

Progress Energy Trust – Active Second Quarter Drilling Program

Consistent Hedging Program Drives Strong Cash Flow

	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	2006	2005
FINANCIAL HIGHLIGHTS				
Income Statement (\$ thousands, except per unit amounts)				
Petroleum and natural gas revenue	81,009	83,222	171,968	162,229
Cash flow ¹	45,871	44,466	93,508	86,977
Per unit – diluted ²	0.52	0.53	1.07	1.05
Cash distributions declared	31,412	28,874	62,248	57,448
Per unit	0.42	0.42	0.84	0.84
Payout Ratio				
Excluding exchangeable shares	68%	65%	67%	66%
Including exchangeable shares	80%	79%	78%	80%
Balance Sheet (\$ thousands)				
Working capital deficiency	25,625	27,297	25,625	27,297
Bank debt	102,355	67,171	102,355	67,171
Convertible debentures	54,893	91,240	54,893	91,240
Total debt	182,873	185,708	182,873	185,708
Capital expenditures	32,489	13,559	68,473	47,939
OPERATIONAL HIGHLIGHTS				
Average Daily Production				
Natural gas (mcf/d)	82,271	79,236	84,341	81,865
Crude oil (bbls/d)	2,099	3,067	2,351	2,810
Natural gas liquids (bbls/d)	1,478	1,305	1,434	1,451
Total daily production (boe/d)	17,288	17,578	17,842	17,905
Average Realized Prices				
Natural gas - before hedging (\$/mcf)	6.53	8.12	7.68	7.70
Natural gas - after hedging (\$/mcf)	7.83	8.13	8.29	7.90
Crude oil (\$/bbl)	72.79	64.20	68.19	62.05
Natural gas liquids (\$/bbl)	63.34	56.41	63.11	51.70
Wells Drilled, Net	11.4	4.5	32.5	17.0

(1) Cash flow is a non-GAAP term, refer to Management's Discussion and Analysis attached.

(2) Total units outstanding include trust units plus exchangeable shares outstanding at period end. The exchangeable shares are converted at the exchange ratio at the end of the period.

Progress Energy Trust (“Progress” or “Trust”) drilled 15 gross wells (11.4 net) in the second quarter with a 100 percent success rate. Five wells were drilled in the Foothills of northeast British Columbia, five wells were drilled in the Deep Basin region of northwest Alberta and five wells were drilled in the Gilby area of central Alberta. With the second quarter typically being an active facility turnaround period, daily production averaged 17,288 barrels of oil equivalent (“boe”) compared to 17,578 boe in the second quarter of 2005.

“Excellent spring weather and good ground conditions created the opportunity to keep rigs operating continuously through break-up allowing us to drill wells originally planned for the third quarter,” said Michael Culbert, President and CEO of Progress. “Production from our successful spring drilling program is expected to be tied-in during the third quarter.”

Progress generated cash flow from operations of \$45.9 million or \$0.52 per unit, diluted, for the second quarter of 2006, compared to \$44.5 million or \$0.53 per unit, diluted, in the second quarter of 2005. Cash distributions declared totaled \$31.4 million or \$0.42 per trust unit resulting in a payout ratio of 68 percent excluding exchangeable shares, which do not receive cash distributions, and 80 percent including exchangeable shares.

Active Second Quarter Drilling Program

Progress had a very active second quarter drilling 15 wells (11.4 net) in three of its core operating regions. In the Deep Basin region in northwest Alberta, Progress had one rig operating throughout the quarter drilling five gas (5.0 net) wells that are expected to be on production by mid-August. Consistent with the variable quality of the sands across the Deep Basin, one of the gas wells tested in excess of 4,000 thousand cubic feet (“mcf”) per day while the balance tested in the range of 750 mcf per day to 1,000 mcf per day. In northeast British Columbia, Progress drilled five wells (2.6 net) in its Foothills project area. All wells were successful gas wells the most significant of which was the deep Debolt exploration discovery at Julienne which will set up a number of new opportunities. This well, in which Progress has a 20 percent working interest, was completed in May and is on production at approximately 2,500 mcf per day. In the Gilby area in central Alberta, five wells (3.8 net) were drilled resulting in four shallow Edmonton sand gas wells and one Glauconite sand oilwell.

Progress will have two to four rigs drilling in the third quarter primarily in the Deep Basin of northwest Alberta and the Foothills and Plains regions of northeast British Columbia.

Preliminary interpretations have been completed on the 280 square kilometer Sasquatch 3-D seismic program recorded this winter to the north of Progress’ current Foothills operations. Initial results suggest a number of features controlled by Progress are present and will be tested over the next 12 months as part of the exploration and development drilling program.

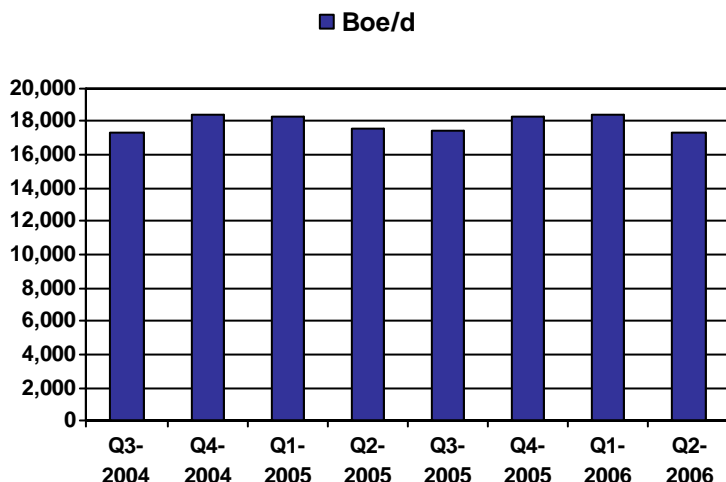
During the second quarter, the Trust added over 8,345 net acres of prospective exploratory acreage from Crown land sales.

Spring Plant Turnarounds Impact Second Quarter Production

Production for the second quarter averaged 17,288 boe per day, 1.6 percent lower than the second quarter of 2005. Second quarter production was impacted by scheduled plant maintenance turnarounds at a number of the gas plants which the Trust owns or through which Trust production flows including Karr, Gold Creek-Dunes, Two Creek, Strachan and Gilby impacting Trust production by approximately 450 boe per day in the quarter. Production was also impacted by approximately 350 boe per day due to construction and regulatory challenges with the waterflood recovery project in the Halfway ‘C’ oil pool at Gold Creek.

In the two years that Progress has operated as an energy trust, it has achieved a very consistent production profile as shown in the graph below by maintaining production through drilling without acquisitions. In quarters where no maintenance occurred within the Trust’s main operating regions, production averaged between 18,000 and 18,500 boe per day. In quarters where maintenance was scheduled, production averaged between 17,200 and 17,600 boe per day. Plant maintenance occurred at Progress’ Gold Creek plant in the third quarter of 2004 and at

its Karr plant in the second quarter of 2006. A plant turnaround at the Duke owned McMahon gas processing facility occurred in the second and third quarters of 2005. The third quarter of 2006 will be impacted by a 20-day shut down of the Fort Nelson gas process facility in northeast British Columbia. Production for the third quarter is expected to average between 17,600 and 18,000 boe per day and average approximately 18,000 boe per day for 2006. Progress' paced drilling program and success rates result in the Trust typically having approximately 1,000 boe per day behind pipe which replaces declines as it is brought on-stream.



Natural Gas Hedges and Low Cost Structure Generates Strong Netbacks

The Trust's average gas price realization in the quarter was \$7.83 per mcf after hedging, four percent lower than the comparable quarter in 2005. Progress receives a premium to AECO because of the high heat content nature of its gas production.

"We currently have approximately 45 percent of our before royalty gas production hedged through the end of March of 2007, achieving an average wellhead realization of approximately \$10.00 per mcf," said Mr. Culbert. "Given our sensitivity to natural gas prices, we will continue to hedge a portion of our gas production as part of our overall risk management program."

A \$0.50 per GJ change in the AECO gas price impacts Progress' cash flow by approximately \$10 million which is the same impact as production of 5 million cubic feet per day.

Operating expenses averaged \$6.15 per boe in the second quarter of 2006 compared to \$5.72 per boe in the second quarter of 2005. Higher second quarter operating costs include costs associated with the spring maintenance turnarounds. On a per boe basis, the Trust's cash flow was six percent higher in the second quarter of 2006 compared to the second quarter of 2005. Lower transportation and interest expense were the key drivers as well as lower royalties. Royalties are levied against the Trust's pre-hedged realized price.

Maintaining financial strength

The Trust invested \$32.5 million in the second quarter, including \$18.5 million for drilling and completions, \$8.2 million for facilities construction and \$5.0 million for land and seismic data acquisition.

Progress' total debt-to-12-month trailing cash flow was 0.9 times at June 30, 2006. The Trust maintains a conservative capital structure and has used hedging as a means to protect the Trust's cash flows supporting its capital program and distributions. At June 30, 2006, Progress had utilized \$102 million on its \$215 million credit facility, resulting in \$113 million of available borrowing capacity.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis ("MD&A") of financial results is dated July 27, 2006 and is to be read in conjunction with the accompanying unaudited consolidated interim financial statements and related notes for the period ended June 30, 2006 and the audited consolidated financial statements and related notes and MD&A of Progress Energy Trust ("Progress" or the "Trust") for the year ended December 31, 2005. The financial data presented has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The reporting and the measurement currency is the Canadian dollar.

Non-GAAP Measurements Management uses cash flow from operations (before changes in non-cash working capital) ("cash flow") to analyze operating performance and leverage. The term distributable cash is also used to present the amount of cash that the Trust distributes to unitholders. Neither distributable cash nor cash flow presented have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Distributable cash and cash flow as presented are not intended to represent operating profit for the period nor should they be viewed as an alternative to operating profit, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. The reconciliation between net earnings and cash flow can be found in the consolidated statements of cash flows in the unaudited interim financial statements. Distributable cash is calculated using cash flow less cash withheld for capital expenditures. The Trust considers cash flow to be a key measure as it demonstrates the Trust's ability to generate the cash necessary to pay distributions, repay debt and to fund future capital investments. Both distributable cash and cash flow are used by research analysts to value and compare oil and gas trusts and are frequently included in published research when providing investment recommendations. Cash flow per unit is calculated using the diluted weighted average number of units for the period. All references to cash flow throughout the MD&A are based on cash flow before changes in non-cash working capital.

Management uses certain industry benchmarks such as operating netback and payout ratio to analyze financial and operating performance. These benchmarks as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities.

Forward-Looking Statements Certain information regarding Progress set forth in this document, including Management's assessment of the Trust's future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond the Trust's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Progress' actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that the Trust will derive there from.

Description of Business

Progress is an open-ended, unincorporated investment trust governed by the laws of the province of Alberta. The principal undertaking of the Trust is to indirectly explore for, develop and hold interests in petroleum and natural gas properties. Progress Energy Ltd., a wholly owned subsidiary of Progress, carries on the business of the Trust and directly owns the petroleum and natural gas properties and assets related thereto. The Trust's unitholders and exchangeable shareholders are the sole beneficiaries of the Trust. Under the Trust Indenture, the Trust may declare payable to unitholders all or any part of the income of the Trust which is primarily comprised of interest earned on debt notes issued to Progress Energy Ltd., as well as, amounts attributed to a net profits interest agreement entered into with Progress Energy Ltd. The aggregate amounts received by the Trust each period are based on the consolidated cash flow each period, as adjusted on a discretionary basis, for cash withheld to fund capital expenditures.

Progress is a Calgary based, natural gas focused, trust targeting sustainable production and reserves per trust unit through utilization of its technical capability and capital investment efficiencies. Primary operating regions include the Deep Basin of northwest Alberta and the northeast British Columbia Foothills and Fort St. John Plains regions. Trust units of Progress trade on the Toronto Stock Exchange (“TSX”) under the symbol PGX.UN. Exchangeable shares and 6.75% convertible unsecured subordinated debentures (the “Debentures”) of Progress trade on the TSX under the symbols PGE and PGX.DB respectively.

Relationship with ProEx Energy Ltd.

The Trust provides personnel and certain administrative and technical services to ProEx Energy Ltd. (“ProEx”) in connection with the management, development, exploitation and operation of the assets of ProEx and the marketing of its production. The Trust provides these services in accordance with the technical services agreement (“Technical Services Agreement”) entered into with ProEx as described below.

The Trust and ProEx have joint interest in certain properties and undeveloped land in the northeast British Columbia Foothills and Fort St. John Plains regions. These joint interest properties are governed by standard industry agreements and in addition the Trust has entered into a protocol arrangement (“Protocol Arrangement”) with ProEx that specifies how each company will manage the joint lands in specifically identified areas of interest. To ensure good governance practices, both the Trust and ProEx have each created independent committees of their Board of Directors to monitor compliance with the Technical Services Agreement and the Protocol Arrangement.

Technical Services Agreement The Technical Services Agreement has no set termination date and will continue until terminated by either party with one year prior written notice to the other party or some other date as mutually agreed. The Trust provides services including management, development, exploitation, operations, administrative, and marketing, as well as, information technology systems to ProEx on an expense reimbursement basis, based on ProEx’s monthly capital activity and production levels relative to the combined capital activity and production levels of both the Trust and ProEx.

Protocol Arrangement The Protocol Arrangement identifies methods and processes to be followed on both existing and new lands, joint facilities, marketing, seismic and surface rights. The Protocol Arrangement also outlines the practices to be followed in the event either party enters into areas outside of the identified areas of interest.

OPERATING SUMMARY

In accordance with Canadian industry practice, production volumes, reserve volumes and revenues are reported on a Trust interest basis (working interest plus royalty interest), before deduction of Crown and other royalties, unless otherwise indicated. The Trust’s results of operations are dependent on production volumes of natural gas, crude oil and natural gas liquids and the prices received for this production. Prices for these commodities have shown significant volatility during recent years and are determined by supply and demand factors, including weather, general economic conditions and changes in the Canadian/United States (“US”) currency exchange rate.

In this MD&A, production and reserves information may be presented on a “barrel of oil equivalent” or “boe” basis with six thousand cubic feet (“mcf”) of natural gas being equivalent to one barrel (“bbl”) of crude oil or natural gas liquids. Boe’s may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Production

	Three Months Ended June 30		Six Months Ended June 30		Change
	2006	2005	2006	2005	
Average Daily Production					
Natural gas (<i>mcf/d</i>)	82,271	79,236	84,341	81,865	3%
Crude oil (<i>bbls/d</i>)	2,099	3,067	2,351	2,810	(16)%
Natural gas liquids (<i>bbls/d</i>)	1,478	1,305	1,434	1,451	(1)%
Total daily production (<i>boe/d</i>)	17,288	17,578	17,842	17,905	-
Natural gas as a % of total production	79%	75%	79%	76%	

For the three months ended June 30, 2006 (the “Quarter”), Progress’ production averaged 17,288 boe per day consisting of 82,271 mcf per day of natural gas, 2,099 bbls per day of crude oil and 1,478 bbls per day of natural gas liquids. Production during the Quarter was slightly lower than the same period in 2005 of 17,578 boe per day. The Trust’s production portfolio for the Quarter was weighted 79 percent to natural gas, 12 percent to crude oil and nine percent to natural gas liquids.

Natural gas production of 82,271 mcf per day during the Quarter was slightly higher than the same period in 2005 of 79,236 mcf per day as successful drilling results exceeded the impact of production downtime from plant turnarounds during the Quarter. Production for the Quarter was reduced by approximately 450 boe per day as a result of scheduled plant maintenance turnarounds at a number of gas plants including Karr, Gold Creek-Dunes, Two Creek, Strachan and Gilby. Crude oil and natural gas liquids production for the Quarter of 3,577 bbls per day was lower than the 4,372 bbls per day produced during same period in 2005. Crude oil production for the Quarter was reduced by approximately 350 bbls per day due to construction and regulatory challenges with the waterflood recovery project in the Halfway ‘C’ oil pool at Gold Creek.

Year-to-date 2006 production was 17,842 boe per day consisting of 84,341 mcf per day of natural gas, 2,351 bbls per day of crude oil and 1,434 bbls per day of natural gas liquids. This production was consistent with the same period in 2005 of 17,905 boe per day. The Trust’s production portfolio for the six months ended June 30, 2006 was weighted 79 percent to natural gas, 13 percent to crude oil and eight percent to natural gas liquids.

Management anticipates production to average approximately 18,000 boe per day in 2006. This estimate takes into account natural reservoir declines and forecasted capital expenditures of \$115 million.

Production by Region

	Three Months Ended June 30		Six Months Ended June 30		Change
	2006	2005	2006	2005	
Average Daily Production (boe/d)					
Foothills	3,602	2,801	3,657	2,997	22%
Fort St. John Plains	2,094	2,384	2,164	2,391	(9)%
Other	439	557	430	559	(23)%
Total British Columbia	6,135	5,742	6,251	5,947	5%
Deep Basin	8,156	9,216	8,593	9,233	(7)%
Central Alberta	1,865	1,426	1,785	1,508	18%
Other	787	758	850	816	4%
Total Alberta	10,808	11,400	11,228	11,557	(3)%
Saskatchewan	345	436	363	401	(9)%
Total daily production	17,288	17,578	17,842	17,905	-

Pricing and Risk Management

Natural Gas Markets

Progress' realized natural gas price for the Quarter was \$6.53 per mcf, before the impact of hedging, compared to the AECO daily index average of \$5.69 per gigajoule ("gj"). The higher realization reflects the higher heat content of Progress' natural gas stream. Including the impact of hedging, the Trust realized an average of \$7.83 per mcf.

For the six months ended June 30, 2006 Progress' realized natural gas price was \$7.68 per mcf, before the impact of hedging, compared to the AECO daily index average of \$6.41 per gj. Including the impact of hedging, the Trust realized an average of \$8.29 per mcf.

Natural gas prices across North America continued to weaken throughout the Quarter. Demand is typically lower during the second quarter, referred to as the 'shoulder season', because of a lack of weather related demand in advance of the summer cooling season. As well, the immense overhang of natural gas in storage remains the largest impediment to any near term recovery in natural gas prices.

The North American natural gas supply-demand imbalance is likely to remain tight and volatile over the coming months. Natural gas remains one of the cheapest fuels on a heating equivalency basis and should provide support for gas prices as dual fuel users make the economic decision to switch to natural gas.

In the longer term, weaker gas prices, if sustained, will have the likely impact of reducing rig activity across North America and ultimately gas completions. This would further exacerbate the challenges for production in North America which is running harder and faster to offset steep annual declines in natural gas production.

Oil Markets

Progress' realized prices for its liquids streams for the Quarter were \$72.79 per bbl for crude oil and \$63.34 per bbl for natural gas liquids and for the six months ended June 30, 2006 were \$68.19 per bbl for crude oil and \$63.11 per bbl for natural gas liquids.

Crude oil prices continued to strengthen through the Quarter reaching an all-time high of US\$77.03 per bbl on July 14th. Global crude markets remain in a tight supply and demand balance. Recent heightened political tensions in the Middle East and a potential Israel-Lebanon war will only add further uncertainty about OPEC's ability to increase supply. Non-OPEC supply growth also remains weak and forecasters have been lowering estimates for this component of supply.

Although global crude demand growth has not slowed appreciably, there are concerns that economic growth is slowing, particularly in the US. Rising interest rates and inflation concerns remain at the forefront of discussions about US economic activity. Globally, the oil demand picture is ever evolving with a steady rotation toward transportation fuels and economic growth in developing countries such as China and India. This growth will likely continue to underpin the demand for light sweet crude streams like West Texas Intermediate ("WTI") and weigh upon heavier grades of crude. Progress' crude oil production is made up predominately of light crude and does not include any heavy oil.

Commodity Prices

	Three Months Ended June 30		Six Months Ended June 30		Change
	2006	2005	2006	2005	
Average Benchmark Prices					
Natural gas – AECO (daily) (\$/gj)	5.69	6.98	6.41	6.76	(5)%
Natural gas – AECO (monthly) (\$/gj)	5.95	6.99	7.37	6.67	10%
Crude oil – WTI (US\$/bbl)	70.70	53.17	67.09	51.51	30%
Crude oil – Edmonton par price (Cdn\$/bbl)	78.60	65.79	73.80	63.64	16%
Exchange rate (Cdn\$/US\$)	1.1224	1.2439	1.1385	1.2355	(8)%
Average Realized Prices					
Natural gas - before hedging (\$/mcf)	6.53	8.12	7.68	7.70	-
Hedge settlements (\$/mcf)	1.45	-	0.67	0.20	235%
Hedge premiums (\$/mcf)	(0.17)	(0.01)	(0.08)	(0.02)	300%
Amortization of commodity sales contract (\$/mcf) ¹	0.02	0.02	0.02	0.02	-
Natural gas - after hedging (\$/mcf)	7.83	8.13	8.29	7.90	5%
Crude oil (\$/bbl)	72.79	64.20	68.19	62.05	10%
Natural gas liquids (\$/bbl)	63.34	56.41	63.11	51.70	22%

(1) Amortization of physical natural gas sales contract acquired in conjunction with the acquisition of Campion Resources Ltd. on June 3, 2002. Contract expires in 2008.

Risk Management

The Trust has entered into several natural gas financial contracts for the purpose of protecting its cash flow from the volatility of natural gas prices. For the Quarter, the Trust's natural gas price risk management program had a net gain of \$9.6 million (2005 - \$0.1 million net loss), which is included in petroleum and natural gas revenue on the statements of earnings. For the six months ended June 30, 2006, the Trust's natural gas price risk management program had a net gain of \$9.0 million (2005 - \$2.6 million net gain).

The Trust's hedging activities are conducted pursuant to the Trust's Risk Management Policy approved by the Board of Directors. Progress uses financial derivative instruments designed to establish a minimum floor price while retaining exposure to upside price movements. The Risk Management Policy has the following objectives:

- To reduce risk exposure to budgeted annual cash flow projections resulting from uncertainty or changes in commodity prices, interest rates or foreign exchange.
- To provide greater certainty and stability to monthly distributions.
- To limit the permissible structures to ensure hedging effectiveness.
- To limit hedging up to a maximum of 50 percent of budgeted production before royalties.
- To limit hedging activity to counter-parties that provide sufficient collateral in support of payment or have investment grade credit ratings.

Progress' commodity risk management positions are described in Note 10 in the unaudited interim consolidated financial statements attached. The Trust currently has natural gas instruments in place which consist of swap and call spread contracts, for the following production volumes:

	Contract Natural Gas Volumes (^{'000} gj/d)	% of Estimated Natural Gas Production
Third quarter of 2006	40.0	45
Fourth quarter of 2006	40.0	45
First quarter of 2007	40.0	45

Revenue

For the Quarter, petroleum and natural gas revenue decreased three percent to \$81.0 million from \$83.2 million for the same period in 2005 due to lower realized natural gas prices. Production revenue before hedging for the Quarter consisted of \$48.9 million from natural gas sales, \$13.9 million from crude oil sales and \$8.5 million from the sale of natural gas liquids.

For the six months ended June 30, 2006, revenues increased six percent to \$172.0 million from \$162.2 million for the same period in 2005 due to higher realized commodity prices after the impact of hedging.

(\$ thousands)	Three Months Ended June 30		Six Months Ended June 30		Change
	2006	2005	2006	2005	
Natural gas sales	48,874	58,527	117,319	114,168	3%
Crude oil sales	13,904	17,920	29,016	31,559	(8)%
Natural gas liquids sales	8,517	6,698	16,381	13,577	21%
Hedge settlements	10,853	(4)	10,244	2,926	250%
Hedge premiums	(1,283)	(83)	(1,283)	(333)	285%
Amortization of commodity sales contract ¹	144	164	291	332	(12)%
Petroleum and natural gas revenue	81,009	83,222	171,968	162,229	6%

(1) Amortization of physical natural gas sales contract acquired in conjunction with the acquisition of Campion Resources Ltd. on June 3, 2002. Contract expires in 2008.

(\$ thousands)	Natural Gas	Crude Oil & NGLs	Total
Three months ended June 30, 2005 petroleum and natural gas revenue	58,604	24,618	83,222
Price variance	(2,261)	(844)	(3,105)
Production variance	2,245	(1,353)	892
Three months ended June 30, 2006 petroleum and natural gas revenue	58,588	22,421	81,009

(\$ thousands)	Natural Gas	Crude Oil & NGLs	Total
Six months ended June 30, 2005 petroleum and natural gas revenue	117,093	45,136	162,229
Price variance	5,937	5,303	11,240
Production variance	3,541	(5,042)	(1,501)
Six months ended June 30, 2006 petroleum and natural gas revenue	126,571	45,397	171,968

Royalties

Royalty expense consists of royalties paid to provincial governments, freehold landowners and overriding royalty owners, net of credits received through the Alberta royalty tax credit program. For the Quarter, royalties decreased 11 percent to \$18.8 million from \$21.1 million for the same period in 2005 due to lower revenues. For the six months ended June 30, 2006 royalties increased seven percent to \$43.4 million from \$40.4 million in 2005 due to higher revenues. The Trust's average royalty rate (after removing the effects of hedging charges) for the Quarter was 26.3 percent compared to 25.3 percent in 2005. The year-to-date average royalty rate was 26.7 percent compared to 25.4 percent in 2005.

Management anticipates, based on current commodity prices, the average royalty rate for the remainder of 2006, before the impact of hedging will be approximately 26.0 percent of petroleum and natural gas revenue.

Operating Expenses

Operating expenses during the Quarter increased six percent to \$9.7 million from \$9.1 million for the same period in 2005 and for the six months ended June 30, 2006 increased four percent to \$19.3 million compared to \$18.5 million for the same period in 2005. The variance is due to increased plant turnaround costs in 2006 compared to 2005. On a boe basis, operating expenses for the Quarter increased eight percent to \$6.15 from \$5.72 in the same period in 2005, while year-to-date operating expenses increased five percent to \$5.98 from \$5.70 in the same period in 2005. Progress has experienced increased costs for well servicing, insurance, workovers and well maintenance. Through increased operating efficiencies and the addition of low operating cost per boe production, the Trust has been able to offset a large portion of these increases and keep operating costs per boe for the three and six months ended June 30, 2006 consistent with the same periods in 2005.

Management anticipates operating expense for the remainder of 2006 to be between \$5.50 to \$6.00 per boe.

Transportation Expenses

Transportation expenses for the Quarter decreased 17 percent to \$2.6 million compared to \$3.2 million for the same period in 2005. For the six months ended June 30, 2006 transportation expenses decreased seven percent to \$5.8 million compared to \$6.3 million for the same period in 2005. The decrease is due to reduced tolls negotiated with Duke Energy in 2006, as well as lower oil production in 2006 which incur higher transportation costs. On a boe basis, transportation expenses during the Quarter decreased 15 percent to \$1.68 compared to \$1.98 for the same period in 2005, while year-to-date transportation expenses decreased seven percent to \$1.80 compared to \$1.93 for the same period in 2005. In British Columbia, there is an infrastructure owned by Duke Energy that enables gas producers to avoid facility construction in exchange for regulated gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

Operating Netbacks

Although many wells produce both crude oil and natural gas, a well is categorized as a natural gas well or an oil well based upon the higher proportion of natural gas or crude oil production. The following table summarizes the operating netbacks for natural gas and oil properties for the three and six months ended June 30, 2006 compared to the same periods in 2005:

	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	2006	2005
Natural Gas Properties (\$/mcf)				
Sales price - before hedging	7.03	8.31	8.01	7.86
Hedging settlements	1.34	-	0.63	0.18
Hedge premiums	(0.16)	(0.01)	(0.08)	(0.02)
Amortization of commodity sales contract	0.02	0.02	0.02	0.02
Royalties	(1.64)	(2.09)	(2.11)	(2.14)
Operating expenses	(0.88)	(0.93)	(0.91)	(0.85)
Transportation expenses	(0.27)	(0.33)	(0.30)	(0.32)
Operating netback – natural gas properties	5.44	4.97	5.26	4.73
Oil Properties (\$/bbl)				
Sales Price	64.15	60.57	62.79	57.82
Royalties	(24.43)	(15.73)	(17.64)	(10.74)
Operating expenses	(11.38)	(6.37)	(8.69)	(8.30)
Transportation expenses	(1.87)	(1.92)	(1.84)	(1.86)
Operating netback – oil properties	26.47	36.55	34.62	36.92
All Properties (\$/boe)				
Sales Price – before hedging	45.32	51.98	50.39	49.16
Hedging settlements	6.90	-	3.17	0.90
Hedge premiums	(0.82)	(0.05)	(0.40)	(0.10)
Amortization of commodity sales contract	0.09	0.10	0.09	0.10
Royalties	(11.94)	(13.16)	(13.44)	(12.46)
Operating expenses	(6.15)	(5.72)	(5.98)	(5.70)
Transportation expenses	(1.68)	(1.98)	(1.80)	(1.93)
Operating netback – all properties	31.72	31.17	32.03	29.97

General and Administrative Expenses

For the Quarter, general and administrative expenses net of overhead recoveries, (“G&A”) decreased 20 percent to \$1.7 million (\$1.08 per boe) compared to \$2.1 million (\$1.33 per boe) for the same period in 2005. For the six months ended June 30, 2006, G&A expenses decreased 16 percent to \$3.5 million (\$1.08 per boe) compared to \$4.1 million (\$1.28 per boe) for the same period in 2005. The decrease in G&A for the Quarter and year-to-date is due to higher overhead recoveries as a result of the higher capital spending in 2006 compared to 2005, as well as higher technical service fees from ProEx as a result of its increased production.

In accordance with the Technical Services Agreement with ProEx, the Trust provides personnel and certain administrative and technical services in connection with the management, development, exploitation and operation of the assets of ProEx and the marketing of its production. The Trust provides these services to ProEx on an expense reimbursement basis, based on ProEx’s monthly capital activity and production levels relative to

the combined capital activity and production levels of both the Trust and ProEx. Total expenses reimbursed by ProEx for the Quarter were \$0.9 million (2005 - \$0.6 million) and for the six months ended June 30, 2006 were \$2.0 million (2005 - \$1.1 million).

The Trust capitalized approximately \$0.2 million of G&A during the Quarter (2005 - \$0.4 million) and \$0.5 million for the six months ended June 30, 2006 (2005 - \$0.8 million). The majority of these costs represent geological and geophysical salaries.

Management anticipates G&A expenses to average in the range of \$1.00 to \$1.20 per boe for the remainder of 2006.

Unit Based Compensation Expenses

For the Quarter, unit based compensation expenses relating to the performance unit incentive plan increased 97 percent to \$1.0 million (\$0.64 per boe) compared to \$0.5 million (\$0.32 per boe) for the same period in 2005. For the six months ended June 30, 2006 unit based compensation expenses increased 97 percent to \$2.0 million (\$0.62 per boe) compared to \$1.0 million (\$0.32 per boe) for the same period in 2005. The increase is due to the performance units granted effective July 2, 2005. The Progress performance unit plan provides for employees and directors to be granted performance units which vest at the end of a three year performance period at which time they will be converted to trust units, or the cash equivalent, and include the accumulated distributions over the three year period. The actual number of trust units paid is dependent upon a performance factor that is determined based on the Trust's performance relative to its peers and ranges from 0.5 to 1.5 times the initial grant. Payment may be in the form of cash or trust units, at the Trust's option. Management anticipates, at the end of the performance period, accumulated distributions will be paid in cash and trust units will be paid from treasury. Progress' performance unit incentive plan is described in note 7 in the unaudited consolidated interim financial statements attached.

Management anticipates unit based compensation expenses will average \$0.75 per boe in 2006 as an additional layer of performance units were granted in the third quarter.

Interest and Financing Expenses

Interest and financing expenses during the Quarter decreased 13 percent to \$2.5 million compared to \$2.9 million for the same period in 2005. For the six months ended June 30, 2006 interest and financing expenses of \$4.9 million were consistent with the same period in 2005 of \$5.0 million. The decrease in Debenture interest in 2006, due to convertible debenture conversions, was offset by higher interest on bank debt due to higher debt levels in 2006. For a further discussion of the Debentures see the "Liquidity and Capital Resources" section below.

(\$ thousands)	Three Months Ended		Six Months Ended	
	2006	2005	2006	2005
Interest on bank debt	1,238	750	2,160	1,507
Interest on Debentures	1,023	1,706	2,213	2,760
Amortization of Debenture issue costs	125	207	263	337
Accretion on debt portion of Debentures ¹	134	223	279	362
Total interest and financing expense	2,520	2,886	4,915	4,966

(1) Under Canadian GAAP, the fair value of the conversion feature of the Debentures is classified as equity and the remainder is classified as debt. Over the term of the Debentures, the debt portion will accrete up to the principal balance at maturity with the charge going to interest and financing expenses.

Depletion, Depreciation and Accretion

For the Quarter, depletion and depreciation of property, plant and equipment and the accretion of the asset retirement obligations (“DD&A”) of \$22.8 million was consistent with the same period in 2005 of \$22.7 million. For the six months ended June 30, 2006 DD&A of \$46.4 million was consistent with the same period in 2005 of \$45.8 million. On a boe basis, DD&A for the Quarter was \$14.49 compared to \$14.19 for the same period in 2005 and for the six months ended June 30, 2006 was \$14.38 compared to \$14.12 for the same period in 2005.

Management expects depletion, depreciation and accretion per boe for the remainder of 2006 to be approximately \$14.50 per boe.

Income and Capital Taxes

Capital taxes for the Quarter decreased 146 percent to a recovery of \$0.2 million compared to an expense of \$0.5 million for the same period in 2005. For the six months ended June 30, 2006 capital taxes decreased 92 percent to \$0.1 million compared to \$1.1 million for the same period in 2005. The decrease is due to the federal budget passed during the Quarter which eliminates the large corporation tax effective for the 2006 taxation year.

The provision for future income taxes for the Quarter was a recovery of \$11.0 million compared to an expense of \$0.9 million in same period in 2005. For the six months ended June 30, 2006 the provision for future income taxes was a recovery of \$11.9 million compared to a recovery of \$1.5 million for the same period in 2005. The three and six months ended June 30, 2006 include a recovery of \$8.2 million relating to a reduction in future federal and provincial income tax rates enacted during the Quarter and includes the impact of certain tax balance adjustments. The three and six months ended June 30, 2005 includes a charge of \$3.0 million due to adjustments relating to tax audits performed during the periods. The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. It is expected the Trust will not incur any cash income taxes in the future and as such the future tax liability recorded on the balance sheet will recover through future net earnings.

Non-Controlling Interest - Exchangeable Shares

The exchangeable shares of the Trust’s subsidiary trade on the TSX, thereby allowing holders of the exchangeable shares to dispose of them without having to exchange them for trust units and consequently, they must be classified as non-controlling interest outside of unitholders’ equity. The net earnings attributable to the exchangeable shares is charged to the consolidated statement of earnings as non-controlling interest with a corresponding increase to non-controlling interest on the consolidated balance sheet.

	Six Months Ended June 30			
	2006		2005	
<i>(\$ thousands, except unit amounts)</i>	Number	Amount	Number	Amount
Exchangeable Shares				
Balance, beginning of period	11,388,751	127,205	14,533,506	141,060
Exchanged for trust units	(1,480,512)	(16,906)	(1,787,326)	(17,588)
Non-controlling interest expense		8,609		7,296
Balance, end of period	9,908,239	118,908	12,746,180	130,768

The charge to net earnings of \$8.6 million for 2006 and \$7.3 million for 2005 represents the net earnings attributable to the exchangeable shares over the period.

Net Earnings and Cash Flow

Net earnings increased 69 percent to \$28.4 million for the Quarter compared to \$16.8 million during the same period in 2005. The increase was due to an \$8.2 million future income tax recovery in the Quarter as a result of a reduction in future federal and provincial income tax rates while the same period in 2005 had a charge of \$3.0 million relating to tax audits performed during that period. Basic and diluted net earnings for the Quarter were \$0.38 per unit compared to \$0.25 per unit and \$0.24 per unit, respectively during the same period in 2005.

Net earnings for the six months ended June 30, 2006 increased 45 percent to \$49.8 million compared to \$34.4 million for the same period in 2005. The increase was the result of higher revenues, as well as a higher future income tax recovery as noted above. Basic and diluted net earnings for the six months ended June 30, 2006 were \$0.68 per unit and \$0.67 per unit, respectively compared to \$0.50 per unit for both basic and diluted net earnings for the same period in 2005.

Cash flow for the Quarter of \$45.9 million was consistent with the same period in 2005 of \$44.5 million. Diluted cash flow for the Quarter was \$0.52 per unit compared to \$0.53 per unit during the same period in 2005.

Cash flow increased eight percent to \$93.5 million for the six months ended June 30, 2006 compared to \$87.0 million for the same period in 2005. The increase was due to higher revenues. Year-to-date diluted cash flow for 2006 was \$1.07 per unit compared to \$1.05 per unit for the same period in 2005.

Quarterly Financial Summary ^{1,2}

(\$ thousands, except per unit amounts)	Three Months Ended							
	June 30 2006	Mar 31 2006	Dec 31 2005	Sept 30 2005	June 30 2005	Mar 31 2005	Dec 31 2004	Sept 30 2004
Petroleum and natural gas revenue	81,009	90,959	114,167	93,372	83,222	79,007	76,767	68,299
Cash flow	45,871	47,637	65,785	53,215	44,466	42,511	41,344	36,355
Per unit diluted	0.52	0.55	0.77	0.63	0.53	0.51	0.50	0.45
Net earnings	28,425	21,383	29,398	25,159	16,840	17,526	18,196	15,324
Per unit basic	0.38	0.29	0.41	0.36	0.25	0.26	0.28	0.24
Per unit diluted	0.38	0.29	0.40	0.36	0.24	0.26	0.28	0.24

(1) The above amounts have been restated for the change in accounting policy related to non-controlling interest.

(2) Petroleum and natural gas revenue and cash flow increased in the fourth quarter of 2004 due to higher production and commodity prices and continued increasing through to the fourth quarter of 2005 as a result of strengthening commodity prices. Petroleum and natural gas revenue and cash flow for the first and second quarter of 2006 decreased as a result of lower natural gas prices.

Distributable Cash and Distributions

Management monitors the Trust's distribution payout policy with respect to forecasted net cash flow, debt levels and capital expenditures. Progress expects to distribute approximately 60 to 70 percent of its annual cash flow to unitholders and retain the remaining cash flow for capital expenditures and debt repayment. Exchangeable shares are convertible into trust units of the Trust based on the exchange ratio, which is adjusted monthly to reflect that distributions are not paid on the exchangeable shares and cash flow related to the exchangeable shares is retained by the Trust for additional capital expenditures or debt repayment. The key drivers of Progress' cash flow, as is generally the case with other energy trusts, are commodity prices and production. Since the Trust's production is heavily weighted to natural gas (79 percent in the Quarter), natural gas prices have a significant effect on its cash flow.

Distributable cash is not a measure under Canadian GAAP and there is no standard measure of distributable cash. Distributable cash, as presented, may not be comparable to similar measures presented by other trusts. Progress' initial cash distribution declared was \$0.14 per trust unit for the month of July 2004. The Trust has maintained this distribution to date.

	Six Months Ended June 30 2006
<i>(\$ thousands, except per unit amounts)</i>	
Cash flow	93,508
Cash withheld to fund capital expenditures	(31,260)
Cash distributions declared	62,248
Accumulated cash distributions, beginning of period	172,165
Accumulated cash distributions, end of period	234,413
Cash distributions per unit ¹	0.84
Accumulated cash distributions per unit, beginning of period	2.52
Accumulated cash distributions per unit, end of period	3.36

¹ Cash distributions per trust unit reflect the sum of the per trust unit amounts paid and declared to unitholders.

Capital Expenditures

During the Quarter, the Trust invested \$32.5 million in capital expenditures compared to \$13.6 million in the same period in 2005. For the six months ended June 30, 2006 the Trust invested \$68.5 million in capital expenditures compared to \$47.9 for the same period in 2005.

<i>(\$ thousands)</i>	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	2006	2005
Land acquisitions and retention	2,777	1,071	5,617	2,798
Geological and geophysical	2,244	302	4,246	1,525
Drilling and completions	18,510	7,409	40,922	28,236
Equipping and facilities	8,215	4,764	16,611	14,011
Net property acquisitions (dispositions)	650	(533)	948	431
Corporate assets	93	546	129	938
Total capital expenditures	32,489	13,559	68,473	47,939

During the Quarter, the Trust disposed of its petroleum and natural gas assets in the Unity, Saskatchewan area to a private company for 2,860,000 common shares valued at \$1.20 per share for a total consideration of \$3.4 million. As this was a non-cash transaction, it is excluded from the table above.

During the Quarter, Progress drilled 15 gross wells (11.4 net) with a 100 percent success rate. Five gross wells (5.0 net) were drilled in the Deep Basin region of northwest Alberta, five wells (2.6 net) in northeast British Columbia, and five wells (3.8 net) in Central Alberta.

The Trust's remaining 2006 capital investment program will continue to be directed to the three focus regions of the Deep Basin in northwest Alberta and the Fort St. John Plains and Foothills of northeast British Columbia. The total 2006 capital program is estimated to be approximately \$115.0 million with 55 to 65 net wells expected to be drilled for the year. The capital program is expected to be split approximately 65 percent to drilling and completions, 10 percent to major facilities and 25 percent to land and seismic expenditures. The Trust does not set a budget for property acquisitions.

Liquidity and Capital Resources

<i>(\$ thousands, except per unit amounts)</i>	June 30 2006	December 31 2005
Working capital deficiency	25,625	22,873
Bank debt	102,355	71,326
Convertible debentures	54,893	79,381
Total debt	182,873	173,580
Units outstanding and issuable for exchangeable shares (thousands)	87,215	84,784
Market price per unit at end of period	16.30	17.17
Market value of trust units and exchangeable shares	1,421,605	1,455,741
Cash flow (12 month trailing)	212,508	205,977
Total debt to cash flow ratio	0.86	0.84

At June 30, 2006 the Trust had \$102.4 million outstanding on its credit facilities, \$54.9 million for the debt portion of the Debentures and a working capital deficiency of \$25.6 million, totaling \$182.9 million of total debt. The Trust currently has a \$200 million extendible revolving term credit facility and a \$15 million working capital credit facility with a syndicate of banks. The facilities are available on a revolving basis for a period of at least 364 days until May 29, 2007, and such initial term out date may be extended for further 364 day periods at the request of the Trust, subject to approval by the banks. Following the term out date, the facilities will be available on a non-revolving basis for a one year term, at which time the facilities would be due and payable. The credit facilities are secured by a \$500 million fixed and floating charge debenture on the assets of the Trust and by a guarantee and subordination provided by Progress Energy Ltd. in respect of the Trust's obligations. The \$215 million borrowing base is subject to semi-annual review by the banks.

Bank debt increased from \$71.3 million as at December 31, 2005 to \$102.4 million as at June 30, 2006 due to capital spending in the first six months of 2006. The working capital deficiency of \$25.6 million at June 30, 2006 is higher than the December 31, 2005 deficiency of \$22.9 million, primarily due to a reduced accounts receivable balance as a result of lower natural gas prices.

At June 30, 2006 the Trust had outstanding \$59.0 million principal amount of 6.75 percent convertible unsecured subordinated debentures, the debt portion of which, net of debenture issue costs was \$54.9 million. The Debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of \$15.00 per trust unit. The Debentures mature on June 30, 2010 at which time they are due and payable.

The Debentures are classified as debt net of the fair value of the conversion feature which has been classified as part of unitholders' equity and net of issue costs. At June 30, 2006 the debt portion was \$54.9 million and the equity portion was \$2.9 million. Issue costs are amortized over the term of the Debentures, and the debt portion will accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed within interest and financing expense on the consolidated statements of earnings.

Outstanding as at July 26, 2006 were 74.9 million trust units, 9.9 million exchangeable shares and \$59.0 million convertible debentures convertible into 3.9 million trust units.

The Trust's investing activities in the Quarter and six months ended June 30, 2006 primarily consists of expenditures on its capital program. Management anticipates that the Trust will continue to have adequate liquidity to fund future working capital and forecasted capital expenditures during 2006 through a combination of cash flow and debt. Cash flow used to finance these commitments may reduce the amount of cash distributions paid to unitholders.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Trust is accumulated and communicated to the Trust's Management, as appropriate, to allow timely decisions regarding required disclosures. The Trust's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by the interim filings that the Trust's disclosure controls and procedures are effective to provide reasonable assurance that material information related to the issuer, is made known to them by others within the Trust. It should be noted that while the Trust's Chief Executive Officer and Chief Financial Officer believe that the Trust's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system is met.

Additional Information

Additional information regarding the Trust and its business and operations, including the annual information form ("AIF") is available on the Trust's company profiles at www.sedar.com. Copies of the AIF can also be obtained by contacting the Trust at Progress Energy Trust 1400, 440 – 2nd Avenue S.W., Calgary, Alberta, Canada T2P 5E9 or by e-mail at ir@progressenergy.com. This information is also accessible on the Trust's web site at www.progressenergy.com.

OUTLOOK

We will continue to focus on sustainability through the drill bit and supplement our asset base through select, opportunistic acquisitions. Our consistent hedging program and low cost profile are generating strong cash flows providing support for our distributions and capital program.

Capital investment for 2006 is currently forecasted to be approximately \$115 million which includes additional capital associated with ProEx Energy's increased capital program for the Foothills region of northeast British Columbia. Approximately \$25 million of our capital is targeted at land acquisition in our core areas, as well as seismic data acquisition in the Foothills of northeast British Columbia to further expand our inventory of drilling locations.

Natural gas prices remain weak relative to the beginning of the year largely due to excess natural gas in storage and no major weather event to increase demand. We do however expect natural gas prices to recover as we move closer to the start of the winter heating season and expectations build for increased weather-related demand.

Management, directors and employees are aligned with unitholders through the ownership of approximately 13 percent of the units of Progress.

On behalf of the Board of Directors,

(Signed) "Michael R. Culbert"

Michael R. Culbert
President & CEO
July 27, 2006

PROGRESS ENERGY TRUST

CONSOLIDATED BALANCE SHEETS

<i>(\$ thousands)</i>	June 30 2006	December 31 2005
<i>(Unaudited)</i>		
ASSETS		
Current		
Cash and short-term investments	-	-
Accounts receivable	25,294	45,870
Prepaid expenses and deposits	8,375	5,144
	33,669	51,014
Property, plant and equipment <i>(Note 2)</i>	721,036	687,316
Goodwill	414,655	414,655
	1,169,360	1,152,985
LIABILITIES		
Current		
Accounts payable and accrued liabilities	44,299	58,904
Cash distributions payable	10,486	9,982
Current income taxes payable	4,509	5,001
	59,294	73,887
Bank debt <i>(Note 3)</i>	102,355	71,326
Convertible debentures <i>(Note 4)</i>	54,893	79,381
Commodity sales contract <i>(Note 10)</i>	1,155	1,446
Asset retirement obligations <i>(Note 5)</i>	22,292	20,906
Future income taxes <i>(Note 8)</i>	116,227	124,186
	356,216	371,132
NON-CONTROLLING INTEREST		
Exchangeable shares <i>(Note 6)</i>	118,908	127,205
UNITHOLDERS' EQUITY		
Unitholders' capital <i>(Note 7)</i>	732,289	681,263
Convertible debentures <i>(Note 4)</i>	2,919	4,261
Contributed surplus <i>(Note 7)</i>	5,874	3,530
Deficit	(46,846)	(34,406)
	694,236	654,648
	1,169,360	1,152,985

See accompanying notes to the consolidated financial statements

PROGRESS ENERGY TRUST
CONSOLIDATED STATEMENTS OF EARNINGS AND DEFICIT

(Unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
<i>(\$ thousands, except per unit amounts)</i>	2006	2005	2006	2005
REVENUE				
Petroleum and natural gas	81,009	83,222	171,968	162,229
Royalties	(18,786)	(21,055)	(43,405)	(40,392)
	62,223	62,167	128,563	121,837
EXPENSES				
Operating	9,671	9,146	19,299	18,476
Transportation	2,639	3,163	5,800	6,258
General and administrative	1,702	2,136	3,491	4,146
Unit based compensation	1,008	511	2,015	1,023
Interest and financing	2,520	2,886	4,915	4,966
Depletion, depreciation and accretion	22,803	22,700	46,446	45,764
	40,343	40,542	81,966	80,633
Earnings before taxes and non-controlling interest	21,880	21,625	46,597	41,204
TAXES (Note 8)				
Capital taxes	(249)	543	90	1,086
Future income taxes	(10,984)	885	(11,910)	(1,545)
	(11,233)	1,428	(11,820)	(459)
Net earnings before non-controlling interest	33,113	20,197	58,417	41,663
Non-controlling interest – exchangeable shares (Note 6)	(4,688)	(3,356)	(8,609)	(7,296)
NET EARNINGS	28,425	16,841	49,808	34,367
Deficit, beginning of period	(43,859)	(17,918)	(34,406)	(6,870)
Distributions	(31,412)	(28,874)	(62,248)	(57,448)
Deficit, end of period	(46,846)	(29,951)	(46,846)	(29,951)
NET EARNINGS PER UNIT (Note 7)				
Basic	\$0.38	\$0.25	\$0.68	\$0.50
Diluted	\$0.38	\$0.24	\$0.67	\$0.50

See accompanying notes to the consolidated financial statements

PROGRESS ENERGY TRUST
CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
<i>(\$ thousands)</i>	2006	2005	2006	2005
OPERATING ACTIVITIES				
Net earnings	28,425	16,841	49,808	34,367
Depletion, depreciation and accretion	22,803	22,700	46,446	45,764
Non-controlling interest – exchangeable shares <i>(Note 6)</i>	4,688	3,356	8,609	7,296
Convertible debentures accretion <i>(Note 4)</i>	134	223	279	362
Amortization of convertible debenture issue costs <i>(Note 4)</i>	125	207	263	337
Amortization of commodity sales contract	(144)	(164)	(291)	(332)
Unit based compensation expense <i>(Note 7)</i>	1,008	511	2,015	1,023
Asset retirement expenditures <i>(Note 5)</i>	(184)	(93)	(1,711)	(295)
Future income taxes	(10,984)	885	(11,910)	(1,545)
	45,871	44,466	93,508	86,977
Changes in non-cash working capital <i>(Note 9)</i>	1,112	1,125	3,810	2,842
	46,983	45,591	97,318	89,819
FINANCING ACTIVITIES				
Increase (decrease) in bank debt	7,355	11,476	31,029	(66,551)
Issue of 6.75 % convertible debentures <i>(Note 4)</i>	-	-	-	100,000
Convertible debenture issue costs <i>(Note 4)</i>	-	34	-	(4,515)
Cash distributions	(31,330)	(28,851)	(61,744)	(57,179)
Changes in non-cash working capital <i>(Note 9)</i>	-	-	-	-
	(23,975)	(17,341)	(30,715)	(28,245)
INVESTING ACTIVITIES				
Capital expenditures	(32,489)	(13,559)	(68,473)	(47,939)
Changes in non-cash working capital <i>(Note 9)</i>	5,927	(14,691)	1,870	(13,635)
	(26,562)	(28,250)	(66,603)	(61,574)
CHANGE IN CASH AND SHORT-TERM INVESTMENTS	(3,554)	-	-	-
Cash and short-term investments, beginning of period	3,554	-	-	-
CASH AND SHORT-TERM INVESTMENTS, END OF PERIOD	-	-	-	-

See accompanying notes to the consolidated financial statements

PROGRESS ENERGY TRUST

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited) (tabular amounts are in \$ thousands except for trust units and per trust unit amounts)

Progress Energy Trust (“Progress” or the “Trust”) is an open-ended, unincorporated investment trust governed by the laws of the province of Alberta. The principal undertaking of the Trust is to indirectly explore for, develop and hold interests in petroleum and natural gas properties through investments in securities of subsidiaries and royalty interests in petroleum and natural gas properties. Progress Energy Ltd. carries on the business of the Trust and directly owns the petroleum and natural gas properties and assets related thereto. The Trust owns, directly and indirectly, 100 percent of the common shares (excluding the exchangeable shares – see note 6) of Progress Energy Ltd. The activities of Progress Energy Ltd. are financed through interest bearing notes from the Trust and third party debt. The convertible debentures are direct obligations of the Trust. Under the Trust Indenture, the Trust may declare payable to unitholders all or any part of the income of the Trust, which is primarily comprised of interest earned on debt notes issued to Progress Energy Ltd., as well as, amounts attributed to a net profits interest (“NPI”) agreement entered into with Progress Energy Ltd. The aggregate amounts received by the Trust each period are based on the consolidated cash flow from operations before changes in non-cash working capital each period, as adjusted on a discretionary basis, for cash withheld to fund capital expenditures.

Pursuant to the terms of the NPI agreement, the Trust is entitled to a payment from Progress Energy Ltd. each month equal to the amount by which 99% of the gross proceeds from the sale of production exceed 99% of certain deductible expenditures (as defined). Under the terms of the NPI agreement, deductible expenditures may include amounts, determined on a discretionary basis, to fund capital expenditures, to repay third party debt and to provide for working capital required to carry out the operations of Progress Energy Ltd.

Relationship with ProEx Energy Ltd.

A technical services agreement (“Technical Service Agreement”) is currently in place between the Trust and ProEx Energy Ltd. (“ProEx”) whereby the Trust provides personnel and certain administrative and technical services in connection with the management, development, exploitation and operation of the assets of ProEx and the marketing of its production. ProEx has granted performance shares to the employees of Progress as service providers. The Trust provides these services to ProEx on an expense reimbursement basis, based on ProEx’s monthly capital activity and production levels relative to the combined capital activity and production levels of both the Trust and ProEx. Total expense reimbursed by ProEx for the three and six months ended June 30, 2006 was \$0.9 million and \$2.0 million, respectively (2005 – \$0.6 million and \$1.1 million).

As at June 30, 2006, accounts payable included \$5.7 million (2005 – \$3.8 million) payable to ProEx which includes standard joint venture amounts and a Crown royalty adjustment this Quarter relating to prior periods. These amounts were paid subsequent to June 30, 2006.

1. SUMMARY OF ACCOUNTING POLICIES

The interim consolidated financial statements of the Trust have been prepared following the same accounting policies and methods of computation as the consolidated financial statements of the Trust for the year ended December 31, 2005. The disclosures provided below are incremental to those included with the annual consolidated financial statements and certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. These interim consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto in the Trust's annual report for the year ended December 31, 2005.

Progress is involved in the exploration, development and production of petroleum and natural gas in British Columbia, Alberta and Saskatchewan. The consolidated financial statements include the accounts of the Trust and its wholly owned subsidiary. The consolidated financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP").

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

2. PROPERTY, PLANT AND EQUIPMENT

	June 30 2006	December 31 2005
Property, plant and equipment	932,819	865,173
Conversions of exchangeable shares	44,252	32,553
Accumulated depletion and depreciation	(256,035)	(210,410)
Property, plant and equipment, net	721,036	687,316

The conversion of exchangeable shares held by previous Progress Energy Ltd. shareholders to Trust units is accounted for as a step-purchase. Consequently a charge of \$11.7 million was made to property, plant and equipment for the six months ended June 30, 2006 (2005 - \$12.3 million).

During the three months ended June 30, 2006 the Trust disposed of its assets in the Unity, Saskatchewan area to a private company for 2,860,000 common shares valued at \$1.20 per share for a total consideration of \$3.4 million.

The calculation of 2006 depletion and depreciation expense included an estimated \$16.0 million for future development costs associated with proved undeveloped reserves and excluded \$24.1 million for the estimated future net realizable value of production equipment and facilities and \$63.5 million for the estimated value of unproven properties. Depletion and depreciation expense for the three and six months ended June 30, 2006 was \$22.4 million and \$45.6 million, respectively (2005 - \$22.4 million and \$45.1 million).

Included in the Trust's property, plant and equipment balance is \$13.8 million, net of accumulated depletion, related to asset retirement obligations (\$21.0 million before accumulated depletion) (Refer to note 5).

The Trust capitalized approximately \$0.9 million of geological and geophysical compensation costs associated with the exploration and development of capital assets during the six months ended June 30, 2006 (2005 - \$0.8 million).

3. BANK DEBT

	June 30 2006	December 31 2005
Direct advances	5,355	1,326
Banker's acceptances	97,000	70,000
Total bank debt	102,355	71,326

The Trust's credit facilities totaling \$215 million are with a syndicate of banks consisting of a \$200 million extendible revolving term credit facility and a \$15 million working capital credit facility. The facilities are available on a revolving basis for a period of at least 364 days until May 29, 2007, and such initial term out date may be extended for further 364 day periods at the request of the Trust, subject to approval by the banks. Following the term out date, the facilities will be available on a non-revolving basis for a one year term, at which time the facilities would be due and payable. Various borrowing options are available under the facilities including prime rate based advances and banker's acceptance loans. Average cost of borrowing under these facilities for the six months ended June 30, 2006 was 5.0 percent. The credit facilities are secured by a \$500 million fixed and floating charge debenture on the assets of the Trust and by a guarantee and subordination provided by Progress in respect of the Trust's obligations. The \$215 million borrowing base is subject to semi-annual review by the banks.

4. CONVERTIBLE DEBENTURES

On February 2, 2005 the Trust issued \$100 million principal amount of 6.75 percent convertible unsecured subordinated debentures (the "Debentures") for net proceeds of \$95.5 million. The Debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of \$15.00 per trust unit. The Debentures mature on June 30, 2010 at which time they are due and payable. The Trust may elect to satisfy the interest and principal obligations of the Debentures by the issuance of Trust Units. The net proceeds were used to reduce outstanding bank indebtedness.

The Debentures have been classified as debt, net of issue costs and net of the fair value of the conversion feature at the date of issue which has been classified as part of unitholders' equity. The issue costs will be amortized over the term of the Debentures and the debt portion will accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed within interest and financing expense on the consolidated statements of earnings. If Debentures are converted to units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to unitholders' capital along with the conversion price paid. The following table sets forth a reconciliation of the Debenture activity:

	Six Months Ended June 30	
	2006	2005
Debt portion, beginning of period ⁽¹⁾	79,381	90,541
Accretion	279	362
Amortization of issue costs	263	337
Conversions to trust units	(25,030)	-
Debt portion, end of period	54,893	91,240
Equity portion, beginning of period ⁽¹⁾	4,261	4,944
Conversions to trust units	(1,342)	-
Equity portion, end of period	2,919	4,944
Total debentures, end of period	57,812	96,184

(1) The beginning of period for 2005 is February 2, 2005, the date of issue of the Debentures.

Total interest charged to earnings for the three months ended June 30, 2006 was \$1.3 million (2005 - \$2.1 million) which includes \$0.1 million of debenture accretion (2005 - \$0.2 million) and \$0.1 million of amortized issue costs (2005 - \$0.2 million).

Total interest charged to earnings for the six months ended June 30, 2006 was \$2.8 million (2005 - \$3.5 million) which includes \$0.3 million of debenture accretion (2005 - \$0.4 million) and \$0.3 million of amortized issue costs (2005 - \$0.3 million).

5. ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations were estimated based on the Trust's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The total undiscounted amount of the estimated cash flows required to settle the asset retirement obligations is approximately \$53.7 million which will be incurred over the next 42 years with the majority of costs incurred between 2009 and 2020. A credit adjusted risk-free rate of eight percent was used to calculate the fair value of the asset retirement obligations. The following reconciles the Trust's asset retirement obligations:

	Six Months Ended June 30	
	2006	2005
Balance, beginning of period	20,906	16,065
Liabilities incurred	2,649	652
Liabilities settled	(1,711)	(295)
Dispositions	(374)	-
Accretion expense	822	668
Balance, end of period	22,292	17,090

6. NON-CONTROLLING INTEREST - EXCHANGEABLE SHARES

The non-controlling interest on the consolidated balance sheet consists of the book value of exchangeable shares issued to Progress Energy Ltd. shareholders and the fair value of exchangeable shares issued to Cequel Energy Inc. shareholders as part of a Plan of Arrangement that became effective on July 2, 2004, plus net earnings attributable to the exchangeable shares, less exchangeable shares (and related cumulative earnings) redeemed. The non-controlling interest charge on the consolidated statement of earnings represents the share of net earnings attributable to the exchangeable shares based on the trust units issuable for exchangeable shares in proportion to total trust units issued and issuable each period end.

	Six months ended June 30			
	2006		2005	
	Number	Amount	Number	Amount
Exchangeable Shares				
Balance, beginning of period	11,388,751	127,205	14,533,506	141,060
Exchanged for trust units	(1,480,512)	(16,906)	(1,787,326)	(17,588)
Non-controlling interest expense		8,609		7,296
Balance, end of period	9,908,239	118,908	12,746,180	130,768

The exchangeable shares can be converted, at the option of the holder, into trust units at any time and are listed on the Toronto Stock Exchange under the symbol PGE. If the number of exchangeable shares outstanding is less than 1,600,000, the Trust can elect to redeem the exchangeable shares for trust units or an amount in cash equal to the amount determined by multiplying the exchange ratio on the last business day prior to the redemption date by the current market price of a trust unit on the last business day prior to such redemption date. The number of trust units issued upon conversion is based on the exchange ratio in effect on the date of conversion. The exchange ratio is calculated monthly based on the five day weighted average trust unit trading price preceding the monthly effective date. The exchangeable shares are not eligible for cash distributions.

Retraction of Exchangeable Shares

Exchangeable shareholders may redeem their shares at any time by delivering their share certificates to the Trustee, together with a properly completed retraction request. The retraction price will be satisfied with trust units equal to the amount determined by multiplying the exchange ratio on the last business day prior to the retraction date by the number of exchangeable shares redeemed.

Redemption of Exchangeable Shares

On July 2, 2009 the exchangeable shares will be redeemed by the Trust unless the Board of Directors of Progress Energy Ltd. elect to extend the redemption period. The exchangeable shares will be redeemed by either issuing units or payment in cash for an amount equivalent to the value of the exchangeable shares at the current exchange ratio.

7. UNITHOLDERS' CAPITAL

The Trust Indenture provides that an unlimited number of trust units may be authorized and issued. Each trust unit is transferable, carries the right to one vote and represents an equal undivided beneficial interest in any distributions from the Trust and in the assets of the Trust in the event of termination or winding-up of the Trust. All trust units are of the same class with equal rights and privileges.

Trust Units

	Six months ended June 30			
	2006		2005	
	Number	Amount	Number	Amount
Trust Units				
Balance, beginning of period	71,302,265	681,263	66,898,498	621,490
Exchangeable shares converted	1,788,907	24,654	1,921,915	25,631
Issued on conversion of convertible debentures	1,809,523	26,372	-	-
Balance, end of period	74,900,695	732,289	68,820,413	647,121

Redemption Right

Unitholders may redeem their trust units for cash at any time, up to a maximum value of \$250,000 in any calendar month, by delivering their unit certificates to the Trustee, together with a properly completed notice requesting redemption. The redemption amount per trust unit will be the lesser of 90 percent of the simple average closing price of the trust units on the principal market on which they are traded for the 10 day trading period after the trust units have been validly tendered for the redemption and the closing market price of the trust units on the principal market on which they are traded on the date on which they were validly tendered for redemption, or if there was no trade of the trust units on that date, the average of the last bid and ask prices of the trust units on that date.

Net Earnings Per Unit

The following table summarizes the weighted average trust units used in calculating net earnings per unit:

	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	2006	2005
Weighted average trust units - basic	74,667,967	68,713,016	73,741,056	68,199,255
Trust units issuable on conversion of exchangeable shares ¹	12,422,806	14,387,969	13,062,641	14,923,437
Performance units	466,282	74,887	429,441	67,333
Weighted average trust units - diluted	87,557,055	83,175,872	87,233,138	83,190,025

(1) Calculated based on the weighted average exchangeable shares outstanding during the period at the period end exchange ratio.

An adjustment to the numerator of \$4.7 million and \$8.6 million for the three and six months ended June 30, 2006 (2005 - \$3.4 million and \$7.3 million) is required in the diluted earnings per unit calculation to provide for earnings attributable to non-controlling interest. Units potentially issuable on the conversion of the Debentures are anti-dilutive and are not included in the calculation of diluted weighted average units for the three and six months ended June 30, 2006.

Performance Unit Incentive Plan

The Trust has established a Performance Unit Incentive Plan (the "Plan") for employees and directors of the Trust or its subsidiary. The number of units reserved for issuance under the Plan shall not exceed 5 percent of the aggregate number of issued and outstanding units of the Trust and including the number of units which may be issued on the exchange of the outstanding exchangeable shares, which may be converted into trust units. Under the Plan, performance units shall be granted by the Board of Directors of Progress Energy Ltd. from time to time at its sole discretion. The performance units will vest on the third anniversary of the date of grant and actual payment will be determined based on the performance of the Trust relative to its peers. Performance factors range from 0.5 to 1.5 times the initial performance units granted. Over the three year term the performance units will attract distributions. The Trust expects to pay out the distribution portion in cash while the units earned will be issued from treasury.

As at June 30, 2006 there are 383,867 performance units outstanding that were granted effective July 2, 2004. As a result, the fair value of the performance units granted, calculated using a performance factor of 1.0, was approximately \$5.3 million of which \$4.7 million will be amortized through unit based compensation expense and \$0.6 million will be capitalized over the vesting period with a corresponding increase to contributed surplus.

As at June 30, 2006 there are 510,600 performance units outstanding that were granted effective July 2, 2005. The fair value of the performance units using a performance factor of 1.0 was approximately \$8.0 million of which \$6.9 million will be amortized through unit based compensation expense and \$1.1 million will be capitalized over the vesting period with a corresponding increase to contributed surplus.

For the three and six months ended June 30, 2006 \$1.0 million and \$2.0 million, respectively were charged to unit based compensation expense (2005 - \$0.5 million and \$1.0 million) and \$0.2 million and \$0.3 million, respectively were capitalized (2005 - nil) relating to the total performance units outstanding.

The following table reconciles the Trust's contributed surplus:

	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	2006	2005
Balance, beginning of period	4,701	683	3,530	171
Unit based compensation expense	1,008	511	2,015	1,023
Unit based compensation capitalized	165	-	329	-
Balance, end of period	5,874	1,194	5,874	1,194

8. TAXES

Included in the provision for capital taxes for the three and six months ended June 30, 2006 is a recovery of \$0.4 million due to the new federal government budget eliminating the large corporation tax effective for 2006.

The future income tax provision for the three and six months ended June 30, 2006 includes a recovery of \$8.2 million relating to a reduction in future federal and provincial income tax rates enacted during the Quarter and includes the impact of certain tax balance adjustments.

9. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	2006	2005
Accounts receivable	9,113	2,574	20,576	7,114
Prepaid expenses and deposits	48	(934)	201	(339)
Accounts payable	(1,696)	(15,141)	(14,605)	(17,346)
Current income taxes payable	(426)	(65)	(492)	(222)
Change in non-cash working capital	7,039	(13,566)	5,680	(10,793)
Relating to:				
Financing activities	-	-	-	-
Investing activities	5,927	(14,691)	1,870	(13,635)
Operating activities	1,112	1,125	3,810	2,842

Interest and taxes paid

	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	2006	2005
Interest paid	4,126	3,671	8,138	4,231
Income and other taxes paid	178	609	583	980

10. FINANCIAL INSTRUMENTS

Fair Value of Financial Instruments

The Trust's financial instruments recognized on the balance sheet consist of accounts receivable, accounts payable and accrued liabilities, bank debt and convertible debentures. The fair value of these instruments, excluding the convertible debentures, approximate their carrying amounts due to their short terms to maturity or the indexed rate of interest on the bank debt. The fair value of the convertible debentures outstanding as at June 30, 2006 was approximately \$64.1 million.

Commodity Price Contracts

The Trust has entered into several derivative natural gas financial instruments for the purpose of protecting its cash flow from operations before changes in non-cash working capital from the volatility of natural gas prices. For the three months ended June 30, 2006, the Trust's natural gas price risk management program had a net gain of \$9.6 million (2005 - \$0.1 million net loss) which is included in petroleum and natural gas revenue on the statements of earnings. For the six months ended June 30, 2006, the Trust's natural gas price risk management program had a net gain of \$9.0 million (2005 - \$2.6 million net gain).

Contracts outstanding in respect to financial instruments are as follows:

Natural Gas Contracts ¹	Volume	Pricing Point	Strike Price \$/gj	Cost/ Premium	Term
Swap - call spread	5,000 gj/d	AECO	\$10.55 - \$11.55	\$0.38/gj	Apr 01/06 - Oct 31/06
Swap - call spread	5,000 gj/d	AECO	\$10.74 - \$11.74	\$0.38/gj	Apr 01/06 - Oct 31/06
Swap - call spread	5,000 gj/d	AECO	\$10.75 - \$11.75	\$0.38/gj	Apr 01/06 - Oct 31/06
Swap - call spread	5,000 gj/d	AECO	\$10.68 - \$11.68	\$0.38/gj	Apr 01/06 - Oct 31/06
Swap - call spread	5,000 gj/d	AECO	\$7.22 - \$8.22	\$0.36/gj	Apr 01/06 - Oct 31/06
Swap - call spread	10,000 gj/d	AECO	\$7.20 - \$8.20	\$0.32/gj	Apr 01/06 - Oct 31/06
Swap - call spread	5,000 gj/d	AECO	\$7.10 - \$8.10	\$0.30/gj	Apr 01/06 - Oct 31/06
Swap - call spread	10,000 gj/d	AECO	\$9.51 - \$10.51	\$0.44/gj	Nov 01/06 - Mar 31/07
Swap - call spread	10,000 gj/d	AECO	\$8.97 - \$9.97	\$0.38/gj	Nov 01/06 - Mar 31/07
Swap - call spread	10,000 gj/d	AECO	\$9.60 - \$10.60	\$0.40/gj	Nov 01/06 - Mar 31/07
Swap - call spread	10,000 gj/d	AECO	\$9.63 - \$10.63	\$0.43/gj	Nov 01/06 - Mar 31/07

(1) Call spread strike prices indicate minimum floor and maximum ceiling

The estimated fair value of the natural gas financial instruments, that qualify for hedge accounting, was a gain of \$16.8 million as at June 30, 2006 and represents the amount the Trust would receive to terminate the contracts at June 30, 2006. These instruments have no carrying value recorded in the financial statements.

Commodity Sales Contract

The following physical gas sales contract was outstanding at June 30, 2006. This contract was acquired in conjunction with the acquisition of Campion Resources Ltd. on June 3, 2002, at which time the fair value of the contracts was a liability of \$4.1 million. This value was recorded as a liability on June 3, 2002, and is being amortized over the life of the contract. At June 30, 2006 the unamortized remaining liability was \$1.2 million.

Volume	Pricing Point	Progress Price	Term
1,000 gj/d	AECO	\$2.11/gj in 2006 escalating at 2.5% annually	Jun 1/97 - Oct 31/08

SELECTED QUARTERLY INFORMATION

FINANCIAL HIGHLIGHTS

Three Months Ended

	2005				2006	
(\$ thousands except per unit amounts)	March 31	June 30	Sept 30	Dec 31	March 31	June 30
Income Statement						
Petroleum and natural gas revenue	79,007	83,222	93,372	114,167	90,959	81,009
Cash flow ¹	42,511	44,466	53,215	65,785	47,637	45,871
Per unit - diluted	0.52	0.53	0.64	0.77	0.55	0.52
Cash distributions declared	28,574	28,874	29,210	29,802	30,836	31,412
Per unit	0.42	0.42	0.42	0.42	0.42	0.42
Net earnings	17,527	16,840	25,159	29,398	21,383	28,425
Per unit - basic	0.27	0.25	0.36	0.41	0.29	0.38
Per unit - diluted	0.27	0.24	0.36	0.40	0.29	0.38
Payout Ratio						
Excluding exchangeable shares	67%	65%	55%	45%	65%	68%
Including exchangeable shares	81%	79%	66%	54%	76%	80%
Balance Sheet						
Capital Expenditures	34,380	13,559	24,492	35,227	35,984	32,489
Total debt	187,312	185,708	186,115	173,580	172,106	182,873
Unitholders' equity	632,700	623,308	635,630	654,648	687,953	694,236
Trust Units (thousands, except where otherwise stated)						
Units outstanding, end of period	68,646	68,820	69,956	71,302	74,315	74,901
Units issuable for exchangeable shares	13,992	14,281	13,601	13,482	12,309	12,314
Total units outstanding and issuable for exchangeable shares, end of period	82,638	83,101	83,557	84,784	86,624	87,215
Weighted average units – diluted ²	82,485	83,176	83,700	84,675	86,579	87,557
Exchange ratio, end of period	1.08438	1.12038	1.15421	1.18384	1.21322	1.24284
Trust Unit Trading Statistics (\$)						
High	14.50	13.79	17.82	17.85	18.20	18.33
Low	12.52	11.90	13.07	14.08	14.75	14.73
Closing	13.38	13.03	17.61	17.17	17.45	16.30
Unit volume traded (thousands)	17,788	11,544	19,159	18,385	18,619	12,619
Exchangeable Shares Trading Statistics (\$)						
High	15.85	15.50	20.62	20.36	21.29	21.76
Low	13.96	13.27	15.00	16.61	18.49	18.28
Closing	14.60	14.96	19.26	20.36	20.70	19.57
Share volume traded (thousands)	1,460	290	613	52	85	15

(1) Refer to discussion in the Management Discussion and Analysis

(2) Includes exchangeable shares converted at the end of period exchange ratio.

SELECTED QUARTERLY INFORMATION

OPERATIONAL HIGHLIGHTS

	Three Months Ended					
	2005			2006		
	March 31	June 30	Sept 30	Dec 31	March 31	June 30
Daily Production						
Natural gas (mcf/d)	84,523	79,236	80,804	85,173	86,433	82,271
Crude oil (bbls/d)	2,550	3,067	2,734	2,762	2,605	2,099
Natural gas liquids (bbls/d)	1,598	1,305	1,280	1,355	1,390	1,478
Total daily production (boe/d)	18,235	17,578	17,481	18,312	18,401	17,288
Average Realized Prices						
Natural gas - before hedging (\$/mcf)	7.31	8.12	9.33	12.18	8.80	6.53
Natural gas - after hedging (\$/mcf)	7.69	8.13	9.11	11.38	8.74	7.83
Crude oil (\$/bbl)	59.44	64.20	72.66	67.22	64.45	72.79
Natural gas liquids (\$/bbl)	47.82	56.41	62.68	63.63	62.86	63.34
Highlights (\$/boe)						
Weighted average sales price	48.14	52.02	58.06	67.77	54.92	51.49
Royalties	11.78	13.16	14.39	18.38	14.87	11.94
Operating expenses	5.69	5.72	5.70	5.66	5.81	6.15
Transportation expenses	1.89	1.98	1.95	1.89	1.91	1.68
Operating Netbacks	28.78	31.16	36.02	41.84	32.33	31.72
General and administrative expense	1.23	1.33	0.83	0.75	1.08	1.08
Unit based compensation	0.31	0.32	0.62	0.59	0.61	0.64
Interest and financing expenses	1.26	1.80	1.80	1.62	1.45	1.60
Depletion, depreciation and accretion	14.05	14.19	14.26	13.86	14.27	14.49
Net earnings before taxes	11.93	13.52	18.51	25.02	14.92	13.91
Capital taxes	0.33	0.34	0.34	0.32	0.20	(0.16)
Future income taxes (recovery)	(1.48)	0.55	(0.63)	3.93	(0.56)	(6.98)
Non-controlling interest – exchangeable shares	2.40	2.10	3.16	3.32	2.37	2.98
Net earnings	10.68	10.53	15.64	17.45	12.91	18.07
Drilling Results						
Gross	24	8	24	31	39	15
Net – natural gas	9.9	3.3	9.6	16.0	18.8	11.0
Net – crude oil	1.2	0.0	1.9	1.7	0.8	0.4
Success Rate (percent)	89	78	89	100	93	100

CORPORATE INFORMATION

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President & CEO
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Senior Vice President and
Managing Director
BMO Nesbitt Burns
Calgary, Alberta

⁽¹⁾ Member of Audit Committee

⁽²⁾ Member of Reserve Committee

⁽³⁾ Member of Compensation
Committee

⁽⁴⁾ Member of Technical Services
Committee

⁽⁵⁾ Member of Corporate Governance
and Nominating Committee

Environment, Health and Safety matters
are addressed by the entire Board of
Directors

OFFICERS

David D. Johnson
Chairman

Michael R. Culbert
President & CEO

Steven A. Allaire
Senior Vice President

Greg W. Kist
Vice President, Investor Relations
and Marketing

Art A. MacNichol
Vice President, Finance &
Chief Financial Officer

Cindy R. Rutherford
Vice President, Land

Neil H. Samis
Vice President, Production

Daniel C. Topolinsky
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TRUSTEE AND TRANSFER AGENT

Computershare Trust Company
of Canada
Calgary, Alberta

STOCK EXCHANGE

The Toronto Stock Exchange
trading symbols:
Trust Units - PGX.UN
Exchangeable Shares – PGE
Convertible Debentures – PGX.DB

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