

CREW ENERGY INC. (TSX:CR) OF CALGARY, ALBERTA IS PLEASED TO PRESENT ITS OPERATING AND FINANCIAL RESULTS FOR THE THREE AND NINE MONTH PERIODS ENDED SEPTEMBER 30, 2007.

HIGHLIGHTS

- Third quarter production averaged 9,268 boe per day representing a 61% increase over the third quarter of 2006;
- Production per share increased 18% in the third quarter compared to the third quarter of 2006;
- Funds from operations increased to \$21.2 million in the third quarter, a 49% increase over 2006;
- Funds from operations per share increased to \$0.44, a 10% increase over the third quarter of 2006;
- Operating costs remained amongst the lowest in the Company's peer group at \$6.29 per boe resulting in an operating netback of \$28.44 and a funds from operations netback of \$24.83;
- Successfully completed a \$54 million equity financing in October, resulting in a strengthened balance sheet with additional capital available to finance the Company's remaining 2007 and 2008 capital expenditure program;
- Successfully integrated the May 3, 2007 acquired operation of Enco Gas Ltd. with Crew's northeast B.C. operations; and
- Drilled a series of exploration successes in the deep basin of West Central Alberta highlighted by four wells with cumulative test rates in excess of 36 mmcf per day of natural gas.

FINANCIAL <i>(\$ thousands, except per share amounts)</i>	Three months ended Sept 30, 2007	Three months ended Sept 30, 2006	Nine months ended Sept 30, 2007	Nine months ended Sept 30, 2006
Petroleum and natural gas sales	33,390	22,267	101,524	66,223
Funds from operations (NOTE 1)	21,171	14,245	59,043	39,953
Per share - basic	0.45	0.41	1.32	1.19
- diluted	0.44	0.40	1.31	1.16
Net income (loss)	(449)	1,633	2,221	8,980
Per share - basic	(0.01)	0.05	0.05	0.27
- diluted	(0.01)	0.05	0.05	0.26
Exploration and development expenditures	25,385	38,914	71,059	93,529
Property acquisitions (net of dispositions)	(51)	-	(49)	15,929
Business acquisition	-	-	137,456	-
Total capital investment	25,334	38,914	208,466	109,458
Working capital deficiency (NOTE 2)			11,737	15,206
Bank loan			139,737	22,810
Net debt			151,474	38,016
Pro-forma net debt (NOTE 3)			99,974	-
Weighted average shares (thousands)				
Basic	47,321	34,537	44,648	33,714
Diluted	47,704	35,238	45,032	34,493

(1) Funds from operations is calculated as cash provided by operating activities from the statement of cash flows, adding the change in non-cash working capital, asset retirement expenditures and the excess transportation liability charge. Funds from operations is used to analyze the Company's operating performance and leverage. Funds from operations does not have a standardized measure prescribed by Canadian Generally Accepted Accounting Principles and therefore may not be comparable with the calculations of similar measures for other companies.

(2) Working capital deficiency does not include the fair value of financial instruments or current portion of other long-term obligations.

(3) Pro-forma net debt includes the September 30, 2007 net debt less the \$51.5 million net proceeds of the Company's October 25, 2007 equity issue.

	Three months ended September 30, 2007	Three months ended September 30, 2006	Nine months ended September 30, 2007	Nine months ended September 30, 2006
OPERATIONS				
Daily production				
Light oil and ngl (bbl/d)	1,298	983	1,403	814
Natural gas (mcf/d)	47,820	28,710	41,842	28,209
Oil equivalent (boe/d @ 6:1)	9,268	5,768	8,377	5,516
Production per share (boepd/mm diluted shares)	194	164	186	160
Average prices (NOTE 1)				
Light oil and ngl (\$/bbl)	70.02	70.64	59.97	65.99
Natural gas (\$/mcf)	5.84	6.01	6.93	6.69
Oil equivalent (\$/boe)	39.92	41.96	44.65	43.98
Operating expenses				
Light oil and ngl (\$/bbl)	6.73	4.32	6.19	5.03
Natural gas (\$/mcf)	1.04	0.90	1.03	0.88
Oil equivalent (\$/boe @ 6:1)	6.29	5.22	6.18	5.22
Operating netback (\$/boe) (NOTE 2)	28.44	28.35	29.00	28.15
G&A (\$/boe)	0.95	0.70	1.03	0.84
Interest (\$/boe)	2.66	0.82	2.15	0.77
Funds from operations (\$/boe)	24.83	26.83	25.82	26.54
Drilling Activity				
Gross wells	9	15	20	42
Working interest wells	7.4	13.3	18.1	36.2
Success rate, net wells	100%	87%	100%	93%

(1) Average prices are before deduction of transportation costs and include realized gains and losses on financial instruments.

(2) Operating netback equals petroleum and natural gas sales including realized gains and losses on financial instruments less royalties, operating costs and transportation costs calculated on a boe basis. Operating netback and funds from operations netback do not have a standardized measure prescribed by Canadian Generally Accepted Accounting Principles and therefore may not be comparable with the calculations of similar measures for other companies.

OVERVIEW

Crew's third quarter was highlighted by a 61% increase in production to 9,268 boe per day. Funds from operations increased to \$21.2 million which is a 49% increase over the same period in 2006. Production per share increased by 18% while funds from operations per share of \$0.44 was an increase of 10% over the same period of 2006.

Crew invested \$25.3 million in the third quarter drilling nine (7.4 net) wells with a 100% success rate. The Company also invested in Crown land acquisitions, production facilities and production infrastructure in west central Alberta.

Crew's 2007 drilling program has been the most successful in its history. Over the first nine months of 2007, the number of wells drilled is down by 50% over 2006 however, well deliverability has improved significantly. Crew has tested over 36 mmcf per day of deliverability from wells recently drilled in the deep basin of west central Alberta. The Company is constructing a 10 mmcf per day gas compression and dehydration facility to accommodate a portion of these volumes currently scheduled to be operational by December 1, 2007.

ALBERTA

Edson

In the third quarter Crew received approval from the Alberta Energy and Utilities Board for its downspacing application to develop the Rock Creek resource at four wells per section and the Company's lower Mannville resource at two wells per section. Crew is currently drilling its first well after receiving downspacing approval and plans to

keep a drilling rig in the area active until spring break-up in 2008. With success, Crew has a three to four year inventory of drilling in this area.

Ferrier

Crew drilled two (1.33 net) wells in this area in the third quarter that resulted in a producing gas/condensate well and a cased gas well. One well started production in the fourth quarter and is currently producing approximately 150 boe per day. Crew has approximately 400 boe per day of shut-in production that is scheduled to begin production by mid January 2008.

Viking-Kinsella

Crew continues to acquire land and seismic in this area. The Company expects to drill two to three wells by year end in close proximity to Company owned infrastructure. If successful, these wells are expected to be tied-in before year end.

Hanlan

Crew (WI 50%) re-completed one well in the third quarter. The well indicated low permeability in the zone of interest and is uneconomic to produce. In the fourth quarter Crew (WI 42.5%) plans on re-completing another well in the area targeting gas from the Nisku formation. Crew's (WI 50%) Nisku discovery is currently producing 8.5 mmcf per day.

BRITISH COLUMBIA

Inga

Crew has plans to drill a horizontal well in this area targeting natural gas from the Baldonnel Formation. If successful, the Company could drill six additional locations targeting this formation. The Company also has plans to drill a Halfway Formation test targeting a five bcf prospect.

Dahl

The Company has identified nine developmental drilling locations targeting Bluesky-Gething sandstones. Drilling in this area is expected to begin in 2008.

Kobes-Bernadet

Crew drilled and cased two (1.06 net) wells targeting gas at Bernadet in the third quarter. The Company has one re-completion and two drilling locations planned for this area.

Yoyo-Sierra

At Sierra Crew experienced significant down-time due to the previously announced repair to the diesel driver at the Sierra facility. This facility has also experienced down-time in the fourth quarter. Crew has made property and business interruption claims with its insurance company.

At Yoyo Crew (WI 25-100%) expects to drill three to four wells this winter targeting natural gas.

Missile-Helmet

These areas are located on the Muskwa shale gas play. Crew has 11.5 net sections of land on this play. Third party estimates of the natural gas resource in place in these areas suggest the potential for 0.4 - 2.1 tcf of gas in place on Crew lands.

EXPLORATION

At Pine Creek, Alberta Crew (WI 100%) has now drilled five successful gas/condensate wells. Crew is building a 10 mmcf per day natural gas dehydration and compression facility scheduled to start production on or about December 1, 2007.

Crew has plans to drill two wells in this area in the fourth quarter and has now amassed an interest in over 45 sections at Pine Creek and has plans to drill 10-15 wells in 2008.

At Carrot Creek, Alberta Crew (WI 100%) has drilled its third successful well in the area. Current production from this new area is approximately 500 boe per day based on field estimates. Crew has five additional drilling locations identified at Carrot Creek.

At Strachan, Alberta Crew (WI 29% bpo 46.5% apo) plans to drill a 3,700 meter Leduc prospect which is currently expected to spud in January, 2008 subject to EUB approval. Successful wells in the area have produced ten to several hundred bcf of gas with high daily production rates.

At Medicine River, Alberta Crew (WI 100%), in the fourth quarter of 2007, unsuccessfully drilled a 3,200 meter test targeting light oil from the Leduc Formation. The Company is re-evaluating its three dimensional seismic in the area in light of these results.

OUTLOOK

Business Environment

Natural gas prices have continued to come under pressure as a result of high storage levels, high natural gas directed drilling in the U.S. and more recently because of the strengthening of the Canadian dollar.

We maintain the view that long term natural gas fundamentals will improve as we see a Canadian supply response from reduced activity levels as well as an increase in domestic natural gas requirements. Crew is well prepared for this low natural gas price environment. Our low cost structure and healthy balance sheet positions Crew to successfully cope with the current price environment.

Crew will continue to evaluate oil and natural gas investment opportunities using current natural gas pricing as an economic hurdle. We will continue to search for attractive acquisition opportunities and attempt to capitalize on the current environment with attractive terms on farm-in commitments in core areas. Service costs have generally declined since the first quarter of 2007. We will continue to concentrate on reducing capital and operating costs in order to optimize investment efficiencies.

Alberta Royalty Review

During the past year, the Government of Alberta commissioned a review by an independent panel to perform a review of the province's royalty system to determine if the people of Alberta were receiving their "fair share" of the resource extracted by the oil and gas industry. On September 18, 2007 a report was issued by the Alberta Royalty Review Panel. Utilizing this report as a framework, on October 25, 2007 the Government of Alberta released its proposed New Royalty Framework ("NRF") for the province.

Crew has reviewed the modifications proposed in the NRF that, if implemented, would take effect on January 1, 2009. While more detailed analysis of the potential impact of the NRF on Crew is ongoing, we wish to make the following preliminary observations:

- The proposed NRF rewards the development of low productivity wells and deters multi-well, full cycle exploration where cash flow from high productivity wells is reduced by significantly higher royalties but is still required to recover the costs of seismic and land acquisitions, dry holes, pipelines and processing facilities;
- We expect the proposed NRF will reduce exploratory drilling and industry activity levels as it fails to recognize the current cost structure in Alberta;

- We believe the proposed NRF has resulted in a loss of confidence and attraction of capital in the oil and gas industry particularly as it relates to conventional oil and gas development;
- 35% of Crew's production is from properties located in British Columbia and therefore is not affected by the NRF; and
- GLJ Petroleum Consultants Ltd., our third party engineering firm, has recalculated our adjusted January 1, 2007 reserves with their October 1, 2007 escalated price forecast under both the existing and proposed January 1, 2009 royalty rates. The results indicate that the change in royalty rates would have a positive impact of approximately three percent on the net present value of our proved and probable reserves at January 1, 2007, discounted at 10%. This evaluation is essentially a "blowdown" of our existing production and development of our existing non-producing reserves at the effective date of the report.

Strong Balance Sheet

At the end of the third quarter Crew had \$151.5 million of debt and working capital. On October 25, 2007 Crew closed a \$54 million equity financing to significantly reduce the Company's current net debt to the \$100 million level. Absent any major acquisitions, Crew currently anticipates year end net debt to be approximately \$105 to \$110 million.

2007 Exit Production Estimated To Exceed 11,500 Boe Per Day

Crew expects to drill 8-10 wells and tie-in over 2,000 boe per day of tested production in the fourth quarter. Fourth quarter average production will be reduced by approximately 500 boe per day due to facility downtime at Carrot Creek and Ferrier, Alberta and Sierra, British Columbia. Production is currently expected to average approximately 9,650 boe per day in the fourth quarter.

Our industry has been forced to deal with a number of setbacks over the last year. Despite these challenges, Crew believes that we have the ability and motivation to continue to add value for our shareholders. We have a strong asset base and abundant opportunities to continue to economically increase our production. We have been acquiring land on a number of exciting new prospects and will direct capital to areas where the best rate of returns reside in the current environment. We look forward to evaluating these prospects with the drill bit and updating you on many other initiatives in our year end report.

On behalf of the Board,

Dale Shwed
President and C.E.O.

November 8, 2007

MANAGEMENT'S DISCUSSION AND ANALYSIS

ADVISORIES

Management's discussion and analysis ("MD&A") is the Company's explanation of its financial performance for the period covered by the financial statements along with an analysis of the Company's financial position. Comments relate to and should be read in conjunction with the consolidated financial statements of the Company for the three and nine month periods ended September 30, 2007 and 2006 and the audited consolidated financial statements and MD&A for the year ended December 31, 2006. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in Canada.

Forward Looking Statements

This MD&A contains forward-looking statements. Management's assessment of future plans and operations, capital expenditures and the method of funding thereof, available bank lines, production estimates, wells to be drilled, timing of drilling, completion and tie-in of wells and the production resulting there from, expected royalty rates, impact of proposed new royalty rates, transportation costs, operating costs and general and administrative costs, may constitute forward-looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploration, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, the timing and length of plant turnarounds and the impact of such turnarounds and the timing thereof, delays resulting from or inability to obtain required regulatory approvals and the ability to access sufficient capital from internal and external sources. As a consequence, the Company's actual results could differ materially from those expressed in, or implied by, the forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), or at the Company's website (www.crewenergy.com). Furthermore, the forward-looking statements contained in this MD&A are made as of the date of this MD&A and the Company does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Conversions

Our industry commonly expresses production volumes and reserves on a "barrel of oil equivalent" basis ("boe") whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved analysis of results and comparisons with other industry participants.

Throughout this MD&A Crew has used the 6:1 boe measure which is the approximate energy equivalency of the two commodities at the burner tip. Boe does not represent a value equivalency at the plant gate which is where Crew sells its production volumes and therefore may be a misleading measure if used in isolation.

Non-GAAP Measures

Crew evaluates performance based on net income and funds from operations. Funds from operations is a measure not based on GAAP that is commonly used in the oil and gas industry. It represents cash provided by operating activities before changes in non-cash working capital, asset retirement expenditures and the excess transportation liability charge. The Company considers it a key measure as it demonstrates the ability of the business to generate the cash flow necessary to fund future growth through capital investment and to repay debt. Funds from operations should not be considered as an alternative to, or more meaningful than cash flow provided by operating activities as determined in accordance with GAAP as an indicator of the Company's performance. Crew's determination of funds from operations may not be comparable to that reported by other companies. Crew also presents funds from operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of income per share.

	Three months ended Sept 30, 2007	Three months ended Sept 30, 2006	Nine months ended Sept 30, 2007	Nine months ended Sept 30, 2006
(\$ thousands)				
Cash provided by operating activities	23,035	11,984	62,518	40,933
Asset retirement expenditures	18	13	32	245
Excess transportation liability charge	283	–	471	–
Change in non-cash working capital	(2,165)	2,248	(3,978)	(1,225)
Funds from operations	21,171	14,245	59,043	39,953

In addition, management uses netback, a non-GAAP term, to analyze operating performance and leverage. Netback equals total petroleum and natural gas sales including realized gains and losses on financial instruments less royalties, operating costs and transportation calculated on a boe basis.

RESULTS OF OPERATIONS

Production

	Three months ended Sept 30, 2007			Three months ended Sept 30, 2006		
	Oil and ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)	Oil and ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
Plains Core	958	31,053	6,134	827	26,011	5,162
North Core	340	16,767	3,134	156	2,699	606
Total	1,298	47,820	9,268	983	28,710	5,768

Third quarter 2007 production increased over the third quarter of 2006 as a result of a successful drilling program that added new natural gas production at Ferrier, Alberta, new light oil production at Edson and Ferrier, Alberta and the closing of two private company acquisitions. The first acquisition closed in November 2006 adding production in the Company's Ferrier area and the second acquisition closed in May 2007 adding mainly natural gas production in the Company's northeastern British Columbia operating area. Production increases in the third quarter were partially offset by several unplanned facility outages at Sierra in northeast British Columbia and in the Company's Plains Core area.

	Nine months ended Sept 30, 2007			Nine months ended Sept 30, 2006		
	Oil and ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)	Oil and ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
Plains Core	1,120	31,322	6,340	635	24,482	4,715
North Core	283	10,520	2,037	179	3,727	801
Total	1,403	41,842	8,377	814	28,209	5,516

Production for the first nine months of 2007 increased as a result of the previously mentioned new wells in Ferrier and Edson as well as the two corporate acquisitions.

Revenue

	Three months ended Sept 30, 2007	Three months ended Sept 30, 2006	Nine months ended Sept 30, 2007	Nine months ended Sept 30, 2006
<i>(\$ thousands)</i>				
Revenue				
Light oil and ngl	8,362	6,388	22,971	14,674
Natural gas	25,028	15,879	78,553	51,549
Realized gain on financial instruments	647	–	579	–
Total	34,037	22,267	102,103	66,223
Crew average prices				
Light oil and ngl (\$/bbl)	70.02	70.64	59.97	65.99
Natural gas (\$/mcf)	5.69	6.01	6.88	6.69
Realized gain on financial instruments (\$/mcf)	0.15	–	0.05	–
Total natural gas (\$/mcf)	5.84	6.01	6.93	6.69
Oil equivalent (\$/boe)	39.92	41.96	44.65	43.98
Benchmark pricing				
Oil and ngl – Light Sweet @ Edmonton (Cdn \$/bbl)	79.79	79.15	72.65	75.57
Natural Gas – AECO C daily index (Cdn \$/mcf)	5.31	5.91	6.82	6.71

Crew's third quarter revenue increased 53% over the same period in 2006 as a result of a 67% increase in the Company's natural gas production partially offset by a 5% reduction in the price received for the sale of natural gas. The Company also increased liquids production by 32% which was offset by a 1% drop in liquids prices. Revenue was further enhanced by a \$0.7 million net gain on the Company's commodity price risk management program.

The Company's natural gas price for the third quarter decreased 5% over 2006 as compared to a 10% decrease in the benchmark price. This was a result of Crew's increased natural gas production with higher heat content in the Edson and Ferrier areas. The sales price for the Company's light oil and ngl production has decreased as compared to an increase in the Company's benchmark. The decrease was a result of the addition of lower value ethane production acquired with the private company acquisition in November 2006.

Revenue for the nine months ended September 30, 2007 has increased 54% as compared to the similar period in 2006. This increase resulted from a 48% increase in natural gas production and a 72% increase in liquids production. Revenue also benefited from a 3% increase in natural gas prices offset by a corresponding 9% reduction in liquids prices. Revenue for the nine months was also enhanced by a \$0.6 million recognized net gain on the Company's commodity price risk management program.

During the first nine months of 2007, Crew's natural gas price increased at a higher rate than the Company's benchmark prices due to the added higher heat content production from Edson and Ferrier. Liquids pricing during the nine months declined at a higher rate than the benchmark as a result of the added lower valued ethane production as described above.

Financial Instruments

On occasion, the Company will enter into commodity price risk management contracts in order to reduce volatility in financial results, to protect acquisition economics and to ensure a certain level of cash flow to fund planned capital projects. Crew's strategy will focus on the use of natural gas price "puts" and costless collars to limit exposure to downturns in commodity prices, while allowing for participation in commodity price increases.

As at September 30, 2007, the Company had entered into direct sales agreements to sell natural gas as follows:

	Volume (gj/day)	Term	Price (Cdn \$/gj)	Floor (Cdn \$/gj)	Fair Value (thousands)
AECO Floor	9,000	July 1 – December 31, 2007	AECO C	\$ 6.80	\$ 853
AECO/Station 2 Differential Swap	15,000	July 1 – October 31, 2007 November 1, 2007– October 31, 2008	AECO 5A less \$ 0.24	–	–
AECO/Station 2 Differential Swap	10,000		AECO 5A less \$ 0.16	–	\$ (436)
Total Fair Value					\$ 417

The net effect of these contracts was a realized gain of \$0.7 million and an unrealized loss of \$0.5 million during the three months ended September 30, 2007 and a realized gain of \$0.6 million and an unrealized gain of \$0.4 million for the nine months ended September 30, 2007.

Royalties

	Three months ended Sept 30, 2007	Three months ended Sept 30, 2006	Nine months ended Sept 30, 2007	Nine months ended Sept 30, 2006
<i>(\$ thousands, except per BOE)</i>				
Royalties	2,009	3,925	16,820	14,480
Per BOE	2.36	7.40	7.36	9.62
Percentage of revenue	6.0%	17.6%	16.6%	21.9%

Royalties for the three and nine months ended September 30, 2007 have been reduced by royalty holidays received for natural gas wells drilled in Alberta and 2006 Alberta gas cost allowance recoveries that were greater than estimated. The Company benefited from the receipt of \$2.3 million of deep well royalty credits primarily related to wells drilled at Hanlan and Ferrier. The Company also received \$1.7 million of additional Alberta gas cost allowance credits related to capital spent on facilities built in Alberta during 2006. The increase in the Company's gas cost allowance pools has also translated into lower Alberta Crown royalties for the remainder of 2007. The Company expects fourth quarter 2007 royalties to average 20%.

Operating Costs

	Three months ended Sept 30, 2007	Three months ended Sept 30, 2006	Nine months ended Sept 30, 2007	Nine months ended Sept 30, 2006
<i>(\$ thousands, except per BOE)</i>				
Operating costs	5,361	2,768	14,129	7,828
Per BOE	6.29	5.22	6.18	5.22

The Company's operating costs per unit increased during the third quarter and the first nine months of 2007 compared to the same periods of 2006 as a result of continued inflationary pressures and the addition of higher cost production from the private company acquisition completed in November 2006. In addition, increased emulsion handling costs associated with the new oil production from Edson and Ferrier negatively impacted operating costs. The Company has also experienced an increase in third party processing fees in the Viking and Plain Lake area. The Company's third quarter 2007 operating costs per unit were slightly above the projected range of \$6.00 to \$6.25 due to reduced production volume resulting from unplanned facility outages during the quarter. The Company is estimating its operating costs to remain at this level through the remainder of 2007.

Transportation

	Three months ended Sept 30, 2007	Three months ended Sept 30, 2006	Nine months ended Sept 30, 2007	Nine months ended Sept 30, 2006
<i>(\$ thousands, except per BOE)</i>				
Transportation costs	2,413	523	4,824	1,498
Per BOE	2.83	0.99	2.11	0.99

The Company's third quarter and year-to-date 2007 increase in transportation costs is the result of the Company's May, 2007 acquisition of a private company with natural gas production mainly in northeast British Columbia which has a higher transportation cost. In northeast British Columbia, natural gas is produced into a third party owned gathering and processing infrastructure that enables producers to avoid facility construction. The all-in regulated fees charged for gathering, processing and transmission of the Company's natural gas through this system is included in transportation expense. Third quarter transportation per boe was higher than expected as Crew incurred firm service transportation charges for northeastern British Columbia gas despite the production disruption at Sierra. Transportation costs are expected to remain between \$2.50 and \$2.75 per boe for the remainder of the year.

Operating Netbacks

	Three months ended Sept 30, 2007			Three months ended Sept 30, 2006		
	Oil and ngl (\$/bbl)	Natural gas (\$/mcf)	Total (\$/boe)	Oil and ngl (\$/bbl)	Natural gas (\$/mcf)	Total (\$/boe)
Revenue	70.02	5.84	39.92	70.64	6.01	41.96
Royalties	(11.77)	(0.13)	(2.36)	(13.65)	(1.06)	(7.40)
Operating costs	(6.73)	(1.04)	(6.29)	(4.32)	(0.90)	(5.22)
Transportation costs	(1.59)	(0.51)	(2.83)	(1.35)	(0.15)	(0.99)
Operating netbacks	49.93	4.16	28.44	51.32	3.90	28.35

	Nine months ended Sept 30, 2007			Nine months ended Sept 30, 2006		
	Oil and ngl (\$/bbl)	Natural gas (\$/mcf)	Total (\$/boe)	Oil and ngl (\$/bbl)	Natural gas (\$/mcf)	Total (\$/boe)
Revenue	59.97	6.93	44.65	65.99	6.69	43.98
Royalties	(12.12)	(1.07)	(7.36)	(14.45)	(1.52)	(9.62)
Operating costs	(6.19)	(1.03)	(6.18)	(5.03)	(0.88)	(5.22)
Transportation costs	(1.19)	(0.38)	(2.11)	(1.41)	(0.15)	(0.99)
Operating netbacks	40.47	4.45	29.00	45.10	4.14	28.15

General and Administrative

	Three months ended Sept 30, 2007	Three months ended Sept 30, 2006	Nine months ended Sept 30, 2007	Nine months ended Sept 30, 2006
<i>(\$ thousands, except per BOE)</i>				
Gross costs	2,143	1,302	5,973	3,998
Operator's recoveries	(519)	(556)	(1,251)	(1,457)
Capitalized costs	(812)	(373)	(2,361)	(1,271)
General and administrative expenses	812	373	2,361	1,270
Per BOE	0.95	0.70	1.03	0.84

Increased general and administrative costs before recoveries and capitalization were the result of increased staff levels and inflationary pressures on salaries in the first nine months of 2007 compared to 2006. The Company continues to forecast annual general and administrative costs per unit at between \$0.80 and \$1.00 per boe. Unit costs are expected to be lower for the remainder of 2007 as compared to the first nine months due to increased production, increased overhead recoveries and lower net costs as most of the Company's annual regulatory and filing costs were incurred in the first half of the year.

Interest

Interest expense totaled \$2.3 million for the third quarter of 2007 compared with \$0.4 million for the third quarter of 2006 and interest costs were \$4.9 million during the nine months ended 2007 compared to \$1.2 million in the same period of 2006. In 2007, higher interest rates combined with higher average debt levels used to finance Crew's corporate acquisitions and exploration and development program have increased the Company's interest expense over 2006. Interest expense will be reduced in the fourth quarter of 2007 as a result of the pay-down of the Company's bank debt with the \$51.5 million of net proceeds received from an equity issue completed on October 25, 2007.

Stock-Based Compensation

	Three months ended Sept 30, 2007	Three months ended Sept 30, 2006	Nine months ended Sept 30, 2007	Nine months ended Sept 30, 2006
<i>(\$ thousands)</i>				
Gross costs	1,544	1,195	3,808	3,414
Capitalized costs	(772)	(598)	(1,904)	(1,707)
Total stock-based compensation	772	597	1,904	1,707

The Company's stock-based compensation expense has increased in 2007 as a result of the increase in stock options issued as a result of increased staff levels over the same period in 2006.

Depletion, Depreciation and Accretion

	Three months ended Sept 30, 2007	Three months ended Sept 30, 2006	Nine months ended Sept 30, 2007	Nine months ended Sept 30, 2006
<i>(\$ thousands, except per BOE)</i>				
Depletion, depreciation and accretion	20,565	10,536	54,938	27,618
Per BOE	24.12	19.85	24.02	18.34

Per unit depletion has increased in 2007 due to an increase in the average cost of adding proved reserves in 2006 and 2007. This increase has resulted from inflationary pressures experienced throughout the industry, the addition of higher priced proven reserves acquired through the acquisition of the private companies in November, 2006 and May, 2007 and the 2006 acquisition and construction of facilities in order to maintain lower operating costs and to ensure processing capacity for the Company's natural gas production.

Funds from Operations and Net Income

	Three months ended Sept 30, 2007	Three months ended Sept 30, 2006	Nine months ended Sept 30, 2007	Nine months ended Sept 30, 2006
<i>(\$ thousands)</i>				
Funds from operations	21,171	14,245	59,043	39,953
Per share - basic	0.45	0.41	1.32	1.19
- diluted	0.44	0.40	1.31	1.16
Net income (loss)	(449)	1,633	2,221	8,980
Per share - basic	(0.01)	0.05	0.05	0.27
- diluted	(0.01)	0.05	0.05	0.26

The Company's increase in funds from operations for the third quarter and the first nine months of 2007 was the result of the increased production levels and the decrease in royalties from royalty holidays and gas cost allowance credits. Net income has been negatively impacted by higher costs experienced throughout the industry over the past year. In addition, 2006 net income was positively impacted by a \$2.6 million future tax adjustment from a reduction in tax rates in 2006.

Capital Expenditures and Acquisitions

During the third quarter, the Company drilled nine (7.4 net) wells resulting in nine (7.4 net) successful natural gas wells. In addition, the Company also completed nine (8.1 net) wells, recompleted seven (6.5 net) wells and spent \$3.4 million on Crown land sales adding to its inventory of undeveloped land in central Alberta. On May 3, 2007, the Company closed the acquisition of a private company with the majority of its operations in the Company's north core in northeastern British Columbia.

Total exploration and development expenditures for the third quarter of 2007 were \$25.3 million compared to \$38.9 million for the same period in 2006. The expenditures are detailed below:

<i>(\$ thousands)</i>	Three months ended Sept 30, 2007	Three months ended Sept 30, 2006	Nine months ended Sept 30, 2007	Nine months ended Sept 30, 2006
Land	3,407	2,319	7,676	6,777
Seismic	1,090	451	2,742	3,520
Drilling and completions	15,647	29,177	43,435	60,074
Facilities, equipment and pipelines	3,750	6,495	13,962	21,591
Other	1,491	472	3,244	1,567
Total exploration and development	25,385	38,914	71,059	93,529
Property acquisitions (dispositions)	(51)	–	(49)	15,929
Business acquisition	–	–	137,456	–
Total	25,334	38,914	208,466	109,458

The Company has budgeted exploration and development expenditures for 2007 of \$100 million and combined with the Company's May corporate acquisition, total capital expenditures are expected to be approximately \$237 million.

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

On October 25, 2007, the Company completed a bought deal share financing with a syndicate of underwriters resulting in an issuance of 4,181,860 common shares at \$8.25 per common share and 1,860,500 common shares on a flow through basis at \$10.75 per flow through share for aggregate proceeds of \$54.5 million.

On May 3, 2007, Crew acquired all of the issued and outstanding shares of a private oil and gas company with producing oil and natural gas properties in northeastern British Columbia and central Alberta. Crew's total consideration for the acquisition was approximately \$137 million before closing adjustments and costs.

In conjunction with the acquisition Crew issued, on a bought deal basis, 5,750,000 Common Shares at \$10.30 per share for aggregate gross proceeds of \$59.2 million. The common shares were issued concurrently with the closing of the acquisition and the net proceeds of approximately \$56 million were used to partially fund the acquisition price.

The remainder of the acquisition price was provided by a newly arranged credit facility with a syndicate of banks. The new facility consists of a revolving line of credit of \$165 million (the "Syndicated Facility") and an operating line of credit of \$15 million (the "Operating Facility"). The facility will revolve for a 364 day period and will be subject to annual review. If not extended, the Syndicated Facility will cease to revolve and all outstanding advances under the facility will become repayable in one year.

The Company's exploration and development expenditures were funded through a combination of bank debt and cash flow from ongoing operations. Crew will continue to fund its on-going operations from a combination of cash flow, debt, and equity financings as needed. As the majority of our on-going capital expenditure program is directed to the further growth of reserves and production volumes, Crew is readily able to adjust its budgeted capital expenditures should the need arise.

Working Capital

The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficit. However, the Company maintains sufficient unused bank credit lines to satisfy such working capital deficiencies. At September 30, 2007, the Company's indebtedness, consisting of \$11.7 million of working capital deficiency and drawings on its bank line, represented 84% of its available bank facility at that time. On October 25, 2007, the Company completed an equity offering for net proceeds of \$51.5 million. Pro-forma this financing, the Company's September 30, 2007 indebtedness represents 54% of the Company's available bank line.

Share Capital

As at November 8, 2007, Crew had 53,577,319 Common Shares and 3,309,800 options to acquire Common Shares of the Company issued and outstanding.

Commitments

The Company has the following fixed term commitments related to its on-going business:

<i>(\$ thousands)</i>	Total	2007	2008	2009	2010	2011
Operating leases	3,960	248	990	990	990	742
Capital commitments	2,500	700	1,800	–	–	–
Exploration and development	20,000	–	20,000	–	–	–
Firm transportation agreements	29,138	1,602	6,689	7,026	7,243	6,578
Total	55,598	2,550	29,479	8,016	8,233	7,320

The exploration and development commitment relates to the Company's obligation under its October 25, 2007 flow-through share issue.

The firm transportation commitments were acquired as part of the Company's May 2007 private company acquisition and represent firm service commitments for transportation and processing of natural gas in British Columbia.

GUIDANCE

Crew's production in the third quarter of 2007 was negatively impacted by significant downtime at Company owned and third party facilities. This down time has continued to impact the Company in the fourth quarter with production expected to average 9,650 boe per day for the quarter. Despite these mechanical issues, Crew remains on track to tie-in over 2,000 boe per day of tested production and achieve its projected exit rate of in excess of 11,500 boe per day.

ADDITIONAL DISCLOSURES

Quarterly Analysis

The following table summarizes Crew's key quarterly financial results for the past eight financial quarters:

<i>(\$ thousands, except per share amounts)</i>	Sept. 30 2007	June 30 2007	Mar. 31 2007	Dec. 31 2006	Sept. 30 2006	June 30 2006	Mar. 31 2006	Dec. 31 2005
Petroleum and natural gas sales	33,390	38,703	29,431	26,590	22,267	19,164	24,792	30,520
Funds from operations	21,171	20,885	16,987	16,705	14,245	10,645	15,063	21,084
Per share – basic	0.45	0.46	0.41	0.43	0.41	0.32	0.45	0.69
– diluted	0.44	0.46	0.41	0.43	0.40	0.31	0.44	0.65
Net income (loss)	(449)	1,351	1,319	1,796	1,633	3,753	3,594	8,746
Per share – basic	(0.01)	0.03	0.03	0.05	0.05	0.11	0.11	0.28
– diluted	(0.01)	0.03	0.03	0.05	0.05	0.11	0.11	0.27
Total daily production (boe/d)	9,268	8,967	6,869	6,227	5,768	5,049	5,731	4,730
Average wellhead price (\$/boe)	39.92	47.34	47.61	46.41	41.96	41.71	48.07	70.14

Crew's petroleum and natural gas sales, funds from operations and net income are all impacted by production levels and volatile commodity pricing. Through 2006 and into 2007, despite increased production, these performance measures have fluctuated as a result of volatile natural gas prices combined with the escalating cost of operations.

Significant factors and trends that have impacted the Company's results during the above periods include:

- Revenue is directly impacted by the Company's ability to replace existing declining production and add incremental production through its on-going capital expenditure program.
- Production is impacted in the second quarter of every year by the limited ability to transport oil and ngl production to market during spring break-up. The Company's Laprise production is shut-in for eight to ten weeks during this period.
- Production in the third quarter of 2007 was reduced by significant facility outages at Sierra in northeastern British Columbia and Edson and Ferrier, Alberta.
- Revenue and royalties are significantly impacted by underlying commodity prices. To date the Company has used a limited amount of derivative contracts or forward sales contracts to reduce the exposure to commodity price fluctuations.
- During the quarter ended September 30, 2007 the Company's funds from operations and net income were positively impacted by the one time receipt of Alberta deep well royalty holiday credits and 2006 Alberta gas cost allowance adjustments totaling \$4.0 million.
- During 2006 and 2007, the Company's operating costs and capital expenditures have been subject to inflationary pressures brought on by increasing demand for services and supplies within the Canadian oil and gas industry.
- In November, 2006, the Company acquired a private oil and gas company with approximately 1,000 boe per day of production at closing.
- In May, 2007, the Company acquired a private oil and gas company with approximately 3,100 boe per day of production at closing, consisting mainly of natural gas in the northeastern British Columbia area.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

Crew's Chief Executive Officer and Chief Financial Officer are required to cause the Company to disclose herein any change in Crew's disclosure controls and procedures and internal controls over financial reporting that occurred during the Company's most recent interim period that has materially affected, or is reasonably likely to materially affect the Company's internal controls over financial reporting. No material changes in Crew's disclosure controls and procedures and internal controls over financial reporting were identified during the nine months ended September 30, 2007, that have materially affected, or are reasonably likely to materially affect the Company's internal controls over financial reporting.

New Accounting Pronouncements

On January 1, 2007, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3855, "Financial Instruments – Recognition and Measurement", Handbook Section 3865, "Hedges", and Handbook Section 1530, "Comprehensive Income".

The adoption of these standards has no material impact on the Company's net earnings or cash flows. The effect of the implementation on other statements is discussed below:

(a) Financial instruments

The financial instruments standard establishes recognition and measurement criteria for financial assets, financial liabilities and derivatives. All financial instruments are required to be measured at fair value on initial recognition of the instrument except in specific circumstances. Measurement in subsequent periods depends on whether the financial instrument has been classified as "held for trading", "available for sale", "held to maturity", "loans and receivables" or "other financial liabilities" as defined by the standard.

Financial assets and financial liabilities "held for trading" are measured at fair value with changes in those fair values recognized in net earnings. Financial assets "available for sale" are measured at fair value, with changes in those fair values recognized in other comprehensive income. Financial assets "held to maturity", "loans and receivables" and "other financial liabilities" are measured at amortized cost using the effective interest method of amortization.

Cash and deposits, included in current assets, are designated as "held for trading" and are measured at carrying value, which approximates fair value due to the short-term nature of these instruments. Accounts receivable are designated as "loans and receivables" and accounts payable and long-term debt are designated as "other financial liabilities".

At January 1, 2007, the Company held no financial instruments that required valuation adjustments.

(b) Derivative Instruments and Hedges

The Company may use derivative instruments to manage its exposure to the volatility in commodity prices. These derivatives will be recorded on the balance sheet at fair value. Gains and losses on these instruments will be charged to income in the period that they occur.

(c) Comprehensive income

The new standard introduced the statements of comprehensive income and accumulated other comprehensive income to temporarily provide for gains, losses and other amounts arising from changes in fair value until they are realized and recorded in net earnings. The Company has determined that it had no comprehensive income nor accumulated other comprehensive income for the period ended September 30, 2007.

Additional disclosure requirements have been approved by the CICA for Handbook Section 3862, "Financial Instruments – Disclosures", Handbook Section 3863, "Financial Instruments – Presentation" and Handbook Section 1535, "Capital Disclosures" that will be required disclosure for the Company beginning on January 1, 2008. The Company's management is currently assessing the impact that these requirements will have on Crew's disclosure.

New Royalty Framework

On October 25, 2007, the Government of Alberta released its proposed New Royalty Framework ("NRF") for Alberta. The NRF was the government's response to a report issued September 18, 2007 by the Alberta Royalty Review Panel. The panel was commissioned by the Government of Alberta to perform a review of the province's royalty system to determine if the people of Alberta were receiving their "fair share" of the resources being extracted by the oil and gas industry.

Crew has reviewed the modifications proposed in the NRF that, if implemented as proposed, will take effect on January 1, 2009. Crew is continuing to assess the potential impact of the NRF on its Alberta operations and while more detailed analysis is ongoing, we wish to make the following preliminary observations:

- We have conducted a review of the Company's assets using the details of the NRF currently available and have determined the potential impact of the changes on the net present value of Crew's reserves to be immaterial based on current natural gas prices;
- The overall impact of the NRF on Crew is mitigated by the fact that 35% of Crew's production is from properties located in British Columbia which is not affected by the NRF;
- The NRF is a framework of proposed changes to Alberta's existing laws which encompass the existing Alberta oil and gas royalty regime. Before these proposed changes are definitive, the Government must draft a series of changes to Alberta legislation which will then have to pass through the legislative process. At this time it is not certain that the process will be completed prior to the proposed implementation date of January 1, 2009 or that the changes will be as they have been proposed;
- The actual effect of the proposed Alberta royalty rate changes on Crew will be determined based on, among other things, the actual legislation enacted, Alberta production rates, commodity prices, foreign exchange rates, Alberta product mix, service costs and the percentage of production from Alberta after January 1, 2009.

Dated as of November 8, 2007

CONSOLIDATED BALANCE SHEETS

(unaudited)

(\$ thousands)	September 30, 2007	December 31, 2006
ASSETS		
Current assets:		
Accounts receivable	\$ 24,593	\$ 22,063
Income taxes receivable (note 3)	6,701	–
Fair value of financial instruments (note 9)	417	–
	31,711	22,063
Property, plant and equipment (note 4)	541,122	338,660
Goodwill	20,252	14,558
	\$ 593,085	\$ 375,281
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	\$ 43,031	\$ 39,777
Current portion of other long-term obligations (note 6)	1,298	–
	44,329	39,777
Bank loan (note 5)	139,737	41,157
Other long-term obligations (note 6)	3,087	–
Asset retirement obligations (note 7)	18,414	10,485
Future income taxes	84,672	39,552
SHAREHOLDERS' EQUITY		
Share capital (note 8)	245,610	192,814
Contributed surplus (note 8)	9,085	5,566
Retained earnings	48,151	45,930
	302,846	244,310
Commitments (note 11)		
Subsequent event (note 12)		
	\$ 593,085	\$ 375,281

See accompanying notes to the consolidated financial statements.

**CONSOLIDATED STATEMENTS OF OPERATIONS, COMPREHENSIVE
INCOME (LOSS) AND RETAINED EARNINGS**

(unaudited)

<i>(\$ thousands, except per share amounts)</i>	Three months ended Sept 30, 2007	Three months ended Sept 30, 2006	Nine months ended Sept 30, 2007	Nine months ended Sept 30, 2006
Revenue				
Petroleum and natural gas sales	\$ 33,390	\$ 22,267	\$ 101,524	\$ 66,223
Royalties	(2,009)	(3,925)	(16,820)	(14,480)
	31,381	18,342	84,704	51,743
Realized gain on financial instruments (note 9)	647	-	579	-
Unrealized gain (loss) on financial instruments (note 9)	(542)	-	417	-
	31,486	18,342	85,700	51,743
Expenses				
Operating	5,361	2,768	14,129	7,828
Transportation	2,413	523	4,824	1,498
Interest	2,271	433	4,926	1,194
General & administrative	812	373	2,361	1,270
Stock-based compensation	772	597	1,904	1,707
Depletion, depreciation & accretion	20,565	10,536	54,938	27,618
	32,194	15,230	83,082	41,115
Income (loss) before income taxes	(708)	3,112	2,618	10,628
Income taxes				
Current	-	-	-	-
Future	(259)	1,479	397	1,648
	(259)	1,479	397	1,648
Net income (loss) and comprehensive income (loss)	(449)	1,633	2,221	8,980
Retained earnings, beginning of period	48,600	42,501	45,930	35,154
Retained earnings, end of period	\$ 48,151	\$ 44,134	\$ 48,151	\$ 44,134
Net income (loss) per share (note 8(d))				
Basic	\$ (0.01)	\$ 0.05	\$ 0.05	\$ 0.27
Diluted	\$ (0.01)	\$ 0.05	\$ 0.05	\$ 0.26

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)

<i>(\$ thousands)</i>	Three months ended Sept 30, 2007	Three months ended Sept 30, 2006	Nine months ended Sept 30, 2007	Nine months ended Sept 30, 2006
Cash provided by (used in):				
Operating activities:				
Net income (loss)	\$ (449)	\$ 1,633	\$ 2,221	\$ 8,980
Items not involving cash:				
Depletion, depreciation & accretion	20,565	10,536	54,938	27,618
Stock-based compensation	772	597	1,904	1,707
Future income taxes	(259)	1,479	397	1,648
Unrealized gain (loss) on financial instruments	542	-	(417)	-
Excess transportation liability charge (note 6)	(283)	-	(471)	-
Asset retirement expenditures	(18)	(13)	(32)	(245)
Change in non-cash working capital	2,165	(2,248)	3,978	1,225
	23,035	11,984	62,518	40,933
Financing activities:				
Increase (decrease) in bank loan	(1,074)	(20,328)	98,580	22,810
Issue of common shares	(53)	37,953	55,947	38,309
	(1,127)	17,625	154,527	61,119
Investing activities:				
Exploration and development	(25,385)	(38,914)	(71,059)	(93,529)
Property acquisitions, net of dispositions	51	-	49	(15,929)
Business acquisition (note 3)	-	-	(137,325)	-
Change in non-cash working capital	3,426	9,305	(8,710)	(8,896)
	(21,908)	(29,609)	(217,045)	(118,354)
Change in cash and cash equivalents	-	-	-	(16,302)
Cash and cash equivalents, beginning of period	-	-	-	16,302
Cash and cash equivalents, end of period	\$ -	\$ -	\$ -	\$ -

See accompanying notes to the consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the three and nine months ended September 30, 2007 and 2006

(Unaudited, Tabular amounts in thousands)

1. SIGNIFICANT ACCOUNTING POLICIES:

The interim consolidated financial statements of Crew Energy Inc. have been prepared by management in accordance with accounting principles generally accepted in Canada. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the year ended December 31, 2006, except as disclosed below. The disclosure which follows is incremental to the disclosure included with the December 31, 2006 consolidated financial statements. These interim consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto for the year ended December 31, 2006.

Certain comparative amounts have been reclassified to conform to current period presentation.

2. CHANGE IN ACCOUNTING POLICY:

On January 1, 2007, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3855, "Financial Instruments – Recognition and Measurement", Handbook Section 3865, "Hedges", and Handbook Section 1530, "Comprehensive Income".

The adoption of these standards had no material impact on the Company's net earnings or cash flows. The effect of the implementation on other statements is discussed below:

(a) Financial instruments

The financial instruments standard establishes recognition and measurement criteria for financial assets, financial liabilities and derivatives. All financial instruments are required to be measured at fair value on initial recognition of the instrument except in specific circumstances. Measurement in subsequent periods depends on whether the financial instrument has been classified as "held for trading", "available for sale", "held to maturity", "loans and receivables" or "other financial liabilities" as defined by the standard.

Financial assets and financial liabilities "held for trading" are measured at fair value with changes in those fair values recognized in net earnings. Financial assets "available for sale" are measured at fair value, with changes in those fair values recognized in other comprehensive income. Financial assets "held to maturity", "loans and receivables" and "other financial liabilities" are measured at amortized cost using the effective interest method of amortization.

Cash and deposits, included in current assets, are designated as "held for trading" and are measured at carrying value, which approximates fair value due to the short-term nature of these instruments. Accounts receivable are designated as "loans and receivables" and accounts payable and long-term debt are designated as "other financial liabilities".

At January 1, 2007, the Company held no financial instruments that required valuation adjustments.

(b) Derivative Instruments and Hedges

The Company uses derivative instruments to manage its exposure to the volatility in commodity prices. These derivatives are recorded on the balance sheet at fair value. Gains and losses on these instruments will be charged to income in the period that they occur.

(c) Comprehensive income

The new standard introduced the statements of comprehensive income and accumulated other comprehensive income to temporarily provide for gains, losses and other amounts arising from changes in fair value until they are realized and recorded in net earnings. The Company has determined that it had no items that would affect comprehensive income nor accumulated other comprehensive income for the period ended September 30, 2007.

Additional disclosure requirements have been approved by the CICA for Handbook Section 3862, "Financial Instruments – Disclosures", Handbook Section 3863, "Financial Instruments – Presentation" and Handbook Section 1535, "Capital Disclosures" that will be required disclosure for the Company beginning on January 1, 2008. The Company's management is currently assessing the impact that these requirements will have on Crew's disclosure.

3. BUSINESS ACQUISITION:

On May 3, 2007 Crew acquired all of the issued and outstanding shares of a private oil and gas company with producing oil and natural gas properties in northeastern British Columbia and central Alberta (the "Acquisition"). Total consideration paid for the Acquisition was approximately \$137 million before transaction costs which was financed through a concurrently announced equity financing and a newly arranged credit facility. The operating results of the acquired company were included in the accounts of Crew from May 3, 2007.

The acquisition has been accounted for using the purchase method of accounting as follows:

	Amount
Consideration	
Cash	\$ 136,956
Transaction costs	500
	\$ 137,456
Net assets received at fair value	
Cash	131
Accounts receivable	4,944
Income tax receivable	7,614
Property and equipment	182,397
Goodwill	5,694
Accounts payable	(11,313)
Excess transportation obligation (note 6)	(4,856)
Asset retirement obligations	(6,646)
Future income taxes	(40,509)
	\$ 137,456

The above amounts are estimates made by management based on currently available information. Amendments may be made to the purchase equation as the cost estimates and balances are finalized.

The income tax receivable relates to non-capital loss carrybacks from the acquired company's May 3, 2007 and December 31, 2006 tax returns. These amounts have been pledged to the vendor upon receipt by the Company. As at September 30, 2007, the Company has received and subsequently paid to the vendor \$0.9 million relating to the December 31, 2006 tax return. The income tax receivable is offset by a corresponding amount included in accounts payable.

4. **PROPERTY, PLANT AND EQUIPMENT:**

September 30, 2007	Cost	Accumulated depletion & depreciation	Net book value
Petroleum and natural gas properties and equipment	\$ 666,168	\$ 125,046	\$ 541,122

December 31, 2006	Cost	Accumulated depletion & depreciation	Net book value
Petroleum and natural gas properties and equipment	\$ 409,608	\$ 70,948	\$ 338,660

The cost of unproved properties at September 30, 2007 of \$35,603,000 (2006 - \$24,205,000) was excluded from the depletion calculation. Estimated future development costs associated with the development of the Company's proved reserves of \$31,295,000 (2006 - \$15,366,000) have been included in the depletion calculation and estimated salvage values of \$20,953,000 (2006 - \$15,560,000) have been excluded from the depletion calculation.

The following corporate expenses related to exploration and development activities were capitalized:

	Nine months ended September 30, 2007	Year ended December 31, 2006
General and administrative expense	\$ 2,361	\$ 1,688
Stock-based compensation expense, including future income taxes	2,678	3,176
	\$ 5,039	\$ 4,864

5. **BANK LOAN:**

The Company's bank facility consists of a revolving line of credit of \$165 million and an operating line of credit of \$15 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by April 28, 2008. If not extended, the Facility will cease to revolve, the margins there under will increase by 0.25 per cent and all outstanding advances there under will become repayable in one year.

Advances under the Facility are available by way of prime rate loans, bankers acceptances and LIBOR loans which have interest of up to 0.75 per cent over the bank's prime lending rate and bankers' acceptances and LIBOR loans are subject to stamping fees and margins ranging from 0.95 per cent to 1.75 per cent depending upon the debt to EBITDA ratio of the Company calculated at the Company's previous quarter end. As at September 30, 2007, the Company's applicable pricing included a 0.20 percent margin on prime lending and a 1.2 percent stamping fee and margin on Bankers' Acceptances and LIBOR loans. The facility is secured by a first floating charge debenture over the Company's consolidated assets.

6. **OTHER LONG-TERM OBLIGATIONS:**

As part of the May 3, 2007 private company acquisition, the Company acquired several firm transportation agreements. These agreements had a fair value at the time of the acquisition of a \$4.9 million liability. This amount was accounted for as part of the acquisition cost and will be charged as a reduction to transportation expenses over the life of the contracts as they are incurred. This charge for the three and nine months ended September 30, 2007 was \$0.3 million and \$0.5 million, respectively.

7. ASSET RETIREMENT OBLIGATIONS:

Crew has estimated the net present value of its total asset retirement obligation as at September 30, 2007 to be \$18,414,000 (December 31, 2006 - \$10,485,000) based on a total future liability of \$34,824,000 (December 31, 2006 - \$23,503,000). These payments are expected to be made over the next 49 years. An 8% (2006 - 8%) credit adjusted risk free discount rate and 2% (2006 - 2%) inflation rate were used to calculate the present value of the asset retirement obligation.

The following table reconciles Crew's asset retirement obligations:

	Nine months ended September 30, 2007	Year ended December 31, 2006
Carrying amount, beginning of period	\$ 10,485	\$ 7,182
Liabilities incurred	475	1,690
Liabilities acquired	6,646	679
Accretion expense	840	655
Change in estimate	-	727
Liabilities settled	(32)	(448)
Carrying amount, end of period	\$ 18,414	\$ 10,485

8. SHARE CAPITAL:**(a) Common Shares:**

	Number of shares	Amount
Common shares, December 31, 2006	41,440	\$ 192,810
Public offering issued for cash	5,750	59,225
Exercise of Class C performance shares	315	4
Exercise of stock options	6	49
Stock-based compensation	-	289
Flow through share tax adjustment	-	(4,401)
Share issue costs, net of income taxes of \$961	-	(2,366)
Common shares, September 30, 2007	47,511	\$ 245,610

In conjunction with the private company acquisition (note 3), Crew issued 5,750,000 Common Shares at \$10.30 per share for aggregate gross proceeds of \$59.2 million (\$56 million net of estimated issue costs).

(b) Contributed Surplus:

	Amount
Contributed surplus, December 31, 2006	\$ 5,566
Stock-based compensation	3,808
Conversion of stock options	(20)
Conversion of Class C performance shares	(269)
Contributed surplus, September 30, 2007	\$ 9,085

(c) Stock-based compensation:

During the first nine months of 2007, the Company recorded \$3,808,000, (2006 - \$3,415,000) of stock-based compensation expense related to the stock options, of which \$1,904,000 (2006 - \$1,707,000) was capitalized in accordance with the Company's full cost accounting policy. As stock-based compensation is non-deductible for income tax purposes, a future tax liability of \$774,000 associated with the current period's capitalized

stock-based compensation has been recorded. The fair value of each stock option is determined at each issue or grant date using the Black-Scholes model with the following weighted average assumptions: risk free interest rate 3.85% (2006 – 4.33%), expected life 4 years (2006 – 4 years), volatility 45% (2006 – 45%), and an expected dividend of nil (2006 – nil).

(i) *Performance shares*

	Number of shares	Amount
Class C, performance shares, December 31, 2006	402	\$ 4
Converted to common shares	(402)	(4)
Class C, performance shares, September 30, 2007	–	\$ –

(ii) *Stock options*

The average fair value of the stock options granted during the nine months ended September 30, 2007, as calculated by the Black-Scholes method, was \$4.04 per option (September 30, 2006 - \$5.02).

	Number of Options	Price Range	Weighted average exercise price
Balance December 31, 2006	2,019	\$ 3.50 to \$18.60	\$ 14.97
Granted	2,247	\$ 7.59 to \$12.18	\$ 10.14
Forfeited	(408)	\$ 9.97 to \$17.75	\$ 13.89
Cancelled	(643)	\$ 13.40 to \$18.60	\$ 16.22
Exercised	(6)	\$ 8.25	\$ 8.25
Balance September 30, 2007	3,209	\$ 3.50 to \$ 18.60	\$ 11.49

(d) **Per share amounts:**

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average number of shares outstanding for the three month period ended September 30, 2007 was 47,321,000 (September 30, 2006 – 34,537,000) and for the nine month period ended September 30, 2007, the weighted average number of shares outstanding was 44,648,000 (September 30, 2006 – 33,714,000).

The Company's net loss for the three months ended September 30, 2007 results in no dilution from the Company's stock options. The number of shares that would have been added to the weighted average number of common shares for the dilution added by stock options is 383,000 (September 30, 2006 – 701,000). In computing diluted earnings per share for the nine months ended September 30, 2007, 384,000 (September 30, 2006 – 779,000) shares were added to the weighted average number of common shares for the dilution added by the performance shares and stock options.

(e) **Flow through shares**

On August 10, 2006, the Company closed a public offering in which 2,426,300 shares were issued for gross proceeds of \$40,002,125. Of the shares issued, 759,500 shares were issued on a flow-through basis in which the Company had committed to renounce to the purchasers certain Canadian tax deductions totaling \$15.0 million. During the nine months ended September 30, 2007, the Company renounced the \$15.0 million of Canadian income tax deductions and at September 30, 2007, the Company has incurred all eligible expenditures under this arrangement.

9. FINANCIAL INSTRUMENTS:

As at September 30, 2007, the Company had entered into direct sales agreements to sell natural gas as follows:

	Volume (gj/day)	Term	Price (Cdn \$/gj)	Floor (Cdn \$/gj)	Fair Value (thousands)
AECO Floor	9,000	July 1 – December 31, 2007	AECO C	\$ 6.80	\$ 853
AECO/Station 2 Differential Swap	15,000	July 1 – October 31, 2007	AECO 5A less \$ 0.24	–	–
AECO/Station 2 Differential Swap	10,000	November 1, 2007– October 31, 2008	AECO 5A less \$ 0.16	–	\$ (436)
Total Fair Value					\$ 417

10. SUPPLEMENTAL CASH FLOW INFORMATION:

	September 30, 2007	September 30, 2006
Changes in non-cash working capital:		
Accounts receivable	\$ 3,327	\$ 2,449
Accounts payable and accrued liabilities	(8,059)	(10,120)
	\$ (4,732)	\$ (7,671)
Operating activities	\$ 3,978	\$ 1,225
Investing activities	(8,710)	(8,896)
	\$ (4,732)	\$ (7,671)

The Company made the following cash outlays in respect of interest expense and current income taxes:

	September 30, 2007	September 30, 2006
Interest	\$ 6,098	\$ 1,291
Income taxes	\$ –	\$ –

11. COMMITMENTS:

The Company has the following fixed term commitments related to its on-going business:

	Total	2007	2008	2009	2010	2011
Operating Leases	\$ 3,960	\$ 248	\$ 990	\$ 990	\$ 990	\$ 742
Capital commitments	2,500	700	1,800	–	–	–
Exploration and development	20,000	–	20,000	–	–	–
Firm transportation agreements	29,138	1,602	6,689	7,026	7,243	6,578
Total	\$ 55,598	\$ 2,550	\$ 29,479	\$ 8,016	\$ 8,233	\$ 7,320

The exploration and development commitment relates to the Company's obligation under its October 25, 2007 flow-through share issue as described in note 12.

The firm transportation commitments were acquired as part of the Company's May 2007 private company acquisition and represent firm service commitments for transportation and processing of natural gas in British Columbia.

12. SUBSEQUENT EVENT:

On October 25, 2007, the Company completed a bought deal share financing with a syndicate of underwriters resulting in the issuance of 4,181,860 common shares at \$8.25 per common share and 1,860,500 common shares on a flow through basis at \$10.75 per flow through share for aggregate proceeds of \$54.5 million (\$51.5 million net of issue costs).

CORPORATE INFORMATION

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The Toronto-Dominion Bank

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Burnet, Duckworth & Palmer LLP

RESERVE ENGINEERS

GLJ Petroleum Consultants

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Stock Symbol: CR

ABBREVIATIONS

bbl	barrels
bbl/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent (6 mcf: 1 bbl)
bopd	barrels of oil per day
mmbtu	million British thermal units
mboe	thousand barrels of oil equivalent (6 mcf: 1 bbl)
mmboe	million barrels of oil equivalent (6 mcf: 1 bbl)
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
ngl	natural gas liquids

CAUTIONARY STATEMENT

This Q3 Report contains forward-looking statements relating to Management's approach to operations, expectations relating to the number of wells, amount and timing of capital projects, Company production, commodity prices, foreign exchange rates, royalties, proposed royalty rates, operating costs, transportation costs, general and administrative costs and cash flow. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable by Crew at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the ability to produce and transport crude oil and natural gas to markets; the result of exploration and development drilling and related activities; fluctuation in foreign currency exchange rates; the imprecision of reserve estimates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes and royalties; decisions or approvals of administrative tribunals; change in environmental and other regulations; risks associated with oil and gas operations; the weather in the Company's areas of operations; and other factors, many of which are beyond the control of the Company. There is no representation by Crew that actual results achieved during the forecast period will be the same in whole or in part as that forecast.



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