



## Active Third Quarter Exploration Program for Progress Energy Trust

Financial strength positions Progress to capture opportunities

	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	2006	2005
<b>FINANCIAL HIGHLIGHTS</b>				
<b>Income Statement</b> (\$ thousands, except per unit amounts)				
Petroleum and natural gas revenue	82,854	93,372	254,822	255,601
Cash flow <sup>1</sup>	47,218	53,215	140,726	140,192
Per unit – diluted <sup>2</sup>	0.54	0.64	1.60	1.68
Cash distributions declared	31,626	29,210	93,873	86,658
Per unit	0.42	0.42	1.26	1.26
<b>Payout Ratio</b>				
Excluding exchangeable shares	67%	55%	67%	62%
Including exchangeable shares	78%	66%	78%	75%
<b>Balance Sheet</b> (\$ thousands)				
Working capital deficiency	23,975	23,789	23,975	23,789
Bank debt	47,663	71,167	47,663	71,167
Convertible debentures	118,893	91,159	118,893	91,159
Total debt	190,531	186,115	190,531	186,115
Capital expenditures	30,875	24,492	99,348	72,431
<b>OPERATIONAL HIGHLIGHTS</b>				
<b>Average Daily Production</b>				
Natural gas ( <i>mcf/d</i> )	85,701	80,804	84,799	81,507
Crude oil ( <i>bbls/d</i> )	2,056	2,734	2,251	2,784
Natural gas liquids ( <i>bbls/d</i> )	1,327	1,280	1,398	1,393
Total daily production ( <i>boe/d</i> )	17,667	17,481	17,783	17,762
<b>Average Realized Prices</b>				
Natural gas - before hedging ( <i>\$/mcf</i> )	6.28	9.33	7.21	8.25
Natural gas - after hedging ( <i>\$/mcf</i> )	7.63	9.11	8.07	8.31
Crude oil ( <i>\$/bbl</i> )	75.69	72.66	70.50	65.56
Natural gas liquids ( <i>\$/bbl</i> )	68.29	62.68	64.77	55.10
<b>Wells Drilled, Net</b>	12.0	12.9	44.5	30.3

(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”) generated quarterly cash flow of \$47.2 million or \$0.54 per unit, diluted for the third quarter of 2006, compared to \$53.2 million or \$0.64 per unit in the third quarter of 2005. Cash distributions declared totaled \$31.6 million or \$0.42 per trust unit resulting in a payout ratio of 67 percent excluding exchangeable shares which do not receive cash distributions. Production averaged 17,667 barrels of oil equivalent (“boe”) per day during the third quarter of 2006.

**Active drilling and land capture program**

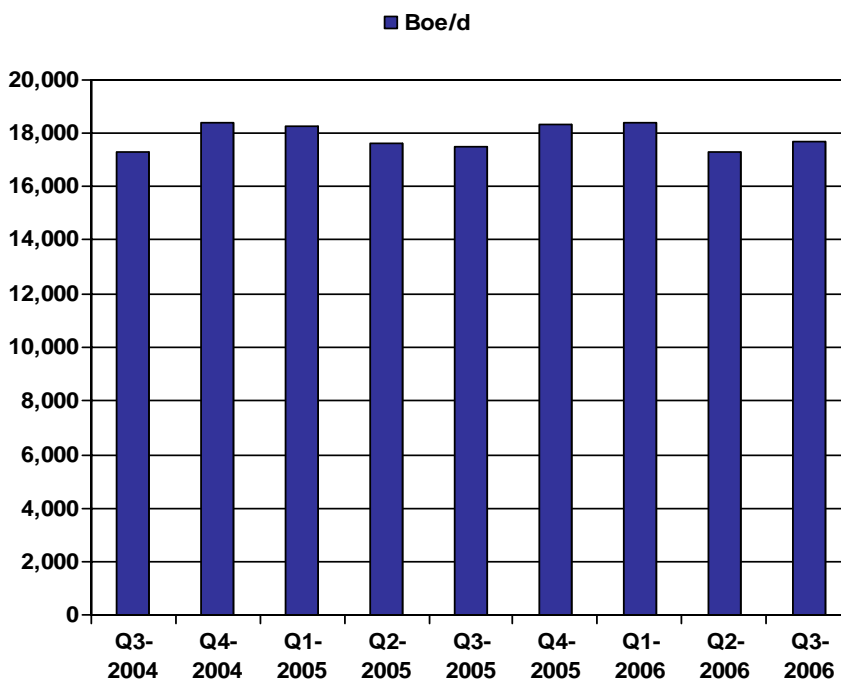
Progress had an active third quarter exploration and development drilling program by drilling or participating in 22 gross wells (12.0 net) with a 95 percent success rate. The program yielded 17 gas wells and three oil wells. New discoveries were made at Town, Dogrib and Lily Lake in the Foothills region of northeast British Columbia and at Wapiti in the Deep Basin region of northwest Alberta. Development drilling is expected to result from these new discoveries after the Trust completes its field tests.

“We currently have two rigs drilling Progress operated wells and another three rigs drilling wells in which Progress has a working interest,” said Michael Culbert, President and Chief Executive Officer of Progress. “We remain committed to our strategy of sustainability through the drill bit. Our financial flexibility allows us to remain patient for the right opportunity in the acquisition market because of our strong inventory of drilling locations.”

In the third quarter, Progress added over 15,000 net acres of land in established fairways in the Foothills and Deep Basin regions. Land acquisition will continue along mapped or seismically identified trends as Progress strengthens its position as a dominant player in its operating regions. In total, Progress controls nearly 450,000 net acres of undeveloped land.

**Consistent production profile**

Daily production for the third quarter of 2006 averaged 17,667 boe including 85.7 million cubic feet per day of natural gas and 3,383 barrels of light and medium oil and natural gas liquids. Third quarter production was impacted by the scheduled and previously announced Fort Nelson gas processing facility turnaround. A turbine failure at the Karr gas plant and maintenance outages at the Gold Creek gas plant also impacted quarterly production.



**Strong hedging program**

Progress has a natural gas risk management program that targets stability of its cash flows supporting the Trust's distribution and capital program. The Trust has currently hedged approximately 45 percent of its before-royalty gas production at an average AECO floor price of \$9.02 per gigajoule ("gj") through the end of March of 2007, resulting in an average wellhead realization of approximately \$10.50 per thousand cubic feet ("mcf") on that portion of Progress' natural gas which is hedged.

The Trust's average natural gas price realization in the third quarter was \$7.63 per mcf after hedging, compared to \$9.11 per mcf for the comparable quarter in 2005. On a before hedging basis, the Trust's natural gas price realization was \$6.28 per mcf. Progress' price realization represents a premium to the average daily AECO index price of \$5.33 per gj. The premium reflects the marketing portfolio and high heat content of the Trust's gas production.

**Financial strength**

Capital investment in the third quarter of 2006 was \$30.9 million or \$99.3 million for the nine months ended September 30, 2006. Capital expenditures are forecast to be \$125 million in 2006 which reflects Progress' expanded drilling program and incremental land capture.

In August, the Trust further enhanced its financial flexibility by issuing \$75 million of convertible debentures with a coupon rate of 6.25 percent and convertible to Trust units at \$19.50 per unit. Proceeds from the offering were used to pay down bank debt. As a result this provides the Trust with additional available funds from its \$215 million credit facility of which \$167 million is currently unutilized. With total debt-to-cash flow under 1.0 times based on twelve months trailing cash flow, the Trust has a strong balance sheet and is well positioned to be opportunistic during periods of weakness in the oil and gas sector.

## MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis ("MD&A") of financial results is dated October 26, 2006 and is to be read in conjunction with the accompanying unaudited consolidated interim financial statements and related notes for the period ended September 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. Cash flow 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. Cash flow as presented is not intended to represent operating profit for the period nor should it 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. Cash flow is 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 the 6.75% and 6.25% convertible unsecured subordinated debentures (the “Debentures”) of Progress trade on the TSX under the symbols PGE, PGX.DB and PGX.DB.A, 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 September 30		Nine Months Ended September 30		Change
	2006	2005	2006	2005	
<b>Average Daily Production</b>					
Natural gas ( <i>mcf/d</i> )	85,701	80,804	84,799	81,507	4%
Crude oil ( <i>bbls/d</i> )	2,056	2,734	2,251	2,784	(19)%
Natural gas liquids ( <i>bbls/d</i> )	1,327	1,280	1,398	1,393	-
Total daily production ( <i>boe/d</i> )	17,667	17,481	17,783	17,762	-
Natural gas as a % of total production	81%	77%	79%	76%	

For the three months ended September 30, 2006 (the “Quarter”), Progress’ production averaged 17,667 boe per day consisting of 85,701 mcf per day of natural gas, 2,056 bbls per day of crude oil and 1,327 bbls per day of natural gas liquids. Production during the Quarter was slightly higher than the same period in 2005 of 17,481 boe per day as production additions offset production decline. The Trust’s production portfolio for the Quarter was weighted 81 percent to natural gas, 12 percent to crude oil and seven percent to natural gas liquids.

Natural gas production increased six percent to 85,701 mcf per day for the Quarter compared to 80,804 mcf per day for the same period in 2005 due to reduced production in 2005 as a result of the shutdown of the McMahon gas processing facility during that period. Natural gas production for the Quarter was reduced by the scheduled and previously announced Fort Nelson gas processing facility turnaround, as well as a turbine failure at the Karr gas plant and maintenance outages at the Gold Creek gas plant. Crude oil and natural gas liquids production for the Quarter decreased 16 percent to 3,383 bbls per day compared to 4,014 bbls per day produced during the same period in 2005. The decrease is due to the natural gas focused drilling program, as well as, reduced production due to water source and regulatory challenges with the waterflood project in the Halfway ‘C’ oil pool at Gold Creek.

Year-to-date 2006 production was 17,783 boe per day consisting of 84,799 mcf per day of natural gas, 2,251 bbls per day of crude oil and 1,398 bbls per day of natural gas liquids. This production was consistent with the same period in 2005 of 17,762 boe per day. The Trust’s production portfolio for the nine months ended September 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 between 18,000 to 18,500 boe per day in the fourth quarter of 2006.

## Production by Region

	Three Months Ended September 30		Nine Months Ended September 30		Change
	2006	2005	2006	2005	
<b>Average Daily Production (boe/d)</b>					
Foothills	3,676	2,881	3,663	2,958	24%
Fort St. John Plains	1,948	2,120	2,091	2,300	(9)%
Milo	298	439	377	518	(27)%
Total British Columbia	5,922	5,440	6,131	5,776	6%
Deep Basin	8,977	9,353	8,732	9,274	(6)%
Central Alberta	1,687	1,356	1,752	1,456	20%
Other	779	889	826	840	(2)%
Total Alberta	11,443	11,598	11,310	11,570	(2)%
Saskatchewan	302	443	342	416	(18)%
Total daily production	17,667	17,481	17,783	17,762	-

## Pricing and Risk Management

### Natural Gas Markets

Progress' realized natural gas price for the Quarter was \$6.28 per mcf, before the impact of hedging, compared to the AECO daily index average of \$5.33 per gigajoule ("gj"). Including the impact of hedging, the Trust realized an average of \$7.63 per mcf.

For the nine months ended September 30, 2006 Progress' realized natural gas price was \$7.21 per mcf, before the impact of hedging, compared to the AECO daily index average of \$6.05 per gj. Including the impact of hedging, the Trust realized an average of \$8.07 per mcf.

The Quarter began with record high volumes of natural gas in storage and moderate weather which placed further downward pressure on natural gas prices through the Quarter. A mid-summer heat wave across much of the US resulted in record high levels of natural gas consumption, as well as the first ever recorded withdrawals of natural gas from storage during the summer. For the remainder of the summer, the weather turned back to a more moderate pattern and natural gas storage continued on its path toward record levels prior to the heating season. By the end of September, natural gas prices had slid back to pre-summer levels as moderating weather and sizable natural gas storage injections created a record high storage volume of 3.3 trillion cubic feet with four weeks remaining in the injection season.

Looking forward, natural gas prices in the very near term are not expected to rise substantially given the relatively large natural gas storage overhang. Winter weather and a pullback in natural gas directed capital investment is expected to result in a decline in the supply of natural gas and should have a positive impact on gas prices in the future. In the longer term, natural gas prices are expected to rise to levels higher than are currently being experienced as a result of increasing residential and commercial heating demand under normal winter weather conditions combined with the decline in supply.

### Oil Markets

Progress' realized prices for its liquids streams for the Quarter were \$75.69 per bbl for crude oil and \$68.29 per bbl for natural gas liquids and for the nine months ended September 30, 2006 were \$70.50 per bbl for crude oil and \$64.77 per bbl for natural gas liquids.

Crude oil prices began the Quarter with West Texas Intermediate ("WTI") oil averaging US\$74.46 per bbl, a record high. This high in July was supported by supply concerns and a significant "risk premium" resulting from Middle East tensions and in particular, the Israel-Lebanon conflict. Prices softened through August and September as global tensions eased and supply concerns passed. World oil production increased and storage of oil and refined products grew to comfortable levels. In September, OPEC production had increased such that daily volumes were the highest since November 2005. Slowing demand in North America was confirmed by the American Petroleum Institute with a reported 2.1 percent demand loss in August which confirmed slowing economic growth, particularly in the US. By Quarter-end, WTI had pulled back by more than eight percent to average US\$63.90 per bbl in September.

## Commodity Prices

	Three Months Ended September 30		Nine Months Ended September 30		Change
	2006	2005	2006	2005	
<b>Average Benchmark Prices</b>					
Natural gas – AECO (daily) (\$/gj)	5.33	8.81	6.05	7.44	(19)%
Natural gas – AECO (monthly) (\$/gj)	5.72	7.75	6.82	7.03	(3)%
Crude oil – WTI (US\$/bbl)	70.48	63.19	68.22	55.40	23%
Crude oil – Edmonton par price (Cdn\$/bbl)	78.83	76.54	75.47	67.94	11%
Exchange rate (US\$/Cdn\$)	1.1212	1.2015	1.1327	1.2241	(7)%
<b>Average Realized Prices</b>					
Natural gas - before hedging (\$/mcf)	6.28	9.33	7.21	8.25	(13)%
Hedge settlements (\$/mcf)	1.50	(0.23)	0.95	0.06	1,483%
Hedge premiums (\$/mcf)	(0.17)	(0.01)	(0.11)	(0.02)	(450)%
Amortization of commodity sales contract (\$/mcf) <sup>1</sup>	0.02	0.02	0.02	0.02	-
Natural gas - after hedging (\$/mcf)	7.63	9.11	8.07	8.31	(3)%
Crude oil (\$/bbl)	75.69	72.66	70.50	65.56	8%
Natural gas liquids (\$/bbl)	68.29	62.68	64.77	55.10	18%

(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 \$10.7 million (2005 - \$1.8 million net loss), which is included in petroleum and natural gas revenue on the statements of earnings. For the nine months ended September 30, 2006, the Trust's natural gas price risk management program had a net gain of \$19.5 million (2005 - \$0.8 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. 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 ( <sup>'000</sup> gj/d)	% of Estimated Natural Gas Production
Fourth quarter of 2006	40.0	45
First quarter of 2007	40.0	45

The estimated fair value of the natural gas financial instruments, that qualify for hedge accounting, was a gain of \$18.4 million as at September 30, 2006 and represents the amount the Trust would receive to terminate the contracts at September 30, 2006. These instruments have no carrying value recorded in the financial statements.

### Revenue

For the Quarter, petroleum and natural gas revenue decreased 11 percent to \$82.9 million from \$93.4 million for the same period in 2005 due to lower realized natural gas prices. Production revenue before hedging for the Quarter consisted of \$49.5 million from natural gas sales, \$14.3 million from crude oil sales and \$8.3 million from the sale of natural gas liquids.

For the nine months ended September 30, 2006, revenues of \$254.8 million was consistent with the same period in 2005 of \$255.6 million as hedging gains offset the impact of lower realized natural gas prices.

(\$ thousands)	Three Months Ended September 30		Nine Months Ended September 30		Change
	2006	2005	2006	2005	
Natural gas sales	49,528	69,349	166,847	183,516	(9)%
Crude oil sales	14,319	18,275	43,334	49,835	(13)%
Natural gas liquids sales	8,341	7,380	24,723	20,957	18%
Hedge settlements	11,823	(1,709)	22,067	1,217	1,713%
Hedge premiums	(1,297)	(82)	(2,580)	(415)	(522)%
Amortization of commodity sales contract <sup>1</sup>	140	159	431	491	(12)%
<b>Petroleum and natural gas revenue</b>	<b>82,854</b>	<b>93,372</b>	<b>254,822</b>	<b>255,601</b>	-

(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 September 30, 2005 petroleum and natural gas revenue	67,717	25,655	93,372
Price variance	(11,627)	1,038	(10,589)
Production variance	4,104	(4,033)	71
<b>Three months ended September 30, 2006 petroleum and natural gas revenue</b>	<b>60,194</b>	<b>22,660</b>	<b>82,854</b>

(\$ thousands)	Natural Gas	Crude Oil & NGLs	Total
Nine months ended September 30, 2005 petroleum and natural gas revenue	184,809	70,792	255,601
Price variance	(5,508)	6,214	706
Production variance	7,464	(8,949)	(1,485)
<b>Nine months ended September 30, 2006 petroleum and natural gas revenue</b>	<b>186,765</b>	<b>68,057</b>	<b>254,822</b>

## 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. Effective for 2007, the Alberta government eliminated the Alberta royalty tax credit program. The estimated impact to Progress will be an increase to royalty expense in 2007 of approximately \$0.5 million.

For the Quarter, royalties decreased 21 percent to \$18.3 million from \$23.1 million for the same period in 2005 due to lower revenues. For the nine months ended September 30, 2006 royalties decreased three percent to \$61.7 million from \$63.5 million in 2005 due to lower revenues. The Trust's average royalty rate (after removing the impact of hedging) for the Quarter was 25.3 percent compared to 24.3 percent in 2005. The year-to-date average royalty rate was 26.3 percent compared to 25.0 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 10 percent to \$10.0 million from \$9.2 million for the same period in 2005 and for the nine months ended September 30, 2006 increased six percent to \$29.3 million compared to \$27.6 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 \$6.18 from \$5.70 in the same period in 2005, while year-to-date operating expenses increased six percent to \$6.04 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 low.

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

## Transportation Expenses

Transportation expenses for the Quarter decreased 16 percent to \$2.6 million compared to \$3.1 million for the same period in 2005. For the nine months ended September 30, 2006 transportation expenses decreased 10 percent to \$8.4 million compared to \$9.4 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 17 percent to \$1.61 compared to \$1.95 for the same period in 2005, while year-to-date transportation expenses decreased ten percent to \$1.74 compared to \$1.94 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 nine months ended September 30, 2006 compared to the same periods in 2005:

	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	2006	2005
<b>Natural Gas Properties (\$/mcf)</b>				
Sales price - before hedging	6.78	9.46	7.59	8.40
Hedging settlements	1.41	(0.21)	0.89	0.05
Hedge premiums	(0.15)	(0.01)	(0.10)	(0.02)
Amortization of commodity sales contract	0.02	0.02	0.02	0.02
Royalties	(1.80)	(2.37)	(2.03)	(2.23)
Operating expenses	(0.89)	(0.87)	(0.94)	(0.87)
Transportation expenses	(0.26)	(0.33)	(0.29)	(0.33)
Operating netback – natural gas properties	5.11	5.69	5.14	5.02
<b>Oil Properties (\$/bbl)</b>				
Sales Price	67.71	68.85	64.38	61.05
Royalties	(14.04)	(15.05)	(15.69)	(11.85)
Operating expenses	(11.25)	(7.78)	(8.47)	(7.63)
Transportation expenses	(1.85)	(1.81)	(1.85)	(1.80)
Operating netback – oil properties	40.57	44.21	38.37	39.77
<b>All Properties (\$/boe)</b>				
Sales Price – before hedging	44.41	59.07	48.39	52.45
Hedging settlements	7.27	(1.06)	4.55	0.25
Hedge premiums	(0.80)	(0.05)	(0.53)	(0.09)
Amortization of commodity sales contract	0.09	0.10	0.09	0.10
Royalties	(11.24)	(14.39)	(12.70)	(13.10)
Operating expenses	(6.18)	(5.70)	(6.04)	(5.70)
Transportation expenses	(1.61)	(1.95)	(1.74)	(1.94)
Operating netback – all properties	31.94	36.02	32.02	31.97

## General and Administrative Expenses

For the Quarter, general and administrative expenses net of overhead recoveries, (“G&A”) of \$1.3 million (\$0.79 per boe) was consistent with the same period in 2005 of \$1.3 million (\$0.83 per boe). For the nine months ended September 30, 2006, G&A expenses decreased 13 percent to \$4.8 million (\$0.98 per boe) compared to \$5.5 million (\$1.14 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 growth.

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 nine months ended September 30, 2006 were \$2.9 million (2005 - \$1.7 million).

The Trust capitalized approximately \$0.3 million of G&A during the Quarter (2005 - \$0.3 million) and \$0.9 million for the nine months ended September 30, 2006 (2005 - \$1.0 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

Effective July 2, 2006, 407,350 performance units were granted to employees and directors, the fair value of which, using a performance factor of 1.0, was approximately \$6.5 million. Over the three year vesting period, approximately \$5.6 million will be amortized through unit based compensation expense and \$0.9 million will be capitalized over the vesting period with a corresponding increase to contributed surplus. As at September 30, 2006, 404,850 of these performance units were outstanding.

For the Quarter, unit based compensation expenses relating to the performance unit incentive plan increased 36 percent to \$1.4 million (\$0.84 per boe) compared to \$1.0 million (\$0.62 per boe) for the same period in 2005. For the nine months ended September 30, 2006 unit based compensation expenses increased 67 percent to \$3.4 million (\$0.70 per boe) compared to \$2.0 million (\$0.42 per boe) for the same period in 2005. The increase is due to the performance units granted effective July 2, 2006 and 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. As at September 30, 2006 the total performance units outstanding amounted to 1.5 percent of the total outstanding trust units and units which may be issued on the exchange of exchangeable shares.

	Nine Months Ended September 30	
	2006	2005
<b>Performance Units</b>		
Balance, beginning of period	898,367	395,267
Granted	412,650	506,000
Forfeited	(18,300)	(7,200)
Balance, end of period	1,292,717	894,067
<b>Vesting Date</b>		
July 2, 2007	380,567	388,067
July 2, 2008	507,300	506,000
July 2, 2009	404,850	-
Total	1,292,717	894,067

Management anticipates unit based compensation expenses in the fourth quarter of 2006 will be similar to the third quarter at \$0.84 per boe.

### Interest and Financing Expenses

Interest and financing expenses during the Quarter increased 14 percent to \$3.3 million compared to \$2.9 million for the same period in 2005. For the nine months ended September 30, 2006 interest and financing expenses of \$8.2 million were consistent with the same period in 2005 of \$7.9 million. The decrease in Debenture interest in 2006 is due to Debenture conversions in 2005 and 2006.

<i>(\$ thousands)</i>	Three Months Ended		Nine Months Ended	
	September 30		September 30	
	2006	2005	2006	2005
Interest on bank debt	1,422	765	3,582	2,272
Interest on Debentures	1,460	1,694	3,673	4,454
Amortization of Debenture issue costs	175	209	438	546
Accretion on debt portion of Debentures <sup>1</sup>	229	226	508	588
<b>Total interest and financing expense</b>	<b>3,286</b>	<b>2,894</b>	<b>8,201</b>	<b>7,860</b>

(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 \$23.7 million was consistent with the same period in 2005 of \$22.9 million. For the nine months ended September 30, 2006 DD&A of \$70.2 million was consistent with the same period in 2005 of \$68.7 million. On a boe basis, DD&A for the Quarter was \$14.59 compared to \$14.26 for the same period in 2005 and for the nine months ended September 30, 2006 was \$14.45 compared to \$14.17 for the same period in 2005.

Management expects DD&A per boe for the fourth quarter of 2006 to be approximately \$14.50 per boe.

### Income and Capital Taxes

Capital taxes for the Quarter decreased 92 percent to \$0.1 million compared to \$0.5 million for the same period in 2005. For the nine months ended September 30, 2006 capital taxes decreased 92 percent to \$0.1 million compared to \$1.6 million for the same period in 2005. The decrease is due to the federal budget passed in June of 2006 which eliminated the large corporation tax effective for the 2006 taxation year.

The provision for future income taxes for the Quarter was a recovery of \$1.4 million compared to a recovery of \$1.0 million in same period in 2005. For the nine months ended September 30, 2006 the provision for future income taxes was a recovery of \$13.3 million compared to a recovery of \$2.6 million for the same period in 2005. The nine months ended September 30, 2006 includes a recovery of \$8.2 million relating to a reduction in future federal and provincial income tax rates enacted during the second quarter of 2006 and the impact of certain tax balance adjustments. 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 expense with a corresponding increase to non-controlling interest on the consolidated balance sheet.

	Nine Months Ended September 30			
	2006		2005	
<i>(\$ thousands, except unit amounts)</i>	Number	Amount	Number	Amount
<b>Exchangeable Shares</b>				
Balance, beginning of period	11,388,751	127,205	14,533,506	141,060
Exchanged for trust units	(1,738,811)	(20,037)	(2,749,424)	(27,581)
Non-controlling interest expense		11,936		12,372
Balance, end of period	9,649,940	119,104	11,784,082	125,851

The charge to net earnings of \$11.9 million for 2006 and \$12.4 million for 2005 represents the net earnings attributable to the exchangeable shares over the period.

## Net Earnings and Cash Flow

Net earnings decreased 20 percent to \$20.3 million for the Quarter compared to \$25.2 million during the same period in 2005 due to lower revenues. Basic and diluted net earnings for the Quarter were \$0.27 per unit compared to \$0.36 per unit during the same period in 2005.

Net earnings for the nine months ended September 30, 2006 increased 18 percent to \$70.1 million compared to \$59.5 million for the same period in 2005. The increase was the result of a higher future income tax recovery as noted above. Basic and diluted net earnings for the nine months ended September 30, 2006 were \$0.94 per unit and \$0.93 per unit, respectively compared to \$0.87 per unit and \$0.86 per unit, respectively for the same period in 2005.

Cash flow for the Quarter decreased 11 percent to \$47.2 million compared to the same period in 2005 of \$53.2 million due to lower revenues. Diluted cash flow for the Quarter was \$0.54 per unit compared to \$0.64 per unit during the same period in 2005.

Cash flow of \$140.7 million for the nine months ended September 30, 2006 was consistent with the same period in 2005 of \$140.2 million. Year-to-date diluted cash flow for 2006 was \$1.60 per unit compared to \$1.68 per unit for the same period in 2005.

## Quarterly Financial Summary <sup>1,2</sup>

(\$ thousands, except per unit amounts)	Three Months Ended							
	Sept 30 2006	June 30 2006	Mar 31 2006	Dec 31 2005	Sept 30 2005	June 30 2005	Mar 31 2005	Dec 31 2004
Petroleum and natural gas revenue	82,854	81,009	90,959	114,167	93,372	83,222	79,007	76,767
Cash flow	47,218	45,871	47,637	65,785	53,215	44,466	42,511	41,344
Per unit diluted	0.54	0.52	0.55	0.77	0.63	0.53	0.51	0.50
Net earnings	20,252	28,425	21,383	29,398	25,159	16,840	17,526	18,196
Per unit basic	0.27	0.38	0.29	0.41	0.36	0.25	0.26	0.28
Per unit diluted	0.27	0.38	0.29	0.40	0.36	0.24	0.26	0.28

- (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 first quarter of 2005 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, second and third quarters of 2006 decreased as a result of lower natural gas prices.

### 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 (81 percent in the Quarter), natural gas prices have a significant effect on its cash flow.

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. As a result, \$31.6 million of distributions were declared during the Quarter (2005 - \$29.2 million) and \$93.9 million were declared for the nine months ended September 30, 2006 (2005 - \$86.7 million).

### Capital Expenditures

During the Quarter, the Trust invested \$30.9 million in capital expenditures compared to \$24.5 million in the same period in 2005. For the nine months ended September 30, 2006 the Trust invested \$99.3 million in capital expenditures compared to \$72.4 million for the same period in 2005.

(\$ thousands)	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	2006	2005
Land acquisitions and retention	2,002	1,227	7,619	4,025
Geological and geophysical	850	785	5,096	2,310
Drilling and completions	19,624	18,795	60,546	47,031
Equipping and facilities	7,307	3,976	23,918	17,986
Net property acquisitions (dispositions)	(12)	(376)	936	55
Corporate assets	1,104	85	1,233	1,024
Total capital expenditures	30,875	24,492	99,348	72,431

During the Quarter, Progress drilled 22 gross wells (12.0 net) with a 95 percent success rate. The program yielded 17 natural gas wells (9.8 net) and three oil wells (1.6 net). New discoveries were made at Town, Dogrib and Lily Lake in the Foothills region of northeast British Columbia and at Wapiti in the Deep Basin region of

northwest Alberta. Substantial development drilling is expected to result from these new discoveries after the Trust completes its field tests

During the Quarter, Progress added over 15,000 net acres of land in established fairways in the Foothills and Deep Basin regions. Land acquisition will continue along mapped or seismically identified trends as Progress strengthens its position as a dominant player in its operating regions. In total, Progress controls nearly 450,000 net acres of undeveloped land.

In June 2006, 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.

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 \$125.0 million.

### Liquidity and Capital Resources

	September 30	December 31
<i>(\$ thousands, except per unit amounts)</i>	2006	2005
Working capital deficiency	23,975	22,873
Bank debt	47,663	71,326
6.75% Convertible debentures	52,057	79,381
6.25% Convertible debentures	66,836	-
Total debt	190,531	173,580
Units outstanding and issuable for exchangeable shares (thousands)	87,749	84,784
Market price per unit at end of period	15.30	17.17
Market value of trust units and exchangeable shares	1,342,560	1,455,741
Cash flow (12 month trailing)	206,511	205,977
Total debt to cash flow ratio	0.92	0.84

At September 30, 2006 the Trust had \$47.7 million outstanding on its credit facilities, \$118.9 million for the debt portion of the 6.75 percent and 6.25 percent convertible unsecured subordinated debentures (the "Debentures") and a working capital deficiency of \$24.0 million, totaling \$190.5 million of total debt.

On August 22, 2006 the Trust issued \$75 million principal amount of 6.25 percent convertible unsecured subordinated debentures for net proceeds of \$71.6 million. The 6.25 percent 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 \$19.50 per trust unit. The 6.25 percent debentures mature on September 30, 2011 at which time they are due and payable. The net proceeds were used to reduce outstanding bank indebtedness.

The 6.25 percent debentures have been 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. This resulted in \$66.7 million being classified as debt and \$4.9 million being classified as equity. Issue costs will be amortized over the term of the 6.25 percent 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 with interest and financing expense on the consolidated statements of earnings.

At September 30, 2006 the Trust had outstanding \$55.7 million principal amount of the 6.75 percent debentures and \$75.0 million principal amount of the 6.25 percent debentures for a combined total of \$130.7 million. The 6.75 percent 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 6.75 percent debentures mature on June 30, 2010 at which time they are due and payable.

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 decreased from \$71.3 million as at December 31, 2005 to \$47.7 million as at September 30, 2006 as a result of the issuance of the 6.25 percent debentures in August 2006. The working capital deficiency of \$24.0 million at September 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.

Outstanding as at October 25, 2006 were 75,447,578 million trust units, 9,649,940 million exchangeable shares and \$130.7 million of Debentures convertible into 7,561,287 million trust units.

The Trust's investing activities in the Quarter and nine months ended September 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](http://www.sedar.com). Copies of the AIF can also be obtained by contacting the Trust at Progress Energy Trust 1200, 205 – 5th Avenue S.W., Calgary, Alberta, Canada T2P 4B9 or by e-mail at [ir@progressenergy.com](mailto:ir@progressenergy.com). This information is also accessible on the Trust's web site at [www.progressenergy.com](http://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 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 \$125 million which includes additional capital associated with ProEx Energy's increased capital program for the Foothills region of northeast British Columbia.

Natural gas prices are low 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 and exchangeable shares of Progress.

On behalf of the Board of Directors,

    (Signed) "Michael R. Culbert"

Michael R. Culbert  
President & CEO  
October 26, 2006

# PROGRESS ENERGY TRUST

## CONSOLIDATED BALANCE SHEETS

<i>(\$ thousands)</i>	September 30 2006	December 31 2005
	<i>(Unaudited)</i>	
<b>ASSETS</b>		
Current		
Cash and short-term investments	-	-
Accounts receivable	27,114	45,870
Prepaid expenses and deposits	7,909	5,144
	35,023	51,014
Property, plant and equipment <i>(Note 2)</i>	731,212	687,316
Goodwill	414,655	414,655
	1,180,890	1,152,985
<b>LIABILITIES</b>		
Current		
Accounts payable and accrued liabilities	43,228	58,904
Cash distributions payable	10,563	9,982
Current income taxes payable	5,207	5,001
	58,998	73,887
Bank debt <i>(Note 3)</i>	47,663	71,326
Convertible debentures <i>(Note 4)</i>	118,893	79,381
Commodity sales contract <i>(Note 10)</i>	1,015	1,446
Asset retirement obligations <i>(Note 5)</i>	22,986	20,906
Future income taxes <i>(Note 8)</i>	115,387	124,186
	364,942	371,132
<b>NON-CONTROLLING INTEREST</b>		
Exchangeable shares <i>(Note 6)</i>	119,104	127,205
<b>UNITHOLDERS' EQUITY</b>		
Unitholders' capital <i>(Note 7)</i>	739,885	681,263
Convertible debentures <i>(Note 4)</i>	7,702	4,261
Contributed surplus <i>(Note 7)</i>	7,476	3,530
Deficit	(58,219)	(34,406)
	696,844	654,648
	1,180,890	1,152,985

*See accompanying notes to the consolidated financial statements*

**PROGRESS ENERGY TRUST**  
**CONSOLIDATED STATEMENTS OF EARNINGS AND DEFICIT**

*(Unaudited)*

	Three Months Ended September 30		Nine Months Ended September 30	
<i>(\$ thousands, except per unit amounts)</i>	2006	2005	2006	2005
<b>REVENUE</b>				
Petroleum and natural gas	82,854	93,372	254,822	255,601
Royalties	(18,268)	(23,136)	(61,673)	(63,528)
	<b>64,586</b>	<b>70,236</b>	<b>193,149</b>	<b>192,073</b>
<b>EXPENSES</b>				
Operating	10,041	9,160	29,340	27,636
Transportation	2,624	3,135	8,424	9,393
General and administrative	1,282	1,342	4,773	5,488
Unit based compensation	1,363	1,004	3,378	2,027
Interest and financing	3,286	2,894	8,201	7,860
Depletion, depreciation and accretion	23,720	22,934	70,166	68,698
	<b>42,316</b>	<b>40,469</b>	<b>124,282</b>	<b>121,102</b>
Earnings before taxes and non-controlling interest	<b>22,270</b>	<b>29,767</b>	<b>68,867</b>	<b>70,971</b>
<b>TAXES (Note 8)</b>				
Capital taxes	45	543	135	1,629
Future income taxes	(1,354)	(1,011)	(13,264)	(2,556)
	<b>(1,309)</b>	<b>(468)</b>	<b>(13,129)</b>	<b>(927)</b>
Net earnings before non-controlling interest	<b>23,579</b>	<b>30,235</b>	<b>81,996</b>	<b>71,898</b>
Non-controlling interest – exchangeable shares (Note 6)	(3,327)	(5,076)	(11,936)	(12,372)
<b>NET EARNINGS</b>	<b>20,252</b>	<b>25,159</b>	<b>70,060</b>	<b>59,526</b>
Deficit, beginning of period	(46,846)	(29,951)	(34,406)	(6,870)
Distributions	(31,625)	(29,210)	(93,873)	(86,658)
Deficit, end of period	<b>(58,219)</b>	<b>(34,002)</b>	<b>(58,219)</b>	<b>(34,002)</b>
<b>NET EARNINGS PER UNIT (Note 7)</b>				
Basic	<b>\$0.27</b>	<b>\$0.36</b>	<b>\$0.94</b>	<b>\$0.87</b>
Diluted	<b>\$0.27</b>	<b>\$0.36</b>	<b>\$0.93</b>	<b>\$0.86</b>

*See accompanying notes to the consolidated financial statements*

**PROGRESS ENERGY TRUST**  
**CONSOLIDATED STATEMENTS OF CASH FLOWS**

*(Unaudited)*

	Three Months Ended September 30		Nine Months Ended September 30	
<i>(\$ thousands)</i>	2006	2005	2006	2005
<b>OPERATING ACTIVITIES</b>				
Net earnings	20,252	25,159	70,060	59,526
Depletion, depreciation and accretion	23,720	22,934	70,166	68,698
Non-controlling interest – exchangeable shares <i>(Note 6)</i>	3,327	5,076	11,936	12,372
Convertible debentures accretion <i>(Note 4)</i>	229	225	508	588
Amortization of convertible debenture issue costs <i>(Note 4)</i>	175	209	438	546
Amortization of commodity sales contract	(140)	(159)	(431)	(491)
Unit based compensation expense <i>(Note 7)</i>	1,363	1,004	3,378	2,027
Asset retirement expenditures <i>(Note 5)</i>	(354)	(222)	(2,065)	(518)
Future income taxes	(1,354)	(1,011)	(13,264)	(2,556)
	47,218	53,215	140,726	140,192
Changes in non-cash working capital <i>(Note 9)</i>	745	(11,387)	4,555	(8,545)
	47,963	41,828	145,281	131,647
<b>FINANCING ACTIVITIES</b>				
Increase (decrease) in bank debt	(54,691)	3,995	(23,662)	(62,555)
Issue of 6.75% convertible debentures <i>(Note 4)</i>	-	-	-	100,000
6.75% convertible debenture issue costs <i>(Note 4)</i>	-	-	-	(4,515)
Issue of 6.25% convertible debentures <i>(Note 4)</i>	75,000	-	75,000	-
6.25% convertible debenture issue costs <i>(Note 4)</i>	(3,375)	-	(3,375)	-
Cash distributions	(31,549)	(29,051)	(93,293)	(86,231)
Changes in non-cash working capital <i>(Note 9)</i>	205	-	205	-
	(14,410)	(25,056)	(45,125)	(53,301)
<b>INVESTING ACTIVITIES</b>				
Capital expenditures	(30,875)	(24,492)	(99,348)	(72,431)
Changes in non-cash working capital <i>(Note 9)</i>	(2,678)	7,720	(808)	(5,915)
	(33,553)	(16,772)	(100,156)	(78,346)
<b>CHANGE IN CASH AND SHORT-TERM INVESTMENTS</b>	-	-	-	-
Cash and short-term investments, beginning of period	-	-	-	-
<b>CASH AND SHORT-TERM INVESTMENTS, END OF PERIOD</b>	-	-	-	-

*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 nine months ended September 30, 2006 was \$0.9 million and \$2.9 million, respectively (2005 – \$0.6 million and \$1.7 million).

As at September 30, 2006, accounts payable included \$2.6 million (2005 – \$1.8 million) payable to ProEx which includes standard joint venture amounts including revenue. These amounts were paid subsequent to September 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

	September 30 2006	December 31 2005
Property, plant and equipment	964,534	865,173
Conversions of exchangeable shares	45,986	32,553
Accumulated depletion and depreciation	(279,308)	(210,410)
Property, plant and equipment, net	731,212	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 \$13.4 million was made to property, plant and equipment for the nine months ended September 30, 2006 (2005 - \$19.4 million).

In June 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 \$12.5 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 \$60.7 million for the estimated value of unproven properties. Depletion and depreciation expense for the three and nine months ended September 30, 2006 was \$23.3 million and \$68.9 million, respectively (2005 - \$22.5 million and \$67.6 million).

Included in the Trust's property, plant and equipment balance is \$13.9 million, net of accumulated depletion, related to asset retirement obligations (\$21.6 million before accumulated depletion) (Refer to note 5).

The Trust capitalized approximately \$1.5 million of geological and geophysical compensation costs associated with the exploration and development of capital assets during the nine months ended September 30, 2006 (2005 - \$1.1 million).

### 3. BANK DEBT

	September 30 2006	December 31 2005
Direct advances	2,663	1,326
Banker's acceptances	45,000	70,000
Total bank debt	47,663	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 nine months ended September 30, 2006 was 5.1 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 August 22, 2006 the Trust issued \$75 million principal amount of 6.25 percent convertible unsecured subordinated debentures (the "6.25 percent debentures") for net proceeds of \$71.6 million. The 6.25 percent 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 \$19.50 per trust unit. The 6.25 percent debentures mature on September 30, 2011, at which time they are due and payable. The Trust may elect to satisfy the interest and principal obligations by the issuance of Trust Units. The net proceeds were used to reduce outstanding bank indebtedness.

On February 2, 2005 the Trust issued \$100 million principal amount of 6.75 percent convertible unsecured subordinated debentures (the "6.75 percent debentures") for net proceeds of \$95.5 million. The 6.75 percent 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 6.75 percent 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 by the issuance of Trust Units. The net proceeds were used to reduce outstanding bank indebtedness.

The 6.25 percent debentures and the 6.75 percent debentures (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 the 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:

	Nine Months Ended September 30					
	2006			2005		
	6.75%	6.25%	Total	6.75%	6.25%	Total
<b>Debentures</b>						
Principal, beginning of period <sup>1</sup>	86,182	75,000	161,182	100,000	-	100,000
Converted to Trust Units	(30,455)	-	(30,455)	(13,818)	-	(13,818)
Principal, end of period	55,727	75,000	130,727	86,182	-	86,182
Debt portion, beginning of period <sup>1</sup>	79,381	66,679	146,060	90,541	-	90,541
Accretion	408	100	508	588	-	588
Amortization of issue costs	381	57	438	546	-	546
Conversions to Trust Units <sup>2</sup>	(28,113)	-	(28,113)	(516)	-	(516)
Debt portion, end of period	52,057	66,836	118,893	91,159	-	91,159
Equity portion, beginning of period <sup>1</sup>	4,261	4,946	9,207	4,944	-	4,944
Conversions to Trust Units	(1,505)	-	(1,505)	(27)	-	(27)
Equity portion, end of period	2,756	4,946	7,702	4,917	-	4,917

(1) The 6.75 percent debentures were issued February 2, 2005 and the 6.25 percent debentures were issued August 22, 2006.

(2) Net of unamortized issue costs.

Total interest charged to earnings for the three months ended September 30, 2006 was \$1.9 million (2005 - \$2.1 million) which includes \$0.2 million of debenture accretion (2005 - \$0.2 million) and \$0.2 million of amortized issue costs (2005 - \$0.2 million).

Total interest charged to earnings for the nine months ended September 30, 2006 was \$4.6 million (2005 - \$5.6 million) which includes \$0.5 million of debenture accretion (2005 - \$0.6 million) and \$0.4 million of amortized issue costs (2005 - \$0.5 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 \$54.3 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:

	Nine Months Ended September 30	
	2006	2005
Balance, beginning of period	20,906	16,065
Liabilities incurred	3,251	1,794
Liabilities settled	(2,065)	(518)
Dispositions	(374)	-
Accretion expense	1,268	1,059
Balance, end of period	22,986	18,400

## 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.

	Nine months ended September 30			
	2006		2005	
	Number	Amount	Number	Amount
<b>Exchangeable Shares</b>				
Balance, beginning of period	11,388,751	127,205	14,533,506	141,060
Exchanged for trust units	(1,738,811)	(20,037)	(2,749,424)	(27,581)
Non-controlling interest expense		11,936		12,372
Balance, end of period	9,649,940	119,104	11,784,082	125,851

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 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

	Nine months ended September 30			
	2006		2005	
	Number	Amount	Number	Amount
<b>Trust Units</b>				
Balance, beginning of period	71,302,265	681,263	66,898,498	621,490
Exchangeable shares converted	2,114,992	29,004	3,021,978	40,320
Issued on conversion of convertible debentures	2,030,321	29,618	35,932	542
Balance, end of period	75,447,578	739,885	69,956,408	662,352

### 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 September 30		Nine Months Ended September 30	
	2006	2005	2006	2005
Weighted average trust units - basic	75,190,280	69,281,384	74,229,439	68,563,927
Trust units issuable on conversion of exchangeable shares <sup>1</sup>	12,457,109	14,248,104	13,080,522	14,994,612
Performance units	542,264	170,642	469,035	102,394
Weighted average trust units - diluted	88,189,653	83,700,130	87,778,996	83,660,933

(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 \$3.3 million and \$11.9 million for the three and nine months ended September 30, 2006 (2005 - \$5.1 million and \$12.4 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 nine months ended September 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 September 30, 2006 there are 380,567 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 September 30, 2006 there are 507,300 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.

Effective July 2, 2006, 407,350 performance units were granted to employees and directors, the fair value of which, using a performance factor of 1.0, was approximately \$6.5 million. Over the three year vesting period, approximately \$5.6 million will be amortized through unit based compensation expense and \$0.9 million will be capitalized over the vesting period with a corresponding increase to contributed surplus. As at September 30, 2006, 404,850 of these performance units were outstanding.

For the three and nine months ended September 30, 2006 \$1.4 million and \$3.4 million, respectively were charged to unit based compensation expense (2005 – \$1.0 million and \$2.0 million) and \$0.2 million and \$0.6 million, respectively were capitalized (2005 – \$0.2 million) relating to the total performance units outstanding.

	Nine Months Ended September 30	
	2006	2005
<b>Performance Units</b>		
Balance, beginning of period	898,367	395,267
Granted	412,650	506,000
Forfeited	(18,300)	(7,200)
Balance, end of period	1,292,717	894,067
<b>Vesting Date</b>		
July 2, 2007	380,567	388,067
July 2, 2008	507,300	506,000
July 2, 2009	404,850	-
Total	1,292,717	894,067

The following table reconciles the Trust's contributed surplus:

	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	2006	2005
Balance, beginning of period	5,874	1,194	3,530	171
Unit based compensation expense	1,363	1,004	3,378	2,027
Unit based compensation capitalized	239	165	568	165
Balance, end of period	7,476	2,363	7,476	2,363

## 8. TAXES

Included in the provision for capital taxes for the nine months ended September 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 nine months ended September 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 the impact of certain tax balance adjustments.

## 9. SUPPLEMENTAL CASH FLOW INFORMATION

### Changes in non-cash working capital

	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	2006	2005
Accounts receivable	(1,820)	(12,174)	18,756	(5,060)
Prepaid expenses and deposits	465	(602)	666	(941)
Accounts payable	(1,071)	10,354	(15,676)	(6,992)
Current income taxes payable	698	(1,245)	206	(1,467)
Change in non-cash working capital	(1,728)	(3,667)	3,952	(14,460)
Relating to:				
Financing activities	205	-	205	-
Investing activities	(2,678)	7,720	(808)	(5,915)
Operating activities	745	(11,387)	4,555	(8,545)

### Interest and taxes paid

	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	2006	2005
Interest paid	483	812	8,621	5,043
Income and other taxes paid	38	1,788	621	2,768

## 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 September 30, 2006 was approximately \$134.1 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 September 30, 2006, the Trust's natural gas price risk management program had a net gain of \$10.7 million (2005 - \$1.8 million net loss) which is included in petroleum and natural gas revenue on the statements of earnings. For the nine months ended September 30, 2006, the Trust's natural gas price risk management program had a net gain of \$19.5 million (2005 - \$0.8 million net gain).

Contracts outstanding in respect to financial instruments are as follows:

Natural Gas Contracts <sup>1</sup>	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 \$18.4 million as at September 30, 2006 and represents the amount the Trust would receive to terminate the contracts at September 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 September 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 September 30, 2006 the unamortized remaining liability was \$1.0 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		
	March 31	June 30	Sept 30	Dec 31	March 31	June 30	Sept 30
<i>(\$ thousands except per unit amounts)</i>							
<b>Income Statement</b>							
Petroleum and natural gas revenue	79,007	83,222	93,372	114,167	90,959	81,009	82,854
Cash flow <sup>1</sup>	42,511	44,466	53,215	65,785	47,637	45,871	47,218
Per unit - diluted	0.52	0.53	0.64	0.77	0.55	0.52	0.54
Cash distributions declared	28,574	28,874	29,210	29,802	30,836	31,412	31,626
Per unit	0.42	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	20,252
Per unit - basic	0.27	0.25	0.36	0.41	0.29	0.38	0.27
Per unit - diluted	0.27	0.24	0.36	0.40	0.29	0.38	0.27
<b>Payout Ratio</b>							
Excluding exchangeable shares	67%	65%	55%	45%	65%	68%	67%
Including exchangeable shares	81%	79%	66%	54%	76%	80%	78%
<b>Balance Sheet</b>							
Capital expenditures	34,380	13,559	24,492	35,227	35,984	32,489	30,875
Total debt	187,312	185,708	186,115	173,580	172,106	182,873	190,531
Unitholders' equity	632,700	623,308	635,630	654,648	687,953	694,236	696,844
<b>Trust Units (thousands, except where otherwise stated)</b>							
Units outstanding, end of period	68,646	68,820	69,956	71,302	74,315	74,901	75,448
Units issuable for exchangeable shares	13,992	14,281	13,601	13,482	12,309	12,314	12,301
Total units outstanding and issuable for exchangeable shares, end of period	82,638	83,101	83,557	84,784	86,624	87,215	87,749
Weighted average units – diluted <sup>2</sup>	82,485	83,176	83,700	84,675	86,579	87,557	88,190
Exchange ratio, end of period	1.08438	1.12038	1.15421	1.18384	1.21322	1.24284	1.27469
<b>Trust Unit Trading Statistics (\$)</b>							
High	14.50	13.79	17.82	17.85	18.20	18.33	17.50
Low	12.52	11.90	13.07	14.08	14.75	14.73	14.21
Closing	13.38	13.03	17.61	17.17	17.45	16.30	15.30
Unit volume traded (thousands)	17,788	11,544	19,159	18,385	18,619	12,619	15,524
<b>Exchangeable Shares Trading Statistics (\$)</b>							
High	15.85	15.50	20.62	20.36	21.29	21.76	22.48
Low	13.96	13.27	15.00	16.61	18.49	18.28	18.60
Closing	14.60	14.96	19.26	20.36	20.70	19.57	18.60
Share volume traded (thousands)	1,460	290	613	52	85	15	69

(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	Sept 30
<b>Daily Production</b>							
Natural gas (mcf/d)	84,523	79,236	80,804	85,173	86,433	82,271	85,701
Crude oil (bbls/d)	2,550	3,067	2,734	2,762	2,605	2,099	2,056
Natural gas liquids (bbls/d)	1,598	1,305	1,280	1,355	1,390	1,478	1,327
Total daily production (boe/d)	18,235	17,578	17,481	18,312	18,401	17,288	17,667
<b>Average Realized Prices</b>							
Natural gas - before hedging (\$/mcf)	7.31	8.12	9.33	12.18	8.80	6.53	6.28
Natural gas - after hedging (\$/mcf)	7.69	8.13	9.11	11.38	8.74	7.83	7.63
Crude oil (\$/bbl)	59.44	64.20	72.66	67.22	64.45	72.79	75.69
Natural gas liquids (\$/bbl)	47.82	56.41	62.68	63.63	62.86	63.34	68.29
<b>Highlights (\$/boe)</b>							
Weighted average sales price	48.14	52.02	58.06	67.77	54.92	51.49	50.97
Royalties	11.78	13.16	14.39	18.38	14.87	11.94	11.24
Operating expenses	5.69	5.72	5.70	5.66	5.81	6.15	6.18
Transportation expenses	1.89	1.98	1.95	1.89	1.91	1.68	1.61
Operating Netbacks	28.78	31.16	36.02	41.84	32.33	31.72	31.94
General and administrative expense	1.23	1.33	0.83	0.75	1.08	1.08	0.79
Unit based compensation	0.31	0.32	0.62	0.59	0.61	0.64	0.84
Interest and financing expenses	1.26	1.80	1.80	1.62	1.45	1.60	2.02
Depletion, depreciation and accretion	14.05	14.19	14.26	13.86	14.27	14.49	14.59
Net earnings before taxes	11.93	13.52	18.51	25.02	14.92	13.91	13.70
Capital taxes	0.33	0.34	0.34	0.32	0.20	(0.16)	0.03
Future income taxes (recovery)	(1.48)	0.55	(0.63)	3.93	(0.56)	(6.98)	(0.83)
Non-controlling interest – exchangeable shares	2.40	2.10	3.16	3.32	2.37	2.98	2.04
Net earnings	10.68	10.53	15.64	17.45	12.91	18.07	12.46
<b>Drilling Results</b>							
Gross	24	8	24	31	39	15	22
Net – natural gas	9.9	3.3	9.6	16.0	18.8	11.0	9.8
Net – crude oil	1.2	0.0	1.9	1.7	0.8	0.4	1.6
Success Rate (percent)	89	78	89	100	93	100	95

## **CORPORATE INFORMATION**

### **DIRECTORS**

David D. Johnson  
Chairman  
Progress Energy Ltd.  
President & CEO  
ProEx Energy Ltd.  
Calgary, Alberta

Donald F. Archibald <sup>(1)(4)(5)</sup>  
Chairman & CEO  
Cyries Energy Inc.  
Calgary, Alberta

John A. Brussa <sup>(3)(5)</sup>  
Partner  
Burnet, Duckworth and Palmer LLP  
Calgary, Alberta

Frederic C. Coles <sup>(1)(2)(4)(5)</sup>  
Independent Businessman  
Calgary, Alberta

Howard J. Crone <sup>(2)(4)(5)</sup>  
Independent Businessman  
Calgary, Alberta

Michael R. Culbert  
President & CEO  
Progress Energy Ltd.  
Calgary, Alberta

Gary E. Perron <sup>(1)(3)(5)</sup>  
Senior Vice President and  
Managing Director  
BMO Nesbitt Burns  
Calgary, Alberta

<sup>(1)</sup> Member of Audit Committee

<sup>(2)</sup> Member of Reserve Committee

<sup>(3)</sup> Member of Compensation  
Committee

<sup>(4)</sup> Member of Technical Services  
Committee

<sup>(5)</sup> 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  
Vice President, Exploration

Gary R. Bugeaud  
Secretary

### **CORPORATE OFFICE**

1200, 205 – 5th Avenue S.W.  
Calgary, Alberta T2P 4B9  
Telephone: (403) 216-2510  
Fax: (403) 216-2514

### **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  
6.75% Debentures – PGX.DB  
6.25% Debentures – PGX.DB.A

### **SOLICITOR**

Burnet, Duckworth & Palmer LLP  
Calgary, Alberta

### **AUDITOR**

KPMG LLP  
Calgary, Alberta

### **CONSULTING ENGINEERS**

GLJ Petroleum Consultants Ltd.  
Calgary, Alberta

### **INVESTOR RELATIONS**

Greg Kist  
Vice President, Investor Relations  
and Marketing  
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