1.3 million barrels.

b) Natural Gas

For the quarter ended June 30, 2005, Provident paid $0.7 million to settle various natural gas market based contracts on an aggregate of 3.0 million gj, and paid an additional $0.5 million on physical gas hedges. For the quarter ended June 30, 2004, Provident paid $4.6 million to settle various natural gas market based contracts on an aggregate of 2.8 million gj.

For the six months ended June 30, 2005, Provident paid $0.75 million to settle various natural gas market based contracts on an aggregate of 3.8 million gj, and paid an additional $0.6 million on physical gas hedges. In the comparable 2004 period Provident paid $5.0 million to settle various natural gas market based contracts on an aggregate of 6.4 million gj. As at June 30, 2005 the estimated value of contracts in place settled at market prices at June 30 would have resulted in an opportunity cost of $1.2 million (June 30, 2004 - $4.6 million).

c) Midstream

For the quarter ended June 30, 2005, Provident received $0.2 million (2004-$0.5 million cost) on midstream price stabilization hedging activities.

For the six month period ended June 30, 2005, Provident received $0.5 million (2004-$0.3 million cost) on midstream price stabilization hedging activities. As at June 30, 2005 the estimated value of contracts in place settled at market prices at June 30 would have resulted in an opportunity cost of $0.3 million (June 30, 2004 - $4.6 million).

d) Foreign exchange contracts

As at June 30, 2005 the estimated value of contracts in place settled at current foreign exchange rates would have resulted in an opportunity gain of $0.1 million. The foreign exchange gains have been included in note 9 as a component of realized loss on financial derivative instruments and allocated to their respective business segments.

A summary of all of Provident's contracts in place at June 30, 2005 are contained in the following tables:

COGP

		2005	
Product	**Volume (Buy)/Sell**	**Terms**	**Effective Period**
Light Oil	1,000 bpd	US$58.50 per bbl (1)	July 1 - July 31
	440 bpd	US$55.00 per bbl	July 1 - October 31
	2,750 bpd	US$26.07 per bbl (1)	July 1 - December 31
	500 bpd	Costless collar US$26.00 - $30.10 per bbl	July 1 - December 31
		2006	
	750 bpd	Participating Swaps US$51.33 per bbl (63% above floor price) (1) (3)	January 1 - December 31
	500 bpd	Participating Swaps US$48.00 per bbl (max to 90% above floor price) (3)	January 1 - December 31
	500 bpd	Puts US$52.00 per bbl	January 1 - December 31

COGP

		2005	
Product	**Volume (Buy)/Sell**	**Terms**	**Effective Period**
Natural Gas (2)	(4,000) gjpd	Cdn $7.54 per gj	July 1 - October 31
	5,000 gjpd	Participating Swaps Cdn $5.60 per gj (55% above floor price) (3)	July 1 - October 31
	5,000 gjpd	Participating Swaps Cdn $6.00 per gj (max to 80% above floor price) (3)	July 1 - October 31
	5,000 gjpd	Participating Swaps Cdn $6.00 per gj (max to 65% above floor price) (3)	July 1 - October 31
	2,500 gjpd	Puts Cdn $6.50 per gj	July 1 - October 31
	2,000 gjpd	Participating Swaps Cdn $5.75 per gj (60% above floor price) (3)	October 1 - October 31
	5,000 gjpd	Participating Swaps Cdn $6.80 per gj (64% above floor price) (3)	November 1 - November 30
	5,000 gjpd	Participating Swaps Cdn $7.00 per gj (max to 80% above floor price) (3)	November 1 - December 31

2005		
Product	**Terms**	**Effective Period**
Foreign Exchange	Purchase US $3,500,000 @ $1.22490 (4)	July
	Sell US $18,500,000 @ $1.23060 (1) (4)	July 1 - November 30
	Sell US $5,874,726 @ $1.23650 (1) (5)	July 1 - October 31

USOGP

2005			
Product	**Volume (Buy)/Sell**	**Terms**	**Remaining Effective Period**
Light Oil	1,000 bpd	Participating Swaps US$45.50 per bbl (70% above floor price) (1) (3)	July 1 – December 31
	500 bpd	Costless collar US$30.00 - $39.80 per bbl	July 1 – December 31
	500 bpd	Costless collar US$30.00 - $39.50 per bbl	July 1 – December 31
	500 bpd	Costless collar US$30.00 - $39.37 per bbl	July 1 – December 31
	500 bpd	Costless collar US$30.00 - $40.00 per bbl	July 1 – December 31
	750 bpd	Puts US$40.00 per bbl	July 1 – December 31
2006			
	500 bpd	Participating Swap US$40.00 per bbl (66% above floor price) (3)	January 1 – December 31
	250 bpd	Puts US$52.00 per bbl	January 1 – December 31

Midstream

2005			
Product	**Volume (Buy)/Sell**	**Terms**	**Remaining Effective Period**
Condensate	3,000 Bpm	US $59.55 per bbl (6)	July 1 – July 31
Propane	27,720 gpd	US $0.85 per usg	July 1 – October 31
	34,239 gpd	US$0.87375 per usg	October 1 - December 31

(1) Represents a number of transactions entered into over an extended period of time.

(2) Natural gas contracts are settled against AECO monthly index.

(3) Provides a floor price while allowing percentage participation above strike price.

(4) US dollar Cashflow

(5) Foreign exchange contracts to hedge underlying exchange rate on Cdn cashflow.

(6) Settled against monthly calendar average for WTI.

Goodwill

Goodwill represents the excess of the cost of an acquired enterprise over the net of the amounts assigned to assets acquired and liabilities assumed**.** Goodwill arose from the acquisitions of Richland Petroleum Corporation ($13.3 million), Meota Resources Corp.($89.1 million) in 2002 and from Olympia Energy Inc.($106.5 million) and Viracocha Energy Inc. ($122.0 million) in 2004.

Goodwill is assessed for impairment at least annually. If impairment exists, it is charged to income in the period in which the impairment occurred. Provident engaged an independent accounting firm to assist in performing an impairment test at the year-ending 2004. The impairment test included, among other variables, a comparison of the net book value of the Trust’s assets to the market value of the Trust’s equity. Goodwill is not amortized.

Liquidity and capital resources

Consolidated					
($ 000s)		**June 30, 2005**		December 31, 2004	% Change
Long-term debt	$	**417,482**	$	432,206	(3)
Working capital deficit		**30,818**		38,677	(20)
Net debt		**448,300**		470,883	(5)
Equity (at book value)		**1,134,719**		1,009,048	12
Total capitalization at book value	$	**1,583,019**	$	1,479,931	7
Net debt as a percentage of total book value capitalization		**28%**		32%	(13)

Provident operates three business units with similar but not identical monthly cash settlement cycles. Provident's working capital position is affected by seasonal fluctuations that reflect commodity price changes, drilling cycles in its oil and gas operations and inventory balances in its midstream business unit. Provident relies on cash flow from operations, external lines of credit and access to equity markets to fund capital programs and acquisitions.

Long-term debt and working capital

As at June 30, 2005, Provident had drawn $210.5 million or 51 percent of its term credit facility of $410 million as compared to $262.8 million or 64 percent drawn on its $410.0 million, term credit facility as at December 31, 2004. The decrease in the level of bank debt was due primarily to the increase in convertible debentures. On March 1, 2005, the Trust issued $100.0 million ($95.8 million net of issue costs) of 7.5 year unsecured convertible debentures with a 6.5 percent coupon rate maturing August 31, 2012. Convertible debentures are classified as long-term debt, excluding a minor equity component.

At June 30, 2005, Provident had letters of credit guaranteeing its performance under certain commercial and other contracts. The letters of credit totaled $24.9 million, increasing bank line utilization to 57 percent. The guarantees totaled $31.0 million at December 31, 2004.

Provident's working capital increased by $7.9 million as at June 30, 2005 relative to Dec. 31, 2004. Of this amount, $4.0 million was due to an increase in accounts receivable, a $6.0 million increase in inventory, $1.7 million in prepaid expenses and a $10.2 million decrease in accounts payable (partially offset by a $1.0 million decrease in deferred derivative losses), a $1.8 million increase in distributions payable, and an $11.2 million increase in financial derivative instruments and other.

Second quarter cash flow in 2005 was $64.4 million. The ratio of debt to annualized second quarter cash flow improved to 1.6 to one, as compared to second quarter 2004 annualized debt to cash flow of 3.0 to one. The 2004 quarter was significantly higher as it included bridge financing related to the Breitburn acquisition that was repaid in July 2004.

Trust units and exchangeable shares

On March 1, 2005, the Trust issued 8.4 million units at a price of $12.00 per unit for proceeds after underwriting fees of $95.6 million, concurrent with the issue of tconvertible debentures noted above. Proceeds from the issue were used to pay down Provident's bank debt and to finance the Nautilus Resources, LLC acquisition and throughout 2005 will be used to finance the company's 2005 capital budget. In the second quarter of 2005, the Trust also issued 1.0 million units (conversion amount $10.4 million) on conversion of exchangeable shares to units. For the quarter ended June 30, 2005 the Trust issued 4.5 million units on conversion of convertible debentures of which 3.5 million units were the result of Provident's redemption of its 10.5 percent series of convertible debentures (2004 - nil) and 1.0 million units associated with conversions related to other debenture series (2004 - nil). An additional 0.9 million units pursuant to the stock option plan were issued for the quarter ended June 30, 2005 (2004 -0.2 million units). Details of these issues are outlined in the notes to the financial statements. Under Provident's Premium Distribution Plan, Distribution Reinvestment Plan (DRIP) and Optional Unit Purchase Plan, 0.8 million units were elected in the second quarter and will be issued or are to be issued, representing proceeds of $9.4 million (2004 - 0.8 million units for proceeds of $8.3 million).

At June 30, 2005, management and directors held approximately 1.6 percent of the outstanding units and exchangeable shares.

Non-controlling interest

(i.) USOGP operations

Non-controlling interest arose from Provident's June 15, 2004 acquisition of 92 percent of BreitBurn Energy of Los Angeles, California. The founders of BreitBurn Energy beneficially own the non-controlling interest, which share in earnings or losses of BreitBurn. The non-controlling interest is reduced by distributions.

Non-controlling interest - USOGP		**Three months ended June 30,**		**Six months ended June 30,**
($ 000s)		**2005**		**2005**
Non-controlling interest, beginning of period	$	**13,355**	$	**13,649**
Net income attributable to non-controlling interest		**504**		**399**
Distributions to non-controlling interest		**(790)**		**(979)**
Non-controlling interest, end of period	$	**13,069**	$	**13,069**
Accumulated income attributable to non-controlling interest	$	**1,322**	$	**1,322**

The non-controlling interest percentage as at June 30, 2005 was approximately 4.4 percent of BreitBurn, which is unchanged from the position as at March 31, 2005 and was eight percent as at June 30, 2004.

(ii.) Exchangeable shares

As at June 30, 2005, the Trust retroactively applied EIC 151 "Exchangeable Securities Issued by a Subsidiary of an Income Trust". The non-controlling interest on the consolidated balance sheet consists of the fair value of the exchangeable shares upon issuance plus the accumulated earnings attributable to the non-controlling interest. The net income attributable to the non-controlling interest on the consolidated statement of operations represents the cumulative share of net income attributable to the non-controlling interest. This is based on the trust units issuable for exchangeable shares in proportion to total trust units issued and issuable at each period end during the period.

Following is a summary of the non-controlling interest exchangeable shares for the quarter and six month period ended June 30, 2005 and 2004:

Non-controlling interest - Exchangeable shares		Three months ended June 30,				Six months ended June 30,		
($ 000s)		**2005[1]**		2004[1]		**2005[1]**		2004[1]
Non-controlling interest, beginning of period	$	**23,059**	$	18,316	$	35,921	$	20,542
Exchangeable shares issued		-		30,264		-		30,264
Reduction of book value for conversion to trust units		**(10,401)**		(2,540)		**(23,207)**		(4,617)
Net income attributable to non-controlling interest		**321**		(163)		**265**		(312)
Non-controlling interest, end of period	$	**12,979**	$	45,877	$	12,979	$	45,877
Accumulated income attributable to non-controlling interest	$	**1,747**	$	712	$	1,747	$	712

(1) Restated - note 2.

The non-controlling interest percentage as at June 30, 2005 was 1.2 percent. This is a decrease from the retroactively applied non-controlling interest percentage as at December 31, 2004 of 2.2 percent. The decrease is attributable to the conversion of exchangeable shares for trust units.

Capital expenditures and funding

Consolidated		Three months ended June 30,					Six months ended June 30,			
($ 000s)		**2005**		2004	% Change		**2005**		2004	% Change
Capital Expenditures										
Capital expenditures and reclamation fund contributions	$	**(37,748)**	$	(12,222)	209	$	(67,620)	$	(24,293)	178
Property acquisitions		-		-	-		-		(4,718)	-
Corporate acquisitions		-		(172,357)	-		**(91,420)**		(172,357)	(47)
Property dispositions		-		705	-		-		7,114	-
Net capital expenditures	$	**(37,748)**	$	(183,874)	(79)	$	(159,040)	$	(194,254)	(18)
Funded By										
Cash flow net of declared distributions to unitholders and non controlling interest	$	**6,644**	$	1,491	346	$	18,857	$	6,724	180
Bridge Financing		-		158,184	-		-		158,184	-
Issue of convertible debentures, net of cost		-		-	-		**95,759**		-	-
Redemption of convertible debentures		**(2,997)**		-	-		**(2,997)**		-	-
Issue of trust units, net of cost; excluding DRIP		**8,888**		2,006	343		**116,006**		50,637	129
DRIP proceeds		**4,878**		3,729	31		**9,307**		8,333	12
Change in working capital, including cash, payment of financial derivative instruments, sale of marketing contracts and investments		**(16,908)**		(12,193)	39		**(25,635)**		(2,581)	893
Increase (decrease) in long-term debt		**37,243**		30,657	21		**(52,257)**		(27,043)	93
Net capital expenditure funding	$	**37,748**	$	183,874	(79)	$	159,040	$	194,254	(18)

For the comparable quarters, Provident has funded its net capital expenditures with cash flow, debt, working capital and equity issued from treasury through public offerings and the Premium DRIP program.

Acquisition

On March 2, 2005, the Trust, through its U.S. subsidiary, acquired Nautilus Resources, LLC for $90.2 million. At that time, $8.1 million was paid to fully satisfy outstanding financial derivative instruments acquired through the Nautilus acquisition. This acquisition was financed through cash mainly raised through a trust unit issue of $95.6 million net of issue costs.

Asset retirement obligation

Consolidated	Three months ended June 30,			Six months ended June 30,		
($ 000s)	**2005**	2004	% Change	**2005**	2004	% Change
Carrying amount, beginning of period	$ **42,350**	$ 33,023	28	$ **40,506**	$ 33,182	22
Oil and gas corporate acquisitions	**-**	-	-	**1,557**	-	-
Increase in liabilities incurred during the period	**331**	11,078	(97)	**452**	11,407	(96)
Settlement of liabilities during the period	**(366)**	(1,604)	77	**(995)**	(2,672)	63
Accretion of liability	**894**	636	41	**1,689**	1,216	39
Carrying amount, end of period	$ **43,209**	$ 43,133	0	$ **43,209**	$ 43,133	-

The asset retirement obligation (ARO) as at June 30, 2005 of $43.2 million was comparable to the position as at June 30, 2004, as accretion on the historical balance was partially offset by ongoing abandonment and reclamation expenditures.

The Trust’s ARO is based on net ownership of wells, facilities and the midstream assets and represents management’s estimate of the costs to abandon and reclaim those wells, facilities and midstream assets, as well as an estimate of the future timing of the costs to be incurred. Estimated cash flows have been discounted at the Trust’s credit-adjusted risk free rate of seven percent and an inflation rate of two percent.

The total undiscounted amount of future cash flows required to settle ARO related to oil and gas operations is estimated to be $140.7 million. Payments to settle oil and gas ARO occur over the operating lives of the assets, estimated to be from two to 55 years.

The total undiscounted amount of future cash flows required to settle the midstream asset retirement obligations is estimated to be $26.1 million. The estimated costs include such activities as dismantling, demolition and disposal of the facilities, as well as remediation and restoration of the surface land. Payments to settle the Midstream AROs are expected to occur subsequent to the closure of the facilities and related assets. Settlement from the balance sheet date of these obligations is expected to occur over 30 to 35 years.

Non-cash general and administrative

Non-cash general and administrative includes expenses or recoveries associated with Provident’s unit option plan and unit appreciation plan. Provident accounts for the unit option plan using the fair value of the option at the time of issue, and it accounts for the unit appreciation plan based on the market price of the Trust units. Compensation expense associated with the options is deferred and recognized in earnings over the vesting period of the options. The Trust recorded an expense of $0.2 million for the quarter ended June 30, 2005 (2004 - recovery of $0.3 million). For the six months ended June 30, 2005, the Trust recorded an expense of $0.5 million (2004 - recovery of $0.7 million). Compensation expense associated with the unit appreciation plan is expensed over the life of the unit appreciation rights. The Trust recorded an expense of $1.5 million for the quarter ended June 30, 2005 (2004 - nil). For the six months ended June 30, 2005, the Trust recorded an expense of $1.9 million (2004 - nil).

Subsequent event

On July 22, 2005, the Trust expanded its existing term credit facility to $572.5 milion from $410.0 million. The new facility comprises of $450.0 million related to its Canadian assets and $122.5 million (US$100.0 million) of lending capacity for its US assets. The facilities are separate, and are supported by separate syndicates of banks. The terms of the new banking agreement are substantially unchanged from the previous agreement.

COGP segment review

Crude oil and liquids price

The following prices are net of transportation expense.

COGP	Three months ended June 30,			Six months ended June 30,		
($ per boe)	**2005**	**2004**	**% Change**	**2005**	**2004**	**% Change**
Realized pricing before hedging						
Light/medium oil	$ **49.02**	$ 42.28	16	**$ 47.48**	$ 40.86	16
Heavy oil	$ **26.03**	$ 28.26	(8)	**$ 25.93**	$ 27.55	(6)
Natural gas liquids	$ **47.67**	$ 40.55	18	**$ 46.39**	$ 38.89	19
Crude oil and natural gas liquids	$ **41.58**	$ 36.29	15	**$ 40.21**	$ 34.75	16

COGP	Three months ended June 30,			Six months ended June 30,		
($ per bbl)	**2005**	2004	% Change	**2005**	2004	% Change
Oil per barrel						
WTI (US$)	$ **53.17**	$ 38.34	39	$ **51.51**	$ 36.75	40
Exchange rate (from US$ to Cdn$)	**1.24**	1.36	(9)	**1.24**	1.34	(7)
WTI expressed in Cdn$	$ **65.93**	$ 52.14	26	$ **63.87**	$ 49.25	30

In the second quarter of 2005, Provident's realized oil and natural gas liquids price, prior to the impact of hedging, increased by 15 percent to $41.58 per barrel compared to $36.29 in the second quarter of 2004. For the six months ended June 30, 2005, the realized oil and natural gas liquids price was $40.21 per barrel, 16 percent above the $34.75 in the comparable period of 2004. The 2005 increase related to a higher US$ WTI crude oil price partially offset by a stronger Canadian dollar and wider differentials on heavy oil pricing relative to WTI. Quarter over quarter ending June 30, 2005 and 2004 Provident reduced its volume of conventional heavy oil as a percentage of total mix from 24 percent in 2004 to 17 percent in 2005. This is a result of the Viracocha and Olympia acquisitions of light/medium oil and natural gas, and declines in production in Provident's heavy oil areas.

Natural gas price

The following prices are net of transportation expense.

COGP	Three months ended June 30,			Six months ended June 30,		
($ per mcf)	**2005**	2004	% Change	**2005**	2004	% Change
AECO monthly index (Cdn$) per mcf	$ **7.35**	$ 6.80	8	$ **7.11**	$ 6.70	6
Corporate natural gas price per mcf before hedging (Cdn$)	$ **7.28**	$ 7.01	4	$ **7.01**	$ 6.71	4

Provident's second quarter 2005 realized natural gas price, excluding hedges, increased four percent as compared to the second quarter of 2004, slightly more unfavorable than the increase in the benchmark AECO index price of eight percent. For the six months ended June 30, 2005 the realized natural gas price, excluding hedges, increased eight percent to $7.01 per thousand cubic feet (mcf) from $6.71 in the same period of 2004.

Production

COGP	Three months ended June 30,			Six months ended June 30,		
	2005	2004	% Change	**2005**	2004	% Change
Daily production						
Crude oil - Light/Medium (bpd)	**8,536**	7,861	9	**8,649**	6,913	25
- Heavy (bpd)	**4,644**	6,537	(29)	**5,093**	6,563	(22)
Natural gas liquids (bpd)	**1,436**	1,267	13	**1,586**	1,198	32
Natural gas (mcfd)	**76,606**	68,007	13	**77,483**	65,933	18
Oil equivalent (boed) (1)	**27,384**	27,000	1	**28,242**	25,663	10

(1) Provident reports equivalent production converting natural gas to oil on a 6:1 basis.

Production increased one percent to 27,384 bpd during the second quarter of 2005 as compared to 27,000 bpd in 2004. For the six months ended June 30, 2005, production increased 10 percent to 28,242 bpd as compared to 25,663 bpd for the comparable period of 2004. The increase reflects the acquisition of Olympia and Viracocha to the COGP production base as well as drilling and optimization activities partially offset by natural production declines.

Production for the second quarter of 2005 was weighted 47 percent natural gas, 17 percent heavy oil, 36 percent medium/light crude oil and natural gas liquids. Production over the six months ended June 30, 2005 was weighted 46 percent natural gas, 18 percent heavy oil and 36 percent medium/light crude oil and natural gas liquids. Provident mitigates its production risk by not having any single property providing greater than 10 percent of daily production.

Provident's COGP production summarized by core areas is as follows:

COGP

Three months ended June 30, 2005	Lloydminister	West Central Alberta	Southern Alberta	Southern Saskatchewan	Other	**Total**
Daily production						
Crude oil - Light/Medium (bpd)	1,555	1,384	2,900	2,694	3	**8,536**
- Heavy (bpd)	4,644	-	-	-	-	**4,644**
Natural gas liquids (bpd)	15	1,251	168	1	1	**1,436**
Natural gas (mcfd)	2,093	39,996	29,006	5,478	33	**76,606**
Oil equivalent (boed) (1)	6,564	9,301	7,902	3,608	9	**27,384**

COGP

Three months ended June 30, 2004	Lloydminister	West Central Alberta	Southern Alberta	Southern Saskatchewan	Other(2)	Total
Daily production						
Crude oil - Light/Medium (bpd)	328	1,202	2,964	2,824	543	7,861
- Heavy (bpd)	6,451	-	86	-	-	6,537
Natural gas liquids (bpd)	21	1,120	110	5	11	1,267
Natural gas (mcfd)	2,238	43,069	19,677	2,696	327	68,007
Oil equivalent (boed) (1)	7,174	9,504	6,438	3,278	606	27,000

(1) Provident reports equivalent production converting natural gas to oil on a 6:1 basis.

(2) Includes USOGP production for the 15 day period ended June 30, 2004.

COGP

Six months ended June 30, 2005	Lloydminister	West Central Alberta	Southern Alberta	Southern Saskatchewan	Other	Total
Daily production						
Crude oil - Light/Medium (bpd)	1,586	1,425	2,877	2,748	13	**8,649**
- Heavy (bpd)	5,093	-	-	-	-	**5,093**
Natural gas liquids (bpd)	15	1,419	150	1	1	**1,586**
Natural gas (mcfd)	2,123	41,472	28,763	5,093	32	**77,483**
Oil equivalent (boed) (1)	7,048	9,756	7,821	3,598	19	**28,242**

COGP

Six months ended June 30, 2004	Lloydminister	West Central Alberta	Southern Alberta	Southern Saskatchewan	Other(2)	Total
Daily production						
Crude oil - Light/Medium (bpd)	164	1,239	2,424	2,814	272	6,913
- Heavy (bpd)	6,520	-	43	-	-	6,563
Natural gas liquids (bpd)	11	1,077	104	2	4	1,198
Natural gas (mcfd)	1,961	40,461	20,691	2,627	193	65,933
Oil equivalent (boed) (1)	7,021	9,059	6,020	3,254	309	25,663

(1) Provident reports equivalent production converting natural gas to oil on a 6:1 basis.
(2) Includes USOGP production.

Internal development activities included 34.6 net drills during the quarter ended June 30, 2005. Provident’s most active area, Southern Saskatchewan realized 27.0 net drills. The focus of Southern Saskatchewan is a shallow gas drilling program that will realize production and reserve adds for several years. Poor weather conditions have delayed tie-in operations. However, Provident is currently placing these wells on production. Provident’s other areas remain active with additional activity in Lloydminster, where Provident is drilling low risk heavy oil wells and also in Southern Alberta where Provident is actively drilling shallow gas wells. In West Central Alberta, Provident continues with its strategy of farming out high risk exploration land to fully optimize its high risk exploration land.

Provident expects COGP production for the full year of 2005 to average between 27,000 boed and 28,000 boed for 2005.

Revenue and royalties

Revenue figures are presented net of transportation expense.

COGP	Three months ended June 30,				Six months ended June 30,		
($ 000s except per boe data)	**2005**	2004	2004	% Change	**2005**	2004	% Change
Oil							
Revenue	$ **49,076**		$ 47,056	4	**$ 98,229**	$ 84,313	17
Realized loss on non-hedging derivative instruments	**(9,723)**		(11,778)	(17)	**(17,999)**	(21,174)	(15)
Royalties (net of ARTC)	**(10,263)**		(9,505)	8	**(19,186)**	(16,776)	14
Net revenue	$ **29,090**		$ 25,773	13	**$ 61,044**	$ 46,363	32
Net revenue (per barrel)	$ **24.25**		$ 19.67	23	**$ 24.54**	$ 18.90	30
Royalties as a percentage of revenue	**20.9%**		20.2%		**19.5%**	19.9%	
Natural gas							
Revenue	$ **50,718**		$ 43,357	17	**$ 98,348**	$ 80,495	22
Realized loss on non-hedging derivative instruments	**(1,112)**		(4,590)	(76)	**(1,295)**	(5,035)	(74)
Royalties (net of ARTC)	**(11,001)**		(9,322)	18	**(21,239)**	(16,292)	(100)
Net revenue	$ **38,605**		$ 29,445	31	**$ 75,814**	$ 59,168	28
Net revenue (per mcf)	$ **5.54**		$ 4.76	16	**$ 5.41**	$ 4.93	10
Royalties as a percentage of revenue	**21.7 %**		21.5%		**21.6%**	20.2%	
Natural gas liquids							
Revenue	$ **6,230**		$ 4,674	33	**$ 13,318**	$ 8,482	57
Royalties	**(1,551)**		(1,360)	14	**(3,059)**	(2,362)	30
Net revenue	$ 4,679		$ 3,314	41	**$ 10,259**	$ 6,120	68
Net revenue (per barrel)	$ **35.81**		$ 28.74	25	**$ 35.74**	$ 28.07	27
Royalties as a percentage of revenue	**24.9 %**		29.1%		**23.0%**	27.9%	
Total							
Revenue	$ **106,024**		$ 95,087	12	**$ 209,895**	$ 173,290	21
Realized loss on non-hedging derivative instruments	**(10,835)**		(16,368)	(34)	**(19,294)**	(26,209)	(26)
Royalties (net of ARTC)	**(22,815)**		(20,187)	13	**(43,484)**	(35,430)	23
Net revenue	$ **72,374**		$ 58,532	24	**$ 147,117**	$ 111,651	32
Net revenue per boe	$ **29.04**		$ 23.82	22	**$ 28.78**	$ 23.90	20
Royalties as a percentage of revenue	**21.5 %**		21.2%		**20.7%**	20.4%	

Note: the above figures are presented net of transportation expenses.

Quarter over quarter, 2005 COGP production revenue was $106.0 million, an increase of 12 percent from $95.1 million in 2004. The increase in revenue incorporates a one percent increase in production volumes and a 15 percent increase in Provident's realized crude oil and natural gas liquids price. Royalties, which are price sensitive, increased as a percentage of revenue to 21.5 percent in the second quarter of 2005 from 21.2 percent for the comparable quarter in 2004. The preceding factors, as well as the opportunity cost of hedging activities, account for net revenue of $72.4 million in the second quarter of 2005, 24 percent above the $58.5 million recorded in the second quarter of 2004. For the six months ended June 30, 2005 net revenue was $147.1 million, 32 percent above the $111.7 million recorded in the same period of 2004.

Production expenses

COGP		Three months ended June 30,				Six months ended June 30,		
(000s, except per boe data)		**2005**	2004	% change		**2005**	2004	% change
Production expenses	$	**22,272**	$ 19,402	15	$	**47,892**	$ 37,906	26
Production expenses (per boe)	$	**8.94**	$ 7.90	13	$	**9.37**	$ 8.12	15

Second quarter 2005 production expenses increased 15 percent to $22.3 million from $19.4 million in the comparable 2004 quarter. For the six months ended June 30, 2005, production expenses increased 26 percent to $ 47.9 million from $37.9 million in the comparable 2004 period. The increase coincides with the equivalent increase in production volumes as a result of the Olympia and Viracocha acquisitions. However, on a boe basis quarter-over-quarter production expenses have risen to $8.94 per boe, which is a 13 percent increase when compared to $7.90 per boe in the comparable 2004 quarter. Operating expenses increased in a number of categories including well servicing, maintenance, fluid hauling, and power and fuel. Poor weather conditions experienced during the 2005 second quarter resulted in additional maintenance and hauling costs. In addition, costs increases in power and fuel, and well servicing occurred due to higher commodity prices and labour costs.

Based on the current high commodity price environment and increased levels of activity, Provident expects Canadian operating costs to average $9.50 per boe to $9.90 per boe for 2005. Commodity prices affect the demand for services. If commodity prices increase, Provident expects the price of services and labour to increase.

Operating netback

COGP		Three months ended June 30,				Six months ended June 30,		
($ per boe)		**2005**	2004	% change		**2005**	2004	% change
COGP oil equivalent netback per boe								
Gross production revenue	$	**42.55**	$ 38.70	10	$	**41.06**	$ 37.10	11
Royalties (net of ARTC)		**(9.16)**	(8.22)	11		**(8.51)**	(7.59)	12
Operating costs		**(8.94)**	(7.90)	13		**(9.37)**	(8.12)	15
Field operating netback	$	**24.45**	$ 22.58	8	$	**23.18**	$ 21.39	8
Realized loss on cash hedging		**(4.35)**	(6.66)	(35)		**(3.77)**	(5.61)	(33)
Operating netback after hedging	$	**20.10**	$ 15.92	26	$	**19.41**	$ 15.78	23

COGP operating netbacks have transportation expense netted against gross production revenue.

Second quarter 2005 field operating netback of $24.45 per boe was eight percent above the $22.58 per boe operating netback in the same quarter in 2004. Year-to-date field operating netback of $23.18 per boe was eight percent above the field operating netback for the same period in 2004. The increased field operating netback in the second quarter and year-to-date in 2005, reflects a higher WTI crude oil benchmark and a significant shift in Provident’s production mix, which includes a greater weighting towards natural gas and lighter grades of crude oil, partially offset by wider differentials and increases in royalties and operating costs. Operating netbacks after hedging increased by 26 percent to $20.10 from $15.92 for the quarter, and by 23 percent to $19.41 from $15.78 year-to-date. The increase reflects second quarter opportunity costs, due to hedging of $4.35 per boe compared to $6.66 in the comparable quarter in 2004. For the six months ended June 30, 2005, opportunity costs due to hedging were $3.77 per boe (2004 comparable period was $5.61 per boe).

Netbacks by product for crude oil and NGL's and natural gas are as follows:

COGP	Three months ended June 30,			Six months ended June 30,		
($ per bbl)	**2005**	2004	% change	**2005**	2004	% change
COGP crude oil and NGL's netback per bbl						
Gross production revenue	$ **41.58**	$ 36.29	15	$ **40.21**	$ 34.75	16
Royalties (net of ARTC)	**(8.87)**	(7.62)	16	**(8.02)**	(7.17)	12
Operating costs	**(9.90)**	(9.05)	9	**(10.40)**	(9.15)	14
Field operating netback	**22.81**	19.62	16	**21.79**	18.43	18
Realized loss on cash hedging	**(7.30)**	(8.26)	(12)	**(6.49)**	(7.93)	(18)
Operating netback after hedging	$ **15.51**	$ 11.36	37	$ **15.30**	$ 10.50	46

COGP	Three months ended June 30,			Six months ended June 30,		
($ per mcf)	**2005**	2004	% change	**2005**	2004	% change
COGP natural gas netback per mcf						
Gross production revenue	$ **7.28**	$ 7.01	4	$ **7.01**	$ 6.71	4
Royalties (net of ARTC)	**(1.58)**	(1.51)	5	**(1.51)**	(1.36)	11
Operating costs	**(1.30)**	(1.05)	24	**(1.36)**	(1.12)	21
Field operating netback	**4.40**	4.45	(1)	**4.14**	4.23	(2)
Realized loss on cash hedging	**(0.16)**	(0.74)	(78)	**(0.09)**	(0.42)	(79)
Operating netback after hedging	$ **4.24**	$ 3.71	14	$ **4.05**	$ 3.81	6

General and administrative

The following table does not incorporate the COGP portion of non-cash general and administrative expenses associated with Provident's unit option plan. Second quarter non-cash general and administrative expenses for COGP totaled $0.2 million for the 5.6 million options granted on or after January 1, 2004 compared to a recovery of $0.3 million in the comparable period. For the six months ended June 30, 2005 the non-cash and general and administrative expenses for COGP totaled $0.5 million compared to a $0.6 million recovery in the same period of 2004.

COGP	Three months ended June 30,			Six months ended June 30,		
($ 000s, except per boe data)	**2005**	2004	% change	**2005**	2004	% change
Cash general and administrative	$ **4,965**	$ 4,246	17	$ **9,448**	$ 8,632	9
Cash general and administrative per boe	$ **1.99**	$ 1.73	15	$ **1.85**	$ 1.85	-

Cash general and administrative expenses for COGP in the second quarter increased 17 percent to $5.0 million from $4.2 million in the 2004 comparable quarter. On a boe basis the cash general and administrative expenses in the second quarter 2005 increased 15 percent to $1.99 from $1.73 in the second quarter of 2004. On a year-to-date basis for both 2005 and 2004, the cash general and administrative charge was $1.85 per boe.

The Canadian operations are capable of absorbing additional production, particularly in existing core areas, with little impact on general and administrative expenses. For 2005, costs per boe are forecast to increase as a result of further increases in costs associated with compliance (including costs associated with the implementation of procedures and documentation to be in compliance with the U. S. Sarbanes-Oxley Act), and of a more competitive landscape impacting the cost of hiring and compensating employees.

Capital expenditures

COGP	Three months ended June 30,		Six months ended June 30,	
($000s)	**2005**	2004	**2005**	2004
Capital expenditures				
Lloydminster	$ **3,021**	$ 711	$ **3,963**	$ 1,211
West central and southern Alberta	**7,488**	5,597	**13,127**	7,787
Southeast and southwest Saskatchewan	**10,115**	4,348	**16,872**	12,098
Office and other	**402**	582	**1,312**	1,122
Total additions	$ **21,026**	$ 11,238	$ **35,274**	$ 22,218
Property acquisitions	**-**	-	**-**	4,718
Property dispositions	$ **-**	$ 705	$ **-**	$ 7,114

In the second quarter of 2005, COGP spent $3.0 million in the Lloydminster area primarily on drilling (2.8 million) and facility work ($0.2 million). In West Central Alberta $3.7 million was spent largely on non-operated drilling ($1.4 million) and facility work ($2.5 million) partially offset by seismic sales ($0.2 million). In Southern Alberta $3.8 million was spent on drilling activities and recompletions ($1.2 million), facility upgrades ($2.2 million) and seismic and mineral rights acquisitions ($0.4 million). Provident spent $10.1 million in the Southeast and Southwest Saskatchewan core areas on acquiring mineral rights for future development ($1.1 million), drilling for shallow gas and recompletions ($3.8 million), facility work ($5.2 million), and office and other items accounted for $0.4 million of capital.

In the first six months of 2005, asset dispositions of non-core assets totaled nil compared to $4.7 million in the first six months period of 2004. Provident will seek to dispose of its non-core properties given the competitive property market.

The 2005 COGP capital budget is $78.8 million.

Depletion, depreciation and accretion (DD&A)

COGP	Three months ended June 30,			Six months ended June 30,		
($000s, except per boe data)	**2005**	2004	% change	**2005**	2004	% change
DD&A	$ **41,206**	$ 36,746	12	$ **82,757**	$ 68,899	20
DD&A per boe	$ **16.54**	$ 14.96	11	$ **16.19**	$ 14.75	10

The COGP DD&A of $16.54 per boe increased 11 percent for the second quarter of 2005 compared to $14.96 per boe for the second quarter of 2004. The increase is mainly due to the cost of acquiring proved reserves late in the second quarter of 2004. The reserves are in western Canada, where reserve costs have escalated along with higher commodity prices. The proved reserves acquired in 2004 were acquired at a higher cost per boe than Provident's historical asset base, resulting in a higher per boe DD&A charge going forward.

In the second quarter of 2005, accretion expense associated with AROs of $0.6 million compared to $0.6 million in the comparable period of 2004. For the six months ended June 30, 2005, the accretion expense was $1.3 million compared to $1.2 million in the comparable period of 2004.

USOGP segment review

The USOGP business unit incorporates activities from Provident's subsidiary, Breitburn Energy LP (Breitburn), an oil and gas exploitation and production business based in Los Angeles, California. Breitburn was purchased June 15, 2004 and, therefore results for the 15 days ended June 30, 2004 are immaterial. For this reason, comparative discussion and analysis is not included for that period.

On March 2, 2005 Breitburn acquired Nautilus Resources, LLC, a U.S. private company with operations focused in the Big Horn and Wind River basins of Wyoming, for cash consideration of $90.2 million.

USOGP pricing

USOGP	Three months ended June 30,	Six months ended June 30,
	2005	2005
Realized pricing before hedging		
Light/medium oil and natural gas liquids (Cdn$ per bbl)	$ **53.29**	$ 53.60
Natural Gas (Cdn $ per mcf)	$ **7.74**	$ 7.46

The majority of USOGP oil production is light, sweet crude that attracts smaller differentials to benchmark prices relative to heavier blends. The oil production from the recently acquired Nautilus properties is heavier and attracts slightly wider differentials. Production from the former Nautilus properties represents approximately 31 percent of second quarter production.

Production

USOGP	Three months ended June 30,	Six months ended June 30,
	2005	2005
Daily production		
Crude oil - Light/Medium (bpd)	**7,355**	6,495
Natural gas liquids (bpd)	**18**	18
Natural gas (mcfd)	**2,520**	2,309
Oil equivalent (boed) [1]	**7,793**	6,898

(1) Provident reports equivalent production converting natural gas to oil on a 6:1 basis.

USOGP production increased 1,801 boed or 30 percent to 7,793 in the second quarter of 2005 when compared to the first quarter of 2005. The increase is primarily attributable to the first full quarter of production from the Nautilus properties acquired on March 2, 2005. In total, the Nautilus properties added 2,400 boed to production in the second quarter. Production from the California properties saw modest gains in the second quarter when compared to the first quarter of 2005.

USOGP production for the remainder of the year is expected to average between 7,700 boed and 8,200 boed.

Revenue and royalties

The following table outlines USOGP revenue and royalties by product line. The table excludes revenues earned from operating certain properties ($0.3 million in the second quarter of 2005 and $0.5 million in the six months ended June 30, 2005) on behalf of third parties.

USOGP		Three months ended June 30,Three months ended June 30,		Six months ended June 30,
($ 000s, except per boe amounts)		**2005**		2005
Oil				
Revenue	$	**35,669**	$	63,023
Realized loss on non-hedging derivative instrument		**(3,314)**		(5,668)
Royalties		**(3,491)**		(5,968)
Net revenue	$	**28,864**	$	51,387
Net revenue (per bbl)	$	**43.12**	$	43.71
Royalties as a percentage of revenue		**9.8%**		9.5%
Natural gas				
Revenue	$	**1,775**	$	3,118
Royalties		**(245)**		(431)
Net revenue	$	**1,530**	$	2,687
Net revenue (per mcf)	$	**6.67**	$	6.43
Royalties as a percentage of revenue		**13.8%**		13.8%
Natural gas liquids				
Revenue	$	**87**	$	158
Royalties		**(2)**		(4)
Net revenue	$	**85**	$	154
Net revenue (per bbl)	$	**51.83**	$	47.24
Royalties as a percentage of revenue		**2.3%**		2.5%
Total				
Revenue	$	**37,531**	$	66,299
Realized loss on non-hedging derivative instrument		**(3,314)**		(5,668)
Royalties		**(3,738)**		(6,403)
Net revenue	$	**30,479**	$	54,228
Net revenue (per boe)	$	**42.98**	$	43.43
Royalties as a percentage of revenue		**10.0%**		9.7%

Royalty rates in the U.S. are significantly lower than in Canada.

Production expenses

USOGP		Three months ended June 30,		Six months ended June 30,
($ 000s, except per boe amounts)		**2005**		2005
Production expenses	$	**9,925**	$	17,351
Production expenses (per boe)	$	**14.00**	$	13.90

Production expenses were $14.00 per boe in the second quarter of 2005, up $0.23 per boe or two percent from the first quarter of 2005. Continuing strong crude oil prices have resulted in USOGP field operations continuing to focus on a return to production or to maintain production on wells with higher operating costs. Year-to-date operating costs of $13.90 per boe are 11 percent below the $15.62 per boe incurred in the period from June 15 to December 31, 2004. USOGP operating costs for the remainder of 2005 are expected to improve to an average of $13.50 to $14.00 per boe.

General and administrative

The following table does not incorporate the USOGP portion of non-cash general and administrative charges associated with the USOGP unit appreciation rights plan (first quarter 2005 - $1.5 million). Year-to-date non-cash expenses of $1.9 million have been recorded for the unit appreciation rights plan.

	Three months ended June 30,		Six months ended June 30,	
USOGP				
($ 000s, except per boe amounts)		**2005**		2005
Cash general and administrative	$	**2,324**	$	4,095
Cash general and administrative per boe	$	**3.28**	$	3.28

Cash and general administrative expenses were $2.3 million or $3.28 per boe in the second quarter of 2005 and on a boe basis remains the same as the first quarter of 2005. The addition of Nautilus on March 2, 2005 was absorbed without a significant increase in general and administrative expenses however costs associated with compliance (including costs associated with the implementation of procedures and documentation required to be in compliance with the U. S. Sarbanes-Oxley Act) and a more competitive landscape impacting the cost of hiring and compensating employees continue to put upward pressure on general and administrative costs.

Year-to-date, general and administrative expenses of $3.28 per boe were $1.57 per boe, or 32 percent lower than the $4.85 per boe incurred in the period from June 15 to December 31, 2004. This is primarily due to the addition of Orcutt on October 4, 2004 and the addition of Nautilus on March 2, 2005. The acquisitions added in excess of 3,700 boed of production without a significant increase in general and administrative expenses.

Operating netback

	Three months ended June 30,		Six months ended June 30,	
USOGP				
(000's) except per unit amounts		**2005**		2005
USOGP oil equivalent netback per boe				
Gross production revenue	$	**52.92**	$$	53.10
Royalties		**(5.27)**		($5.13)
Operating costs		**(14.00)**		($13.90)
Field Operating Netback	$	**33.65**	$$	34.07
Cash hedging		**(4.67)**		($4.54)
Operating netback after hedging	$	**28.98**	$$	29.53

Operating netbacks in the second quarter of 2005 remain strong. They are driven by high commodity prices partially offset by increased production costs and opportunity costs associated with hedge activities.

USOGP ($ per bbl)	Three months ended June 30, 2005	Six months ended June 30, 2005
USOGP crude oil and NGL's netback per bbl		
Gross production revenue	$ **53.29**	$ 53.60
Royalties	**(5.21)**	(5.07)
Operating costs	**(13.99)**	(13.90)
Field Operating Netback	$ **34.09**	$ 34.63
Cash hedging	**(4.94)**	(4.81)
Operating netback after hedging	$ **29.15**	$ 29.82

USOGP ($ per mcf)	Three months ended June 30, 2005	Six months ended June 30, 2005
USOGP natural gas netback per mcf		
Gross production revenue	$ **7.74**	7.46
Royalties	**(1.07)**	(1.03)
Operating costs	**(2.33)**	(2.32)
Field and Operating Netback	$ **4.34**	4.11

Operating netbacks in the second quarter of 2005 remain strong driven by high commodity prices.

Capital expenditures

USOGP capital expenditures, excluding corporate acquisitions, for the second quarter of 2005 totaled $15.3 million. Of the total, $9.5 million was directed at drilling, optimization and facility upgrades at West Pico, Santa Fe Springs and Orcutt. As well, $3.8 million was directed to the purchase of real estate adjacent to the West Pico facility. At the newly acquired Nautilus fields in Wyoming, $1.1 million was directed at optimization projects with a further $0.9 million directed at optimization projects at smaller fields and office equipment. A significant portion of optimization capital was directed at improvements to infrastructure, aimed at reducing future operating expenses. In addition, optimization capital continues to incorporate returning previously uneconomic wells to production, to take advantage of high oil prices.

For the six months ended June 30, 2005, capital expenditures, excluding corporate acquisitions, totaled $30.2 million. Of the total, $23.6 million was directed at drilling, optimization and facility upgrades at West Pico, Santa Fe Springs and Orcutt, $3.7 million was directed to the purchase of real estate adjacent to the West Pico site, $1.1 million was directed at optimization projects at the newly acquired Nautilus fields and $1.8 million was directed at optimization projects at smaller fields and office equipment.

The March 2, 2005 corporate acquisitions of Nautilus added $99.9 million to property, plant and equipment for the six months ended June 30, 2005. The capital budget for 2005, excluding corporate acquisitions, is $46.0 million.

Depletion, depreciation and accretion (DD&A)

USOGP ($ 000s, except per boe amounts)	Three months ended June 30, 2005	Six months ended June 30, 2005
DD&A	$ **6,677**	$ 11,784
DD&A per boe	$ **9.42**	$ 9.44

The USOGP’s DD&A rate is low due to the long-lived nature of the assets.

Midstream segment review

The assets

Midstream processes natural gas liquids (NGL) at the Redwater fractionation, storage and transportation facility located near Edmonton, Alberta. The integrated Redwater system is comprised of three core assets:

- 100 percent ownership of the Redwater NGL Fractionation Facility, a 65,000 barrel per day (bbl/d) fractionation, storage and transportation facility that includes 12 pipeline receipt and delivery points, railcar loading facilities with direct access to CN and CP rail, two propane truck loading facilities, and six million gross barrels of salt cavern storage. The facility can process high-sulphur NGL streams and is one of only two facilities in western Canada capable of extracting ethane from the natural gas liquids stream.

- 43.3 percent ownership of the 38,500 bbl/d Younger NGL extraction plant located at Taylor in northeastern British Columbia. The plant supplies 16,700 bbl/d of net NGLs for processing at Redwater.

- 100 percent ownership of the 565 kilometer proprietary Liquids Gathering System (LGS) that runs along the Alberta-British Columbia border, and provides access to a highly active basin for liquids-rich natural gas exploration and exploitation. Provident also has long-term shipping rights on the Pembina Peace Pipeline. These rights extend Provident’s product delivery transportation network through to the Redwater facility.

The majority of the property, plant and equipment are depreciated over 30 years on a straight-line basis reflecting the long useful life of these assets.

Midstream and marketing services

Provident’s midstream services offer customers several types of services and contractual arrangements, which include:

Fee-for-service processing - (Transportation and Fractionation - T&F) In these arrangements, NGL owners (typically natural gas producers) deliver to Provident their NGLs and pay fees for the transportation, fractionation, short term storage and distribution of their NGL barrels. The NGL owners are responsible for marketing their product.

Marketing Services: This service involves NGL owners delivering their product to Provident with Provident taking title and paying the NGL owner an amount that is a delivery price of raw NGLs that is discounted to postings. The discounted purchase price that Provident pays for the product covers the costs of transportation, fractionation, storage, and marketing of the NGLs.

Storage: NGL owners pay fees to store their NGLs.

Transport and Distribution: NGL owners or purchasers pay fees to transport NGLs through the LGS pipeline and use rail and truck loading facilities.

The contracts

At the Redwater facility, approximately 75 percent of the available capacity is contracted through fee-for-service or fixed margin arrangements with major oil and natural gas producers and petrochemical businesses. As a result of these contracts, approximately 68 percent of Redwater’s system capacity is contracted for 10 years or longer.

Fractionation plant capacity and throughput

The Redwater facility was constructed between 1996 and 1998. It is the most modern facility of its kind in Canada and currently has a throughput capacity of 65,000 bpd of NGLs with an expectation to average approximately 63,000 bpd over the year.

Operations - throughput

Second quarter 2005 throughput at the Redwater facility averaged 52,175 bpd, which reflects a 10-day shutdown for annual plant maintenance in May. Throughput in the second quarter of 2004 was 48,452 bpd which was impacted by a constricted supply of NGL mix as a result of a third party pipeline shutdown during the quarter. Year-to-date throughput averaged 55,322 bpd compared to 58,945 bpd for the first six months of 2004. Midstream managed an average of 58,200 bpd in the second quarter of 2005 as compared to 50,835 in the second quarter of 2004 (2005 year-to-date amount is 59,205 bpd compared to 59,336 bpd in 2004).

Revenues

For the second quarter of 2005 product sales and services revenues are $186.6 million and year-to-date, they are $431.5 million. These revenue have been calculated after the elimination of intersegment transactions, including product sales related to T&F processing and marketing, revenues generated through storage and distribution services, and oil sales generated through oil marketing activities. The majority of NGL revenues are earned pursuant to the long-term contracts and annual evergreen purchase and sales commitments.

Cost of goods sold

The cost of goods sold is $164.2 million and $383.8 million after elimination of intersegment transactions for the quarter, and for the six months ended June 30, 2005, respectively. These costs relate to NGL product sales revenue included in the product sales and services revenue, where Provident has purchased natural gas liquids. These costs also relate to oil purchased pursuant to oil marketing activities. The NGL costs would be applicable to the T&F and marketing contracts, as well as to a small percentage of volume delivered from the Younger facility on which Provident retains fractionation risk. The majority of the natural gas liquids are purchased pursuant to long-term contracts and annual evergreen purchase commitments.

Other expenses

The plant has modern technology and low cost operations. Second quarter 2005 operating costs are $8.7 million, and six months ended June 30, 2005 are $16.1 million (quarter and six months ended June 30, 2004 - $10.8 million and $19.9 million respectively) represent normal operations. General and administrative expenses is $2.1million for the second quarter 2005 (2004 - $1.5 million), interest is $1.4 million for 2005 (2004 - $2.2 million), and depreciation of $2.5 million for 2005 (2004 - $2.3 million).

Earnings before interest, taxes, depletion, depreciation, accretion, and non-cash revenue (EBITDA) and cash flow from operations

Midstream second quarter 2005 results reflected in EBITDA, cash flow and net income benefited from a continuation of efficient operations, marketing opportunities and increased revenues associated with storage and distribution services. Second quarter 2005 EBITDA of $11.8 million increased $2.9 million or 32 percent from $8.9 million in the second quarter of 2004. For the six months ended June 30, 2005, EBITDA of $28.1 million increased $7.0 million or 33 percent from $21.1 million in the comparable 2004 period. Cash flow for the second quarter of 2005 was $10.6 million, an increase of $3.7 million or 52 percent above the $6.9 million for the second quarter 2004. For the six months ended June 30, 2005 cash flow was $25.8 million, an increase of $9.0 million or 53 percent above the $16.8 million for the comparable period of 2004. Second quarter net income at $12.1 million was 195 percent above the $4.1 million of net income recorded in the second quarter of 2004.

Management's 2005 forecast for Midstream EBITDA is $42.0 - $46.0 million.

Management uses EBITDA to analyze the operating performance of the Midstream business unit. EBITDA 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 for other entities. EBITDA 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 EBITDA throughout this report are based on Earnings before interest, taxes, depletion, depreciation, accretion, and non-cash revenue (EBITDA).

Gain on sale of marketing contracts

On May 1, 2005, the Trust disposed of certain marketing contracts for net proceeds of $5.5 million and recorded a gain of $5.2 million net of disposal costs. The sale of these contracts will not materially impact cash flows and has been recognized through Midstream. During 2004, the marketing business generated $203.0 million in revenues. For the four months period ended April 30, 2005 the marketing business generated $105.7 million in revenues. The sale of these contracts is not expected to have a material impact on the cash flow or net income of Midstream.

Distributions

The following table summarizes distributions paid or declared by the Trust since inception:

Record Date	Payment Date		Distribution Amount (Cdn$)	(US$)*
2005				
January 20, 2005	February 15, 2005	$	0.12	0.10
February 18, 2005	March 15, 2005		0.12	0.10
March 21, 2005	April 15, 2005		0.12	0.10
April 20, 2005	May 13, 2005		0.12	0.10
May 19, 2005	June 15, 2005		0.12	0.10
June 20, 2005	July 15, 2005		0.12	0.10
Q1 2005 Cash Distributions paid as declared		$	0.72	0.60
2004 Cash Distributions paid as declared			1.44	1.10
2003 Cash Distributions paid as declared			2.06	1.47
2002 Cash Distributions paid as declared			2.03	1.29
2001 Cash Distributions paid as declared – March 2001 – December 2001			2.54	1.64
Inception to June 30, 2005 – Distributions paid as declared		$	8.79	6.10

*exchange rate based on the Bank of Canada noon rate on the payment date.

For Canadian tax purposes, 2004 distributions were determined to be 71 percent taxable and 29 percent a tax deferred return of capital in the hands of Canadian unitholders. Distributions received by U.S. resident unitholders in 2004 were classified as 83 percent qualified dividend and 17 percent tax deferred return of capital. In both the Canada and the U.S., the tax-deferred portion of the distribution would usually be treated as an adjustment to the cost base of the units. Unitholders or potential unitholders should consult their own legal or tax advisors as to their particular income tax consequences of holding Provident units.

Foreign ownership

As at June 2005, based on information received from the transfer agent and financial intermediaries, an estimated 85 percent of Provident’s outstanding trust units are held by non-residents. However, this estimate may not be accurate as it is based on certain assumptions and data (from the security industry) that are not derived from clear methods of determining the residency of beneficial securities holders. Since January 2002, Provident has seen increased trading volumes and levels of ownership by non-residents of Canada.

In March 2004, the Canadian government announced that it would change current legislation to ensure that all mutual fund trusts, including resources trusts, would be subject to a minimum 50 per cent Canadian ownership standard and that there would be withholding taxes on all distributions to non-residents of Canada. The specific legislation, providing the details of the changes, was tabled on September 16, 2004. These changes would have required that Provident have no more than 50 percent foreign ownership by January 1, 2007.

In December 2004, Canada’s Minister of Finance tabled a Notice of Ways and Means Motion to Implement Budget 2004 Measures (the Notice). The Notice does not include restrictions upon foreign ownership of mutual fund trusts as was previously proposed in draft legislation on September 16, 2004. Under the terms of the Notice, non-resident taxable and non-resident tax-exempt accounts will have tax withheld by the Canadian government on the entire distribution, including the return of capital and return on capital portions. The Notice is effective January 1, 2005.

On September 17, 2003 Canadian unitholders approved an amendment to the Trust's Trust Indenture providing that residency restriction provisions need not be enforced while the Trust continues to qualify as a Mutual Fund Trust under Canadian tax legislation.

The Trust qualifies as a Mutual Fund Trust under the Canadian Income Tax Act because substantially all the value of its asset portfolio is derived from non-taxable Canadian properties, comprised principally of royalties and inter-company debt. To allow Provident to remain a Mutual Fund Trust and to execute a business plan that maximizes unitholder returns without regard to the types of assets the Trust may hold, the approved amendment provides for Provident's board of directors to have sole discretion in determining whether and when it is appropriate to reduce or limit the number of trust units held by non-residents of Canada.

Business prospects

Provident intends to execute a balanced portfolio strategy. In the COGP business, internal development projects with a board approved capital budget of $78.8 million are planned. Acquisitions of interest in properties close to properties already owned or partially owned by Provident will be pursued. In USOGP, internal development projects are planned with a board approved capital budget of $46.0 million. Major corporate or property acquisitions are being evaluated. In Midstream, Provident will expand and build upon the Redwater facility and evaluate additional infrastructure with a goal of adding quality assets at reasonable prices. The goal of these strategies is to maintain and increase per unit distributable cash flow and net asset value.

Critical accounting policies

Certain accounting policies are identified as critical accounting policies because they form an integral part of Provident's financial position. In addition, these policies require management to make judgments and estimates based on conditions and assumptions that are inherently uncertain. These accounting policies could result in materially different results should the underlying assumptions or conditions change.

Management assumptions are based on Provident's historical experience, management's experience, and other factors that, in management's opinion, are relevant and appropriate. Management assumptions may change over time, as further experience is gained or as operating conditions change.

Details of Provident's critical accounting policies are as follows:

Property, plant and equipment

Provident follows the full cost method of accounting, whereby all costs associated with the acquisition and development of oil and natural gas reserves are capitalized. Utilization of the full cost method of accounting requires the use of management estimates and assumptions for amounts recorded for depletion and depreciation of property, plant and equipment as well as for the ceiling test.

The provision for depletion and depreciation is calculated using the unit of production method based on current production divided by Provident's share of estimated total proved oil and natural gas reserve volumes before royalties. The recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted cash flows expected from the cost centre. If the carrying value is not recoverable the cost centre is written down to its fair value.

Proved reserves are an estimate, under existing reserve evaluation polices, of volumes that can reasonably be expected to be economically recoverable under existing technology and economic conditions. Changes in underlying assumptions or economic conditions could have a material impact on Provident's financial results. To mitigate these risks, management utilizes McDaniel & Associates Consultants Ltd., an independent engineering firm, to evaluate Provident's Canadian reserves. For Provident's U.S. based assets, management utilizes Cawley, Gillespie & Associates, Inc. and Netherland, Sewell & Associates, Inc., two independent engineering firms, to evaluate reserves.

Estimates of future production, oil and natural gas prices and future costs used in the ceiling test are, by their very nature, subject to uncertainty and changes in underlying assumptions could have a material impact on Provident’s financial results.

Asset retirement obligation

Under the asset retirement obligation (ARO) standard, the fair value of AROs is recorded as a liability on a discounted basis, when incurred. The value of the related assets are increased by the same amount as the liability, and depreciated over the useful life of the asset. Over time the liability is adjusted for the change in present value of the liability or as a result of changes to either the timing or amount of the original estimate of undiscounted future cash flows.

ARO requires that management make estimates and assumptions regarding future liabilities and cash flows involving environmental reclamation and remediation. Such assumptions are inherently uncertain and subject to change over time due to factors such as historical experience, changes in environmental legislation or improved technologies. Changes in underlying assumptions, based on the above noted factors, could have a material impact on Provident’s financial results.

Convertible debentures

Effective December 31, 2004, the Trust retroactively adopted the revised CICA Handbook Section 3860 (HB 3860), "Financial Instruments - presentation and disclosure" for financial instruments that may be settled at the issuer's option in cash or its own equity. The revised standard requires the Trust to classify proceeds from convertible debentures issued in 2002, 2003 and 2004 as either debt or equity based on fair value measurement and the substance of the contractual arrangement. The Trust previously presented the convertible debenture proceeds (net of financing costs) and related interest obligations as equity on the consolidated balance sheet, on the basis that the Trust could settle its obligations in exchange for trust units.

The Trust's obligation to make scheduled payments of principal and interest constitutes a financial liability under the revised standard and exists until the instrument is either converted or redeemed. The holders' option to convert the financial liability into trust units is an embedded conversion option. The financial statement effect of this accounting treatment is outlined in this MD&A in the section entitled “Interest Expense”.

Changes in accounting policies

Exchangeable securities - non-controlling interest

The Canadian Institute of Chartered Accountants issued an amendment to standard EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" that states 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. The exchangeable shares issued by Provident Acquisitions Inc. and Provident Energy Ltd., corporate subsidiaries of the Trust, considered under this standard to be transferable to third parties. EIC-151 states that if the exchangeable shares are transferable to a third party, they should be reflected as non-controlling interest. Previously, the exchangeable shares were reflected as a component of unitholders' equity.

As a result of this change in accounting policy, the Trust has reflected non-controlling interest of $13.0 million and $35.9 million, respectively, on the Trust's consolidated balance sheet as at June 30, 2005 and December 31, 2004, respectively. Consolidated net income or loss has been adjusted for the earnings attributable to the non-controlling interest of $0.3 million in the six months ended June 30, 2005 and the loss of $0.3 million in the six month period ended June 30, 2004. As at June 30, 2005 unitholders' equity was reduced by $11.2 million and non-controlling interest on the consolidated balance sheet increased by $13.0 million. In accordance with the transitional provisions of EIC-151, retroactive application has been applied with restatement of prior periods. The retroactive application of this abstract as at March 31, 2005 and December 31, 2004 was an accumulated loss of $1.4 and $1.5 million respectively. Cash flow was not affected by this change.

Recent accounting pronouncements

The following new accounting guidelines or standards have been reviewed by Provident but have been assessed as not having any impact on Provident's financial results for the period ended June 30, 2005.

Variable interest entities ("VIEs")

In June 2003 the CICA issued Accounting Guideline 15 (AcG-15) "Consolidation of Variable Interest Entities". AcG-15 defines VIEs as entities in which either: the equity at risk is not sufficient to permit that entity to finance its activities without additional financial support from other parties; or equity investors lack voting control, an obligation to absorb expected losses or the right to receive expected residual returns. AcG-15 harmonizes Canadian and U.S. GAAP and provides guidance for companies consolidating VIEs in which they are the primary beneficiary. The guideline is effective for all annual and interim periods beginning on or after November 1, 2004. This guideline does not have a material impact on the Trust.

Business risks

The oil and natural gas trust industry is subject to numerous risks that can affect the amount of cash flow available for distribution to unitholders and the ability to grow. These risks include but are not limited to:

- fluctuations in commodity prices, exchange rates and interest rates;
- government and regulatory risk with respect to royalty and income tax regimes;
- operational risks that may affect the quality and recoverability of reserves;
- geological risk associated with accessing and recovering new quantities of reserves;
- transportation risk with respect to the ability to transport oil and natural gas to market; and
- capital markets risk and the ability to finance future growth.

The midstream industry is also subject to risks that can affect the amount of cash flow available for distribution to unitholders and the ability to grow. These risks include but are not limited to:

- operational matters and hazards including the breakdown or failure of equipment, information systems or processes, the performance of equipment at levels below those originally intended, operator error, labour disputes, disputes with owners of interconnected facilities and carriers, and catastrophic events such as natural disasters, fires, explosions, fractures, acts of eco-terrorists and saboteurs, and other similar events, many of which are beyond the control of the Trust or Provident.

- the Midstream NGL assets are subject to competition from other gas processing plants, and the pipelines and storage, terminal and processing facilities are also subject to competition from other pipelines and storage, terminal and processing facilities in the areas they serve. The gas products marketing business is subject to competition from other marketing firms.

Provident strives to minimize these business risks by:

- employing and empowering management and technical staff with extensive industry experience;
- adhering to a strategy of acquiring, developing and optimizing quality, low-risk reserves in areas of technical and operational expertise;
- developing a diversified, balanced asset portfolio that generally offers developed operational infrastructure, year-round access and close proximity to markets;
- adhering to a consistent and disciplined Commodity Price Risk Management Program to mitigate the impact that volatile commodity prices have on the cash flow available for distribution;
- marketing crude oil and natural gas to a diverse group of customers, including aggregators, industrial users, well-capitalized third-party marketers and spot market buyers;
- marketing natural gas liquids and related services to selected, credit worthy customers at competitive rates;
- maintaining a low cost structure to maximize cash flow and profitability;
- maintaining prudent financial leverage and developing strong relationships with the investment community and capital providers;
- adhering to strict guidelines and reporting requirements with respect to environmental, health and safety practices; and
- maintaining an adequate level of property, casualty, comprehensive, and directors' and officers' insurance coverage.

Unit trading activity

The following table summarizes the unit trading activity of the Provident units for the three months ended June 30, 2005 on both the Toronto Stock Exchange and the American Stock Exchange:

($ 000s, except per boe amounts)	**Q1**	**Q2**	**Six months ended June 30,**
TSE – PVE.UN (Cdn$)			
High	$ 12.60	$ 13.05	$ 13.05
Low	$ 11.17	$ 11.82	$ 11.17
Close	$ 11.98	$ 12.82	$ 12.82
Volume (000s)	26,122	15,951	42,073
AMEX – PVX (US$)			
High	$ 10.40	$ 10.55	$ 10.55
Low	$ 9.15	$ 9.48	$ 9.15
Close	$ 9.89	$ 10.49	$ 10.49
Volume (000s)	64,223	46,548	110,771

Segmented information by quarter

($000s except for per unit amounts)	2005		
	First Quarter[1]	Second Quarter	Year-to-Date
Financial - consolidated			
Revenue	$ 322,023	$ 300,504	$ 622,527
Cash flow	$ 64,137	$ 64,435	$ 128,572
Net income	$ (2,783)	$ 26,822	$ 24,039
Unitholder distributions	$ 51,734	$ 57,001	$ 108,735
Distributions per unit	$ 0.36	$ 0.36	$ 0.72
Oil and gas production			
Cash revenue	$ 100,447	$ 104,478	$ 204,925
Earnings before interest, DD&A, taxes and other non-cash items	$ 59,262	$ 63,584	$ 122,846
Cash flow	$ 48,937	$ 53,868	$ 102,805
Net income (loss)	$ (15,046)	$ 14,681	$ (365)
Midstream services and marketing			
Cash revenue	$ 245,338	$ 186,635	$ 431,973
Earnings before interest, DD&A and taxes	$ 16,380	$ 11,765	$ 28,145
Cash flow	$ 15,200	$ 10,567	$ 25,767
Net income	$ 12,263	$ 12,141	$ 24,404
Operating			
Oil and gas production			
Light/medium oil (bpd)	14,388	15,891	15,144
Heavy oil (bpd)	5,547	4,644	5,093
Natural gas liquids (bpd)	1,756	1,454	1,604
Natural gas (mcfd)	80,466	79,126	79,792
Oil equivalent (boed)	35,102	35,177	35,140
(Cdn $)			
Average selling price net of transportation expense			
Light/medium oil per bbl (before hedges)	$ 49.32	$ 51.20	$ 50.31
Light/medium oil per bbl (including hedges)	$ 40.93	$ 42.18	$ 41.69
Heavy oil per bbl (before hedges)	$ 25.85	$ 26.03	$ 25.93
Heavy oil per bbl (including hedges)	$ 25.78	$ 26.03	$ 25.89
Natural gas liquids per barrel	$ 45.30	$ 47.75	$ 46.42
Natural gas per mcf (before hedges)	$ 6.76	$ 7.29	$ 7.03
Natural gas per mcf (including hedges)	$ 6.74	$ 7.13	$ 6.94
Midstream services and marketing			
Redwater throughput (bpd)	58,504	52,175	55,322

(1) Restated - note 2

Segmented information by quarter

($000s except per unit amounts)	2004[1]				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	YTD Total
Financial - consolidated					
Revenue	$ 234,432	$ 218,304	$ 287,686	$ 369,435	$ 1,109,857
Cash flow	$ 36,269	$ 36,530	$ 54,076	$ 58,371	$ 185,246
Net income	$ (5,995)	$ (6,873)	$ (4,221)	$ 38,314	$ 21,225
Unitholder distributions	$ 31,036	$ 35,039	$ 46,489	$ 52,064	$ 164,628
Distributions per unit	$ 0.36	$ 0.36	$ 0.36	$ 0.36	$ 1.44
Oil and gas production					
Cash revenue	$ 54,865	$ 59,316	$ 89,129	$ 91,569	$ 294,879
Earnings before interest, DD&A, taxes and other non-cash items	$ 30,741	$ 34,974	$ 51,767	$ 50,498	$ 167,980
Cash flow	$ 26,386	$ 29,593	$ 44,825	$ 41,798	$ 142,602
Net income (loss)	$ (9,761)	$ (10,950)	$ (17,356)	$ 27,490	$ (10,577)
Midstream services and marketing					
Cash revenue	$ 233,031	$ 218,388	$ 287,679	$ 288,768	$ 1,027,866
Earnings before interest, DD&A and	$ 12,197	$ 8,945	$ 10,986	$ 17,957	$ 50,085
taxes					$ 42,644
Cash flow	$ 9,883	$ 6,937	$ 9,251	$ 16,573	
Net income	$ 3,766	$ 4,077	$ 13,135	$ 10,824	$ 31,802
Operating					
Oil and gas production					
Light/medium oil (bpd)	5,965	7,861	12,674	14,012	10,146
Heavy oil (bpd)	6,588	6,537	6,770	6,536	6,608
Natural gas liquids (bpd)	1,130	1,267	1,803	1,770	1,494
Natural gas (mcfd)	63,859	68,007	88,642	87,339	77,022
Oil equivalent (boed)	24,326	27,000	36,021	36,874	31,085
(Cdn $)					
Average selling price net of transportation expense					
Light/medium oil per bbl (before hedges)	$ 39.00	$ 42.28	$ 48.59	$ 45.83	$ 45.01
Light/medium oil per bbl (including hedges)	$ 26.15	$ 29.97	$ 38.00	$ 33.88	$ 33.29
Heavy oil per bbl (before hedges)	$ 26.84	$ 28.26	$ 34.23	$ 25.33	$ 28.72
Heavy oil per bbl (including hedges)	$ 22.80	$ 23.26	$ 25.72	$ 22.17	$ 23.51
Natural gas liquids per barrel	$ 37.03	$ 40.55	$ 40.88	$ 42.80	$ 40.68
Natural gas per mcf (before hedges)	$ 6.40	$ 7.01	$ 6.47	$ 6.56	$ 6.60
Natural gas per mcf (including hedges)	$ 6.31	$ 6.26	$ 6.05	$ 6.31	$ 6.23
Midstream services and marketing					
Redwater throughput (bpd)	58,640	48,452	55,759	56,599	55,120

[1] Restated - note 2.

Segmented information by quarter

($000s except per unit amounts)	2003 (1)				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	YTD Total
Financial - consolidated					
Revenue	$ 66,710	$ 57,520	$ 67,622	$ 214,477	$ 406,329
Cash flow	$ 40,372	$ 30,106	$ 27,544	$ 30,343	$ 128,365
Net income	$ (9,853)	$ 19,828	$ (4,088)	$ 16,610	$ 22,497
Unitholder distributions	$ 33,091	$ 35,528	$ 28,969	$ 32,024	$ 129,612
Distributions per unit	$ 0.60	$ 0.60	$ 0.47	$ 0.39	$ 2.06
Oil and gas production					
Cash revenue	$ 66,710	$ 57,520	$ 55,260	$ 54,648	$ 234,138
Earnings before interest, DD&A and taxes	$ 26,845	$ 33,989	$ 31,517	$ 25,660	$ 118,011
Cash flow	$ 40,372	$ 30,106	$ 27,463	$ 21,620	$ 119,561
Net income	$ (11,811)	$ 19,828	$ (4,567)	$ 10,268	$ 16,278
Midstream services and marketing					
Cash revenue	$ -	$ -	$ 23,713	$ 173,435	$ 197,148
Earnings before interest, DD&A and taxes	-	-	$ -	$ 10,242	$ 10,242
Cash flow	$ -	$ -	$ 81	$ 8,723	$ 8,804
Net income	$ -	$ -	$ 85	$ 8,018	$ 8,103
Operating					
Oil and gas production					
Light/medium oil (bpd)	7,285	6,770	6,748	6,454	6,812
Heavy oil (bpd)	6,245	6,700	7,495	7,151	6,902
Natural gas liquids (bpd)	1,085	1,162	1,276	1,145	1,167
Natural gas (mcfd)	83,924	72,898	73,090	68,657	74,596
Oil equivalent (boed)	28,602	26,781	27,701	26,193	27,314
(Cdn $ per boe)					
Average selling price net of transportation expense					
Light/medium oil per bbl (before hedges)	$ 43.64	$ 33.57	$ 33.49	$ 32.79	$ 36.02
Light/medium oil per bbl (including hedges)	$ 32.04	$ 29.18	$ 28.24	$ 26.61	$ 29.09
Heavy oil per bbl (before hedges)	$ 31.63	$ 23.47	$ 24.17	$ 20.61	$ 24.74
Heavy oil per bbl (including hedges)	$ 24.63	$ 21.92	$ 22.16	$ 20.25	$ 22.09
Natural gas liquids per barrel	$ 45.13	$ 37.16	$ 28.26	$ 34.48	$ 35.87
Natural gas per mcf (before hedges)	$ 7.94	$ 6.87	$ 5.88	$ 5.62	$ 6.63
Natural gas per mcf (including hedges)	$ 6.49	$ 5.64	$ 5.14	$ 5.48	$ 5.71
Midstream services and marketing					
Redwater throughput (bpd)	-	-	-	63,616	N/A

(1) Restated - note 2.

PROVIDENT ENERGY TRUST
CONSOLIDATED BALANCE SHEETS
Canadian dollars (000s)
(unaudited)

	As at June 30, 2005	As at December 31, 2004 (restated note 2)
Assets		
Current assets		
Cash	$ **464**	$ 244
Accounts receivable	**147,144**	143,142
Petroleum product inventory	**23,199**	17,151
Deferred derivative loss	**1,175**	2,144
Prepaid expenses	**11,937**	10,265
	183,919	172,946
Cash reserve for future site reclamation	**1,993**	1,454
Investments	**3,570**	3,000
Deferred financing charges	**6,626**	5,584
Property, plant and equipment	**1,371,933**	1,299,654
Goodwill	**330,944**	330,944
	$ **1,898,985**	$ 1,813,582
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ **161,175**	$ 171,412
Cash distributions payable	**17,195**	15,416
Distribution payable to non-controlling interest	**377**	271
Financial derivative instruments	**35,990**	24,524
	214,737	211,623
Long-term debt (note 5)	**417,482**	432,206
Asset retirement obligation (note 6)	**43,209**	40,506
Long-term financial derivative instruments	**1,993**	-
Future income taxes	**60,797**	70,629
Non-controlling interest		
USOGP operations	**13,069**	13,649
Exchangeable shares (note 7)	**12,979**	35,921
Unitholders' equity		
Unitholders' contributions (note 8)	**1,642,048**	1,438,393
Convertible debentures equity component (note 2)	**13,831**	9,785
Contributed surplus (note 10)	**1,271**	2,002
Cumulative translation adjustment (note 2)	**(25,451)**	(28,848)
Accumulated income	**24,401**	362
Accumulated cash distributions (note 11)	**(521,381)**	(412,646)
	1,134,719	1,009,048
	$ **1,898,985**	$ 1,813,582

PROVIDENT ENERGY TRUST

CONSOLIDATED STATEMENT OF OPERATIONS AND ACCUMULATED INCOME (LOSS)

Canadian dollars (000s except per unit amounts)

(unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	**2005**	2004
		(restated note 2)	(restated note 2)	(restated note 2)
Revenue (note 9)				
Revenue	$ **305,226**	$ 244,424	$ **661,349**	$ 511,071
Realized loss on financial derivative instruments	**(14,113)**	(16,833)	**(24,451)**	(26,489)
Unrealized gain (loss) on financial derivative instruments	**9,391**	(9,287)	**(14,371)**	(31,331)
	300,504	218,304	**622,527**	453,251
Expenses				
Cost of goods sold	**164,179**	146,717	**383,799**	327,253
Production, operating and maintenance	**40,874**	30,237	**81,295**	57,785
Transportation	**1,336**	694	**3,028**	1,928
Depletion, depreciation and accretion	**50,389**	39,023	**99,550**	73,472
General and administrative	**9,360**	5,757	**17,637**	11,007
Non cash general and administrative (recovery) (note 10)	**1,791**	(276)	**2,422**	(695)
Interest on bank debt	**1,914**	2,929	**5,240**	5,073
Interest and accretion on convertible debentures (notes 2 and 5)	**6,481**	3,600	**12,093**	7,649
Amortization of deferred financing charges (note 2)	**468**	359	**558**	718
Foreign exchange gain and other	**(221)**	(2,252)	**(108)**	(2,767)
Loss on redemption of convertible debentures (note 5)	**49**	-	**49**	-
Gain on sale of marketing contracts (note 4)	**(5,188)**	-	**(5,188)**	-
	271,432	226,788	**600,375**	481,423
Income (loss) before taxes and non-controlling interests	**29,072**	(8,484)	**22,152**	(28,172)
Capital taxes	**1,533**	1,167	**2,910**	2,172
Current and withholding taxes	**2,004**	292	**4,371**	292
Future income tax recovery	**(2,112)**	(3,037)	**(9,832)**	(17,586)
	1,425	(1,578)	**(2,551)**	(15,122)
Net income (loss) before non-controlling interest	**27,647**	(6,906)	**24,703**	(13,050)
Non-controlling interest income (loss)				
USOGP operations	**504**	130	**399**	130
Exchangeable shares (note 7)	**321**	(163)	**265**	(312)
Net income (loss)	**26,822**	(6,873)	**24,039**	(12,868)
Accumulated income (loss), beginning of period	$ **(995)**	$ (6,280)	$ **1,844**	$ (4,029)
Retroactive application of changes in accounting policies (note 2)	**(1,426)**	(10,622)	**(1,482)**	(6,878)
Accumulated income (loss), beginning of period, restated	**(2,421)**	(16,902)	**362**	(10,907)
Accumulated income (loss), end of period	$ **24,401**	$ (23,775)	$ **24,401**	$ (23,775)
Net income (loss) per unit – basic	$ **0.17**	$ (0.07)	$ **0.16**	$ (0.14)
Net income (loss) per unit – diluted	$ **0.17**	$ (0.07)	$ **0.16**	$ (0.14)

PROVIDENT ENERGY TRUST

CONSOLIDATED STATEMENT OF CASH FLOWS

Canadian Dollars (000s)

(unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	**2005**	2004
		(restated note 2)		(restated note 2)
Cash provided by operating activities				
Net income (loss) for the period	$ **26,822**	$ (6,873)	$ **24,039**	$ (12,868)
Add (deduct) non-cash items:				
Depletion, depreciation and accretion	**50,389**	39,023	**99,550**	73,472
Debenture accretion and amortization of deferred charges (note 2)	**1,475**	958	**2,772**	1,846
Non-cash general and administrative (note 10)	**1,791**	(276)	**2,422**	(695)
Unrealized loss (gain) on non-hedging derivative instruments (note 9)	**(9,391)**	9,287	**14,371**	31,331
Unrealized foreign exchange gain	**(195)**	(2,519)	**(215)**	(2,519)
Future income tax recovery	**(2,112)**	(3,037)	**(9,832)**	(17,586)
Equity in earnings of investee	**(30)**	-	**(60)**	-
Net income (loss) attributable to non-controlling interests	**825**	(33)	**664**	(182)
Loss on redemption of convertible debentures (note 5)	**49**	-	**49**	-
Gain on sale of marketing contracts (note 4)	**(5,188)**	-	**(5,188)**	-
Cash flow from operations before changes in working capital and site restoration expenditures	**64,435**	36,530	**128,572**	72,799
Site restoration expenditures	**(366)**	81	**(995)**	(987)
Change in non-cash operating working capital	**(18,868)**	(5,741)	**(23,669)**	4,131
	45,201	30,870	**103,908**	75,943
Cash used for financing activities				
Increase (decrease) of long-term debt	**37,243**	30,657	**(52,257)**	(27,043)
Proceeds of bridge financing	-	158,184	-	158,184
Declared distributions to unitholders (note 11)	**(57,001)**	(35,039)	**(108,735)**	(66,075)
Declared distributions to non-controlling interest	**#(790)**	-	**(979)**	-
Issue of trust units, net of issue costs	**13,765**	5,735	**125,312**	58,970
Issue of debentures, net of costs (note 5)	**-**	-	**95,759**	-
Redemption of debentures, net of costs (note 5)	**(2,997)**	-	**(2,997)**	-
Change in non-cash financing working capital	**(533)**	(4,175)	**4,227**	(3,395)
	(10,313)	155,362	**60,330**	120,641
Cash used for investing activities				
Net capital expenditures, OGP acquisitions and dispositions	**(37,000)**	(10,902)	**(66,086)**	(20,730)
Acquisition of Nautilus (note 3)	**-**	-	**(91,420)**	-
Acquisition of Breitburn Energy (note 3)	**-**	(165,649)	**-**	(165,649)
Acquisition of Olympia Energy Inc. (note 3)	**-**	(4,715)	**-**	(4,715)
Acquisition of Viracocha Energy Inc. (note 3)	**-**	(1,993)	**-**	(1,993)
Acquisition of investment	**(510)**	-	**(510)**	-
Proceeds on sale of marketing contracts net of disposal costs (note 4)	**5,546**	-	**5,546**	-
Reclamation fund contributions	**(748)**	(615)	**(1,534)**	(1,167)
Reclamation fund withdrawals	**366**	-	**995**	-
Payment of financial derivative instruments (note 3)	**-**	(23,302)	**(8,137)**	(23,302)
Change in non-cash investing working capital	**(2,272)**	20,919	**(2,872)**	20,994
	(34,618)	(186,257)	**-(164,018)**	(196,562)
Increase (decrease) in cash	**270**	(25)	**220**	22
Cash beginning of year	**194**	92	**244**	45
Cash end of year	$ **464**	$ 67	$ **464**	$ 67
Supplemental disclosure of cash flow information				
Cash interest paid including debenture interest	$ **7,559**	$ 8,364	$ **13,925**	$ 10,831

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(Tabular amounts in Cdn$000's, except unit and per unit amounts)
(unaudited)

June 30, 2005

The Interim Consolidated Financial Statements of Provident Energy Trust (the Trust) have been prepared by management in accordance with accounting principals generally accepted in Canada. Certain information and disclosures normally required in the notes to the annual financial statements have been condensed or omitted. The Interim Consolidated Financial Statements should be read in conjunction with the Trust's audited Financial Statements and notes for the year ended December 31, 2004, which are disclosed in the annual report filed by the Trust.

1. **Significant accounting policies**

   The interim Consolidated Financial Statements have been prepared based on the consistent application of the accounting policies and procedures as set out in the Financial Statements of the Trust for the year ended December 31, 2004 and are consistent with policies adopted in the second quarter of 2004 except as described in note 2.

2. **Changes in accounting policies and practices**

   (i.) Convertible debentures

   Effective December 31, 2004, the Trust retroactively adopted the revised CICA Handbook Section 3860 (HB 3860), "Financial Instruments - Presentation and Disclosure" for financial instruments that may be settled at the issuer's option in cash or its own equity. The revised standard requires the Trust to classify proceeds from convertible debentures issued in 2002, 2003 and 2004 as either debt or equity based on fair value measurement and the substance of the contractual arrangement. The Trust previously presented the convertible debenture proceeds (net of financing costs) and related interest obligations as equity on the consolidated balance sheet on the basis that the Trust could settle its obligations in exchange for trust units. Issue costs on convertible debentures are recorded as deferred financing charges and are amortized over the life of the debenture. The retroactive application of this standard as at March 31, 2004 and December 31, 2003 was an accumulated loss of $9.7 and $5.9 million, respectively.

   The Trust's obligation to make scheduled payments of principal and interest constitutes a financial liability under the revised standard and exists until the instrument is either converted or redeemed. The holders' option to convert the financial liability into trust units is an embedded conversion option. The effect of the adoption of this standard is presented in note 5 to the financial statements.

   (ii.) Foreign currency translation

In the fourth quarter of 2004, the Trust reviewed its practices for U. S. operations and determined that such operations are self-sustaining as a result of the development of the Trust's management practices for U.S. operations. The accounts of self-sustaining foreign operations are translated using the current rate method, whereby assets and liabilities are translated at period-end exchange rates, while revenues and expenses are translated using rates for the period. Translation gains and losses related to the operations are deferred and included as a separate component of unitholders' equity. Previously, operations outside of Canada were considered to be integrated and translated using the temporal method. Under the temporal method, monetary assets and liabilities were translated at the period end exchange rates, other assets and liabilities at the historical rates, and revenues and expenses at the rates for the period except depreciation, depletion and accretion, which were translated on the same basis as the related assets. This change in practice was adopted prospectively beginning October 1, 2004.

(i.) Exchangeable securities - non-controlling interest

The Canadian Institute of Chartered Accountants issued an amendment to EIC abstract 151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" that states 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. The exchangeable shares issued by Provident Acquisitions Inc. and Provident Energy Ltd., corporate subsidiaries of the Trust are considered under this standard to be transferable to third parties. EIC-151 states that if the exchangeable shares are transferable to a third party, they should be reflected as non-controlling interest. Previously, the exchangeable shares were reflected as a component of unitholders' equity.

As a result of this change in accounting policy, the Trust has reflected non-controlling interst of $13.0 million and $35.9 million, respectively, on the Trust's consolidated balance sheet as at June 30, 2005 and December 31, 2004. Consolidated net income or loss has been adjusted for the earnings attributable to the non-controlling interest of $0.3 million for the six months ended June 30, 2005 and the loss of $0.3 million for the six months ended June 30, 2004. As at June 30, 2005 unitholders' equity was reduced by $11.2 million and non-controlling interest on the consolidated balance sheet increased by $13.0 million. In accordance with the transitional provisions of EIC-151, retroactive application has been applied with restatement of prior periods. The retroactive application of this abstract as at March 31, 2005 and December 31, 2004 was an accumulated loss of $1.4 million and $1.5 million respectively. For the comparative periods ended March 31, 2004 and December 31, 2003, there were retroactive accumulated loss adjustments of $0.9 and $1.0 million, respectively. The retroactive accumulated loss adjustments represent the cumulative net income attributable to the non controlling interest for prior periods. Cash flow was not affected by this change.

3. Acquisitions

(i.) Acquisition of Nautilus

On March 2, 2005, Provident acquired Nautilus Resources, LLC (Nautilus) for cash consideration of $90.2 million and acquisition costs of $1.2 million. Nautilus was a private oil and gas exploration and production company active in Wyoming, USA. The transaction has been accounted for using the purchase method with the allocation of the purchase price as follows:

Net assets acquired and liabilities assumed		
Property, plant and equipment	$	99,877
Working capital		1,237
Asset retirement obligation		(1,557)
Financial derivative instrument		(8,137)
	$	91,420
Consideration		
Acquisition costs	$	1,237
Cash		90,183
	$	91,420

The result of this acquisition was the non-controlling interest on USOGP operations decreased by 1.4 percent from 5.8 percent to 4.4 percent.

(ii.) Acquisition of BreitBurn

On June 15, 2004, Provident acquired 92 percent of Breitburn Energy LLC (Breitburn) for consideration of $157.4 million and acquisition costs of $8.2 million. Breitburn is a private company (now a limited partnership) active in the oil and gas exploitation and production business in the Los Angeles basin, USA. The transaction has been accounted for using the purchase method with the allocation of the purchase price as follows:

Net assets acquired and liabilities assumed		
Property, plant and equipment	$	214,261
Working capital deficiency		(8,402)
Non-hedging derivative instruments		(25,181)
Other assets		1,028
Asset retirement obligation		(2,367)
Non-controlling interest		(13,690)
	$	165,649
Consideration		
Acquisition costs	$	8,214
Cash		157,435
	$	165,649

On October 4, 2004, the Trust funded Breitburn $58.5 million (US$45 million) for the Orcutt property acquisition. The result of this funding increased Provident's ownership interest in Breitburn by 2.2 percent to a total of 94.2 percent.

(iii.) Acquisition of Olympia

On June 1, 2004, Provident acquired Olympia Energy Inc. for consideration of 13,385,579 Trust units with an ascribed value of $152.9 million and 1,325,000 exchangeable shares with an ascribed value of $15.1 million plus acquisition costs, which when netted with option proceeds total $4.7 million. Olympia was a public oil and gas exploration and production company active in the Western Canadian sedimentary basin. The transaction has been accounted for using the purchase method with the allocation of the purchase price as follows:

Net assets acquired and liabilities assumed		
Property, plant and equipment	$	162,352
Goodwill		106,499
Working capital deficiency		(326)
Bank debt		(53,852)
Asset retirement obligation		(1,909)
Non-hedging derivative instrument		(947)
Future income taxes		(39,107)
	$	172,710
Consideration		
Acquisition costs	$	8,700
Option proceeds		(3,985)
Exchangeable shares issued (note 7)		15,132
Trust units issued (note 8)		152,863
	$	172,710

(iv.) Acquisition of Viracocha

On June 1, 2004, Provident acquired Viracocha Energy Inc. for consideration of 12,758,386 Trust units with an ascribed value of $145.7 million and 1,325,000 exchangeable shares with an ascribed value of $15.1 million and acquisition costs, which when netted with option proceeds total $2.0 million. Viracocha was a public oil and gas exploration and production company active in the Western Canadian sedimentary basin. The transaction has been accounted for using the purchase method with the allocation of the purchase price as follows:

Net assets acquired and liabilities assumed		
Property, plant and equipment	$	109,907
Goodwill		122,002
Working capital		2,172
Bank debt		(49,891)
Capital lease obligation		(77)
Deferred lease obligation		(98)
Asset retirement obligation		(7,895)
Future income taxes		(13,294)
	$	162,826
Consideration		
Acquisition costs	$	9,000
Option and warrant proceeds		(7,007)
Exchangeable shares issued (note 7)		15,132
Trust units issued (note 8)		145,701
	$	162,826

4. Sale of marketing contracts

On May 1, 2005, the Trust disposed of certain oil purchase and sale contracts for net proceeds of $5.5 million and recorded a gain of $5.2 million net of disposal costs.

5. Long-term debt

		As at June 30, 2005		As at Dec 31, 2004
Revolving term credit facility	$	210,500	$	262,750
Convertible debentures		**206,982**		169,456
	$	417,482	$	432,206

(i.) Revolving term credit facility

At June 30, 2005 and December 31, 2004, Provident had a $410.0 million term credit facility.

At June 30, 2005, Provident had letters of credit guaranteeing its performance under certain commercial and other contracts that totaled $24.9 million, increasing bank line utilization to 57.4 percent. The guarantees totaled $31.0 million at December 31, 2004.

(ii.) Convertible debentures

On May 31, 2005, the Trust completed the redemption of its 10.5 percent convertible unsecured subordinated debentures that were originally scheduled to mature May 15, 2007. A total of 3.5 million units were issued at the conversion price of $10.70 per unit. A further $3 million cash was paid to the remaining debenture holders who did not convert to trust units at $1,050 for each $1,000 of convertible debenture held plus accrued interest to May 31, 2005. This resulted in a loss on redemption of $49 thousand. Unamortized deferred debt issue costs of $2.5 million, originally incurred on the issuance of the 10.5 percent convertible debentures, were reclassified to trust unit issue costs as a result of the issuance of 3.5 million trust units.

On March 1, 2005, the Trust issued $100.0 million of unsecured convertible subordinated debentures ($95.8 million net of issue costs) with a 6.5 percent coupon rate maturing August 31, 2012. Issue costs have been classified as deferred financing charges. The debentures may be converted into trust units at the option of the holder at a conversion price of $13.75 per trust unit prior to August 31, 2012 and may be redeemed by the Trust under certain circumstances. The unsecured subordinated convertible debentures were initially recorded at fair value of $91.8 million. The difference between the fair value and proceeds of $8.2 was recorded as equity. The face value of these instruments as at June 30, 2005 was $99.5 million.

On July 6, 2004, the Trust issued $50.0 million of unsecured subordinated convertible debentures ($48.0 million net of issue costs) with an 8.0 percent coupon rate maturing July 31, 2009. Issue costs have been classified as deferred financing charges. The debentures may be converted into trust units at the option of the holder at a conversion price of $12.00 per trust unit prior to July 31, 2009, and may be redeemed by the Trust under certain circumstances. The unsecured subordinated convertible debentures were initially recorded fair value of $48.1 million under accounting rules. The difference between the fair value and proceeds of $1.9 million was recorded as equity. The face value of these instruments as at June 30, 2005 was $50.0 million.

On September 30, 2003, the Trust issued $75 million of unsecured subordinated convertible debentures ($71.8 million net of issues costs) with an 8.75 percent coupon rate maturing December 31, 2008. Issue costs have been classified as deferred financing charges. The debentures may be converted into trust units at the option of the holder at a conversion price of $11.05 per trust unit prior to December 31, 2008, and may be redeemed by the Trust under certain circumstances. The unsecured subordinated convertible debentures were initially recorded at fair value under accounting rules of $70.6 million. The difference between the fair value and proceeds of $4.4 million was recorded as equity. The face value of these instruments as at June 30, 2005 was $69.6 million.

The Trust may elect to satisfy interest and principal obligations by the issue of trust units. For the six month period ended June 30, 2005, $52.8 million of the face value of debentures were converted to trust units at the election of debenture holders and early extinguishment (2004 - nil). The following table details each convertible debenture:

	As at June 30, 2005		As at Dec 31, 2004			
($000s except conversion pricing)						
	Carrying Value (1)	Face Value	Carrying Value(1)	Face Value	Maturity Date	Conversion Price per unit(2)
10.5% Convertible Debentures	$ -	$ -	$ 49,423	$ 49,881	May 15, 2007	10.70
6.5% Convertible Debentures	**91,651**	**99,500**	-	-	Aug. 31, 2012	13.75
8.0% Convertible Debentures	**48,658**	**50,000**	48,199	50,000	July 31, 2009	12.00
8.75% Convertible Debentures	**66,673**	**69,552**	71,834	74,930	Dec. 31, 2008	11.05
	$ **206,982**	$ 219,052	$ 169,456	$ 174,811		

(1) Excluding equity component of convertible debentures
(2) The debentures may be converted into trust units at the option of the holder of the Trust at the conversion price per unit

6. Asset retirement obligation

The Trust's asset retirement obligation is based on the Trust's net ownership in wells, facilities and the midstream assets and represents management's estimate of the costs to abandon and reclaim those wells, facilities and midstream assets as well as an estimate of the future timing of the costs to be incurred. Estimated cash flows have been discounted at the Trust's credit-adjusted risk free rate of seven percent and an inflation rate of two percent.

The total undiscounted amount of future cash flows required to settle asset retirement obligations related to oil and gas operations is estimated to be $140.7 million. Payments to settle oil and gas asset retirement obligations occur over the operating lives of the assets estimated to be from two to 55 years.

The total undiscounted amount of future cash flows required to settle the midstream asset retirement obligations is estimated to be $26.1 million. The estimated costs include such activities as dismantling, demolition and disposal of the facilities, as well as remediation and restoration of the surface land. Payments to settle the Midstream asset retirement obligations are expected to occur subsequent to the closure of the facilities and related assets. Settlement of these obligations is expected to occur in 30 to 35 years.

	Three months ended June 30,		**Six months ended June 30,**	
	2005	2004	**2005**	2004
Carrying amount, beginning of period	$ **42,350**	$ 33,023	$ 40,506	$ 33,182
Liabilities assumed on corporate acquisitions	-	11,078	**1,557**	11,407
Liabilites incurred during the period	**331**	(1,604)	**452**	(2,672)
Accretion expense	**894**	636	**1,689**	1,216
Settlement of liabilities during the period	**(366)**	-	**(995)**	-
Carrying amount, end of period	$ **43,209**	$ 43,133	$ 43,209	$ 43,133

7. Exchangeable shares - non-controlling interest

The Trust retroactively applied EIC 151, "Exchangeable Securities Issued by a Subsidiary of an Income Trust", as at June 30, 2005. The non-controlling interest on the consolidated balance sheet consists of the fair value of the exchangeable shares upon issuance plus the accumulated earnings attributable to the non-controlling interest. The net income attributable to the non-controlling interest on the consolidated statement of operations 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 at each period end during the period.

Following is a summary of the non-controlling interest - exchangeable shares for the quarter and six-month period ended June 30, 2005 and 2004:

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	**2005**	2004
Non-controlling interest, beginning of period	$ **23,059**	$ 18,316	$ 35,921	$ 20,542
Exchangeable shares issued	**-**	30,264	-	30,264
Reduction of book value for conversion to trust units	**(10,401)**	(2,540)	(23,207)	(4,617)
Net income attributable to non-controlling interest	**321**	(163)	**265**	(312)
Non-controlling interest, end of period	$ **12,979**	$ 45,877	$ 12,979	$ 45,877
Accumulated income attributable to non-controlling interest	$ **1,747**	$ 712	$ 1,747	$ 712

The following table details the number of exchangeable shares converted and outstanding in addition to the associated book value:

	Six months ended June 30,			
	2005		2004	
Exchangeable shares	**Number**	**Amount**	Number	Amount
Provident Acquisitions Inc.	**of Units**	**(000s)**	of Units	(000s)
Balance at beginning of period	**336,876**	$ 3,675	534,357	$ 5,829
Converted to trust units	**(336,876)**	**(3,675)**	(191,171)	(1,618)
Balance, end of period	-	-	343,186	4,211
Exchange ratio, end of period	-		1.3351	-
Trust units issuable upon conversion, end of period	-	$ -	458,188	$ 4,211
Exchangeable shares	**Number**	**Amount**	Number	Amount
Provident Energy Ltd.*	**of Units**	**(000s)**	of Units	(000s)
Balance at beginning of period	**638,474**	$ 6,833	1,279,227	$ 13,689
Converted to trust units			(238,650)	(2,020)
Balance, end of period	**638,474**	**6,833**	1,040,577	11,669
Exchange ratio, end of period	**1.43226**		1.26579	
Trust units issuable upon conversion, end of period	**914,461**	$ 6,833	1,317,152	$ 11,669
Exchangeable shares (Series B)				
Provident Energy Ltd.**	**Number of Units**	**Amount (000s)**	Number of Units	Amount (000s)
Balance at beginning of period	**2,095,271**	$ 23,931	-	$ -
Issued to acquire Olympia Energy Inc.	-	-	1,325,000	15,132
Issued to acquire Viracocha Energy Ltd.	-	-	1,325,000	15,132
Converted to trust units	**(1,710,273)**	**(19,532)**	(115,530)	(979)
Balance, end of period	**384,998**	**4,399**	2,534,470	29,285
Exchange ratio, end of period	**1.13194**	-	1.0	
Trust units issuable upon conversion, end of period	**435,795**	$ 4,399	2,534,470	$ 29,285
Total Trust units issuable upon conversion				
of all exchangeable shares, end of period	**1,350,256**	$ 11,232	4,309,810	$ 45,165

*Automatic maturity date is January 15, 2006.

** Automatic maturity date is June 30, 2006.

8. Unitholders' contributions

The Trust has authorized capital of an unlimited number of common voting trust units.

During the period April 6 through to May 31, 2005, the Trust issued 3.5 million units at $10.70 per unit to redeem the face value of $42.8 million of the 10.5 percent unsecured convertible debentures. The Trust recognized $46.7 million in trust units from the redemption of the 10.5 percent debentures which is comprised of the carrying value of the debt redeemed and the proportion of the equity component related to the 10.5 percent convertibles debentures.

On March 1, 2005, the Trust issued 8.4 million units at $12.00 per unit for proceeds of $100.8 million ($95.6 million net of issue costs) pursuant to a February 18, 2005 public offering.

On June 1, 2004, the Trust issued 13.4 million and 12.8 million trust units with an ascribed value of $152.9 and $145.7 million as part of the consideration to acquire Olympia Energy Inc. and Viracocha Energy Inc., respectively.

On February 4, 2004, the Trust issued 4.5 million units at $11.20 per unit for proceeds of $50.4 million ($47.9 million net of issue costs) pursuant to a January 22, 2004 public offering.

	Six months ended June 30,			
	2005		2004	
Trust Units	**Number of Units**	**Amount (000s)**	Number of Units	Amount (000s)
Balance at beginning of period	**142,226,248**	$ 1,438,393	82,824,688	$ 803,299
Issued to acquire Olympia Energy Inc.	**-**	**-**	13,385,579	152,863
Issued to acquire Viracocha Energy Ltd.	**-**	**-**	12,758,386	145,701
Issued for cash	**8,400,000**	**100,800**	4,500,000	50,400
Exchangeable share conversions	**2,375,782**	**23,207**	545,351	4,617
Issued pursuant to unit option plan	**2,018,211**	**20,749**	354,042	2,988
Issued pursuant to the distribution reinvestment plan	**624,572**	**7,288**	626,289	6,733
To be issued pursuant to the distribution reinvestment plan	**164,003**	**2,103**	162,389	1,600
Debenture conversions	**1,410,708**	**10,906**	2,336	25
Redemption of the 10.5% debentures (note 5)	**3,507,570**	**46,707**	-	-
Unit issue costs	**-**	**(8,105)**	-	(2,678)
Balance at end of period	**160,727,094**	$ 1,642,048	115,159,060	$ 1,165,548

The per trust unit amounts for the quarter ended June 30, 2005 were calculated based on the weighted average number of units outstanding of 157,517,351 which excludes the shares exchangeable into trust units (2004 - 97,266,910). The diluted per trust unit amounts for 2005 are calculated at 1,810,130 trust units (2004 - 4,561,683) for the effect of the unit option plan and exchangeable shares. For the quarter ended June 30, 2005, these additional units have been included in the dilution calculation as their effect is dilutive when applied against the net income of the quarter. For the quarter ended June 30, 2004, these additional units have been excluded in the dilution calculation as their effect is anti-dilutive when applied against the net losses for the prior quarter. Provident’s convertible debentures are excluded in the computation of diluted earnings per unit for the quarter ended June 30, 2005 and 2004, as the effect of including the debentures is anti-dilutive.

The per trust unit amounts for the six month period ended June 30, 2005 were calculated based on the weighted average number of units outstanding of 152,730,232 which excludes the shares exchangeable into trust units (2004 - 91,799,972). The diluted per trust unit amounts for 2005 are calculated at 1,810,130 trust units (2004 - 4,561,683) for the effect of the unit option plan and exchangeable shares. For the six month period ended June 30, 2005, these additional units have been included in the dilution calculation as their effect is dilutive when applied against the net income of the period. For the six month period ended June 30, 2004, these additional units have been excluded in the dilution calculation as their effect is anti-dilutive when applied against the net losses of the prior period. Provident’s convertible debentures are excluded in the computation of diluted earnings per unit for the six month period ended June 30, 2005 and 2004 as the effect of including the debentures is anti-dilutive.

9. Revenue

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	**2005**	2004
Gross production revenue	$ **145,180**	$ 95,868	$ **279,774**	$ 175,305
Product sales and service revenue	**186,599**	168,741	**431,462**	371,196
Royalties	**(26,553)**	(20,185)	**(49,887)**	(35,430)
Revenue	$ **305,226**	$ 244,424	$ **661,349**	$ 511,071
Realized loss on financial derivative instruments	**(14,113)**	(16,833)	**(24,451)**	(26,489)
Unrealized gain (loss) on financial derivative instruments	**9,391**	(9,287)	**(14,371)**	(31,331)
	$ **300,504**	$ 218,304	$ **622,527**	$ 453,251
Change in unrealized loss on financial derivative instruments	$ **9,971**	$ (2,544)	$ **(13,402)**	$ (17,996)
Amortization of loss on financial derivative instruments	**(580)**	(6,743)	**(969)**	(13,335)
Unrealized gain (loss) on financial derivative instruments	$ **9,391**	$ (9,287)	$ **(14,371)**	$ (31,331)

The realized loss on financial derivative instruments for the quarter ended June 30, 2005 of $14.1 million (2004 - $16.8 million) and for the period ended June 30, 2005 of $24.5 million ($26.5 million) relates to the cash settlement on derivative instruments.

10. Non-cash general & administrative

(i.) Unit option plan

The Trust option plan (the Plan) is administered by the Board of Directors of Provident. Under the Plan, all directors, officers and employees of Provident, are eligible to participate in the Plan. There are 8,000,000 trust units reserved for the Plan. Options are granted at a “strike price” which is not less than the closing price of the units on the Toronto Stock Exchange on the last trading day preceding the grant. In certain circumstances, based upon the cash distributions made on the trust units, the strike price may be reduced at the time of exercise of the option at the discretion of the option holder. Options vest six months after grant and every year thereafter in equal increments except for options granted to existing employees which vest immediately.

	Six months ended June 30,			
	2005		2004	
	Number of Options	**Weighted Average Exercise Price**	Number of Options	Weighted Average Exercise Price
Outstanding, beginning of period	**5,200,331**	**$ 11.01**	4,008,744	$ 11.06
Granted	**296,200**	**11.73**	230,750	10.91
Exercised	**(2,018,211)**	**10.94**	(354,042)	8.47
Forfeited	**(25,728)**	**10.92**	(49,497)	11.09
Outstanding, end of period	**3,452,592**	**11.11**	3,835,955	11.06
Exercisable, end of period	**1,619,209**	**$ 11.20**	2,089,999	$ 11.06

At June 30, 2005, the Trust had 3,452,592 options outstanding with strike prices ranging between $8.91 and $12.14 per unit. The weighted average remaining contractual life of the options is 2.66 years and the weighted average exercise price is $11.11 per unit, excluding average potential reductions to the strike prices of $0.92 per unit.

At June 30, 2004, the Trust had 3,835,955 options outstanding with strike prices ranging between $8.40 and $12.39 per unit. The weighted average remaining contractual life of the options was 2.2 years and the weighted average exercise price was $11.06 per unit, excluding average potential reductions to the strike prices of $1.42 per unit.

On December 31, 2004, the Trust prospectively applied the fair value based method of accounting for the Plan. Previously, the Trust applied the intrinsic value methodology due to the uncertainties of future expected distributions. The Trust now uses the Black-Scholes option-pricing model to calculate the estimated fair value of the outstanding options issued on or after January 1, 2003 at their issue date. The Trust has reevaluated the assumptions required to calculate the fair value of options and considers the estimates required to calculate the fair value reasonably estimated at the time of the issue of the options.

For the quarter ended June 30, 2005, the Trust recorded unit-based compensation (non-cash general and administrative) of $0.2 million, for the 5.6 million options granted on or after January 1, 2003 (2004 - recovery of $0.3 million).

In 2005, the Trust recorded unit-based compensation (non-cash general and administrative) of $0.5 million, for the 5.6 million options granted on or after January 1, 2003 (2004 - recovery of $0.7 million).

As at June 30, 2005, the following assumptions are the weighted averages of the individual assumptions applied at each grant date to arrive at an estimate of fair value of all granted options on or after January 1, 2003 of $3.8 million:

	Three months ended June 30,	For the year ended	
		Dec 31, 2004	Dec 31, 2003
Expected annual dividend	**8.00%**	8.00%	8.00%
Expected volatility	**19.88%**	20.18%	19.46%
Risk - free interest rate	**3.26%**	3.30%	3.66%
Expected life of option (yrs)	**3.31**	3.31	3.31
Expected forteitures	**-**	-	-
Fair Value of Granted Options	**$ 0.2 million**	$ 1.2 million	$ 2.4 million

The following table reconciles the year-to-date movement in the contributed surplus balance:

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	**2005**	2004
Contributed surplus, beginning of the period	**$ 1,606**	$ 870	**$ 2,002**	$ 1,305
Compensation expense (recovery)	**243**	(276)	**499**	(695)
Benefit on options exercised charged to unitholders' equity	**(578)**	(9)	**(1,230)**	(25)
Contributed surplus, end of the period	**$ 1,271**	$ 585	**$ 1,271**	$ 585

(ii.) Unit appreciation rights

During 2004, the Trust put in place a program whereby certain employees of its U.S subsidiary are granted unit appreciation rights (UARs) which entitle the employee to receive cash compensation in relation to the value of a specified number of underlying notional trust units. UARs vest evenly over a period of three years commencing one year after grant and expire after four years.

The UARs, upon vesting, provide certain employees entitlement to receive a cash payment equal to the excess of the market price of the Trust's units over the exercise price of the right less notionally accrued distributions in excess of an eight percent return.

The following table summarizes the information about UARs

	As at June 30, 2005	
	Number of Units Appreciation Rights	Weighted Average Exercise Price
Outstanding, beginning of year	976,000	$ 9.78
Granted	147,000	$ 12.27
Exercised	281,755	9.69
Forfeited	16,000	9.85
Outstanding, end of quarter	825,245	$ 10.16
Exerciseable, end of quarter	20,912	9.69
Weighted average remaining contract life	3.09	
Average reductions to exercise price	$ 0.51	

The fair value associated with the UARs is expensed in the statement of income over the vesting period. During the quarter, the Trust recorded compensation costs of $1.5 million with respect to the outstanding UARs (2004 - nil). For the six month period ended June 30, 2005, the Trust recorded compensation costs of $1.9 million with respect to the outstanding UARs (2004 - nil).

11. **Reconciliation of cash flow and distributions**

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	**2005**	2004
Cash provided by operating activities	$ **45,201**	$ 30,870	**$ 103,908**	$ 75,943
Change in non cash working capital	**18,868**	5,741	**23,669**	(4,131)
Site restoration expenditures	**366**	(81)	**995**	987
Cash flow from operations	**64,435**	36,530	**128,572**	72,799
Cash reserved for financing and investing activities	**(7,434)**	(1,491)	**(19,837)**	(6,724)
Cash distributions to unitholders	**57,001**	35,039	**108,735**	66,075
Accumulated cash distributions, beginning of period	**464,380**	279,054	**412,646**	248,018
Accumulated cash distributions, paid and declared, end of period	$ **521,381**	$ 314,093	$ **521,381**	$ 314,093
Cash distributions per unit	$ **0.36**	$ 0.36	$ **0.72**	$ 0.72

Cash reserved for financing and investing activities is a discretionary amount and represents the difference between cash flow from operations less distributions.

12. **Subsequent Event**

On July 22, 2005, the Trust expanded its existing term credit facility to $572.5 million from $410 million. The terms of the banking agreement are substantially unchanged.

13. **Comparative balances**

Certain comparative numbers have been restated to conform to the current period's presentation.

14. **Segmented Information**

The Trust's business activities are conducted through three business segments: Canadian oil and gas production (COGP), United States oil and gas production (USOGP) and Midstream Services and Marketing (Midstream).

Oil and natural gas production in Canada and the United States includes exploitation, development and production of crude oil and natural gas reserves. Midstream includes fractionation, transportation, loading and storage of natural gas liquids, and marketing of crude oil and natural gas liquids.

Geographically, Provident operates in Canada and the USA in the oil and gas production business segment. The geographic components have been presented as well as the midstream and marketing business that operates in Canada. Interest and long-term debt have been allocated to the business segments on the basis of invested capital at net book value.

	Three months ended June 30, 2005					
	Canada Oil and Natural Gas Production	United States Oil and Natural Gas Production	Total Oil & Natural Gas Production	Midstream Services and Marketing	Inter-segment Elimination	Total
Revenue						
Gross production revenue	$ 107,360	$ 37,820	145,180	-	$ -	$ 145,180
Royalties	(22,815)	(3,738)	(26,553)	-	-	(26,553)
Product sales and service revenue	-	-	-	199,798	(13,199)	186,599
Realized gain (loss) on financial derivative instruments	(10,835)	(3,314)	(14,149)	36	-	(14,113)
	73,710	30,768	104,478	199,834	(13,199)	291,113
Expenses						
Cost of goods sold	-	-	-	177,378	(13,199)	164,179
Production, operating and maintenance	22,272	9,925	32,197	8,677	-	40,874
Transportation	1,336	-	1,336	-	-	1,336
Foreign exchange gain (loss)	26	46	72	(57)	-	15
General and administrative	4,965	2,324	7,289	2,071	-	9,360
	28,599	12,295	40,894	188,069	(13,199)	215,764
Earnings before interest, taxes, depletion, depreciation, accretion and non-cash revenue	45,111	18,473	63,584	11,765	-	75,349
Non-cash revenue						
Unrealized gain (loss) on financial derivative instruments	8,231	2,493	10,724	(753)	-	9,971
Amortization of loss on financial derivative instruments	(580)	-	(580)	-	-	(580)
	7,651	2,493	10,144	(753)	-	9,391
Other expenses						
Depletion, depreciation and accretion	41,205	6,677	47,882	2,507	-	50,389
Loss on redemption of convertible debentures	31	10	41	8	-	49
Interest on bank debt	1,182	399	1,581	333	-	1,914
Interest & accretion on convertible debentures	4,038	1,359	5,397	1,084	-	6,481
Amortization of deferred financing charges	293	99	392	76	-	468
Unrealized foreign exchange gain	-	(142)	(142)	(94)	-	(236)
Non-cash general and administrative	243	1,548	1,791	-	-	1,791
Internal management charge	(1,161)	1,161	-	-	-	-
Gain on sale of investment	-	-	-	(5,188)	-	(5,188)
Capital, income and withholding taxes	1,534	2,003	3,537	-	-	3,537
Future income tax recovery	(2,112)	-	(2,112)	-	-	(2,112)
	45,253	13,114	58,367	(1,274)	-	57,093
Non-controlling interest - USOGP	-	504	504	-	-	504
Non-controlling interest - Exchangeables	90	86	176	145	-	321
Net income for the period	$ 7,419	$ 7,262	$ 14,681	$ 12,141	$ -	$ 26,822

	Three months ended June 30, 2005					
	Canada Oil and Natural Gas Production	United States Oil and Natural Gas Production	Total Oil and Natural Gas Production	Midstream Services and Marketing	Inter-segmentElimination	Total
Selected balance sheet items						
Capital Assets						
Property, plant and equipment net	$ 723,749	$ 377,000	$ 1,100,749	$ 271,184	$ -	$ 1,371,933
Goodwill	330,944	-	330,944	-	-	330,944
Capital Expenditures						
Property, plant and equipment net	21,100	15,279	36,379	497	-	36,876
Property, plant and equipment through corporate acquisitions	-	-	-	-	-	-
Goodwill additions	-	-	-	-	-	-
Working capital						
Accounts receivable	40,131	16,889	57,020	93,406	(3,282)	147,144
Petroleum product inventory	-	-	-	23,199	-	23,199
Accounts payable and accrued liabilities	69,756	31,945	101,701	62,756	(3,282)	161,175
Long-term debt	$ 259,716	$ 87,496	$ 347,212	$ 70,270	$ -	$ 417,482

	Three months ended June 30, 2004 [1]					
	Canada Oil and Natural Gas Production	United States Oil and Natural Gas Production	Total Oil & Natural Gas Production	Midstream Services and Marketing	Inter-segmentElimination	Total
Revenue						
Gross production revenue	$ 93,196	$ 2,672	$ 95,868	$ -	$ -	$ 95,868
Royalties	(19,893)	(292)	(20,185)	-	-	(20,185)
Product sales and service revenue	-	-	-	218,854	(50,113)	168,741
Realized loss on financial derivative instruments	(16,367)	-	(16,367)	(466)	-	(16,833)
	56,936	2,380	59,316	218,388	(50,113)	227,591
Expenses						
Cost of goods sold	-	-	-	196,830	(50,113)	146,717
Production, operating and maintenance	18,385	1,017	19,402	10,835	-	30,237
Transportation	694	-	694	-	-	694
Foreign exchange gain	-	-	-	267		267
General and administrative	3,858	388	4,246	1,511	-	5,757
	22,937	1,405	24,342	209,443	(50,113)	183,672
Earnings before interest, taxes, depletion, depreciation, accretion and non-cash revenue	33,999	975	34,974	8,945	-	43,919
Non-cash revenue (expense)						
Unrealized loss on financial derivative instruments	(2,544)	-	(2,544)	-	-	(2,544)
Amortization of loss on financial derivative instruments	(6,743)	-	(6,743)	-	-	(6,743)
Foreign exchange gain		2,519	2,519	-		2,519
	(9,287)	2,519	(6,768)	-		(6,768)
Other expenses					-	
Depletion, depreciation and accretion	36,476	270	36,746	2,277	-	39,023
Interest on bank debt	1,604	425	2,029	900	-	2,929
Interest & accretion on convertible debentures	1,922	365	2,287	1,313	-	3,600
Amortization of deferred financing charges	235	-	235	124	-	359
Non-cash general and administrative recovery	(256)	-	(256)	(20)	-	(276)
Capital taxes	733	157	890	277	-	1,167
Capital, current and withholding taxes	292	-	292	-	-	292
Future income tax recovery	(2,937)	-	(2,937)	(100)	-	(3,037)
	38,069	1,217	39,286	4,771	-	44,057
Non-controlling interest - USOGP	-	130	130	-		130
Non-controlling interest - Exchangeables	(310)	50	(260)	97		(163)
Net income (loss) for the period	**$ (13,047)**	**$ 2,097**	**$ (10,950)**	**$ 4,077**	**$ -**	**$ (6,873)**

[1] Restated - note 2

	Three months ended June 30, 2004 (1)					
	Canada Oil and Natural Gas Production	**United States Oil and Natural Gas Production**	**Total Oil and Natural Gas Production**	**Midstream Services and Marketing**	**Inter-segmentElimination**	**Total**
Selected balance sheet items						
Capital Assets						
Property, plant and equipment net	$ 828,284	$ 212,904	$ 1,041,188	$ 278,433	$ -	$ 1,319,621
Goodwill	323,937	-	323,937	-	-	323,937
Capital Expenditures						
Property, plant and equipment net	10,661	577	11,238	369	-	11,607
Property, plant and equipment through corporate acquisitions	272,259	212,904	485,163	-	-	485,163
Goodwill additions	221,494	-	221,494	-	-	221,494
Working capital						
Accounts receivable	77,230	12,273	89,503	99,156	(18,184)	170,475
Petroleum product inventory	-	-	-	20,332	-	20,332
Accounts payable and accrued liabilities	101,575	18,259	119,834	88,262	(18,184)	189,912
Bridge Financing	-	158,184	158,184	-	-	158,184
Long-term debt	$ 212,631	$ 35,298	$ 247,929	$ 65,271	$ -	$ 313,200

	Six months ended June 30, 2005 [1]					
	Canada Oil and Natural Gas Production	United States Oil and Natural Gas Production	Total Oil and Natural Gas Production	Midstream Services and Marketing	Inter-segment Elimination	Total
Revenue						
Gross production revenue	$ 212,923	$ 66,851	$ 279,774	$ -	$ -	$ 279,774
Royalties	(43,484)	(6,403)	(49,887)	-	-	(49,887)
Product sales and service revenue	-	-	-	521,882	(90,420)	431,462
Realized gain (loss) on financial derivative instruments	(19,294)	(5,668)	(24,962)	511	-	(24,451)
	150,145	54,780	204,925	522,393	(90,420)	636,898
Expenses						
Cost of goods sold	-	-	-	474,219	(90,420)	383,799
Production, operating and maintenance	47,892	17,351	65,243	16,052	-	81,295
Transportation	3,028	-	3,028	-	-	3,028
Foreign exchange loss (gain) and other	769	(504)	265	(117)	-	148
General and administrative	9,448	4,095	13,543	4,094		17,637
	61,137	20,942	82,079	494,248	(90,420)	485,907
Earnings before interest, taxes, depletion, depreciation, accretion and non-cash revenue	89,008	33,838	122,846	28,145	-	150,991
Non-cash revenue						
Unrealized loss on financial derivative instruments	(3,860)	(8,645)	(12,505)	(897)	-	(13,402)
Amortization of loss on financial derivative instruments	(969)	-	(969)	-	-	(969)
	(4,829)	(8,645)	(13,474)	(897)	-	(14,371)
Other expenses						
Depletion, depreciation and accretion	82,757	11,784	94,541	5,009	-	99,550
Loss on redemption of convertible debentures	31	10	41	8	-	49
Interest on bank debt	3,293	1,104	4,397	843	-	5,240
Interest & accretion on convertible debentures	7,598	2,550	10,148	1,945	-	12,093
Amortization of deferred financing charges	350	118	468	90	-	558
Unrealized foreign exchange gain	-	-	-	(256)	-	(256)
Non-cash general and administrative recovery	499	1,923	2,422	-	-	2,422
Internal management charge	(1,161)	1,161	-	-	-	-
Gain on sale of marketing contracts	-	-	-	(5,188)	-	(5,188)
Capital, current and withholding taxes	2,911	4,370	7,281	-	-	7,281
Future income tax recovery	(9,832)	-	(9,832)	-	-	(9,832)
	86,446	23,020	109,465	2,451	-	111,917
Non-controlling interest - USOGP	-	399	399	-	-	399
Non-controlling interest - Exchangeables	(104)	(24)	(128)	393	-	265
Net income (loss) for the period	$ (2,163)	**$ 1,798**	**$ (365)**	**$ 24,404**	**$ -**	**$ 24,039**

[1] Restated - note 2

	Six months ended June 30, 2005					
	Canada Oil and Natural Gas Productio	United States Oil and Natural Gas Production	Total Oil and Natural Gas Production	Midstream Services and Marketing	Inter-segmentElimination	Total
Selected balance sheet items						
Capital Assets						
Property, plant and equipment net	$ 723,749	$ 377,000	$ 1,100,749	$ 271,184	$ -	$ 1,371,933
Goodwill	330,944	-	330,944	-	-	330,944
Capital Expenditures						
Property, plant and equipment net	35,158	30,164	65,322	650	-	65,972
Property, plant and equipment through corporate acquisitions	-	99,877	99,877	-	-	99,877
Goodwill additions	-	-	-	-	-	-
Working capital						
Accounts receivable	40,131	16,889	57,020	93,406	(3,282)	147,144
Petroleum product inventory	-	-	-	23,199	-	23,199
Accounts payable and accrued liabilities	69,756	31,945	101,701	62,756	(3,282)	161,175
Long-term debt	$ 262,325	$ 88,001	$ 350,326	$ 67,156	$ -	$ 417,482

	Six months ended June 30, 2004 (1)					
	Canada Oil and Natural Gas Production	**United States Oil and Natural Gas Production**	**Total Oil & Natural Gas Production**	**Midstream Services and Marketing**	**Inter- segment Elimination**	**Total**
Revenue						
Gross production revenue	$ 173,148	$ 2,672	$ 175,820	$ -	$ (515)	$ 175,305
Royalties	(35,138)	(292)	(35,430)	-	-	(35,430)
Product sales and service revenue	-	-	-	451,699	(80,503)	371,196
Realized loss on financial derivative instruments	(26,209)	-	(26,209)	(280)	-	(26,489)
	111,801	2,380	114,181	451,419	(81,018)	484,582
Expenses						
Cost of goods sold	-	-	-	408,271	(81,018)	327,253
Production, operating and maintenance	36,889	1,017	37,906	19,879	-	57,785
Transportation	1,928	-	1,928	-	-	1,928
Foreign exchange gain	-	-	-	(248)		(248)
General and administrative	8,244	388	8,632	2,375	-	11,007
	47,061	1,405	48,466	430,277	(81,018)	397,725
Earnings before interest, taxes, depletion, depreciation, accretion and non-cash revenue	64,740	975	65,715	21,142	-	86,857
Non-cash revenue						
Unrealized loss on financial derivative instruments	(16,938)	-	(16,938)	(1,058)	-	(17,996)
Amortization of loss on financial derivative instruments	(13,335)	-	(13,335)	-	-	(13,335)
Forign exchange gain		2,519	2,519	-		2,519
	(30,273)	2,519	(27,754)	(1,058)		(28,812)
Other expenses						
Depletion, depreciation and accretion	68,629	270	68,899	4,573	-	73,472
Interest on bank debt	2,628	425	3,053	2,020	-	5,073
Interest & accretion on convertible debentures	4,694	365	5,059	2,590	-	7,649
Amortization of deferred financing charges	472	-	472	246	-	718
Non-cash general and administrative recovery	(640)	-	(640)	(55)	-	(695)
Capital taxes	1,628	157	1,785	387	-	2,172
Current and withholding taxes	292		292	-	-	292
Future income tax expense (recovery)	(19,876)	-	(19,876)	2,290	-	(17,586)
	57,827	1,217	59,044	12,051	-	71,095
Non-controlling interest - USOGP		130	130	-		130
Non-controlling interest - Exchangeables	(552)	50	(502)	190		(312)
Net income (loss) for the period	$ (22,808)	$ 2,097	$ (20,711)	$ 7,843	$ -	**$ (12,868)**

(1) Restated - note 2

	Six months ended June 30, 2004 (1)					
	Canada Oil and Natural Gas Production	**United States Oil and Natural Gas Production**	**Total Oil and Natural Gas Production**	**Midstream Services and Marketing**	**Inter-segment Elimination**	**Total**
Selected balance sheet items						
Capital Assets						
Property, plant and equipment net	$ 828,284	$ 212,904	$ 1,041,188	$ 278,433	$ -	$ 1,319,621
Goodwill	323,937	-	323,937	-	-	323,937
Capital Expenditures						
Property, plant and equipment net	21,641	577	22,218	908	-	23,126
Property, plant and equipment through corporate acquisitions	272,259	212,904	485,163	-	-	485,163
Goodwill additions	221,494	-	221,494	-	-	221,494
Working capital						
Accounts receivable	77,230	12,273	89,503	99,156	(18,184)	170,475
Petroleum product inventory	-	-	-	20,332	-	20,332
Accounts payable and accrued liabilities	101,575	18,259	119,834	88,262	(18,184)	189,912
Bridge Financing		158,184	158,184	-	-	158,184
Long-term debt	$ 209,781	$ 17,634	$ 227,415	$ 85,785	$ -	$ 313,200

(1) Restated - note 2