November 9, 2007, CALGARY, ALBERTA. Crescent Point Energy Trust, ("Crescent Point" or the "Trust") (TSX: CPG.UN), is pleased to announce its operating and financial results for the third quarter and nine months ended September 30, 2007.

FINANCIAL AND OPERATING HIGHLIGHTS

($000s except trust units, per trust unit and per boe amounts)	Three months ended September 30			Nine months ended September 30		
	2007	2006	% Change	**2007**	2006	% Change
Financial						
Cash flow from operations [1]	**92,215**	52,774	75	**243,338**	145,292	67
Per unit [1] [2]	**0.89**	0.78	14	**2.50**	2.36	6
Net income	**18,410**	39,588	(53)	**58,181**	62,029	(6)
Per unit [2]	**0.18**	0.58	(69)	**0.60**	0.97	(38)
Cash distributions	**63,206**	39,890	58	**177,137**	108,955	63
Per unit [2]	**0.60**	0.60	-	**1.80**	1.80	-
Payout ratio (%) [1]	**69**	76	(7)	**73**	75	(2)
Per unit (%) [1] [2]	**67**	77	(10)	**72**	76	(4)
Net debt [1] [3]	**208,554**	212,073	(2)	**208,554**	212,073	(2)
Capital acquisitions (net) [4]	**20,777**	61,738	(66)	**660,029**	505,927	30
Development capital expenditures	**57,792**	31,921	81	**132,538**	79,956	66
Weighted average trust units outstanding (mm)						
Basic	**102.7**	65.4	57	**96.5**	59.3	63
Diluted	**104.1**	67.8	54	**97.8**	61.5	59
Operating						
Average daily production						
Crude oil and NGLs (bbls/d)	**23,846**	17,940	33	**22,915**	17,238	33
Natural gas (mcf/d)	**22,357**	20,193	11	**20,626**	19,638	5
Total (boe/d)	**27,572**	21,305	29	**26,353**	20,511	28
Average selling prices [5]						
Crude oil and NGLs ($/bbl)	**69.86**	66.14	6	**63.97**	62.22	3
Natural gas ($/mcf)	**5.40**	5.49	(2)	**6.61**	6.29	5
Total ($/boe)	**64.80**	60.90	6	**60.80**	58.31	4
Netback ($/boe)						
Oil and gas sales	**64.80**	60.90	6	**60.80**	58.31	4
Royalties	**(11.77)**	(12.97)	(9)	**(11.07)**	(12.65)	(12)
Operating expenses	**(9.01)**	(9.56)	(6)	**(9.27)**	(8.74)	6
Transportation	**(1.75)**	(1.31)	34	**(1.68)**	(1.23)	37
Netback prior to realized financial instruments	**42.27**	37.06	14	**38.78**	35.69	9
Realized gain (loss) on financial instruments	**(1.17)**	(4.90)	76	**0.19**	(4.76)	104
Netback	**41.10**	32.16	28	**38.97**	30.93	26

(1) Cash flow from operations, payout ratio and net debt as presented do not have any standardized meaning prescribed by GAAP and therefore may not be comparable with the calculation of similar measures presented by other entities.

(2) The per unit amounts (with the exception of per unit distributions) are the per unit – diluted amounts. The net income and cash flow per unit – diluted amounts exclude the cash portion of unit-based compensation.

(3) Net debt includes working capital, but excludes the risk management liabilities and assets. Working capital at September 30, 2007 includes the $16.6 million long-term investment in Innova Exploration Ltd.

(4) Capital acquisitions represent total consideration for the transactions including bank debt and working capital assumed.

(5) The average selling prices reported are before realized financial instruments.

HIGHLIGHTS

In the third quarter of 2007, Crescent Point continued to execute its integrated business strategy of acquiring, exploiting and developing high quality, long life, light and medium oil and natural gas properties.

- Crescent Point increased production in the third quarter of 2007 by 5 percent over the second quarter of 2007 to 27,572 boe/d due to 100 percent drilling success in the Viewfield Bakken play and better than expected results from the Bakken fracture stimulation program.
- Through corporate acquisitions, freehold land acquisitions and Crown land sales, the Trust has grown its undeveloped Bakken land base by nearly 150 percent since the acquisition of Mission Oil & Gas Inc. ("Mission"), from 143 net sections to 353 net sections, including the acquisitions of Innova Exploration Ltd. ("Innova") and Pilot Energy Ltd. ("Pilot").
- Crescent Point is revising upwards its fourth quarter production guidance to 31,250 boe/d from 30,000 boe/d due to better than anticipated fracture stimulation results that have increased current production to more than 32,300 boe/d, 7 percent over previous guidance. The Trust is also revising upwards its 2007 capital expenditure program from $165 million to $215 million to reflect the Trust's Bakken land acquisitions of approximately $40 million in the second half of the year.
- The Trust spent $57.8 million on development capital activities in the quarter, drilling 49 (34.2 net) wells, comprised of 48 (33.5 net) oil wells and 1 (0.7 net) water injection well, achieving a 100 percent success rate. Crescent Point added approximately 2,300 boe/d of initial interest production through its development expenditures in the quarter.
- The Trust's cash flow from operations increased by 75 percent to a record $92.2 million ($0.89 per unit – diluted) in the third quarter of 2007, compared to $52.8 million ($0.78 per unit – diluted) in the third quarter of 2006.
- The Trust's netback increased by 28 percent to $41.10 per boe despite a decline in Canadian dollar benchmark crude oil and natural gas prices. This improvement in corporate netback has been driven predominantly by Viewfield Bakken production which realized a third quarter netback of $62.71 per boe.
- The Trust maintained consistent monthly distributions of $0.20 per unit, totaling $0.60 per unit for the third quarter of 2007 resulting in an overall payout ratio of 67 percent on a per unit – diluted basis. This compares to an overall payout ratio of 77 percent on a per unit – diluted basis in the third quarter of 2006.
- Crescent Point continued to execute its core strategy of managing commodity price risk using a combination of fixed price swaps, costless collars and put option instruments. As at October 30, 2007, the Trust had hedged 55 percent net of royalty interest for the fourth quarter of 2007 and 53, 44, and 18 percent for 2008, 2009 and the first three quarters of 2010, respectively, providing a floor of more than Cdn$70.00 per barrel, with upside participation in rising commodity prices.
- On September 5, 2007, Crescent Point announced the strategic Bakken consolidation acquisition of Innova for $7.55 cash per share, plus assumed debt, for a total consideration of approximately $400 million. The Trust subsequently took effective control of Innova on October 22, 2007 when more than 97 percent of outstanding Innova shares were tendered to the offer. With the completion of the acquisition, Crescent Point acquired approximately 4,300 boe/d of high quality, high netback light oil and natural gas production, more than 97 net sections of undeveloped Bakken land, and 380 net low risk Bakken development drilling locations.
- On September 5, 2007, Crescent Point announced a bought deal equity financing of 8.9 million trust units at $18.55 per trust unit for gross proceeds of approximately $165 million. Closing of the equity financing occurred on September 25, 2007. The Trust used the proceeds to reduce outstanding indebtedness incurred prior to the October 31, 2006 federal government announcement on income trust taxation.
- In late October, 2007, as part of the acquisition of Innova, the Trust's bank syndicate increased the borrowing base from $600 million to $800 million recognizing the strong reserves growth through continued development and acquisition success as well as the stability of the Trust's continued risk management activities.
- The Trust's balance sheet remains strong with debt to annualized cash flow of 0.6 times in the third quarter and forecast 2008 debt to cash flow of 1.4 times.

OPERATIONS REVIEW

Forward-Looking Statements

This report may contain forward-looking statements including expectations of future production, cash flow and earnings. These statements are based on current beliefs and expectations based on information available at the time the assumption was made. By its nature, such forward-looking information is subject to a number of risks, uncertainties and assumptions, which could cause actual results or other expectations to differ materially from those anticipated, including those material risks discussed in our annual information form under "Risk Factors" and in our Management's Discussion and Analysis for the year ended December 31, 2006, under "Business Risks and Prospects". The material assumptions are disclosed in the Results of Operations section of this press release under the headings "Cash Distributions", "Taxation of Cash Distributions", "Capital Expenditures", "Asset Retirement Obligation", "Liquidity and Capital Resources", "Critical Accounting Estimates", "New Accounting Pronouncements", and "Business Risks and Prospects". These risks include, but are not limited to: the risks associated with the oil and gas industry (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks), commodity price and exchange rate fluctuations and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures. Additional information on these and other factors that could affect Crescent Point's operations or financial results are included in Crescent Point's reports on file with Canadian securities regulatory authorities. Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed herein or otherwise and Crescent Point undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise.

Third Quarter Operations Summary

During the third quarter of 2007, Crescent Point continued to aggressively implement management's business strategy of creating sustainable, value added growth in reserves, production and cash flow through acquiring, exploiting and developing high quality, long life, light and medium oil and natural gas properties.

Crescent Point achieved record production in the third quarter, increasing production by 5 percent over the second quarter of 2007 to 27,572 boe/d. The Trust drilled a total of 48 (33.5 net) oil wells and 1 (0.7 net) water injection well, achieving a 100 percent success rate and adding approximately 2,300 boe/d of initial interest production. The Trust fracture stimulated 23 (16.3 net) Bakken horizontal wells achieving average post fracture production rates exceeding 200 boe/d per stimulation.

Drilling Results

Three months ended September 30, 2007	Gas	Oil	D&A	Service	Standing	Total	Net	% Success
Southeast Saskatchewan	-	43	-	1	-	44	31.4	100
Southwest Saskatchewan	-	5	-	-	-	5	2.8	100
South/Central Alberta	-	-	-	-	-	-	-	-
Northeast BC & W Peace River Arch, Alberta	-	-	-	-	-	-	-	-
Total	-	**48**	-	**1**	-	**49**	**34.2**	**100**

Nine months ended September 30, 2007	Gas	Oil	D&A	Service	Standing	Total	Net	% Success
Southeast Saskatchewan	-	89	-	3	1	93	65.8	98
Southwest Saskatchewan	-	13	-	-	-	13	6.4	100
South/Central Alberta	-	1	-	1	-	2	1.9	100
Northeast BC & W Peace River Arch, Alberta	-	4	-	-	-	4	4.0	100
Total	-	**107**	-	**4**	**1**	**112**	**78.1**	**99**

Southeast Saskatchewan

During the third quarter, Crescent Point participated in drilling a total of 43 (30.7 net) horizontal oil wells and 1 (0.7 net) water injector well in southeast Saskatchewan achieving a 100 percent success rate. The Trust operated 39 (29.2 net) – more than 90 percent – of the wells. Of the total wells drilled, 32 (19.7 net) were Bakken horizontal wells at Viewfield. The Trust fracture stimulated 23 (16.3 net) Viewfield Bakken wells utilizing several progressive packer isolation techniques to optimize results and reduce costs. Results for 21 (14.3 net) of the wells indicate average post fracture production rates exceeding 200 boe/d per stimulation. The balance of the wells were drilled in the Trust's core properties of Manor, Ingoldsby and Glen Ewen. Crescent Point added approximately 2,250 boe/d of initial interest production from its drilling activities in southeast Saskatchewan in the quarter.

The Trust completed the Viewfield gas plant expansion in late July, increasing the plant's processing capacity to more than 6.0 mmcf/d. Depropanization and debutanization facilities are expected to be operational in the fourth quarter, which are expected to increase liquid recoveries from the plant. Crescent Point anticipates drilling up to 83 (57.7 net) Bakken horizontal wells during 2007 and up to 56 (39.6 net) Bakken horizontal wells will be fracture stimulated.

The third of four water injectors planned for 2007 was drilled in the Tatagwa Unit in the third quarter. Preliminary development plans for the Tatagwa Unit in 2008 include drilling up to 6 (4.2 net) water injector wells and 4 (2.8 net) oil wells to improve recovery factors. A total of 6 (6.0 net) wells were drilled at Manor and 3 (3.0 net) at Glen Ewen in the third quarter, adding more than 500 boe/d of interest production.

Southwest Saskatchewan

In the third quarter, the Trust participated in drilling 5 (2.8 net) wells in the Cantuar Unit in the third quarter which will be tied in during the fourth quarter, achieving a 100 percent success rate and adding expected initial interest production of 80 boe/d.

The Trust is currently reviewing facility process design at Battrum to increase recovery efficiencies and is also preparing plans for the 2008 budget year. With overall corporate production levels exceeding expectations, plans for fourth quarter drilling of 7 (2.9 net) oil wells at Battrum were postponed to early 2008.

South/Central Alberta

At Sounding Lake, Crescent Point continued to work on recovery optimization activities within the Dina and Cummings formations in the third quarter. The Trust is awaiting regulatory approval, expected in early 2008, of its application for pool delineation of the Sparky formation and is currently completing its application for waterflood implementation. Preliminary plans for 2008, subject to a detailed review of the Alberta royalty changes announced in October 2007, include drilling up to 4 (4.0 net) wells and 5 (5.0 net) injectors in the Sparky formation. Water injection may commence in early to mid 2008.

With natural gas prices remaining weak in the third quarter, the Trust focused on optimization activities at John Lake. Up to 15 (11.3 net) high priority opportunities have been identified for the property, including tubing resizing, pipeline reconfiguring and well bore cleanouts, which could add up to 500 mcf/d of initial interest production to offset production declines.

With corporate production exceeding expectations and Alberta royalty rates uncertain, the Trust delayed completing the first 2 (2.0 net) of up to 19 (19.0 net) recompletion candidates at Little Bow. These activities are subject to a detailed review of the Alberta royalty changes and will be considered for 2008.

Northeast British Columbia and Peace River Arch, Alberta

Conversion of a well for Charlie Lake T pool water injection at Worsley was completed and injection commenced early in October. A Belloy source water well was drilled, completed and tied in, with source water expected to be available in the early part of the fourth quarter. The Trust submitted an application to expand the Charlie Lake S Pool waterflood and tied in approximately 200 boe/d from 4 (4.0 net) wells drilled in late 2006.

Acquisitions

On September 5, 2007, Crescent Point announced the strategic Bakken consolidation acquisition of Innova for $7.55 cash per share, plus assumed debt, for a total consideration of approximately $400.0 million. The Trust subsequently took effective control of Innova on October 22, 2007 when more than 97 percent of outstanding Innova shares were tendered to the offer. With the completion of the acquisition, Crescent Point acquired approximately 4,300 boe/d of high quality, high netback light oil and natural gas production, 65 percent of which is in the Viewfield Bakken resource play. The Innova acquisition consolidated the Trust's dominant Bakken land position, adding more than 97 net sections of undeveloped land and 380 net low risk development locations to the Trust's Bakken development drilling inventory.

Innova was the second largest producer in the Viewfield Bakken play next to Crescent Point. More than 90 percent of Innova's Bakken production was operated by Crescent Point, which adds tremendous flexibility and control in the play with reduced costs. The acquisition increased the majority of the Trust's Bakken working interest to 100 percent and increased Crescent Point's Bakken production to more than 10,000 boe/d.

Crescent Point also closed several minor transactions during the third quarter. The Trust closed one minor corporate acquisition and three minor property acquisitions for total consideration of $20.1 million. On a total basis, the Trust acquired 410 boe/d of production and 0.8 million boe of proved plus probable reserves in its core area of southeast Saskatchewan.

SUBSEQUENT EVENT

On October 31, 2007, Crescent Point and Pilot announced that they had entered into an agreement pursuant to which the Trust would exchange, by way of Plan of Arrangement (the "Plan"), all of Pilot's issued and outstanding shares for trust units of Crescent Point. Under the terms of the Plan, Crescent Point will pay approximately $76 million, comprised of 2.9 million Crescent Point trust units and the assumption of $11 million of net debt (net of option proceeds) to acquire approximately 1,000 boe/d of high netback oil production, 50 percent of which is located in the Trust's Viewfield Bakken resource play. Pilot shareholders will receive 0.1284 Crescent Point trust units for each Pilot common share under the Plan, which is expected to close by January 31, 2008.

Upon completion of the Plan, the Pilot Bakken consolidation acquisition will increase the Trust's dominance in the Viewfield Bakken light oil resource play in southeast Saskatchewan, adding flexibility and control in the play with expected reductions to costs. Approximately 500 boe/d of Pilot's production is from the Viewfield Bakken resource play, increasing Crescent Point's Bakken production to more than 10,500 boe/d. In addition, Pilot has 6.5 net sections of undeveloped Bakken land on which Crescent Point has identified 22 (19.0 net) low risk development drilling locations. With the closing of the Plan, Crescent Point will have 1,275 net low risk drilling locations in inventory, including 1,022 (969 net) locations in the Viewfield Bakken resource play. This represents more than 10 years of low risk drilling to sustain the Trust's current production. To date, over 256 wells have been drilled on the Trust's Bakken lands with a 100 percent success rate. Over the past year, drilling and completion techniques used on these lands have improved significantly and Crescent Point expects to see continued refinement and improvement of these techniques over time.

MARKETS AND PRICING UPDATE

Benchmark crude oil prices strengthened in the third quarter of 2007, with West Texas Intermediate ("WTI") averaging US$75.33 per barrel in the quarter, up 7 percent from the third quarter of 2006. The Canadian dollar, however, also strengthened in the quarter, achieving 30 year record highs and averaging US/Cdn $0.96 contributing to a 1 percent decline in the Canadian dollar benchmark crude oil price compared to the third quarter of 2006. Despite this market price decline, the Trust's netback increased by 28 percent to $41.10 per boe, reflecting the improvement in the Trust's oil quality due to the Mission acquisition, along with its low royalty and operating cost structure. This improvement in corporate netback has been driven predominately by the Viewfield Bakken production which realized a third quarter netback of $62.71 per boe.

The Trust anticipates the trend of high oil prices and a strong Canadian dollar to continue through the remainder of the year and into 2008.

Differentials to WTI for Canadian grades of crude oil remained narrow in July and August before seasonal widening in September. The Trust anticipates wider differentials will remain through the fourth quarter of 2007 and first quarter of 2008 before seasonal narrowing returns in the summer of 2008.

AECO natural gas prices remained weak, averaging only Cdn$5.16 per mcf during the third quarter of 2007. Near record high storage levels combined with mild weather and continued natural gas drilling in the United States has weakened the market considerably. Crescent Point expects this weakness to continue through the winter absent colder than normal winter weather in the major North American markets.

CHANGES TO ALBERTA ROYALTY SYSTEM

On September 18, 2007, the Alberta Royalty Review Panel released its report (the "Report") recommending changes to the Alberta royalty system. The Report recommended significant changes to the system, including significantly higher royalty rates without allowing for grandfathering of existing production. On October 25, 2007, the Premier of Alberta subsequently announced his government's response to the Report, accepting many, but not all, of the Report's recommendations.

Crescent Point has completed an initial evaluation of the October 25, 2007 royalty announcement and has concluded that the royalty changes will have minimal impact on the Trust's current production and operations. The Trust anticipates that its corporate royalty rates on existing production will increase by approximately one percent starting in 2009 when the changes take effect. Approximately 80 percent of the Trust's current production is in Saskatchewan, which lessens the impact on the Trust of the Alberta royalty change.

Crescent Point continues to work on its 2008 capital expenditure plans and will review the government's royalty announcement in more detail before committing to capital expenditures in the province of Alberta in 2008. Crescent Point has more than 1,000 low risk development drilling locations in Saskatchewan, including in the Viewfield Bakken resource play, on which it can focus in 2008 and in the years to come.

OUTLOOK

Crescent Point continues to execute its proven business plan of creating value added growth in reserves, production and cash flow through management's integrated strategy of acquiring, exploiting and developing high quality, long life, light and medium oil and natural gas properties.

With the closing of the Innova acquisition and the announcement of the Pilot acquisition, the Trust has solidified its position as the dominant player in the Viewfield Bakken play, which Crescent Point believes is the third largest conventional oil pool discovered in western Canada, and the largest discovered in 50 years. The Trust has 1,022 (969 net) low risk drilling locations in the Bakken and the potential to add more than 140 mmboe of proved plus probable reserves through infill drilling. Pro forma with Pilot, the Trust is currently producing more than 10,500 boe/d from the Bakken play.

With the acquisition of Mission in February of this year, Crescent Point acquired approximately 143 net sections of prospective Bakken land. Through corporate acquisitions including Innova and Pilot, freehold land acquisitions and Crown land sales, the Trust has grown its undeveloped Bakken land base by nearly 150 percent to 353 net sections.

Crescent Point has more than 3.1 billion barrels of original oil in place and a reserve life index of 12.0 years on a proved plus probable basis. The Innova and Pilot acquisitions provide Crescent Point with increased development drilling flexibility as well as anticipated capital, operating and administrative cost savings in the Trust's main operating area of southeast Saskatchewan. The Trust's drilling inventory has increased to more than 1,275 net lower risk development drilling locations. Through infill drilling, production optimization and waterflood implementation, management believes the Trust has the potential to double its proved plus probable reserves over time.

Crescent Point currently has more than $1.9 billion of future development projects, providing ten years of low risk infill development drilling inventory to sustain current production levels. With a strong balance sheet and a balanced three year hedge profile, Crescent Point is well positioned to sustain distributions over time as the Trust continues to exploit and develop its asset base and actively identify and evaluate accretive acquisition opportunities.

With the significant increase in the Trust's Bakken land holdings and better than anticipated Bakken fracture stimulation results, Crescent Point is revising upwards its 2007 capital program from $165 million to $215 million and its fourth quarter 2007 production guidance from 30,000 boe/d to 31,250 boe/d. The Trust is currently producing in excess of 28,000 boe/d excluding production from the Trust's October 2007 acquisition of Innova and more than 32,300 boe/d including Innova. In the fourth quarter of 2007, the Trust anticipates spending approximately $80 million, of which approximately half will be on land, facilities and seismic.

With continued drilling and fracture stimulation success in the Bakken, significant growth in undeveloped Bakken land holdings and drilling opportunities, and further review required of the Alberta royalty announcement, Crescent Point does not anticipate finalizing its 2008 capital expenditure budget until December of 2007. The preliminary capital budget for 2008 has been set at approximately $150 million, balanced more towards the development and exploitation of the Bakken resource play, with upwards of 53 (50.0 net) Bakken wells planned. Increasing Bakken production is expected to continue to improve and increase the Trust's overall corporate netbacks while 2008 average daily production is expected to be maintained at 31,250 boe/d.

The Trust continues to actively manage its three year commodity hedging program, with 55 percent of production volumes, net of royalty interests, hedged for the fourth quarter of 2007. As of October 30, 2007, 53, 44 and 18 percent had been hedged for 2008, 2009 and the first three quarters of 2010, respectively. Hedge instruments utilized in the program include swaps, collars and put options, providing a floor of more than Cdn$70.00 per barrel, with upside participation in rising commodity prices.

Crescent Point's management believes that with the high quality reserve base and development inventory, excellent balance sheet and solid hedging program, the Trust is well positioned to continue generating strong operating and financial results and delivering sustainable distributions into 2008 and beyond.

Preliminary 2008 Outlook

Crescent Point's preliminary 2008 guidance (pro forma Innova and Pilot) is as follows:

	2008 Preliminary Guidance
Production	
Oil and NGL (bbls/d)	26,900
Natural gas (mcf/d)	26,100
Total (boe/d)	31,250
Cash flow ($000)	396,000
Cash flow per unit – diluted ($)	3.28
Cash distributions per unit ($)	2.40
Payout ratio – per unit – diluted (%)	73
Capital expenditures ($000) (1)	150,000
Wells drilled, net	75
Pricing	
Crude oil – WTI (US$/bbl)	75.00
Crude oil – WTI (Cdn$/bbl)	75.00
Natural gas – Corporate (Cdn$/mcf)	6.50
Exchange rate (US$/Cdn$)	1.00

(1) The projection of capital expenditures excludes acquisitions, which are separately considered and evaluated.

On behalf of the board of directors,

Scott Saxberg
President and Chief Executive Officer
November 9, 2007

MANAGEMENT'S DISCUSSION & ANALYSIS

Management's discussion and analysis ("MD&A") is dated November 9, 2007 and should be read in conjunction with the unaudited interim consolidated financial statements for the period ended September 30, 2007 and the audited consolidated financial statements and MD&A for the year ended December 31, 2006, for a full understanding of the financial position and results of operations of Crescent Point Energy Trust ("Crescent Point" or the "Trust").

Non-GAAP Financial Measures

Throughout this discussion and analysis, Crescent Point uses the terms cash flow from operations, cash flow from operations per unit, cash flow from operations per unit – diluted, net debt, market capitalization and total capitalization. These terms do not have any standardized meaning as prescribed by Canadian generally accepted accounting principles ("GAAP") and therefore they may not be comparable with the calculation of similar measures presented by other issuers.

Cash flow from operations is calculated based on cash flow from operating activities before changes in non-cash working capital and asset retirement obligation expenditures. Cash flow from operations per unit – diluted is calculated based on cash flow from operating activities before changes in non-cash working capital and asset retirement obligation expenditures excluding the cash portion of unit-based compensation. Management utilizes cash flow from operations as a key measure to assess the ability of the Trust to finance distributions, operating activities, capital expenditures and debt repayments. Cash flow from operations as presented is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP.

The following table reconciles the cash flow from operating activities to cash flow from operations:

	Three months ended September 30			Nine months ended September 30		
($000)	**2007**	2006	% Change	**2007**	2006	% Change
Cash flow from operating activities	**80,722**	50,910	59	**233,535**	138,113	69
Changes in non-cash working capital	**11,206**	1,563	617	**8,827**	6,776	30
Asset retirement expenditures	**287**	301	(5)	**976**	403	142
Cash flow from operations	**92,215**	52,774	75	**243,338**	145,292	67

Net debt is calculated as current liabilities less current assets, excluding risk management assets and liabilities and unrealized gains on investments in marketable securities, and including long term investments. Management utilizes net debt as a key measure to assess the liquidity of the Trust. Market capitalization is calculated by applying the period end closing unit trading price to the number of trust units outstanding. Market capitalization is an indication of the enterprise value. Total capitalization is calculated as market capitalization and current liabilities, less current assets and long term investments, excluding the risk management asset and liabilities and unrealized gains on investments in marketable securities. Total capitalization is used by management to measure the proportion of net debt in the Trust's capital structure.

Forward-Looking Information

Certain statements contained in this report constitute forward-looking statements and are based on the Trust's beliefs and assumptions based on information available at the time the assumption was made. By its nature, such forward-looking information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Trust and Crescent Point Resources Inc. ("CPRI"), believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. These statements speak only as of the date of this report.

The material assumptions in making these forward-looking statements are disclosed in this analysis under the headings "Cash Distributions", "Capital Expenditures", "Asset Retirement Obligation", "Liquidity and Capital Resources", "Critical Accounting Estimates" and "New Accounting Pronouncements".

This disclosure contains certain forward-looking estimates that involve substantial known and unknown risks and uncertainties, certain of which are beyond Crescent Point's control, including the impact of general economic conditions; industry conditions including changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; increased competition and the lack of availability of qualified personnel or management; fluctuations in commodity prices, foreign exchange or interest rates; stock market volatility and obtaining required approvals of regulatory authorities. In addition, there are numerous risks and uncertainties associated with oil and gas operations and the evaluation of oil and gas reserves. Therefore Crescent Point's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking estimates and if such actual results, performance or achievements transpire or occur, or if any of them do so, there can be no certainty as to what benefits Crescent Point will derive there from.

A barrel of oil equivalent ("boe") is based on a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

Results of Operations

Production

Crescent Point's production increased 29 percent, from 21,305 boe/d in the third quarter of 2006 to 27,572 boe/d in the third quarter of 2007. Similarly, production for the nine months ended September 30, 2007 increased by 28 percent over the comparable period in 2006. The increase in production for both periods relates primarily to the acquisition of Mission Oil & Gas Inc. ("Mission"), several acquisitions completed in 2007 and the Trust's successful drilling program. The Mission acquisition closed on February 9, 2007 and added over 7,000 boe/d of high quality, long life, light oil and natural gas assets, including more than 5,000 boe/d from the Bakken resource play. This acquisition adds a new core area for the Trust in the Viewfield area of southeast Saskatchewan.

The Trust's weighting to oil increased to 86 percent for the third quarter of 2007, a two percent increase over 2006. The Trust's oil weighting for the nine months ended September 30, 2007 increased three percent to 87 percent over the comparable 2006 period. The increase in the Trust's oil weighting is primarily the result of the Mission acquisition which was focused on light oil assets.

	Three months ended September 30			Nine months ended September 30		
	2007	2006	% Change	**2007**	2006	% Change
Crude oil and NGL (bbls/d)	**23,846**	17,940	33	**22,915**	17,238	33
Natural gas (mcf/d)	**22,357**	20,193	11	**20,626**	19,638	5
Total (boe/d)	**27,572**	21,305	29	**26,353**	20,511	28
Crude oil and NGL (%)	**86**	84	2	**87**	84	3
Natural gas (%)	**14**	16	(2)	**13**	16	(3)
Total (%)	**100**	100	-	**100**	100	-

Marketing and Prices

The Trust's average oil price for the third quarter increased six percent over the comparable period in 2006 due to narrower corporate oil differentials as increases in the US$ benchmark WTI price were offset by a stronger Canadian dollar. Crescent Point's oil differential improved significantly from $12.97 per bbl in the third quarter of 2006 to $8.61 per bbl in the third quarter of 2007. This trend is attributable to both changes in market conditions and a change in the Trust's crude oil quality as a result of the Viewfield Bakken light oil properties acquired through the Mission acquisition.

For the nine months ended September 30, 2007, the Trust's average selling price for crude oil increased by three percent over the comparable 2006 period. The Trust's average selling price increased despite a three percent decline in the benchmark US$ WTI price and a stronger Canadian dollar as improvements in the Trust's average crude quality from the Mission acquisition narrowed corporate oil differentials significantly. In addition, market differentials narrowed from the higher levels experienced in the first quarter of 2006. Collectively, the corporate oil differential for the nine months ended September 30, 2007 was $8.84 per bbl compared to $15.12 per bbl in the comparable 2006 period.

The Trust's average selling price for gas for the three months ended September 30, 2007 decreased two percent compared to the same period for 2006. The Trust's average selling price for gas for the nine months ended September 30, 2007 increased five percent over 2006. These trends were reasonably consistent with the trend in the AECO daily gas price, reflecting the Trust's portfolio of gas marketing contracts.

Average Selling Prices [(1)]	Three months ended September 30			Nine months ended September 30		
	2007	2006	% Change	**2007**	2006	% Change
Crude oil and NGL ($/bbl)	**69.86**	66.14	6	**63.97**	62.22	3
Natural gas ($/mcf)	**5.40**	5.49	(2)	**6.61**	6.29	5
Total ($/boe)	**64.80**	60.90	6	**60.80**	58.31	4

(1) The average selling prices reported are before realized financial instrument losses and transportation charges.

Benchmark Pricing	Three months ended September 30			Nine months ended September 30		
	2007	2006	% Change	**2007**	2006	% Change
WTI crude oil (US$/bbl)	**75.33**	70.55	7	**66.26**	68.29	(3)
WTI crude oil (Cdn$/bbl)	**78.47**	79.11	(1)	**72.81**	77.34	(6)
AECO natural gas [(1)] (Cdn$/mcf)	**5.16**	5.66	(9)	**6.53**	6.39	2
Exchange rate – US$/Cdn$	**0.96**	0.89	8	**0.91**	0.88	3

(1) The AECO natural gas price reported is the average daily spot price.

Financial Instruments and Risk Management

Management of cash flow variability is an integral component of Crescent Point's business strategy. Changing business conditions are monitored regularly and reviewed with the Board of Directors to establish risk management guidelines used by management in carrying out the Trust's strategic risk management program. The risk exposure inherent in movements in the price of crude oil and natural gas, fluctuations in the US/Cdn dollar exchange rate, changes in the price of power and interest rate movements on long-term debt are all proactively managed by Crescent Point through the use of derivatives with reputable, financially sound counterparties. The Trust considers these contracts to be an effective means to manage cash flow.

The Trust's crude oil and natural gas financial instruments are referenced to WTI and AECO, unless otherwise noted. Crescent Point utilizes a variety of financial instruments including swaps, collars and puts to protect against downward commodity price movements while providing the opportunity for some participation during periods of rising prices.

Crescent Point had a realized financial instrument loss for oil of $3.5 million for the third quarter of 2007 compared to a $9.5 million loss for the same period in 2006. The decrease in the loss is attributable to a higher average financial instrument oil price combined with a slight decline in the Cdn$ WTI benchmark price. The Trust's average financial instrument oil price increased $10.13 per bbl, from $64.80 per bbl in the third quarter of 2006 to $74.93 per bbl for the third quarter 2007.

The Trust realized a financial instrument gain for oil of $843,000 for the nine months ended September 30, 2007 compared to a $26.6 million loss for the comparable 2006 period. Consistent with the three month period, this gain is attributable to a higher average financial instrument oil price combined with a decline in the Cdn WTI benchmark price. The Trust's average financial instrument oil price for the nine months ended September 30, 2007 was $73.10 per bbl compared to $62.85 per bbl for the same period in 2006, an increase of $10.25 per bbl.

The Trust has not designated any of its risk management activities as accounting hedges under the Canadian Institute of Chartered Accountants (the "CICA") section 3865 and, accordingly, has marked-to-market its financial instruments. This resulted in an unrealized financial instrument gain of $3.4 million for the third quarter of 2007 compared to a $34.6 million gain for the third quarter of 2006. The gain resulted from the maturity of hedges during the current quarter.

The Trust's unrealized gain for the nine months ended September 30, 2007 was $6.8 million compared to $11.9 million for the comparable period in 2006. The gain for the nine months ended September 30, 2007 is attributable to the decline in Cdn$ WTI.

The Trust has two physical power contracts and one financial power contract. The physical contracts have not been marked-to-market. The unrealized gain on the physical contracts at September 30, 2007 is $106,000.

The following is a summary of the realized financial instrument gains (losses) on oil and gas contracts:

	Three months ended September 30			Nine months ended September 30		
($000, except per boe and volume amounts)	**2007**	2006	% Change	**2007**	2006	% Change
Average crude oil volumes hedged (bbls/d)	**10,750**	7,250	48	**10,832**	6,722	61
Crude oil realized financial instrument gain (loss)	**(3,499)**	(9,544)	63	**843**	(26,586)	103
per bbl	**(1.59)**	(5.78)	72	**0.13**	(5.65)	102
Average natural gas volumes hedged (GJ/d)	**4,000**	1,333	200	**3,341**	444	652
Natural gas realized financial instrument gain (loss)	**526**	(52)	1,112	**547**	(52)	1,152
per mcf	**0.26**	(0.03)	967	**0.10**	(0.01)	1,100
Average barrels of oil equivalent hedged (boe/d)	**11,382**	7,461	53	**11,360**	6,792	67
Total realized financial instrument gain (loss)	**(2,973)**	(9,596)	69	**1,390**	(26,638)	105
per boe	**(1.17)**	(4.90)	76	**0.19**	(4.76)	104

Crescent Point has the following financial instrument contracts in place as at October 30, 2007:

Financial WTI Crude Oil Contracts - Canadian Dollar						
Term	Contract	Volume (bbls/d)	Average Swap Price ($Cdn/bbl)	Average Bought Put Price ($Cdn/bbl)	Average Sold Call Price ($Cdn/bbl)	Average Put Premium ($Cdn/bbl)
2007						
October – December	Swap	6,500	75.72			
October – December	Collar	1,500		66.74	82.27	
October – December	Put	3,250		77.63		(7.65)
2007 Weighted Average		**11,250**	**75.72**	**74.19**	**82.27**	**(7.65)**
2008						
January – June	Swap	1,000	72.73			
January – September	Swap	250	68.10			
January – December	Swap	6,000	76.02			
July – December	Swap	1,000	73.52			
October – December	Swap	250	70.80			
January – June	Collar	250		65.00	82.00	
January – December	Collar	2,250		70.56	83.22	
July – December	Collar	250		70.00	91.00	
January – December	Put	3,500		72.58		(6.66)
2008 Weighted Average		**13,250**	**75.37**	**71.61**	**83.55**	**(6.66)**
2009						
January – March	Swap	2,750	77.68			
April – June	Swap	2,750	77.58			
January – June	Swap	1,250	74.99			
July – September	Swap	3,000	74.07			
July – December	Swap	1,000	76.41			
October – December	Swap	3,000	74.37			
January – December	Swap	1,750	74.55			
January – March	Collar	250		75.00	87.00	
April – June	Collar	250		75.00	83.00	
January – June	Collar	1,250		70.00	81.01	
January – September	Collar	250		70.00	79.00	
January – December	Collar	750		70.67	80.25	
July – September	Collar	250		70.00	84.05	
July – December	Collar	1,250		69.00	80.37	
October – December	Collar	500		70.00	85.93	
January - December	Put	2,750		70.26		(6.15)
2009 Weighted Average		**11,000**	**75.40**	**70.23**	**80.99**	**(6.15)**
2010						
January – March	Swap	3,500	76.22			
April – June	Swap	2,750	74.38			
January – September	Swap	250	74.00			
April – September	Swap	500	74.90			
July – September	Swap	1,750	74.28			
January – June	Collar	500		70.00	80.50	
January – September	Collar	250		70.00	78.50	
July – September	Collar	250		70.00	81.50	
2010 January – September Weighted Average		**3,911**	**75.04**	**70.00**	**79.88**	

Financial WTI Crude Oil Contracts - U.S. Dollar						
Term	Contract	Volume (bbls/d)	Average Swap Price ($US/bbl)	Average Bought Put Price ($US/bbl)	Average Sold Call Price ($US/bbl)	Average Put Premium ($US/bbl)
2007						
October – December	Collar	1,000		67.50	75.73	
2007 Weighted Average		**1,000**		**67.50**	**75.73**	
2009						
January – December	Put	250		72.00		(6.01)
2009 Weighted Average		**250**		**72.00**		**(6.01)**
2010						
July – September	Swap	1,000	74.70			
January – September	Swap	500	74.30			
2010 January – September Weighted Average		**837**	**74.46**			

Financial AECO Natural Gas Contracts - Canadian Dollar Term	Contract	Volume (GJ/d)	Average Bought Put Price ($Cdn/GJ)	Average Sold Call Price ($Cdn/GJ)
2007				
October	Collar	4,000	6.75	8.60
November - December	Collar	2,000	6.75	8.00
2007 Weighted Average		**2,674**	**6.75**	**8.30**
2008				
January – March	Collar	2,000	6.75	8.00
April – October	Collar	2,000	6.75	7.75
2008 January - October Weighted Average		**2,000**	**6.75**	**7.82**

Financial Foreign Exchange Contracts - U.S. Dollar Term	Contract	Amount ($US)	Average Swap ($Cdn/$US)
2007			
October – December	Swap	2,990,000	1.1600
October – December	Swap	3,220,000	1.1012
2007 Weighted Average		**6,210,000**	**1.1295**

Financial Interest Rate Contracts - Canadian Dollar Term	Contract	Principal ($Cdn)	Fixed Annual Rate (%)
October 2007 – May 2008	Swap	50,000,000	4.41
October 2007 – February 2009	Swap	50,000,000	4.37

Financial Power Contracts - Canadian Dollar Term	Contract	Volume (MW/h)	Fixed Rate ($Cdn/MW/h)
October 2007 – December 2008	Swap	3.0	63.25

Physical Power Contracts – Canadian Dollar Term	Contract	Volume (MW/h)	Fixed Rate ($Cdn/MW/h)
October 2007 – December 2009	Swap	1.0	82.45
January 2009 – December 2009	Swap	3.0	81.25

Revenues

Oil revenues increased by 40 percent and 37 percent in the third quarter and nine month period ended September 30, 2007, respectively, compared to the same periods in 2006. These increases in crude oil and NGL sales relate primarily to the increase in production resulting from the 2007 acquisition of Mission, along with several other acquisitions completed in 2007 and the Trust's successful drilling program. A narrowing of corporate oil differentials due to improvements in the Trust's crude quality and realized oil prices further contributed to the increase in revenues in both the three and nine month periods ended September 30, 2007.

Natural gas sales increased 9 percent in the third quarter and 10 percent in the nine month period ended September 30, 2007. These increases are mainly attributable to increases in production for both periods.

	Three months ended September 30			Nine months ended September 30		
($000) [1]	**2007**	2006	% Change	**2007**	2006	% Change
Crude oil and NGL sales	**153,253**	109,165	40	**400,190**	292,800	37
Natural gas sales	**11,115**	10,200	9	**37,237**	33,731	10
Revenues	**164,368**	119,365	38	**437,427**	326,531	34

(1) Revenue is reported before transportation charges and realized financial instruments.

Transportation Expenses

Transportation expense per boe increased 34 percent and 37 percent in the three and nine month periods ended September 30, 2007, respectively compared to the comparable periods in 2006. These increases relate to properties acquired in the past year and their proximity to market, along with pipeline capacity constraint issues in southeast Saskatchewan which began in the fourth quarter of 2006 and continued through 2007. Growing production volumes in southeast Saskatchewan and incremental imports from other areas have exceeded capacity of the area's major oil gathering system, Enbridge Pipelines (Saskatchewan). Efforts to maintain crude sales led to incremental trucking costs in the fourth quarter of 2006 and the nine month period ended September 30, 2007. Expansion of the gathering system is expected to be complete in the second quarter of 2008.

($000, except per boe amounts)	Three months ended September 30 **2007**	2006	% Change	Nine months ended September 30 **2007**	2006	% Change
Transportation expenses	**4,429**	2,562	73	**12,099**	6,882	76
Per boe	**1.75**	1.31	34	**1.68**	1.23	37

Royalty Expenses

Royalties as a percent of sales were 18 percent in both the third quarter of 2007 and the nine month period ended September 30, 2007, down from 21 percent in the third quarter 2006 and 22 percent in the nine month period ended September 30, 2006. These decreases are primarily associated with lower royalty rates on the properties acquired through the Mission acquisition. Further contributing to the Trust's lower royalty rate are royalty incentives on new production associated with the Trust's successful drilling program in southeast Saskatchewan.

Crescent Point Energy completed an initial evaluation of the October 25, 2007 royalty announcement by the Province of Alberta. Crescent Point concluded that the royalty changes will have minimal impact on the Trust's current production and operations.

($000, except per boe amounts)	Three months ended September 30 **2007**	2006	% Change	Nine months ended September 30 **2007**	2006	% Change
Total royalties	**29,853**	25,421	17	**79,620**	70,856	12
As a % of oil and gas sales	**18**	21	(3)	**18**	22	(4)
Per boe	**11.77**	12.97	(9)	**11.07**	12.65	(12)

Operating Expenses

Operating expenses per boe decreased six percent in the third quarter and increased six percent in the nine month period ended September 30, 2007, over comparable periods in 2006. The reduction in operating costs per barrel in the third quarter of 2007 as compared to 2006 reflects the impact of the Mission acquisition and the lower operating cost structure associated with the Viewfield Bakken area. The increase in operating costs per barrel for the nine month period ended September 30, 2007 as compared to 2006 reflects higher costs experienced for repairs and maintenance and one time costs from a partner on a non-operated property during the first half of 2007.

($000, except per boe amounts)	Three months ended September 30 **2007**	2006	% Change	Nine months ended September 30 **2007**	2006	% Change
Operating expenses	**22,859**	18,737	22	**66,726**	48,949	36
Per boe	**9.01**	9.56	(6)	**9.27**	8.74	6

Netbacks

The Trust's netback after realized financial instruments increased 28 percent to $41.10 per boe in the third quarter of 2007 from $32.16 per boe in the third quarter of 2006. The Trust's netback increased due to an improvement in the Trust's average crude quality from the prior year as a result of the Viewfield Bakken production acquired in the first quarter of 2007 resulting in lower corporate oil differentials. Additional factors contributing to the improved netback were higher financial instrument prices, lower royalties and lower operating costs which were modestly offset by increased transportation costs.

The netback for the nine month period ended September 30, 2007 increased 26 percent to $38.97 per boe compared to $30.93 per boe for the same period in 2006. The increase in the Trust's netback relates to narrower corporate oil differentials resulting from the acquired Viewfield Bakken property, partially offset by a lower US$ benchmark price and a stronger Canadian dollar. The Trust's higher financial instrument prices and lower royalties also contributed to the higher netbacks, despite higher operating and transportation costs.

	Three months ended September 30				
	2007			2006	
	Crude Oil and NGL ($/bbl)	**Natural Gas ($/mcf)**	**Total ($/boe)**	Total ($/boe)	% Change
Average selling price	**69.86**	**5.40**	**64.80**	60.90	6
Royalties	**(12.72)**	**(0.95)**	**(11.77)**	(12.97)	(9)
Operating expenses	**(8.97)**	**(1.54)**	**(9.01)**	(9.56)	(6)
Transportation	**(1.83)**	**(0.20)**	**(1.75)**	(1.31)	34
Netback prior to realized financial instruments	**46.34**	**2.71**	**42.27**	37.06	14
Realized gain (loss) on financial instruments	**(1.59)**	**0.26**	**(1.17)**	(4.90)	76
Netback	**44.75**	**2.97**	**41.10**	32.16	28

	Nine months ended September 30				
	2007			2006	
	Crude Oil and NGL ($/bbl)	**Natural Gas ($/mcf)**	**Total ($/boe)**	Total ($/boe)	% Change
Average selling price	**63.97**	**6.61**	**60.80**	58.31	4
Royalties	**(11.40)**	**(1.48)**	**(11.07)**	(12.65)	(12)
Operating expenses	**(9.02)**	**(1.83)**	**(9.27)**	(8.74)	6
Transportation	**(1.72)**	**(0.24)**	**(1.68)**	(1.23)	37
Netback prior to realized financial instruments	**41.83**	**3.06**	**38.78**	35.69	9
Realized gain (loss) on financial instruments	**0.13**	**0.10**	**0.19**	(4.76)	104
Netback	**41.96**	**3.16**	**38.97**	30.93	26

General and Administrative Expenses

General and administrative expenses per boe decreased 21 percent in the third quarter of 2007 compared to the same period in 2006. The decrease is a result of higher legal and professional fees in the third quarter of 2006 associated with the internal reorganization activities that were incurred in preparation for the March 2007 reorganization.

The general and administrative expenses for the nine month period increased five percent primarily due to the overall growth of the Trust along with industry cost pressures to retain and attract high quality employees.

	Three months ended September 30			Nine months ended September 30		
($000, except per boe amounts)	**2007**	2006	% Change	**2007**	2006	% Change
General and administrative costs	**4,589**	4,033	14	**14,563**	10,285	42
Capitalized	**(1,239)**	(757)	64	**(3,119)**	(1,818)	72
General and administrative expenses	**3,350**	3,276	2	**11,444**	8,467	35
Per boe	**1.32**	1.67	(21)	**1.59**	1.51	5

Restricted Unit Bonus Plan

The Trust has a Restricted Unit Bonus Plan and under the terms of this plan, the Trust may grant restricted units to directors, officers, employees and consultants. Restricted units vest at 33 1/3 percent on each of the first, second and third anniversaries of the grant date or at a date approved by the Board of Directors. Restricted unitholders are eligible for monthly distributions, immediately upon grant.

The maximum number of trust units issuable under the Restricted Unit Bonus Plan is 5,000,000 units. The Trust had 1,403,600 restricted units outstanding at September 30, 2007 compared with 984,651 units outstanding at September 30, 2006.

The Trust recorded compensation expense and contributed surplus of $3.5 million for the third quarter ended September 30, 2007, based on the fair value of the units on the date of grant, a decrease of 31 percent over the same period of 2006. Additionally, the Trust recorded $653,000 of cash distributions on restricted units, an increase of 92 percent from $340,000 in the third quarter 2006. The total cash and non-cash unit based compensation recorded in the third quarter of 2007 was $4.2 million as compared to $5.5 million for the same 2006 period. The decrease is attributable to some restricted units granted in the third quarter of 2006 which were subject to shorter vesting terms.

For the nine month period ended September 30, 2007, the Trust recorded compensation and contributed surplus of $10.6 million, based on the fair value of the units on the date of grant, an increase of 26 percent over the same period of 2006. The cash distributions on restricted units increased from $687,000 in the nine month period September 30, 2006 to $1.4 million for the nine month period September 30, 2007. The increase in the number of restricted units and corresponding unit-based compensation expense is attributable to the growth in the Trust's operations and industry pressures to retain and attract high quality employees.

	Three months ended September 30			Nine months ended September 30		
($000, except per boe amounts)	**2007**	2006	% Change	**2007**	2006	% Change
Cash unit-based compensation expense	**653**	340	92	**1,438**	687	109
Non-cash unit-based compensation expense	**3,526**	5,131	(31)	**10,592**	8,436	26
Total	**4,179**	5,471	(24)	**12,030**	9,123	32
Per boe	**1.65**	2.79	(41)	**1.67**	1.63	2

Interest Expense

Interest expense per boe increased six percent for both the three and nine month periods ended September 30, 2007 compared to the same periods for 2006. The increase in the interest expense per boe is attributable to the higher effective interest rates resulting from an increase in the prime interest rate. Crescent Point actively manages exposure to fluctuations in interest rates through interest rate swaps and short term banker's acceptance (refer to Financial Instruments and Risk Management section above).

	Three months ended September 30			Nine months ended September 30		
($000, except per boe amounts)	**2007**	2006	% Change	**2007**	2006	% Change
Interest expense	**4,727**	3,425	38	**13,698**	10,071	36
Per boe	**1.86**	1.75	6	**1.90**	1.80	6

Depletion, Depreciation and Amortization

The depletion, depreciation and amortization ("DD&A") rate increased to $24.75 per boe in the third quarter from $19.14 per boe in the third quarter of 2006. The same trend was experienced for the nine month period ended September 30, 2007. The higher DD&A rate is due to the acquisitions completed in 2006 as well as the Mission acquisition completed in 2007 which carried a higher cost per barrel than the Trust's existing properties.

	Three months ended September 30			Nine months ended September 30		
($000, except per boe amounts)	**2007**	2006	% Change	**2007**	2006	% Change
Depletion, depreciation and amortization	**62,791**	37,507	67	**174,906**	103,063	70
Per boe	**24.75**	19.14	29	**24.31**	18.41	32

Taxes

Capital and other tax expense consists of Saskatchewan Corporation Capital Tax Resource Surcharge. Capital and other tax expense for the third quarter of 2007 remained consistent with 2006 despite higher revenues, due to lower realized capital tax rates on acquisitions. For the nine month period ended September 30, 2007, capital tax increased 21 percent due to an increase in the Trust's Saskatchewan based revenues.

In the first quarter of 2007, the future income tax liability was eliminated due to the March 1, 2007 reorganization providing the Trust with a "flow through" structure. This resulted in a future income tax recovery of $158.8 million in the first quarter of 2007.

On June 12, 2007 the Federal Government's Bill C-52, which included legislation to tax publicly traded trusts, was substantively enacted as defined under Canadian GAAP. As a result of this new legislation, a new 31.5 percent tax will be applied to distributions from Canadian public income trusts. The new tax is not expected to apply to Crescent Point until January 1, 2011 as a transition period applies to publicly traded trusts that existed prior to November 1, 2006. As a result of this change in legislation, a future income tax liability and future tax expense of $152.3 million was recognized in the second quarter of 2007. The future income tax represents the taxable temporary differences of Crescent Point tax effected at 31.5 percent, which is the rate that will be applicable to trusts in 2011 under current legislation.

The Trust recorded a further expense of $9.7 million in the third quarter of 2007 due to differences between forecasted and realized temporary differences for the quarter. Accordingly, for the nine month period ending September 30, 2007 the Trust recorded a $3.2 million charge to future tax expense which is the excess liability recognized in the second and third quarters of 2007 in respect of the taxation on trusts over the recovery recorded in the first quarter of 2007 in respect of the internal reorganization.

Despite the trust tax legislation, Crescent Point continues to aggressively implement its business plan, which remains unchanged since inception as a junior producer in 2001. Crescent Point's key attributes of proven management, high quality, large resource in place assets, and conservative balance sheet and risk management strategy have generated six strong years of successful results and position the Trust well to succeed in the future. In addition, with the Canadian Government's Tax Fairness Plan beginning in 2011, the Trust is well positioned with substantial tax pools, including the acquisition of Innova Exploration Ltd. in October 2007, of approximately $1.0 billion, to minimize future taxable income.

	Three months ended September 30			Nine months ended September 30		
($000)	**2007**	2006	% Change	**2007**	2006	% Change
Capital and other tax expense	**3,309**	3,234	2	**10,520**	8,689	21
Future income tax expense (recovery)	**9,679**	4,292	126	**3,208**	(16,340)	120

Cash Flow and Net Income

Cash flow from operations increased from $52.8 million in the third quarter of 2006 to $92.2 million in the third quarter of 2007. Cash flow from operations per unit – diluted also increased 14 percent from $0.78 to $0.89 per unit – diluted. The increase in the cash flow from operations and cash flow from operations per unit – diluted is primarily the result of the Trust's increased production and increased corporate netbacks due to narrower corporate oil differentials as a result of the Mission acquisition. The same trend was experienced for the nine month period ended September 30, 2007.

Cash flow from operating activities increased from $50.9 million in the third quarter of 2006 to $80.7 million in the third quarter of 2007. Cash flow from operating activities per unit – diluted also increased four percent from $0.75 to $0.78 per unit – diluted. The increase in cash flow from operating activities and cash flow from operating activities per unit – diluted is primarily the result of the same factors described above, along with changes in working capital. The same trend was experienced for the nine month period ended September 30, 2007.

Net income for the third quarter of 2007 decreased to $18.4 million from $39.6 million for the corresponding period in 2006 primarily as a result of a $34.6 million unrealized financial instrument gain in 2006 compared to a $3.4 million unrealized financial instrument gain in 2007. For the nine month period ended September 30, 2007, net income remained reasonably consistent at $58.2 million, down from $62.0 million for the same period of 2006.

($000, except per unit amounts)	Three months ended September 30 2007	2006	% Change	Nine months ended September 30 2007	2006	% Change
Cash flow from operations	**92,215**	52,774	75	**243,338**	145,292	67
Cash flow from operations per unit – diluted	**0.89**	0.78	14	**2.50**	2.36	6
Cash flow from operating activities	**80,722**	50,910	59	**233,535**	138,113	69
Cash flow from operating activities – diluted	**0.78**	0.75	4	**2.40**	2.25	7
Net income	**18,410**	39,588	(53)	**58,181**	62,029	(6)
Net income per unit – diluted (1)	**0.18**	0.58	(69)	**0.60**	0.97	(38)

(1) Net income per unit – diluted is calculated by dividing the net income before non-controlling interest by the diluted weighted average trust units, excluding the cash portion of unit based compensation.

Cash Distributions

The Trust maintained monthly distributions of $0.20 per unit during the third quarter and nine month periods ended September 30, 2007. Crescent Point's risk management strategy minimizes corporate price volatility which has provided the Trust with the ability to maintain sustainable distributions through periods of weakening market prices.

Cash distributions increased by 58 percent for the third quarter of 2007 compared to the same period in 2006, and by 63 percent for the nine month period ended September 30, 2007. The rise in distributions relates to the increase in trust units outstanding, primarily as a result of 2007 corporate acquisitions, a bought deal equity financing in September 2007 and the Trust's distribution reinvestment programs.

The following table provides a reconciliation of cash distributions:

($000,except per unit amounts)	Three months ended September 30 2007	2006	% Change	Nine months ended September 30 2007	2006	% Change
Accumulated cash distributions, beginning of period	**404,373**	209,230	93	**290,442**	140,165	107
Cash distributions declared to unitholders (1)	**63,206**	39,890	58	**177,137**	108,955	63
Accumulated cash distributions, end of period	**467,579**	249,120	88	**467,579**	249,120	88
Accumulated cash distributions per unit, beginning of period	**8.46**	6.06	40	**7.26**	4.86	49
Cash distributions declared to unitholders per unit (1)	**0.60**	0.60	-	**1.80**	1.80	-
Accumulated cash distributions per unit, end of period	**9.06**	6.66	36	**9.06**	6.66	36

(1) Cash distributions reflect the sum of the amounts declared monthly to unitholders, including distributions under the DRIP and Premium DRIP plans.

For the three and nine months ended September 30, 2007, cash flow from operating activities (including changes in non-cash working capital) of $80.7 million and $233.5 million, respectively, exceeded cash distributions of $63.2 million and $177.1 million, respectively. This was consistent with the two previous fiscal years.

For the three and nine months ended September 30, 2007, the cash distributions of $63.2 million and $177.1 million, respectively, exceeded net income of $18.4 million and $58.2 million, respectively. This is consistent with the two previous fiscal years. Net income includes significant non-cash charges which in 2007 were $73.8 million for the quarter and $185.2 million for the nine months September 30, 2007 that do not impact cash flow. The non-cash charges also include fluctuations in future income taxes due to changes in tax rates and tax rules, unrealized gains and losses on financial instruments and unit-based compensation which includes a significant non-cash component. Further, other non-cash charges such as DD&A are not a good proxy for the cost of maintaining our reserves and production.

Crescent Point does not anticipate cash distributions will exceed cash flow from operating activities, however it is likely they will exceed net income as noted above given the significant non-cash items that are recorded such as future income taxes, DD&A, unit based compensation and unrealized losses on financial instruments. Further, the cash flow from operating activities can be significantly impacted by large fluctuations in working capital adjustments that may vary quarter-to-quarter but level out over the period. The distributions paid to unitholders represent a return on their initial investment and is not intended to be a return of capital.

An objective of the Trust's distribution policy is to provide unitholders with relatively stable and predictable monthly distributions. An additional objective is to retain a portion of cash flow to fund ongoing development and optimization projects designed to enhance the sustainability of the Trust's cash flow. Although the Trust strives to provide unitholders with stable and predictable cash flows, the percentage of cash flow from operations paid to unitholders each month may vary according to a number of factors, including, fluctuations in resource prices, exchange rates and production rates, reserves growth, the size of development drilling programs and the portion thereof funded from cash flow and the overall level of debt of the Trust. The actual amount of the distributions are at the discretion of the Board of Directors. In the event that commodity prices are higher than anticipated and a cash surplus develops, such surplus may be used to increase distributions, reduce debt and/or increase the capital program.

The Trust has a strong balance sheet and a balanced three year derivative profile and is therefore well positioned to sustain distributions over time as Crescent Point continues to exploit and develop its asset base and actively identify and evaluate acquisition opportunities. As discussed above, there are many factors impacting the Trust's ability to sustain distributions. The Trust continues to monitor these factors in connection with setting distribution levels.

($000)	**Three months ended**	**Nine months ended**	Year ended	
	September 30, 2007		2006	2005
Cash flow from operating activities	**80,722**	**233,535**	177,426	94,247
Net income	**18,410**	**58,181**	68,947	38,509
Cash distributions paid or payable	**63,206**	**177,137**	150,277	74,591
Excess (shortfall) of cash flows from operating activities over cash distributions paid	**17,516**	**56,398**	27,149	19,656
Excess (shortfall) of net income over cash distributions paid	**(44,796)**	**(118,956)**	(81,330)	(36,082)

Investment in Marketable Securities

During the nine month period ended September 30, 2007, the Trust owned shares of a publicly traded exploration and production company. In accordance with new accounting standards, in the first quarter of 2007, the Trust marked-to-market its investment in marketable securities. The carrying amount of $171,000 at December 31, 2006 was increased to $1.6 million at January 1, 2007 to reflect the fair value of the investment. The unrealized gain of $1.5 million at January 1, 2007 was recorded through retained earnings. In the second quarter of 2007, the Trust sold the securities for a realized gain of $1.4 million.

Long Term Investments

During the three month period ended September 30, 2007, the Trust purchased 2.2 million shares of Innova Exploration Ltd., a publicly traded exploration and production company, for an average price of approximately $7.51 per share or $16.6 million. The Trust acquired all remaining shares of Innova Exploration Ltd. in October 2007 (refer to Capital Expenditures section below). The fair value at September 30, 2007 was $16.6 million, unchanged from the carrying value. Accordingly, there was no adjustment required to mark the investment to market.

Capital Expenditures

During the three month period ended September 30, 2007, the Trust closed the acquisition of a private corporation with properties in the Willmar and Browning areas of southeast Saskatchewan for consideration of approximately $18.9 million including net debt assumed. The purchase was funded through the transfer of 605,815 trust units and cash of $121,000 from the Trust's existing bank lines.

The Trust closed minor property acquisitions in the Viewfield Bakken area of southeast Saskatchewan and the Sounding Lake area of south central Alberta in the third quarter 2007 for total consideration of $1.2 million. The Trust recorded purchase price adjustments of $700,000 on previously closed acquisitions in the third quarter of 2007. In the nine month period ended September 30, 2007, the Trust closed two corporate acquisitions and minor property acquisitions for total consideration of $660.5 million, including closing adjustments and assumed net debt. The Trust recorded favorable purchase price adjustments of $500,000 on previously closed acquisitions in the nine months ended September 30, 2007.

On February 9, 2007, the Trust closed the acquisition of Mission Oil & Gas Inc., a publicly traded company with properties in the Viewfield area of southeast Saskatchewan for consideration of approximately $621.4 million, including closing adjustments and net debt assumed. The acquisition added production of 7,000 boe/d, including more than 5,000 boe/d from the Bakken resource play. The purchase was funded through the Trust's existing bank lines and the issuance of approximately 29.2 million trust units.

Subsequent to the quarter, in late October 2007, the Trust closed the acquisition of Innova Exploration Ltd., a publicly traded company with properties in the Viewfield Bakken area of southeast Saskatchewan for consideration of approximately $400.0 million, before closing adjustments and including assumed net debt. The purchase was funded through the Trust's existing bank lines. The Trust owned 2.2 million shares of Innova Exploration Ltd. prior to the closing which it purchased for an average price of approximately $7.51 per share or approximately $16.6 million in September 2007.

In late October 2007, the Trust also announced an offer to purchase the issued and outstanding shares of Pilot Energy Ltd. by way of a Plan of Arrangement for total consideration of approximately $76.0 million before closing adjustments and including net debt. An Information Circular outlining the plan is expected to be mailed by December 15, 2007 and a shareholder vote to approve the Plan of Arrangement will be held on or about January 15, 2008.

The Trust's development capital expenditures for the third quarter of 2007 were $57.8 million, compared to $31.9 million for the comparable period in 2006. In the third quarter of 2007, 49 wells (34.2 net) were drilled with a success rate of 100 percent**.**

The Trust's budgeted capital program for 2007 is approximately $215.0 million and no budget has been established for acquisitions. The Trust searches for opportunities that align with strategic parameters and evaluates each prospect on a case by case basis. The Trust's acquisitions are expected to be financed through bank debt and new equity issuances.

	Three months ended September 30			Nine months ended September 30		
($000)	**2007**	2006	% Change	**2007**	2006	% Change
Capital acquisitions (net) [1] [2]	**20,777**	61,738	(66)	**660,029**	505,927	30
Development capital expenditures	**57,792**	31,921	81	**132,538**	79,956	66
Capitalized administration	**1,239**	757	64	**3,119**	1,818	72
Office equipment [2]	**680**	132	415	**2,277**	536	325
Total	**80,488**	94,548	(15)	**797,963**	588,237	36

(1) Capital acquisitions represent total consideration for the transactions including bank debt and working capital assumed.

(2) Comparative prior period results have been restated to conform to current period presentation.

Goodwill

The goodwill balance of $68.4 million as at September 30, 2007 is attributable to the corporate acquisitions of Tappit Resources Ltd., Capio Petroleum Corporation and Bulldog Energy Inc. during the period 2003 through 2005.

Asset Retirement Obligation

The asset retirement obligation increased by $2.2 million during the third quarter of 2007. This increase relates to liabilities of $1.3 million recorded in respect of capital acquisitions and new drills in the third quarter of 2007 and accretion expense of $1.2 million, offset slightly by actual expenditures incurred in the quarter of $287,000. For the nine month period ended September 30, 2007, the asset retirement obligation increased by $15.5 million. This increase relates to $13.3 million recorded for capital acquisitions and new drills in the year and accretion expense of $3.2 million, offset by $976,000 in actual expenditures during the 2007 period.

Liquidity and Capital Resources

At September 30, 2007, the Trust had a syndicated credit facility with seven banks and an operating credit facility with one Canadian chartered bank. On May 28, 2007, the amount available under the Trust's combined credit facilities was increased from $470.0 million to $600.0 million, to reflect the growth of the Trust's reserve base and the Mission acquisition. As at September 30, 2007, the Trust had debt of $198.6 million, leaving unutilized borrowing capacity of $401.4 million.

In October 2007, the Trust's credit facility was increased from $600.0 to $800.0 million reflecting the growth in the Trust's lending base and the completion of the Innova Exploration Ltd. acquisition. The Trust's bank syndicate was also expanded from seven to nine banks.

As at September 30, 2007, Crescent Point was capitalized with eight percent net debt and 92 percent equity, an eight percent change from December 31, 2006, reflecting the September 2007 bought deal financing (based on period end market capitalization). The Trust's net debt to cash flow of 0.6 times at September 30, 2007 (December 31, 2006 – 1.2 times) reflects the impact of the September 2007 bought deal financing proceeds which were used to reduce debt. The Trust's projected net debt to 12 month cash flow is less than 1.4 times.

The Trust's ability to raise new equity will be limited by the Safe Harbour Limit guidelines as announced by the Federal Government. The Federal Government's decision to tax income trusts has created uncertainty in the capital markets regarding the future of the trust sector however, Crescent Point believes that it has sufficient capital resources to meet its obligations given the significant credit facility available and success raising new equity as demonstrated in fiscal 2006 and the 2007 period.

Capitalization Table ($000, except unit, per unit and percent amounts)	**September 30, 2007**	December 31, 2006
Bank debt	**198,646**	254,438
Working capital [1]	**9,908**	(26,533)
Net debt [1]	**208,554**	227,905
Trust units outstanding	**112,722,546**	69,531,952
Market price at end of period (per unit)	**20.84**	17.60
Market capitalization	**2,349,138**	1,223,762
Total capitalization	**2,557,692**	1,451,667
Net debt as a percentage of total capitalization (%)	**8**	16
Annualized cash flow from operations	**368,860**	189,135
Net debt to cash flow [2]	**0.6**	1.2

(1) Working capital and net debt exclude the risk management liabilities and assets and include long-term investments.

(2) The net debt reflects the financing of acquisitions, however the cash flow only reflects cash flows generated from the acquired properties since the closing dates of the acquisitions.

Unitholders' Equity

At September 30, 2007, Crescent Point had 112,722,546 trust units issued compared to 69,531,952 trust units at December 31, 2006. The increase by more than 43.0 million trust units relates primarily to the corporate acquisitions completed in 2007, the bought deal financing in September 2007 and the Trust's distribution reinvestment programs.

On February 9, 2007, the Trust issued 29.2 million trust units to Mission shareholders at a price of $17.37 per trust unit. On September 5, 2007, the Trust transferred 605,815 trust units at $20.02 per unit in connection with the acquisition of a private corporation owning properties in the Willmar and Browning areas of southeast Saskatchewan.

On September 25, 2007, the Trust and a syndicate of underwriters closed a bought deal equity financing pursuant to which the syndicate sold 8.9 million trust units for gross proceeds of $165.1 million ($18.55 per trust unit).

For the third quarter of 2007, the distribution reinvestment and premium distribution reinvestment plans resulted in an additional 1.6 million trust units being issued at an average price of $18.76 raising a total of $29.4 million. Participation levels in these plans are approximately 46 percent. The cash raised through these alternative equity programs is used to reduce bank debt. Crescent Point will continue to monitor participation levels and utilize these funds in the most effective manner.

Crescent Point's total capitalization increased 76 percent to $2.6 billion at September 30, 2007 compared to $1.5 billion at December 31, 2006, with the market value of the trust units representing 92 percent of the total capitalization. The increase in capitalization is attributable to the increase in the number of units outstanding along with a significant appreciation in the unit trading price. During the third quarter of 2007, the Trust's units traded in the range of $17.58 to $20.85 with an average daily trading volume of 404,032 units.

Critical Accounting Estimates

The preparation of the Trust's financial statements requires management to adopt accounting policies that involve the use of significant estimates and assumptions. These estimates and assumptions are developed based on the best available information and are believed by management to be reasonable under the existing circumstances. New events or additional information may result in the revision of these estimates over time. A summary of the significant accounting policies used by Crescent Point can be found in Note 2 to the December 31, 2006 consolidated financial statements.

New Accounting Pronouncements

Accounting Changes in the Current Period

Financial Instruments

On January 1, 2007, the Trust adopted the CICA Handbook sections 3855 "Financial Instruments Recognition and Measurement", 3865 "Hedges", 3861 "Financial Instruments – Disclosure and Presentation", 1530 "Comprehensive Income," and 3251 "Equity". Other than the effect on the Investment in Marketable Securities as described in the above section, the adoption of the financial instruments standards has not affected the current or comparative period balances on the consolidated financial statements as all financial instruments identified have been fair valued.

Section 3855 requires that all financial assets be classified as held-for-trading, available-for-sale, held-to-maturity, or loans and receivables and that all financial liabilities must be classified as held-for-trading or other. Financial assets and financial liabilities classified as held-for-trading are measured at fair value with changes in those fair values recognized in earnings. Financial assets held-to-maturity, loans and receivables, and other financial liabilities are measured at amortized cost using the effective interest method of amortization. Available-for-sale financial assets are measured at fair value with unrealized gains and losses, including changes in foreign exchange rates, being recognized in other comprehensive income. Investments in equity instruments classified as available-for-sale that do not have a quoted market price in an active market are measured at cost. Accordingly, the investment in marketable securities balance of $171,000 at January 1, 2007 consisting of an investment in a publicly traded exploration and production company, was fair valued at January 1, 2007 to $1.6 million. Under prospective application, the $1.5 million gain was recorded as an adjustment to opening retained earnings. During the three month period ended June 30, 2007, the Trust sold the investment in marketable securities resulting in a realized gain of $1.4 million.

During the three month period ended September 30, 2007, the Trust purchased 2.2 million shares of Innova Exploration Ltd., a publicly traded exploration and production company, for an average price of approximately $7.51 per share or $16.6 million. The Trust acquired the remaining shares in October 2007 (refer to Capital Expenditures section above). The fair value at September 30, 2007 was $16.6 million, unchanged from the carrying value. Accordingly, there was no adjustment required to mark the investment to market.

Section 1530 establishes new standards for reporting comprehensive income, consisting of Net Income and Other Comprehensive Income ("OCI"). OCI is the change in equity (net assets) of an entity during a reporting period from transactions and other events from non-owner sources and excludes those resulting from investments by owners and distributions to owners. The Trust has no such transactions and events which would require the disclosure of OCI for the three month period ended September 30, 2007. Any changes in these items would be presented in a consolidated statement of comprehensive income.

Future Accounting Changes

The CICA issued new accounting standards, CICA Accounting Standard Handbook Section 3862, "Financial Instruments – Disclosures" and Section 3863 "Financial Instruments – Presentation". These standards require entities to provide disclosures in their financial statements that enable users to evaluate the significance of financial instruments to the entity's financial position and performance. It also requires that entities disclose the nature and extent of risks arising from financial instruments and how the entity manages those risks. The standards establish presentation guidelines for financial instruments and non-financial derivatives and deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset.

The CICA issued Section 1535, "Capital Disclosures". The application of these recommendations will provide readers of financial statements with information pertinent to the Trust's objectives, policies and processes for managing capital. Disclosure of quantitative data regarding what is considered capital and whether the Trust is in compliance with all externally imposed capital requirements and consequences of non-compliance will be disclosed.

The standards are effective for fiscal years beginning on or after October 1, 2007. The Trust has not assessed the impact of these standards on its financial statements.

Internal Controls Update

Crescent Point is required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". The 2007 certificate requires that the Trust disclose in the interim MD&A any changes in the Trust's internal control over financial reporting that occurred during the period that has materially affected, or is reasonably likely to materially affect the Trust's internal control over financial reporting. The Trust confirms that no such changes were made to the internal controls over financial reporting during the third quarter of 2007.

Summary of Quarterly Results

	2007			2006				2005
($000, except per unit amounts)	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1	Q4
Revenues	**164,368**	**144,179**	**128,880**	100,960	119,365	113,790	93,376	75,935
Net income (loss) (1) (5)	**18,410**	**(117,773)**	**157,544**	6,918	39,588	19,260	3,181	33,453
Net income (loss) per unit (1) (5)	**0.18**	**(1.17)**	**1.83**	0.10	0.61	0.32	0.06	0.87
Net income (loss) per unit - diluted (1) (5)	**0.18**	**(1.17)**	**1.80**	0.10	0.58	0.31	0.02	0.87
Cash flow from operating activities	**80,722**	**102,637**	**50,176**	39,313	50,910	49,683	37,520	21,731
Cash flow from operating activities per unit	**0.79**	**1.02**	**0.58**	0.58	0.78	0.84	0.71	0.56
Cash flow from operating activities per unit -diluted	**0.78**	**1.01**	**0.58**	0.56	0.75	0.81	0.68	0.54
Cash flow from operations	**92,215**	**78,248**	**72,875**	43,843	52,774	52,282	40,236	33,424
Cash flow from operations per unit	**0.90**	**0.78**	**0.84**	0.64	0.81	0.88	0.76	0.87
Cash flow from operations per unit – diluted	**0.89**	**0.77**	**0.84**	0.63	0.78	0.85	0.73	0.83
Working capital (2)	**(9,908)**	**(23,346)**	**13,044**	26,533	29,354	29,840	25,946	31,165
Total assets	**2,106,227**	**2,051,979**	**2,076,521**	1,373,466	1,351,245	1,294,214	1,188,260	808,297
Total liabilities	**555,233**	**656,693**	**534,299**	467,086	448,483	503,903	452,648	375,632
Net debt (2)	**208,554**	**353,416**	**340,612**	227,905	212,073	241,371	206,991	194,545
Total long-term financial liabilities	**-**	**7,286**	**16,107**	11,697	8,650	18,791	16,097	4,590
Weighted average trust units - diluted (thousands) (3)	**104,074**	**101,681**	**87,537**	69,764	67,810	61,372	54,958	40,464
Capital expenditures (4)	**80,488**	**58,835**	**658,640**	32,925	94,548	116,487	377,202	167,927
Cash distributions	**63,206**	**60,320**	**53,611**	41,322	39,890	36,123	32,942	22,835
Cash distributions per unit	**0.60**	**0.60**	**0.60**	0.60	0.60	0.60	0.60	0.59

(1) Net income per unit – diluted is calculated by dividing the net income before non-controlling interest by the diluted weighted average trust units, excluding the cash portion of unit – based compensation.

(2) Working capital and net debt exclude the risk management liabilities and assets and unrealized gain on investment in marketable securities, and include long term investments.

(3) The trust units issuable on conversion of the exchangeable shares reflect the weighted average exchangeable shares outstanding converted at the exchange ratio in effect at the end of the period. For the fourth quarter 2006 amounts, the exchangeable share ratio applied is the one in effect for the October 27, 2006 redemption.

(4) Capital expenditures includes capital acquisitions. Capital acquisitions represent total consideration for the transactions including bank debt and working capital assumed. Prior period results have been restated to conform to current period presentation.

(5) Net income for the first quarter of 2007 includes the $158.8 million future income tax recovery resulting from the March 1, 2007 reorganization. Net income for the second quarter of 2007 includes the $152.3 million future income tax expense resulting from the June 12, 2007 Bill C-52 Budget Implementation Act that was substantively enacted.

Crescent Point's revenue has increased due to several property and corporate acquisitions completed over the past two years and the Trust's successful drilling program. The overall growth of the Trust's asset base also contributed to the general increase in cash flow from operations and cashflow from operating activities. Net income through 2005 and 2006 has fluctuated primarily due to unrealized financial instrument gains and losses on oil and gas contracts, which fluctuate with the changes in market conditions. Net income for the nine month period September 30, 2007 fluctuated due to changes in the future tax expense/recovery. The March 1, 2007 internal reorganization resulted in a $158.8 million future tax recovery in the first quarter of 2007. Bill C-52 became substantively enacted on June 12, 2007, resulting in the future tax expense of $152.3 million in the second quarter of 2007. Capital expenditures fluctuated through this period as a result of timing of acquisitions. The general increase in cash flows from operations and operating activities throughout the last eight quarters has allowed the Trust to maintain stable monthly cash distributions of $0.17 per unit through August 2005 with increases to $0.19 per unit in September and to $0.20 per unit in November 2005.

Outlook

Crescent Point's preliminary 2008 guidance (pro forma with Innova Exploration Ltd. and Pilot Energy Ltd.) is as follows:

	2008 Preliminary Guidance
Production	
Oil and NGL (bbls/d)	26,900
Natural gas (mcf/d)	26,100
Total (boe/d)	31,250
Cash flow ($000)	396,000
Cash flow per unit – diluted ($)	3.28
Cash distributions per unit ($)	2.40
Payout ratio – per unit – diluted (%)	73
Capital expenditures ($000) (1)	150,000
Wells drilled, net	75
Pricing	
Crude oil – WTI (US$/bbl)	75.00
Crude oil – WTI (Cdn$/bbl)	75.00
Natural gas – Corporate (Cdn$/mcf)	6.50
Exchange rate (US$/Cdn$)	1.00

(1) The projection of capital expenditures excludes acquisitions, which are separately considered and evaluated.

Additional information relating to Crescent Point, including the Trust's renewal annual information form, is available on SEDAR at www.sedar.com.

CONSOLIDATED BALANCE SHEETS

(UNAUDITED) ($000)	As at **September 30, 2007**	December 31, 2006
ASSETS		
Current assets		
Cash	**1,752**	205
Accounts receivable	**89,997**	53,279
Investments in marketable securities (Note 2)	**-**	171
Prepaids and deposits	**2,581**	4,509
Risk management asset (Note 11)	**2,045**	586
	96,375	58,750
Long-term investment (Note 2 & 3(a))	**16,606**	30,020
Reclamation fund	**2,548**	1,725
Risk management asset (Note 11)	**1,000**	466
Property, plant and equipment (Note 3)	**1,921,348**	1,214,155
Goodwill	**68,350**	68,350
Total assets	**2,106,227**	1,373,466
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**108,932**	53,053
Cash distributions payable	**11,912**	8,598
Bank indebtedness (Note 4)	**198,646**	254,438
Risk management liability (Note 11)	**12,398**	7,581
	331,888	323,670
Asset retirement obligation (Note 5)	**61,320**	45,829
Risk management liability (Note 11)	**-**	11,697
Future income taxes (Note 9)	**162,025**	85,890
Total liabilities	**555,233**	467,086
UNITHOLDERS' EQUITY		
Unitholders' capital (Note 6)	**1,803,782**	1,045,929
Contributed surplus (Note 7)	**13,399**	9,150
Deficit (Note 8)	**(266,187)**	(148,699)
Total unitholders' equity	**1,550,994**	906,380
Total liabilities and unitholders' equity	**2,106,227**	1,373,466

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF OPERATIONS, COMPREHENSIVE INCOME AND DEFICIT

	Three months ended September 30		Nine months ended September 30	
(UNAUDITED) ($000, except per unit amounts)	**2007**	2006	**2007**	2006
REVENUE				
Oil and gas sales	**164,368**	119,365	**437,427**	326,531
Royalties	**(29,853)**	(25,421)	**(79,620)**	(70,856)
Financial instruments				
Realized gains (losses)	**(2,973)**	(9,596)	**1,390**	(26,638)
Unrealized gains (Note 11)	**3,383**	34,648	**6,810**	11,872
	134,925	118,996	**366,007**	240,909
EXPENSES				
Operating	**22,859**	18,737	**66,726**	48,949
Transportation	**4,429**	2,562	**12,099**	6,882
General and administrative	**3,350**	3,276	**11,444**	8,467
Unit-based compensation (Note 7)	**4,179**	5,471	**12,030**	9,123
Interest on bank indebtedness (Note 4)	**4,727**	3,425	**13,698**	10,071
Depletion, depreciation and amortization	**62,791**	37,507	**174,906**	103,063
Accretion on asset retirement obligation (Note 5)	**1,192**	849	**3,195**	2,307
	103,527	71,827	**294,098**	188,862
Income before taxes	**31,398**	47,169	**71,909**	52,047
Capital and other taxes	**3,309**	3,234	**10,520**	8,689
Future income tax expense (recovery) (Note 9)	**9,679**	4,292	**3,208**	(16,340)
Net income before non-controlling interest	**18,410**	39,643	**58,181**	59,698
Non-controlling interest	**-**	(55)	**-**	2,331
Net income and comprehensive income for the period	**18,410**	39,588	**58,181**	62,029
Deficit, beginning of period	**(221,391)**	(113,993)	**(148,699)**	(67,369)
Change in accounting policy (Note 2)	**-**	-	**1,468**	-
Cash distributions paid or declared	**(63,206)**	(39,890)	**(177,137)**	(108,955)
Deficit, end of the period (Note 8)	**(266,187)**	(114,295)	**(266,187)**	(114,295)
Net income per unit (Note 10)				
Basic	**0.18**	0.61	**0.60**	1.05
Diluted	**0.18**	0.58	**0.60**	0.97

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(UNAUDITED) ($000)	Three months ended September 30		Nine months ended September 30	
	2007	2006	**2007**	2006
CASH PROVIDED BY (USED IN)				
OPERATING ACTIVITIES				
Net income for the period	**18,410**	39,588	**58,181**	62,029
Items not affecting cash				
Non-controlling interest	**-**	55	**-**	(2,331)
Future income taxes (Note 9)	**9,679**	4,292	**3,208**	(16,340)
Unit-based compensation (Note 7)	**3,526**	5,131	**10,592**	8,436
Depletion, depreciation and amortization	**62,791**	37,507	**174,906**	103,063
Accretion on asset retirement obligation (Note 5)	**1,192**	849	**3,195**	2,307
Realized gain on sale of investment (Note 2)	**-**	-	**(1,402)**	-
Unrealized gains on financial instruments (Note 11)	**(3,383)**	(34,648)	**(6,810)**	(11,872)
Unrealized loss on investment (Note 2)	**-**	-	**1,468**	-
Asset retirement expenditures (Note 5)	**(287)**	(301)	**(976)**	(403)
Change in non-cash working capital				
Accounts receivable	**(14,285)**	(1,109)	**5,691**	(15,571)
Prepaid expenses and deposits	**1,146**	(207)	**1,928**	3,728
Accounts payable	**1,933**	(247)	**(16,446)**	5,067
	80,722	50,910	**233,535**	138,113
INVESTING ACTIVITIES				
Development capital and other expenditures	**(59,711)**	(32,810)	**(137,934)**	(82,311)
Capital acquisitions (Note 3)	**(2,108)**	(57,938)	**(57,243)**	(360,184)
Proceeds on sale of investment (Note 2)	**-**	-	**1,573**	-
Reclamation fund net contributions	**(348)**	(90)	**(823)**	(1,709)
Long-term investment	**(16,606)**	-	**(16,606)**	-
Change in non-cash working capital				
Accounts receivable	**(2,921)**	(586)	**(7,645)**	(1,566)
Accounts payable	**17,202**	2,149	**37,772**	6,998
	(64,492)	(89,275)	**(180,906)**	(438,772)
FINANCING ACTIVITIES				
Issue of trust units, net of issue costs	**184,851**	108,931	**233,384**	410,241
Restricted unit vests	**-**	(1,377)	**(833)**	(1,377)
Decrease in bank indebtedness	**(137,691)**	(29,784)	**(109,810)**	(1,645)
Cash distributions	**(63,206)**	(39,890)	**(177,137)**	(108,955)
Change in non-cash working capital				
Cash distributions payable	**1,040**	143	**3,314**	2,258
	(15,006)	38,023	**(51,082)**	300,522
INCREASE (DECREASE) IN CASH	**1,224**	(342)	**1,547**	(137)
CASH AT BEGINNING OF PERIOD	**528**	522	**205**	317
CASH AT END OF PERIOD	**1,752**	180	**1,752**	180

See accompanying notes to the consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

SEPTEMBER 30, 2007 (UNAUDITED)

1. SIGNIFICANT ACCOUNTING POLICIES

These interim consolidated financial statements of Crescent Point Energy Trust ("the Trust") have been prepared by management in accordance with Canadian generally accepted accounting principles and follow the same accounting policies as the most recent annual audited financial statements, except as described below. The specific accounting policies used are described in the annual consolidated financial statements appearing on pages 49 through 51 of the Trust's 2006 Annual Report. All amounts reported in these statements are in Canadian dollars.

2. CHANGES IN ACCOUNTING POLICIES

Financial Instruments

On January 1, 2007, the Trust adopted the CICA Handbook sections 3855 "Financial Instruments Recognition and Measurement", 3865 "Hedges", 3861 "Financial Instruments – Disclosure and Presentation", 1530 "Comprehensive Income," and 3251 "Equity". Other than the effect on the Investment in Marketable Securities as described in the section below, the adoption of the financial instruments standards has not affected the current or comparative period balances on the consolidated financial statements as all financial instruments identified have been fair valued.

Financial Instruments

Section 3855 requires that all financial assets be classified as held-for-trading, available-for-sale, held-to-maturity, or loans and receivables and that all financial liabilities must be classified as held-for-trading or other. Financial assets and financial liabilities classified as held-for-trading are measured at fair value with changes in those fair values recognized in earnings. Financial assets held-to-maturity, loans and receivables, and other financial liabilities are measured at amortized cost using the effective interest method of amortization. Available-for-sale financial assets are measured at fair value with unrealized gains and losses, including changes in foreign exchange rates, being recognized in other comprehensive income. Investments in equity instruments classified as available-for-sale that do not have a quoted market price in an active market are measured at cost. The Trust has elected to classify the investment in marketable securities as held for trading. Accordingly, the investment in marketable securities balance of $171,000 at January 1, 2007 consisting of an investment in a publicly traded exploration and production company, was fair valued at January 1, 2007 to $1.6 million. Under prospective application, the $1.5 million gain was recorded as an adjustment to opening retained earnings.

During the three month period ended June 30, 2007, the Trust sold the investment in marketable securities. As a result, the change in the unrealized gain on investment of $1.5 million was recorded through the income statement and a realized gain was recorded for $1.4 million.

During the three month period ended September 30, 2007, the Trust purchased 2.2 million shares of Innova Exploration Ltd., a publicly traded exploration and production company, for an average price of approximately $7.51 per share or $16.6 million. The Trust acquired the remaining shares in October 2007 (refer to Subsequent Event Note 12(a) below).The fair value at September 30, 2007 was $16.6 million, unchanged from the carrying value. Accordingly, there was no adjustment required to mark the investment to market.

Derivative instruments are always carried at fair value and reported as assets where they have a positive fair value and as liabilities where they have a negative fair value. Derivatives may be embedded in other financial instruments. Under the new Financial Instruments standards the derivatives embedded in other financial instruments are valued as separate derivatives when their economic characteristic and risks are not clearly and closely related to those of the host contract; the terms of the embedded derivative are the same as those of a free standing derivative; and the combined contract is not held-for-trading. When an entity is unable to measure the fair value of the embedded derivative separately, the combined contract is treated as a financial asset or liability that is held-for-trading and measured at fair value with changes therein recognized in earnings.

The fair value of a financial instrument on initial recognition is normally the transaction price, i.e. the fair value of the consideration given or received. Subsequent to initial recognition, the fair values are based on quoted market price where available from active markets, otherwise fair values are estimated based upon market prices at reporting date for other similar assets or liabilities with similar terms and conditions, or by discounting future payments of interest and principal at estimated interest rates that would be available to the Trust at the reporting date.

Hedges

Section 3865 replaces the guidance formerly in Section 1650, "Foreign Currency Translation" and Accounting Guideline 13, "Hedging Relationships" by specifying how hedge accounting is applied and what disclosures are necessary when it is applied. The Trust does not have any derivative instruments that have been designated as hedges. Accordingly, the Trust is marking to market its financial instruments.

Comprehensive Income

Section 1530 establishes new standards for reporting the display of comprehensive income, consisting of Net Income and Other Comprehensive Income ("OCI"). OCI is the change in equity (net assets) of an entity during a reporting period from transactions and other events from non-owner sources and excludes those resulting from investments by owners and distributions to owners. The Trust has no such transactions and events which would require the disclosure of OCI for the three month and nine month periods ended September 30, 2007. Any changes in these items would be presented in a consolidated statement of operations and comprehensive income.

Equity

Section 3251 replaces section 3250, "Surplus" and establishes standards for the presentation of equity and changes in equity during reporting period, including changes in Accumulated Other Comprehensive Income ("Accumulated OCI"). Any cumulative changes in OCI would be included in Accumulated OCI and be presented as a new category of Shareholder's Equity on the consolidated balance sheet. As the Trust has no OCI transactions, the Trust does not have any Accumulated OCI.

3. CAPITAL ACQUISITIONS

a) Acquisition of Mission Oil & Gas Inc.

On February 9, 2007, the Trust purchased all the issued and outstanding shares of Mission Oil & Gas Inc., a publicly traded company with properties in the Viewfield area of southeast Saskatchewan for total consideration of $621.4 million, including assumed bank debt and working capital ($700.5 million was allocated to property, plant and equipment). The purchase was paid for through the Trust's existing bank lines and issuance of approximately 29.2 million trust units and was accounted for as a business combination using the purchase method of accounting. The Trust owned 3.8 million shares of Mission Oil & Gas Inc. prior to the closing which it purchased for $7.90 per share or $30.0 million in November 2005.

	($000)
Net assets acquired	
Working capital	488
Risk management asset	2,063
Property, plant and equipment	700,511
Bank debt	(47,751)
Asset retirement obligation	(8,285)
Future income taxes	(72,927)
Total net assets acquired	574,099
Consideration	
Cash	62,767
Trust units issued (29,178,562 trust units)	506,832
Acquisition costs	4,500
Total purchase price	574,099

b) Acquisition of a Private Corporation

On September 5, 2007, the Trust purchased all the issued and outstanding shares of a private corporation with properties in the Willmar and Browning areas of southeast Saskatchewan for total consideration of $18.9 million including assumed bank debt and working capital ($19.6 million was allocated to property, plant and equipment). The purchase was paid for with cash of $121,000 from the Trust's existing bank lines and 605,815 trust units and was accounted for as a business combination using the purchase method of accounting.

	($000)
Net assets acquired	
Property, plant and equipment	19,638
Working capital deficiency	(275)
Bank debt	(6,266)
Asset retirement obligation	(697)
Total net assets acquired	12,400
Consideration	
Cash	121
Trust units issued (605,815 trust units)	12,129
Acquisition costs	150
Total purchase price	12,400

c) Property Acquisitions

During the three months ended September 30, 2007, the Trust closed minor property acquisitions for total consideration of approximately $1.2 million ($1.2 million was also allocated to property, plant and equipment). The Trust recorded purchase price adjustments on previously closed acquisitions for the three months ended September 30, 2007 of $700,000.

During the nine months ended September 30, 2007, the Trust closed minor property acquisitions for total consideration of approximately $20.2 million ($22.9 million was allocated to property, plant and equipment). The Trust recorded favorable purchase price adjustments on previously closed acquisitions for the nine months ended September 30, 2007 of $500,000.

4. BANK INDEBTEDNESS

The Trust has a syndicated credit facility with seven banks and an operating credit with one Canadian chartered bank. On May 28, 2007, the amount available under the combined credit facilities was increased from $470.0 million to $600.0 million. Refer to Subsequent Event Note 12(b) for details of a further increase subsequent to the end of the quarter. The Trust has letters of credit in the amount of $340,000 outstanding at September 30, 2007.

The credit facilities bear interest at the prime rate plus a margin based on a sliding scale ratio of the Trust's debt to cash flows. The credit facility is secured by the oil and gas assets owned by the Trust's wholly owned subsidiaries.

The cash interest paid in the nine months ended September 30, 2007 was $13.1 million (2006 - $10.9 million). The cash interest paid in the third quarter of 2007 was $2.5 million (2006 - $3.4 million).

5. ASSET RETIREMENT OBLIGATION

The following table reconciles the asset retirement obligation:

	($000)
Asset retirement obligation, January 1, 2007	45,829
Liabilities incurred	1,561
Liabilities acquired through capital acquisitions	11,711
Liabilities settled	(976)
Accretion expense	3,195
Asset retirement obligation, September 30, 2007	61,320

6. UNITHOLDERS' CAPITAL

On September 25, 2007, the Trust and a syndicate of underwriters closed a bought deal equity financing pursuant to which the syndicate sold 8,900,000 trust units for gross proceeds of $165.1 million ($18.55 per trust unit)

	Number of trust units	Amount ($000)
Trust units, January 1, 2007	69,531,952	1,083,948
Issued for cash	8,900,000	165,095
Issued on capital acquisitions	29,784,377	518,961
Issued on vesting of restricted units (1)	167,933	3,615
Issued pursuant to the distribution reinvestment plans	3,822,343	68,352
To be issued pursuant to the distribution reinvestment plans	515,941	10,409
Trust units, September 30, 2007	112,722,546	1,850,380
Cumulative unit issue costs	-	(46,598)
Total unitholders' capital, September 30, 2007	112,722,546	1,803,782

(1) The amount of trust units issued on vesting of restricted units is net of trust units purchased in the market to satisfy the issuance of trust units under the restricted unit bonus plan and employee withholding taxes.

7. RESTRICTED UNIT BONUS PLAN

A summary of the changes in the restricted units outstanding under the plan is as follows:

Restricted units, January 1, 2007	1,043,628
Granted	705,647
Exercised	(324,178)
Forfeited	(21,497)
Restricted units, September 30, 2007	1,403,600

8. DEFICIT

The deficit balance is composed of the following items:

	($000)
Accumulated earnings	201,392
Accumulated cash distributions	(467,579)
Deficit	(266,187)

During the period, presentation changes were made to combine the previously reported Accumulated Earnings and Accumulated Cash Distribution figures on the balance sheet into a single Deficit balance. The Trust has historically paid cash distributions in excess of accumulated earnings as cash distributions are based on cash flow from operating activities before changes in non-cash working capital generated in the current period while accumulated earnings are based on cash flow from operating activities before changes in non-cash working capital generated in the current period less a depletion, depreciation, and accretion expense recorded on original property, plant, and equipment, unrealized financial instrument gains/losses and other non-cash charges.

9. INCOME TAXES

On June 12, 2007, Bill C-52 Budget Implementation Act, 2007 was substantively enacted by the Canadian federal government, which contains legislation to tax publicly traded trusts in Canada. As a result, a new 31.5 percent tax will be applied to distributions from Canadian public income trusts. The new tax is not expected to apply to Crescent Point until 2011 as a transition period applies to publicly traded trusts that existed prior to November 1, 2006. The impact of the substantive enactment of trust taxation was that Crescent Point recorded a $152.3 million future income tax liability and future income tax expense in the three month period ended June 30, 2007. For the three month period ended September 30, 2007, the Trust recorded a $9.7 million future tax expense. There was no future tax liability recorded at March 31, 2007 as the Trust completed a reorganization into a flow through structure on March 1, 2007, resulting in the recovery of the future tax liability of $158.8 million in the first quarter of 2007. The future income tax liability of $162.0 million at September 30, 2007 represents the taxable temporary differences of Crescent Point tax effected at 31.5 percent, which is the rate that will be applicable to trusts in 2011 under current legislation.

The cash capital taxes paid during the nine month period ended September 30, 2007 were $11.4 million (2006 - $7.1 million). The cash capital taxes paid during the third quarter of 2007 were $3.9 million (2006 - $4.5 million).

10. PER TRUST UNIT AMOUNTS

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

	Three months ended September 30		Nine months ended September 30	
	2007	2006	**2007**	2006
Weighted average trust units	**102,669,333**	65,401,265	**96,469,405**	59,260,514
Trust units issuable on conversion of exchangeable shares[(1)]	**-**	1,420,988	**-**	1,420,988
Dilutive impact of restricted units	**1,404,420**	987,787	**1,355,073**	780,862
Dilutive trust units and exchangeable shares [(1)]	**104,073,753**	67,810,040	**97,824,478**	61,462,364

(1) The trust units issuable on conversion of the exchangeable shares reflect the weighted average exchangeable shares outstanding converted at the exchange ratio in effect at the end of the period. On October 27, 2006, the Trust purchased all issued and outstanding exchangeable shares.

11. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Trust's financial instruments recognized on the consolidated balance sheet include cash, accounts receivable, the reclamation fund, accounts payable, accrued liabilities and debt. The fair value of these financial instruments approximates their carrying amounts due to their short-term nature. A substantial portion of the Trust's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks.

The Trust entered into fixed price oil, gas, power and foreign exchange contracts along with interest rate swaps to manage its exposure to fluctuations in the price of crude oil, gas, power, foreign exchange and interest on debt.

The following is a summary of the financial instrument contracts in place as at September 30, 2007:

Financial WTI Crude Oil Contracts - Canadian Dollar						
Term	Contract	Volume (bbls/d)	Average Swap Price ($Cdn/bbl)	Average Bought Put Price ($Cdn/bbl)	Average Sold Call Price ($Cdn/bbl)	Average Put Premium ($Cdn/bbl)
2007						
October – December	Swap	6,500	75.72			
October – December	Collar	1,500		66.74	82.27	
October – December	Put	3,250		77.63		(7.65)
2007 Weighted Average		**11,250**	**75.72**	**74.19**	**82.27**	**(7.65)**
2008						
January – June	Swap	1,000	72.73			
January – September	Swap	250	68.10			
January – December	Swap	4,750	75.86			
July – December	Swap	1,000	73.52			
October – December	Swap	250	70.80			
January – June	Collar	250		65.00	82.00	
January – December	Collar	2,000		70.00	83.25	
July – December	Collar	250		70.00	91.00	
January – December	Put	3,500		72.58		(6.66)
2008 Weighted Average		**11,750**	**75.11**	**71.46**	**83.62**	**(6.66)**
2009						
January – March	Swap	2,750	77.68			
April – June	Swap	2,750	77.58			
January – June	Swap	1,250	74.99			
July – September	Swap	3,000	74.07			
July – December	Swap	1,000	76.41			
October – December	Swap	3,000	74.37			
January – December	Swap	1,000	73.30			
January – March	Collar	250		75.00	87.00	
April – June	Collar	250		75.00	83.00	
January – June	Collar	1,250		70.00	81.01	
January – September	Collar	250		70.00	79.00	
January – December	Collar	500		70.00	78.88	
July – September	Collar	250		70.00	84.05	
July – December	Collar	1,250		69.00	80.37	
October – December	Collar	500		70.00	85.93	
January – December	Put	1,750		70.41		(6.43)
2009 Weighted Average		**9,000**	**75.28**	**70.18**	**80.77**	**(6.43)**
2010						
January – March	Swap	3,500	76.22			
April - June	Swap	2,750	74.38			
January – June	Collar	500		70.00	80.50	
2010 January – June Weighted Average		**3,623**	**75.41**	**70.00**	**80.50**	

Financial WTI Crude Oil Contracts - U.S. Dollar				
Term	Contract	Volume (bbls/d)	Average Bought Put Price ($US/bbl)	Average Sold Call Price ($US/bbl)
2007				
October – December	Collar	1,000	67.50	75.73
2007 Weighted Average		**1,000**	**67.50**	**75.73**

Financial AECO Natural Gas Contracts – Canadian Dollar Term	Contract	Volume (GJ/d)	Average Bought Put Price ($Cdn/GJ)	Average Sold Call Price ($Cdn/GJ)
2007				
October	Collar	4,000	6.75	8.60
November – December	Collar	2,000	6.75	8.00
2007 Weighted Average		**2,674**	**6.75**	**8.30**
2008				
January – March	Collar	2,000	6.75	8.00
April – October	Collar	2,000	6.75	7.75
2008 January – October Weighted Average		**2,000**	**6.75**	**7.82**

Financial Foreign Exchange Contracts – U.S. Dollar Term	Contract	Amount ($US)	Average Swap ($Cdn/$US)
2007			
October – December	Swap	2,990,000	1.1600
October – December	Swap	3,220,000	1.1012
2007 Weighted Average		**6,210,000**	**1.1295**

Financial Interest Rate Contracts – Canadian Dollar Term	Contract	Principal ($Cdn)	Fixed Annual Rate (%)
October 2007 – May 2008	Swap	50,000,000	4.41
October 2007 – February 2009	Swap	50,000,000	4.37

Financial Power Contract – Canadian Dollar Term	Contract	Volume (MW/h)	Fixed Rate ($Cdn/MW/h)
October 2007 – December 2008	Swap	3.0	63.25

Physical Power Contracts – Canadian Dollar Term	Contract	Volume (MW/h)	Fixed Rate ($Cdn/MW/h)
October 2007 – December 2009	Swap	1.0	82.45
January 2009 – December 2009	Swap	3.0	81.25

The Trust has two physical power contracts and one financial power contract. The physical contracts have not been marked-to-market. The unrealized gain on the physical contracts at September 30, 2007 is $106,000.

None of the Trust's financial instrument contracts have been designated as accounting hedges. Accordingly, all financial instrument contracts have been recorded on the balance sheet as assets and liabilities based on their fair values.

The following table reconciles the movement in the fair value of the Trust's commodity, power, foreign exchange and interest rate contracts:

	($000)
Risk management asset, January 1, 2007	1,052
Acquired through capital acquisitions	2,063
Unrealized mark-to-market loss	(70)
Risk management asset, September 30, 2007	3,045
Less: current risk management asset, September 30, 2007	(2,045)
Long term risk management asset, September 30, 2007	1,000

	($000)
Risk management liability, January 1, 2007	19,278
Unrealized mark-to-market gain	(6,880)
Risk management liability, September 30, 2007	12,398
Less: current risk management liability, September 30, 2007	(12,398)
Long term risk management liability, September 30, 2007	-

12. SUBSEQUENT EVENTS

a) Acquisition of Innova Exploration Ltd. (Viewfield Bakken Property)

In late October 2007, the Trust closed the acquisition of Innova Exploration Ltd., a publicly traded company with properties in the Viewfield Bakken area of southeast Saskatchewan for consideration of approximately $400.0 million, before closing adjustments and including assumed net debt. The purchase was funded through the Trust's existing bank lines.

The Trust owned 2.2 million shares of Innova Exploration Ltd. prior to the closing which it purchased for an average price of approximately $7.51 per share or approximately $16.6 million in September 2007.

b) Credit Facility

In late October 2007, the amount available under the Trust's credit facility was increased from $600.0 million to $800.0 million and two additional banks joined the syndicate.

c) Acquisition of Pilot Energy Ltd.

In late October 2007, the Trust announced the issuance of an offer to purchase the issued and outstanding shares of Pilot Energy Ltd. by way of a Plan of Arrangement for total consideration of approximately $76.0 million before closing adjustments and including net debt. An Information Circular outlining the plan is expected to be mailed by December 15, 2007 and a shareholder vote to approve the Plan of Arrangement will be held on or about January 15, 2008.

13. COMPARATIVE INFORMATION

Certain information provided for the previous period has been restated to conform to the current period presentation.

Directors

Peter Bannister, Chairman [1] [3]

Paul Colborne [2] [4]

Ken Cugnet [3] [4] [5]

Hugh Gillard [1] [2] [3]

Gerald Romanzin [1] [5]

Scott Saxberg [4]

Greg Turnbull [2] [5]

(1) Member of the Audit Committee of the Board of Directors

(2) Member of the Compensation Committee of the Board of Directors

(3) Member of the Reserves Committee of the Board of Directors

(4) Member of the Health, Safety and Environment Committee of the Board of Directors

(5) Member of the Corporate Governance Committee

Officers

Scott Saxberg
President and Chief Executive Officer

C. Neil Smith
Vice President, Engineering and
Business Development

Greg Tisdale
Chief Financial Officer

Dave Balutis
Vice President, Geosciences

Tamara MacDonald
Vice President, Land

Ken Lamont
Controller and Treasurer

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Banker

The Bank of Nova Scotia
Calgary, Alberta

Auditor

PricewaterhouseCoopers LLP
Calgary, Alberta

Legal Counsel

McCarthy Tétrault LLP
Calgary, Alberta

Evaluation Engineers

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Sproule Associates Ltd.
Calgary, Alberta

Registrar and Transfer Agent

Investors are encouraged to contact
Crescent Point's Registrar and Transfer
Agent for information regarding their security holdings:

Olympia Trust Company
2300, 125 – 9th Avenue SE
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Tel: (403) 261-0900

Stock Exchange

Toronto Stock Exchange – TSX

Stock Symbol

CPG.UN

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