CREW ENERGY PRESENTS 2004 FOURTH QUARTER AND ANNUAL FINANCIAL RESULTS
CALGARY, ALBERTA – March 14, 2005

Crew Energy Inc. (TSX-CR) of Calgary, Alberta is pleased to announce its operating and financial results for the three month period and year ended December 31, 2004.

Highlights

- Cash flow in the fourth quarter totalled $8.3 million, a 118% increase over the fourth quarter of 2003 and a 41% increase over the third quarter of 2004;
- Net income in the fourth quarter was $3.4 million, a 167% increase over the fourth quarter of 2003 and 62% greater than the third quarter of 2004;
- Achieved top tier financial metrics with an earnings to cash flow ratio of 40%, cash flow to revenue ratio of 65%, general and administrative expenses per boe of $0.53 and cash flow netbacks of $29.11 per boe;
- Maintained a strong balance sheet with no bank debt and a $3.8 million working capital deficiency at year-end;
- Fourth quarter production averaged 3,112 boe/d, an increase of 63% over the fourth quarter of 2003 and 28% over the third quarter of 2004;
- Maintained low operating costs of $3.98 per boe in the fourth quarter;
- Achieved annual finding and development costs of $8.49 per boe proved plus probable and $11.56 per boe proved, before including the change in future development costs and $9.34 per boe proved plus probable and $12.75 per boe on a proved basis after including the change in future development costs;
- High netbacks and low finding and development costs resulted in a high return on capital with recycle ratios of 2.2 times proved reserves and 3.0 times proved plus probable reserves.
- Crew's reserve life index (RLI) increased to 8.2 years, an increase of 3 years or 58% over 2003.

Finance ($ thousands, except per share amounts)	**Three months ended Dec. 31, 2004**	Three months ended Dec. 31, 2003	% Chg	**Year ended Dec. 31, 2004**	Period from Sept. 2, 2003 to Dec. 31, 2003 (note 1)
Petroleum and natural gas sales	**12,721**	6,086	109	**37,702**	7,586
Cash flow from operations (note 2)	**8,330**	3,814	118	**24,076**	4,612
Per share - basic	**0.33**	0.17	94	**0.97**	0.20
- diluted	**0.28**	0.15	87	**0.84**	0.18
Net income	**3,358**	1,258	167	**8,948**	1,565
Per share - basic	**0.13**	0.05	160	**0.36**	0.07
- diluted	**0.11**	0.05	120	**0.31**	0.06
Exploration and development	**20,775**	4,860	327	**55,181**	6,689
Working capital deficiency (surplus)				**3,822**	(3,940)
Weighted average shares (thousands)					
Basic	**26,233**	22,981	14	**24,946**	22,981
Diluted	**30,436**	25,620	19	**28,675**	25,734

Notes:

(1) Crew was formed on September 2, 2003 as part of the Plan of Arrangement (the "Plan") entered into by Baytex Energy Ltd. ("Baytex") and its associated companies under which certain producing properties and exploratory assets of Baytex were transferred to Crew, with the remaining assets being reorganized into an income trust, Baytex Energy Trust. Under the Plan, Baytex Energy Trust became the continuing issuer of Baytex and Crew was registered as a new issuer. As a result, the financial information included in this release comprises the operating results of Crew for the three month periods ended December 31, 2004 and 2003 and the year ended December 31, 2004 with comparative information for the 121 day period ended December 31, 2003.

(2) Cash flow from operations is used before changes in non-cash working capital to analyze operating performance and leverage. Cash flow 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.

Operations	**Three months ended Dec. 31, 2004**	Three months ended Dec. 31, 2003	% Chg	**Year Ended Dec. 31, 2004**	Period from Sept. 2, 2003 to Dec. 31, 2003
Daily production					
Light oil and ngls (bbl/d)	**772**	486	59	**569**	454
Natural gas (mcf/d)	**14,041**	8,550	64	**11,248**	8,197
Oil equivalent (boe/d @ 6:1)	**3,112**	1,911	63	**2,444**	1,820
Average prices					
Light oil and ngls ($/bbl)	**53.31**	34.46	55	**47.47**	34.92
Natural gas ($/mcf)	**6.91**	5.77	20	**6.75**	5.72
Oil equivalent ($/boe)	**44.42**	34.61	28	**42.15**	34.45
Operating expenses					
Light oil and ngls ($/bbl)	**4.06**	3.04	34	**3.84**	3.39
Natural gas ($/mcf)	**0.66**	0.84	(21)	**0.67**	0.85
Oil equivalent ($/boe @ 6:1)	**3.98**	4.54	(12)	**3.96**	4.68
Operating netback ($/boe)	**29.55**	22.62	31	**27.57**	21.98
G&A and other cash items ($/boe)	**0.44**	0.93	(53)	**0.66**	1.05
Cash flow netback ($/boe)	**29.11**	21.69	34	**26.91**	20.93
Drilling Activity					
Gross wells	**16**	9	78	**39**	10
Working interest wells	**12.7**	5.6	127	**32.2**	6.6
Success rate, net wells	**92%**	84%		**91%**	78%

Operational Update

Edson, Alberta

Crew drilled three gas wells at Edson in the fourth quarter and has plans to drill three additional wells in the first quarter of 2005. The production capability from this area now exceeds the 7 MMcf/d capacity of the existing facility. The Company is currently installing another 810 bhp compressor that is expected to be operational by the end of March, 2005, which will increase the capacity to 14 MMcf/d. Drilling results from this area have been very encouraging as Crew has experienced 100% success in the drilling of 10 wells and has encountered multiple pay zones in 8 wells. The Company plans to drill 12 wells in this area in 2005 out of a current inventory of 23 drilling locations.

Ferrier, Alberta

Crew was relatively inactive in Ferrier in 2004 drilling one cased gas well. The Company anticipates increasing its level of activity in this area in 2005. Currently Crew has plans to drill two development Rock Creek tests, an Elkton exploration test and a Banff exploration test in the area. The drilling of these wells is anticipated to occur in the second and third quarter of 2005. Within the Ferrier area at Phoenix, Alberta, Crew (58% W.I.) and its partner are constructing a gas plant which is expected to begin production by the end of March.

Laprise, B.C.

The Company continued to develop its Coplin 45 API light oil play in the fourth quarter with the drilling of two (1.5 net) oil wells and one (.97 net) gas well. Crew installed a 325 bhp compressor to conserve solution gas from the two producing oil pools and to accommodate gas from the fourth quarter gas discovery. Production from this area is now over 650 boe/d which is approximately 50 boe/d more than had been expected. The Company's 2005 plans for the Coplin pool are to monitor production and pressure data from existing wells in order to prudently plan further development of the two oil pools. Crew also plans to acquire additional 3-D seismic data in 2005 over its lands at Laprise to evaluate the potential of the Slave Point Formation. Crew's acreage is in an analogous geologic and structural position to a well three miles away that has had cumulative production of over 17 BCF and is currently producing over 21 MMcf/d of gas from the Slave Point Formation.

Viking-Kinsella

Crew drilled four (3.6 net) gas wells in the general Viking-Kinsella area in the fourth quarter. All of these wells are on production at a rate of 310 boe/d net to Crew. The Company now has fifteen drilling locations in this area of which one to two will be drilled in the first quarter of 2005. The Company is also acquiring 3-D seismic over its lands at Viking-Kinsella to further define additional drilling locations.

Wimborne-Drumheller

Crew drilled three (1.4 net) wells at Wimborne in the fourth quarter targeting the Belly River, Edmonton sandstones, and Horseshoe Canyon coal formations. These wells are in various stages of completion and tie-in and are expected to be on production through the Company's gathering system and gas processing facility by the end of the first quarter of 2005. The Company is also expanding its Wimborne gas processing facility to 7 MMcf/d with the installation of an 810 bhp compressor to accommodate low pressure gas production from the area.

Crew's lands in the Wimborne area are surrounded by new natural gas developments targeting the Horseshoe Canyon coals. Typical Horseshoe Canyon natural gas developments would incorporate the drilling of four to eight wells per section with production rates of 70-300 mcf/d per well. Crew has 42 net sections of Horseshoe Canyon coal rights in the Wimborne-Drumheller area. With no reserves currently booked in the Horseshoe Canyon coals this play presents a significant resource to the Company which remains to be realized. The Company also owns and operates an extensive pipeline infrastructure and two gas processing facilities in this area.

Exploration

With over 245,000 net undeveloped acres of land and a larger production and cash flow base, Crew is at a stage in its development where it has the ability to dedicate more of its resources to exploration drilling. The Company (100% W.I.) successfully drilled an exploration well at Inga, British Columbia in the fourth quarter. Crew has 100% interest in five sections of land on this play and has plans to construct a 6 MMcf /d gas processing facility with an anticipated production start by the end of August 2005. The Company has plans to drill up to three wells in this area in the second or third quarter of 2005.

At Columbia, Alberta Crew has a 40% interest in a cased gas well that has two prospective zones awaiting completion. At Edson, Crew has a 75% interest in a well that is currently drilling to an estimated total depth of 3,100 meters. Although a number of zones may be prospective at this drilling location the primary target is gas/condensate in the Winterburn Group. At Hanlan, Alberta, Crew has a 25% interest in a 4,200 meter Winterburn test that is also currently drilling. This well offsets a recent discovery that is currently producing over 6 MMcf/d from the Winterburn Group.

At Brazeau, Alberta Crew has over 18 net sections of land and is currently completing a well (100% W.I.) for gas production in the area. The Company also plans to drill one (100% W.I.) exploration well in the third quarter of 2005 and to drill a Nordegg formation test (100% W.I.) in the Whitehorse area of Alberta in 2005.

Outlook

Crew's large undeveloped land base continues to fuel the Company's growth through its drilling program. The Company's exploration and development budget for 2005 is currently set at $60 million. Plans include the drilling of 40 to 50 wells during the year of which 30 to 40 will be directed toward development initiatives in its core areas of Edson, Ferrier, Wimborne and Viking-Kinsella in Alberta and Laprise in northeast British Columbia. In addition, the Company plans to drill a minimum of 10 exploratory wells in 2005, generally targeting gas/condensate reservoirs in the deeper regions of the basin.

For the first quarter of 2005 Crew is projecting to spend approximately $20 million on its exploration and development program. The program includes the drilling or completion of 15 to 20 wells, the construction of three natural gas facilities and the installation of the associated well-site and pipeline infrastructure.

Crew's current production is estimated at 3,900 boe/d, a 25% increase over the fourth quarter 2004 average of 3,112 boe/d. The Company also estimates it currently has an additional 900 boe/d awaiting production start-up which has placed the Company in a position to achieve its objective of exiting the quarter at over 4,000 boe/d and the year at over 5,000 boe/d. The Company looks forward to reporting its first quarter results and updating its shareholders on the progress of the 2005 capital program in May.

Land Holdings

One of the "Crew advantages" has been its large prospective undeveloped land base. During 2004 the Company continued to strategically acquire additional lands through Crown land sales, freehold mineral leasing and farm-in arrangements. A summary of the Company's undeveloped land at December 31, 2004 is outlined below:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Alberta	126,980	58,125	269,723	227,629
British Columbia	4,195	2,748	26,245	18,025
	131,175	60,873	295,968	245,654

Oil and Gas Reserves

Information regarding the Company's December 31, 2004 reserves has been previously distributed in a press release dated March 2, 2005. The Company's reserves were evaluated for the year ended December 31, 2004 by Gilbert Laustsen Jung Associates Ltd. ("GLJ") in accordance with the rules provided by National Instrument 51-101. The following table provides summary information presented in the GLJ report effective to December 31, 2004 and based on the GLJ (2005-01) price forecast. Additional reserve information will be presented in the Statement of Reserve Data and Other Oil and Gas Information section of the Company's Annual Information Form scheduled to be filed on SEDAR prior to March 31, 2005.

	Light/medium oil		Natural gas liquids		Natural gas		Barrels of oil equivalent	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
Proved								
Producing	510	439	623	444	23,046	18,587	4,974	3,981
Non-producing	28	25	98	68	5,636	4,343	1,065	817
Undeveloped	0	0	177	121	3,231	2,572	715	549
Total proved	537	464	899	633	31,913	25,501	6,755	5,347
Probable	138	120	381	266	11,902	9,647	2,502	1,994
Total proved & probable	675	584	1,280	899	43,815	35,149	9,257	7,341

Notes:

(1) "Gross" reserves means, Crew's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Company.
(2) "Net" reserves means, Crew's working interest (operated and non-operated) share after deduction of royalties obligations, plus Crew's royalty interest in reserves.
(3) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.
(4) May not add due to rounding.

The following reconciliation of the Company's gross reserves compares changes in the Company's reserves as at December 31, 2003 to the reserves as at December 31, 2004, each evaluated following National Instrument 51-101(NI51-101) definitions.

	Proved Producing	Total Proved	Total Proved plus Probable
	(MMboe)	(MMboe)	(MMboe)
Balance December 31, 2003	2.3	2.9	3.7
Technical revisions	0.6	0.5	0.4
Exploration discoveries	0.6	0.6	0.7
Drilling extensions	2.1	3.3	4.9
Improved recoveries	0.3	0.3	0.4
Economic factors	-	0.1	0.1
Production	(0.9)	(0.9)	(0.9)
Balance December 31, 2004	5.0	6.8	9.3

Capital Program Efficiency

The efficiency of the Company's capital program for the year ended December 31, 2004 is summarized below:

	Proved	Proved plus Probable
Capital expenditures ($ thousands)	55,181	55,181
Change in future development capital ($ thousands)	5,649	5,559
Total costs ($ thousands)	60,830	60,740
Reserve additions including revisions (Mboe)	4,772	6,500
Finding and development costs without change in future capital ($/boe)	**$11.56**	**$ 8.49**
Finding and development costs with change in future capital ($/boe)	**$12.75**	**$ 9.34**
Operating net back ($/boe)	27.57	27.57
Finding and development costs ($/boe)	12.75	9.34
Recycle ratio	**2.2x**	**3.0x**
Reserve additions including revisions (Mboe)	4,772	6,500
Total production 2004 (mboe)	894	894
Reserve replacement	**534%**	**727%**
Total gross reserves (Mboe)	6,755	9,257
Fourth quarter 2004 production (boe/d)	3,112	3,112
Annual 2004 production (boe/d)	2,444	2,444
RLI based on fourth quarter annualized production (years)	**6.0**	**8.2**
RLI based on 2004 annual production (years)	**7.6**	**10.4**

Reserve Values

The before tax estimated future net revenues associated with Crew's reserves effective December 31, 2004 and based on the GLJ (2005 – 01) future price forecast and constant dollar pricing are summarized in the following table:

	Forecast Price		Constant Price	
	5%	10%	5%	10%
Proved				
Producing	107,815	94,044	118,054	102,172
Non-producing	17,210	14,557	19,811	16,675
Undeveloped	9,395	7,074	11,023	8,352
Total proved	134,420	115,676	148,887	127,199
Probable	38,931	27,843	43,788	31,568
Total proved and probable	173,351	143,519	192,675	158,767

Notes:

(1) The estimated future net revenues are stated before deducting future estimated site restoration costs, but include the Alberta Royalty Tax Credit, and are reduced for estimated future abandonment costs and estimated capital for future development associated with the reserves.

(2) Constant pricing assumptions include a base Canadian Light/medium oil price of $46.54 per bbl, natural gas of $6.54 per mcf, condensate of $48.91 per bbl, butane of $34.44 per bbl and propane of $29.81 per bbl.

(3) May not add due to rounding.

Management's Discussion and Analysis

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 month periods ended December 31, 2004 and the audited consolidated financial statements for the year ended December 31, 2004 and the audited and consolidated financial statements and Management Discussion and Analysis for the period from September 2, 2003 to December 31, 2003.

As the Company commenced operations effective September 2, 2003, comparative information for the period ended December 31, 2003 is for only 121 days. The limitations of such comparative information should be recognized.

Certain of the statements set forth under "Management's Discussion and Analysis" and elsewhere in this press release, including statements which may contain words such as "could", "expect", "believe", "will", "budgeted", "forecasted" and similar expressions and statements relating to matters that are not historical facts, are forward-looking and are based upon the Company's current belief as to the outcome and timing of such future events. There are numerous risks and uncertainties that can affect the outcome and timing of such events, including many factors beyond the control of the Company. These factors include, but are not limited to, the matters described under the heading "Risk and Risk Management" in the Company's December 31, 2003 management, discussion and analysis on Page 21 of the Company's 2003 Annual Report. Should one or more of these events occur, or should any of the underlying assumptions prove incorrect, the Company's actual results and plans for 2004 and beyond could differ materially from those expressed in the forward-looking statements. The Company does not undertake to update, revise or correct any of the forward-looking information. Such forward-looking statements should be read in conjunction with the Company's disclosures under the heading: "CAUTIONARY STATEMENT" contained in this release.

The consolidated financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in Canada. Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

Crew evaluates performance based on net income and cash flow from operations. Cash flow from operations is a measure not based on GAAP that is commonly used in the oil and gas industry. It represents cash generated from operating activities before changes in non-cash working capital. 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.

Production Production for the quarter ended December 31, 2004 averaged 3,112 boe/d, an increase of 63% over the fourth quarter of 2003. Natural gas volumes grew to 14.0 MMcf/d a 64% increase over the fourth quarter of 2003. Light oil and natural gas liquids ("ngl") production increased 59% to 772 bbls/d in the fourth quarter compared to 486 bbls/d in the fourth quarter of 2003.

Production for 2004 averaged 2,444 boe/d, an increase of 34% over the 1,820 boe/d produced in the 121 day period ended December 31, 2003. Production increased throughout 2004 as a result of the Company's successful drilling program. Natural gas volumes increased 37% to 11.2 MMcf/d as a result of added production from new wells at Edson, Ferrier and Viking Kinsella in Alberta. Liquid production increased 25% to 569 bbl/d in 2004 as a result of increased light oil production from Laprise in northeastern British Columbia and increased ngl production at Edson and Ferrier.

Revenue Revenue for the fourth quarter totalled $12.7 million including natural gas revenue of $8.9 million and light oil and ngl revenue of $3.8 million. These amounts compared to fourth quarter 2003 revenue of $6.1 million including natural gas revenue of $4.6 million and light oil and natural gas liquids of $1.5 million. The 2004 fourth quarter revenue increased over the fourth quarter 2003 due to increased production and higher commodity pricing.

Revenue in 2004 totalled $37.7 million comprised of $27.8 million in natural gas sales and $9.9 million in oil and ngl sales. Revenue for the 121 day period ended December 31, 2003 totalled $7.6 million. Crew's revenue grew quarter over quarter throughout 2004 bolstered by increasing production and strong commodity prices. The Company's oil and ngl price averaged $47.47 per bbl in 2004 representing an increase of 36% over the $34.92 realized in the 121 day period ended December 31, 2003. Average natural gas prices increased 18% to $6.75 in 2004 compared to the $5.72 realized during the Company's 2003 period.

Prior to 2004 the Company had presented petroleum and natural gas sales net of transportation costs. The Company now records petroleum and natural gas sales separate from transportation costs on the statement of operations. Previously reported amounts have been reclassified for comparative purposes.

Royalties Royalties for the fourth quarter of 2004 totalled $2.7 million or 21.5% of revenue compared to $1.1 million or 18.5% of revenue for the fourth quarter of 2003.

Royalties for 2004 totalled $8.5 million in 2004 or 22.5% of revenues. During the 121 day period ended December 31, 2003 the Company paid royalties totaling $1.5 million or 19.5% of revenue. Royalty rates as a percentage of revenue have increased in 2004 due to the addition of production from new wells which attract higher royalty rates than the production from the Company's older wells transferred from Baytex.

Operating Costs Operating costs for the three months ended December 31, 2004 totalled $1.1 million or $3.98 per boe compared to $0.8 million or $4.54 for the same period in 2003.

Operating costs totalled $3.5 million in 2004 or $3.96 per boe. During the 121 day period ended December 31, 2003 the Company incurred total operating costs of $1.0 million or $4.68 per boe. Operating costs per unit have decreased in 2004 as a result of higher production offsetting a larger portion of the Company's fixed operating costs and an increase in processing fees charged to third parties to recover the Company's facility operating costs.

Transportation Transportation costs for the fourth quarter of 2004 were $0.4 million or $1.35 per boe compared to $0.2 million or $1.06 per boe in the fourth quarter of 2003.

Transportation costs totalled $1.0 million or $1.17 per boe in 2004. During the 121 day period in 2003 the Company incurred transportation costs totaling $0.2 million or $1.06 per boe. Transportation costs per unit have increased in 2004 due to increased production from Laprise, which attract higher per unit transportation costs.

Operating Netbacks

	Three months ended December 31, 2004			Three months ended December 31, 2003		
	Oil and Liquids ($/bbl)	**Natural Gas** ($/mcf)	**Total** ($/boe)	Oil and Liquids ($/bbl)	Natural Gas ($/mcf)	Total ($/boe)
Revenue	**$ 53.31**	**$ 6.91**	**$ 44.42**	$ 34.46	$ 5.77	$ 34.61
Royalties	**(9.89)**	**(1.83)**	**(10.71)**	(7.29)	(1.02)	(6.39)
Alberta royalty tax credit	**-**	**-**	**1.15**	-	-	-
Operating costs	**(4.06)**	**(0.66)**	**(3.98)**	(3.04)	(0.84)	(4.54)
Transportation costs	**(2.99)**	**(0.13)**	**(1.33)**	(1.68)	(0.14)	(1.06)
Operating Net backs	**$ 36.37**	**$ 4.29**	**$ 29.55**	$ 22.45	$ 3.77	$ 22.62

	Year ended December 31, 2004			Period from Sept. 2, 2003 to Dec. 31, 2003		
	Oil and Liquids ($/bbl)	**Natural Gas** ($/mcf)	**Total** ($/boe)	Oil and Liquids ($/bbl)	Natural Gas ($/mcf)	Total ($/boe)
Revenue	**$ 47.47**	**$ 6.75**	**$ 42.15**	$ 34.92	$ 5.72	$ 34.47
Royalties	**(8.77)**	**(1.73)**	**(9.99)**	(7.23)	(1.09)	(6.73)
Alberta royalty tax credit	**-**	**-**	**0.54**	-	-	-
Operating costs	**(3.84)**	**(0.67)**	**(3.96)**	(3.39)	(0.85)	(4.68)
Transportation costs	**(2.31)**	**(0.14)**	**(1.17)**	(2.51)	(0.10)	(1.06)
Operating Net backs	**$ 32.55**	**$ 4.21**	**$ 27.57**	$ 21.79	$ 3.68	$ 21.98

General and Administrative General and administrative expenses for the fourth quarter of 2004 totalled $0.2 million or $0.53 per boe compared to $0.2 million or $1.06 per boe for the fourth quarter of 2003.

General and administrative expenses for the year ended December 31, 2004 totalled $0.8 million or $0.89 per boe and for the period from September 2 to December 31, 2003 totalled $0.3 million or $1.14 per boe. The Company's general and administrative costs per boe have decreased in 2004 as a result of the Company's increasing production volumes. Crew follows the full cost method of accounting for its petroleum and natural gas operations under which, $ 0.8 million (2003 - $0.3 million) of corporate expenses were capitalized during the year.

Stock-Based Compensation The Company accounts for its stock-based compensation programs, including the performance shares and stock options, using the fair value method. Under this method, compensation expense related to these programs is recorded in the consolidated statement of operations over the vesting period. For the three months ended December 31, 2004 the Company has recorded a stock-based compensation expense totalling $86,000 or $0.30 per boe compared to $55,500 or $0.31 per boe for the fourth quarter of 2003.

During 2004 stock-based compensation expense of $0.3 million (2003 - $0.1 million) was recorded and $0.3 million (2003 - $0.1 million) was capitalized to the company's full cost pool.

Depletion, depreciation and accretion The provision for depletion, depreciation and accretion was $3.0 million or $10.49 per boe for the three months ended December 31, 2004. This compares to a fourth quarter 2003 provision of $1.5 million or $8.46 per boe.

The provision for depletion, depreciation and accretion for the year ended December 31, 2004 was $9.6 million or $10.78 per boe. During the period from September 2 to December 31, 2003 depletion, depreciation and accretion was $1.8 million or $7.96/boe. Per unit depletion has increased in 2004 due to an increase in the average cost of the Company adding reserves.

Effective January 1, 2004 the Company adopted new Accounting Guideline 16 "Oil and Gas Accounting – Full Cost." Under the new standard the Company assesses if the carrying amount of petroleum and natural gas properties is recoverable when compared to undiscounted cash flows expected from the production of proved reserves, using forecast prices and costs. When the carrying amount is not assessed as recoverable, an impairment loss is recognized based on the discounted cash flows expected from the production of proved plus probable reserves. Adopting Accounting Guideline 16 had no effect on the Company's financial results.

Cash flow and Net income Cash flow from operations in the fourth quarter of 2004 grew to $8.3 million, a 118% increase over the fourth quarter of 2003. On a per share basis, cash flow was $0.33 per basic share and $0.28 per diluted share compared to $0.17 per basic share and $0.15 per diluted share in the fourth quarter of 2003. Net income increased to $3.4 million in the fourth quarter representing a 167% increase over the fourth quarter of 2003. On a per share basis net income was $0.13 per basic share and $0.11 per diluted share.

Cash flow from operations for the year totalled $24.1 million or $0.97 per basic share and $0.84 per diluted share, while net income totalled $8.9 million for the year or $0.36 per basic share and $0.31 per diluted share. These amounts compare to $4.6 million, $0.20 per basic share and $0.18 per diluted share of cash flow and $1.6 million, $0.07 per basic share and $0.06 per diluted share of net income earned in the 121 day period ended December 31, 2003. The Company's increase in cash flow from operations and net income was the result of increased production from new wells and higher commodity prices.

Liquidity and Capital Resources At December 31, 2004 Crew had a net working capital deficiency of $3.9 million including cash and short-term investments of $7.1 million.

The Company currently has a $27 million credit facility with a Canadian chartered bank. At year-end there were no borrowings against this facility. The demand operating facility bears interest at the bank's prime lending rate, bankers' acceptance rates plus scheduled margins and is allowed to revolve at the Company's discretion.

During 2004 the Company completed two private placements issuing 3,800,000 Common Shares and raising gross proceeds of $24.85 million. The second of these issues, completed in December 2004, was issued on a flow-through basis under which the Company has committed to renounce $8.8 million of certain Canadian tax deductions to the purchasers. The capital expenditures related to these tax deductions will be incurred throughout 2005.

Looking forward Crew will continue to focus on maintaining a strong financial position. The Company is currently planning to fund its 2005 capital expenditure program through a combination of existing bank lines, proceeds from the expected exercise of existing warrants in September 2005 and the Company's cash flow from on-going operations. Emphasis will continue to be placed on the Company's strong financial position and management will endeavor not to exceed a total debt to forward cash flow ratio of more than one time.

As at March 10, 2005, 26,780,684 Common Shares and 1,864,000 Class C Performance shares of the Company were outstanding along with 400,500 options and 3,635,000 warrants to acquire Common Shares of the Company.

Operations and Capital Expenditures During the fourth quarter the Company drilled a total of 16 (12.7 net) wells resulting in 13 (10.2 net) natural gas wells, 2 (1. 5 net) oil wells, and 1 (1.0 net) D&A well. In 2004 Crew drilled a total of 39 (32.2 net) wells resulting in 31 (25.7 net) gas wells, 5 (3.5 net) oil wells, and 3 (3.0 net) D&A wells representing a success rate of 92% (91% net). In addition, the Company also continued to follow its strategy of, where possible, owning and controlling it's processing and gathering facilities. As a result, in 2004 the Company spent 25% of its total capital expenditures on the construction of gas processing and compression equipment at Edson, Ferrier and Laprise as well as adding extensive gas gathering systems at Edson, Laprise and Viking-Kinsella.

Total exploration and development expenditures for 2004 were $55.2 million compared to $6.7 million for the period from September 2 to December 31, 2003. The expenditures are detailed below:

(thousands)	**Three months ended December 31, 2004**	**Year ended December 31, 2004**
Land	**$ 1,661**	**$ 6,298**
Seismic	**507**	**1,812**
Drilling and completions	**14,222**	**32,903**
Facilities, equipment and pipelines	**4,328**	**13,933**
Other	**57**	**235**
Total	**$20,775**	**$55,181**

Dated as of March 10, 2004

Cautionary Statement

This press release 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, operating 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; 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.

Crew is a junior oil and gas exploration and production company whose shares are traded on The Toronto Stock Exchange under the trading symbol “CR”.

Financial statements for the three month period and year ended December 31, 2004 are attached.

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CREW ENERGY INC.
Consolidated Balance Sheet
(thousands)

		December 31, 2004		December 31, 2003
Assets				
Current Assets:				
Cash and cash equivalent	$	**7,069**	$	7,721
Accounts receivable		**11,346**		5,848
		18,415		13,569
Future income tax asset (note 7)		**-**		2,041
Property, plant and equipment (note 3)		**77,123**		30,150
	$	**95,538**	$	45,760
Liabilities and Shareholders' Equity				
Current Liabilities:				
Accounts payable and accrued liabilities	$	**22,297**	$	9,629
Asset retirement obligations (note 4)		**4,984**		3,896
Future income tax liability		**2,675**		-
Shareholders' Equity				
Share capital (note 6)		**54,382**		30,524
Contributed surplus (note 6)		**687**		146
Retained Earnings		**10,513**		1,565
		65,582		32,235
	$	**95,538**	$	45,760

See accompanying notes to the consolidated financial statements.

CREW ENERGY INC.
Consolidated Statement of Operations and Retained Earnings
(thousands, except per share amounts)

	Three months ended December 31, 2004 (unaudited)	Three months ended December 31, 2003 (unaudited)	Year ended December 31, 2004	Period September 2 to December 30, 2004
Revenue				
Petroleum and natural gas sales	$ **12,721**	$ 6,086	$ **37,702**	$ 7,586
Royalties (net of Alberta Royalty Tax Credit)	**(2,737)**	(1,124)	**(8,455)**	(1,482)
Other revenue	**41**	39	**243**	38
	10,025	5,001	**29,490**	6,142
Expenses				
Operating	**1,140**	798	**3,538**	1,030
Transportation	**385**	187	**1,042**	232
General and administrative	**152**	188	**801**	250
Stock-based compensation	**86**	55	**274**	73
Depletion, depreciation and accretion	**3,003**	1,487	**9,641**	1,752
	4,766	2,715	**15,296**	3,337
Income before taxes	**5,259**	2,286	**14,194**	2,805
Taxes (note 7)				
Capital	**18**	14	**33**	18
Future	**1,883**	1,014	**5,213**	1,222
	1,901	1,028	**5,246**	1,240
Net income	**3,358**	1,258	**8,948**	1,565
Retained earnings, beginning of period	**7,155**	307	**1,565**	-
Retained earnings, end of period	$ **10,513**	$ 1,565	$ **10,513**	$ 1,565
Per share amounts (note 6(g))				
Basic	$ **0.13**	$ 0.05	**0.36**	$ 0.07
Diluted	$ **0.11**	$ 0.05	**0.31**	$ 0.06

See accompanying notes to the consolidated financial statements.

CREW ENERGY INC.
Consolidated Statement of Cash Flows
(unaudited, thousands)

	Three months ended December 31, 2004	Three months ended December 31, 2003	Year ended December 31, 2004	Period Sept. 2 to December 30, 2004
	(unaudited)	(unaudited)		
Cash provided by (used in):				
Operating activities:				
Net income	$ 3,358	$ 1,258	$ 8,948	$ 1,565
Items not involving cash:				
Depletion, depreciation & accretion	3,003	1,487	9,641	1,752
Stock-based compensation	86	55	274	73
Future income taxes	1,883	1,014	5,213	1,222
Funds flow from operations	8,330	3,814	24,076	4,612
Change in non-cash working capital	(1,180)	(2,145)	1,561	(2,807)
Asset retirement expenditures	1	-	(72)	-
	7,151	1,669	25,565	1,805
Financing activities:				
Issue of common shares	8,800	-	24,850	6,017
Re-purchase of common shares	(74)	-	(74)	-
Share issue costs	(537)	-	(1,421)	-
	8,189	-	23,355	6,017
Investing activities:				
Exploration and development	(20,775)	(4,860)	(55,181)	(6,689)
Change in non-cash working capital	5,895	4,795	5,609	6,588
	(14,880)	(65)	(49,572)	(101)
Change in cash and cash equivalents	460	1,604	(652)	7,721
Cash and cash equivalents, beginning of period	6,609	6,117	7,721	-
Cash and cash equivalents, end of period	$ 7,069	$ 7,721	$ 7,069	$ 7,721

See accompanying notes to the consolidated financial statements.

CREW ENERGY INC.
Notes to Consolidated Financial Statements
For the three months and year ended December 31, 2004,
The three months ended December 31, 2003 and
The period from September 2, 2003 to December 31, 2003
(Tabular amounts in thousands)

1. Significant accounting policies:

Crew Energy Inc. ("Crew" or the "Company") was incorporated on May 12, 2003 and commenced operations on September 2, 2003 when certain assets of Baytex Energy Ltd. ("Baytex") were transferred into Crew under a Plan of Arrangement. The Plan of Arrangement resulted in the shareholders of Baytex becoming unit holders of Baytex Energy Trust and shareholders of Crew.

These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles within the framework of the accounting policies summarized below:

(a) Principles of consolidation:

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiary, Crew Resources Inc. and a partnership, Crew Energy Partnership.

(b) Cash and cash equivalents:

Cash and cash equivalents include monies on deposit and highly liquid short-term investments accounted for at cost and having a maturity date of not more than 90 days.

(c) Petroleum and natural gas properties:

The Company follows the full cost method of accounting for petroleum and natural gas properties, whereby all costs of exploring for and developing petroleum and natural gas properties and related reserves are capitalized. Capitalized costs include land acquisition costs, geological and geophysical expenses, cost of drilling both productive and non-productive wells, production facilities, the fair value of asset retirement obligations and related overhead expenses.

Capitalized costs, excluding costs relating to unproven properties, are depleted using the unit-of-production method based on estimated proved reserves of petroleum and natural gas before royalties as determined by independent petroleum engineers. For purposes of the depletion calculation, natural gas reserves and production are converted to equivalent volumes of crude oil based on relative energy content of six thousand cubic feet of gas to one barrel of oil. Proceeds from the sale of petroleum and natural gas properties are applied against capitalized costs, with no gain or loss recognized unless such a sale would alter depletion by more than 20%.

The cost of acquiring and evaluating unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed periodically for impairment. When proved reserves are assigned or the property is considered impaired the costs of the property or the amount of impairment is added to the costs subject to depletion.

Petroleum and natural gas assets are evaluated in each reporting period to determine that the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre.

The carrying amounts are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying amount of the cost centre. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount of the cost centre exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects of the cost centre. The cash flows are estimated using forecast product prices and costs and are discounted using a risk-free interest rate.

Effective January 1, 2004, the Corporation adopted the new accounting standard relating to full cost accounting including a new ceiling test. The adoption of this new policy on January 1, 2004 resulted in no write-down to the carrying value of petroleum and natural gas assets. Prior to January 1, 2004 the ceiling test amount was the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost or market of unproved properties and the cost of major development projects less estimated future costs for administration, financing, site restoration and income taxes. The cash flows were estimated using period end prices and costs.

(d) Interest in joint ventures:

A portion of the Company's petroleum and natural gas exploration and development activity is conducted jointly with others and, accordingly, the financial statements reflect only the Company's proportionate interest in such activities.

(e) Asset retirement obligations:

The fair value of the liability for the Company's asset retirement obligation ("ARO") is recorded in the period in which it is incurred, discounted to its present value using Crew's credit adjusted risk-free interest rate and the corresponding amount is recognized by increasing the carrying amount of the related long-lived asset. The liability is accreted each period, and the capitalized cost is depreciated over the useful life of the related asset. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would result in an increase or decrease to the ARO. Actual costs incurred upon settlement of the ARO are charged against the ARO.

(f) Revenue recognition:

Revenue from the sale of petroleum and natural gas are recorded when title passes to a third party.

(g) Financial instruments:

From time to time, Crew may use swap agreements or other financial instruments to hedge its exposure to fluctuations in petroleum and natural gas prices. Financial instruments are not used for speculative purposes. When Crew enters into a hedge it formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in the hedging transactions are highly effective in offsetting changes in fair value or cash flows of the hedged item. These derivative contracts, accounted for as hedges, are not recognized on the balance sheet. Realized gains and losses on these contracts are recognized in petroleum and natural gas sales and cash flows in the same period in which the revenues associated with the hedged transactions are recognized. Premiums paid or received are deferred and amortized to earnings over the term of the contract. Financial instruments that do not qualify as a hedge are recorded on a mark-to-market basis with the resulting gains or losses taken into income.

(h) Flow-through shares:

Flow-through shares are issued at a fixed price and the proceeds are used to fund qualifying exploration expenditures within a defined period. The expenditures funded by flow-through arrangements are renounced to investors in accordance with tax legislation. Share capital is reduced and future tax liability is increased by the total estimated future income tax costs of the renounced tax deductions in the period of renouncement.

(i) Per share amounts:

Basic per share amounts are calculated using the weighted average number of shares outstanding during the period. Diluted per share amounts are calculated based on the treasury-stock method, which assumes that any proceeds obtained on exercise of options, warrants and performance shares would be used to purchase common shares at the average market price during the period. The weighted average number of shares outstanding is then adjusted by the net change.

(j) Stock-based compensation plans:

The Company accounts for its stock-based compensation programs including stock options, warrants and performance shares, using the fair value method. Under this method, compensation expense related to these programs is recorded in the consolidated statement of operations over the vesting period.

(k) Income taxes:

The Company uses the asset and liability method of accounting for future income taxes. The future tax asset or liability is calculated assuming the financial assets and liabilities will be settled at their carrying amount. This amount is compared to the tax assets and the difference is multiplied by the substantively enacted tax rate when the temporary differences are expected to reverse.

(l) Use of estimates:

The amounts recorded for depletion of petroleum and natural gas properties and equipment and the asset retirement obligations are based on estimates. The ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

(m) Comparative Information:

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

2. Plan of Arrangement:

Effective September 2, 2003 and pursuant to a Plan of Arrangement, Baytex transferred certain property, plant and equipment to Crew. In exchange, the former Baytex shareholders received 1/3 of a Crew Common Share for every common share of Baytex held prior to the arrangement. The number of shares of Crew, which were issued to former Baytex shareholders as a result of the transaction was 19,345,696. At the time of the transaction, Crew and Baytex were related companies resulting in the transfer of the assets and related liabilities to Crew from Baytex at their carrying value.

Details of the amounts transferred are as follows:

Allocated:	
Petroleum and natural gas properties and equipment	$ 24,848
Office furniture and equipment	137
Future income tax asset	3,263
Asset retirement obligation	(3,741)
Net assets transferred and share capital issued	$ 24,507

In conjunction with the Plan of Arrangement the Company adopted a new accounting standard, Asset Retirement Obligations. As a result of adopting this standard, an entry was recorded to increase the asset retirement obligations by $3,182,000, increase petroleum and natural gas properties and equipment by $3,741,000, decrease the future income tax asset by $195,000 and increase share capital by $364,000.

3. Property, plant and equipment:

December 31, 2004	Cost	Accumulated depletion & depreciation	Net book value
Petroleum and natural gas properties and equipment	$ 88,054	$ 10,931	$ 77,123

December 31, 2003	Cost	Accumulated depletion & depreciation	Net book value
Petroleum and natural gas properties and equipment	$ 31,830	$ 1,680	$ 30,150

The cost of unproven lands at December 31, 2004 of $10,067,000 (2003 - $5,530,000) has been excluded from the depletion calculation.

During the year ended December 31, 2004, $1,074,000 (2003 – $323,000) of corporate expenses related to exploration and development activities were capitalized.

Crew performed a ceiling test under the rules provided by AcG – 16 as at December 31, 2004. Based on the calculation, the carrying values are recoverable as compared to the sum of the undiscounted cash flows of the proved reserves based on the following benchmark prices.

	WTI Oil ($US/Bbl)	F/X Rate ($Cdn/$US)	Edmonton Oil ($/bbl)	Company Liquids ($/bbl)	AECO Gas ($/mmbtu)	Company Gas ($/mcf)
2005	$42.00	0.82	$50.25	$41.76	$6.60	$6.47
2006	$40.00	0.82	$47.75	$39.30	$6.35	$6.18
2007	$38.00	0.82	$45.50	$37.11	$6.15	$5.99
2008	$36.00	0.82	$43.25	$34.96	$6.00	$5.84
2009	$34.00	0.82	$40.75	$32.74	$6.00	$5.85
2010	$33.00	0.82	$39.50	$31.61	$6.00	$5.86
2011	$33.00	0.82	$39.50	$31.62	$6.00	$5.86
2012	$33.00	0.82	$39.50	$31.58	$6.00	$5.88
2013	$33.50	0.82	$40.00	$31.95	$6.10	$5.99
2014	$34.00	0.82	$40.75	$32.75	$6.20	$6.12
2015	$34.50	0.82	$41.25	$33.28	$6.30	$6.24
Annual escalation thereafter +2.0%/yr.						

4. Asset retirement obligations:

The total future asset retirement obligation was determined by management and was based on Crew's net ownership interest, the estimated future cost to reclaim and abandon the Company's wells and facilities and the estimated timing of when the costs will be incurred. Crew has estimated the net present value of its total asset retirement obligation as at December 31, 2004 to be $4,984,000 (2003 - $3,896,000) based on a total future liability of $9,810,000 (2003 - $6,847,000). These payments are expected to be made over the next 41 years. An 8% (2003 – 10%) interest rate and 2% (2003 – 2%) inflation rate were used to calculate the present value of the asset retirement obligation.

The following table reconciles Crew's asset retirement obligations:

	2004	2003
Carrying amount, beginning of year	$ 3,896	$ 3,741
Increase in liabilities during the year	770	83
Accretion expense	390	72
Liabilities settled	(72)	-
Carrying amount, end of year	$ 4,984	$ 3,896

5. Bank facility:

Crew has a $27 million demand operating facility with a Canadian chartered bank, which is available by way of prime rate based loans or bankers acceptances. Advances under the facility bear interest at the bank's prime lending rate, bankers' acceptance rates plus scheduled margins. The facility revolves at the Company's discretion, is repayable on demand of the bank and is secured by a first floating charge debenture over all of Crew's real property and a first priority security interest in all of Crew's personal property.

Cash interest income received during the year ended December 31, 2004 totalled $178,000 (2003 - $30,000).

6. Share capital:

(a) Authorized:

Unlimited number of Common Shares

1,881,000 Class C non-voting performance shares ("performance shares")

(b) Common Shares:

	Number of shares	Amount
Issued for cash as private placement	3,635	$ 5,998
Issued on transfer of assets (note 2)	19,346	24,507
Common shares, December 31, 2003	22,981	30,505
Private placement issued for cash	3,000	16,050
Flow-through shares issued for cash	800	8,800
Exercise of Class C, performance shares	9	6
Buy-back of common shares	(9)	(74)
Share issue costs, net of tax of $497		(924)
Common shares, December 31, 2004	**26,781**	**$ 54,363**

(c) Contributed Surplus:

	Amount
Stock-based compensation	$ 146
Contributed surplus, December 31, 2003	146
Exercise of Class C, performance shares	(6)
Stock-based compensation	547
Contributed surplus, December 31, 2004	**$ 687**

(d) Private placement:

On September 1, 2003 the Company issued 3,635,000 units for proceeds of $5,998,000. Each unit consisted of one Class B non-voting share and one warrant. Each Class B non-voting share was subsequently exchanged for one Common Share. Total proceeds included the value of the shares and the warrants.

On May 13, 2004, the Company completed a bought-deal private placement of 3,000,000 Common Shares at a price of $5.50 per share for gross proceeds of $16,050,000.

On December 2, 2004, the Company completed a bought-deal private placement of 800,000 flow-through Common Shares at $11.00 per shares for gross proceeds of $8,800,000. Under the terms of the sale of the flow-through shares the Company has committed to renounce to the purchasers of the flow-through shares certain Canadian tax deductions totaling $8,800,000.

(e) Warrants:

As at December 31, 2004 and 2003 the Company had 3,635,000 outstanding warrants entitling the holder to acquire one Common Share of the Company at a price of $1.65 per share at any time subsequent to September 1, 2005 and prior to September 30, 2005.

(f) Stock-based compensation:

The Company measures compensation costs associated with stock-based compensation using the fair market value method and the cost is recognized over the vesting period of the underlying security. The fair value of each performance share and stock option is determined at each issue or grant date using the Black-Scholes model with the following assumptions: risk free interest rate 4.5%, expected life 4 years, and volatility 45%.

During 2004 the Company recorded $547,000, (2003 - $146,000) of compensation expense related to the performance shares and stock options, of which $273,000, (2003 - $73,000) was capitalized in accordance with the Company's full cost accounting policy.

(i) Performance shares

In conjunction with the private placement of Common Shares, the Company issued 1,881,000 performance shares to employees, officers and directors at a price of $0.01 per share. Each performance share is convertible into a fraction of a Common Share over a three-year period with the conversion rights expiring on September 1, 2007 after which, if the shares have not been converted, they are redeemed by the Company at $0.01 per share. On conversion, each performance share converts at the rate determined by subtracting $1.65 from the current market price of the Company's Common Shares and dividing the result by the current market price of the Company's Common Shares. The fair value of the performance shares at the date of issue, as calculated by the Black-Scholes method, was $0.67 per share.

	Number of shares	Amount
Issued for cash	1,881	$ 19
Class C, performance shares, December 31, 2003	1,881	19
Converted to Common shares	(12)	--
Class C, performance shares, December 31, 2004	**1,869**	**$ 19**

(ii) Stock options

The Company has a fixed stock option plan in which the Company may grant options to its employees and directors for up to 417,000 Common Shares. Under this plan, the exercise price of each option equals the market price of the Company's Common Shares on the date of grant. All granted options vest over a three-year period and have a four-year term. Stock options are granted periodically throughout the year. The fair value of the stock options granted during the year as calculated by the Black-Scholes method was $2.79 (2003 - $1.50) per option.

	Number of Options	Price Range	Weighted average exercise price
Granted	156	$3.50 to $3.75	$ 3.70
Balance, December 31, 2003	156	$3.50 to $3.75	3.70
Granted	328	$4.70 to $7.90	6.84
Cancelled	120	$3.75	3.75
Balance December 31, 2004	364	$3.50 to $7.90	$ 6.51

The following table summarizes information about the stock options outstanding at December 31, 2004:

	Outstanding at December 31, 2004	Weighted average remaining life (years)	Weighted average exercise price	Exercisable at December 31, 2004	Weighted average exercise price
$3.50 to $5.50	43	2.92	$3.79	12	$3.52
$5.50 to $7.50	276	3.75	$6.72	-	-
$7.50 to $7.90	45	3.88	$7.90	-	-
	364	3.67	$6.51	12	$3.52

(g) Per share amounts:

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average shares outstanding for the period ended December 31, 2004 was 24,946,000 (December 31, 2003 - 22,981,000).

In computing diluted earnings per share for the period ended December 31, 2004, 3,729,000 (December 31, 2003 – 2,753,000) shares were added to the weighted average number of common shares outstanding for the dilution added by the warrants, performance shares and stock options.

7. Income taxes:

(a) Income tax provision:

The provision for income taxes in the financial statements differs from the result which would have been obtained by applying the combined federal and provincial tax rate to the Company's earnings before income taxes. This difference results from the following items:

	2004	2003
Earnings before income taxes	$ 14,194	$ 2,805
Combined federal and provincial tax rate	38.73%	40.90%
Computed "expected" income tax expense	$ 5,497	$ 1,148
Increase (decrease) in income taxes resulting from:		
Non-deductible crown charges	2,044	420
Resource allowance	(1,794)	(400)
Non-taxable provincial royalty credits (ARTC)	(139)	-
Attributed Canadian royalty income	(124)	-
Stock-based compensation	213	60
Benefits relating to change in income tax rates	(307)	(35)
Other	(177)	29
Future income taxes	5,213	1,222
Capital taxes	33	18
Income taxes	$ 5,246	$ 1,240

Cash taxes paid during the period were nil.

(b) Future income tax:

The components of the Company's future income tax liability/asset are as follows:

	2004	2003
Future income tax:		
Property, plant and equipment	$ 4,868	$ (101)
Asset retirement obligation	(1,668)	(1,360)
Share issue costs	(401)	0
Other	(124)	-
Non-capital loss	-	(580)
Future income tax liability (asset)	$ 2,675	$ (2,041)

8. Financial instruments:

(a) Commodity price risk management:

At December 31, 2004, the Company had no fixed price contracts or financial instruments associated with future production.

(b) Foreign currency exchange risk:

The Company is exposed to foreign currency fluctuations as petroleum and natural gas prices received are referenced to U.S. dollar denominated prices.

(c) Credit Risk

Crew's accounts receivable are with customers and joint venture partners in the petroleum and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to several purchasers under normal industry sale and payment terms. Crew routinely assesses the financial strength of its customers. Crew may be exposed to certain losses in the event of non-performance by counterparties to commodity price contracts. Crew attempts to mitigate this risk by entering into transactions with highly rated major financial institutions.

(d) Fair value of financial instruments

The fair values of the financial instruments on the Company's balance sheet approximate their carrying values due to their short term to maturity.