

This Management's Discussion and Analysis ("MD&A") has been prepared by management and reviewed and approved by the Board of Directors of Pinecrest Energy Inc., formerly Antler Creek Energy Corp. ("Pinecrest" or the Company). This MD&A is a review of operations, current financial position and outlook for Pinecrest for the three and six months ended June 30, 2011 with comparatives for the three and six months ended July 31, 2010 and should be read in conjunction with the unaudited condensed interim financial statements for the six months ended June 30, 2011. Pinecrest received approval to change its year end from July 31 to December 31 in late 2010, consequently this MD&A reflects periods for the three and six months ended June 30, 2011 with comparative information for the three and six months ended July 31, 2010. **Due to the different period ends, the information may not be fully comparable. During calendar year 2010 there were significant changes in Pinecrest's management and operations, therefore, the most relevant comparison to the three months ended June 30, 2011 is the three months ended March 31, 2011.** This MD&A is dated as of August 11, 2011.

DESCRIPTION OF THE COMPANY

Pinecrest is a Calgary, Alberta based petroleum and natural gas exploration, production and development company, with operations in the Canadian provinces of Alberta and Saskatchewan. Pinecrest completed its recapitalization transaction in May 2010 and trades on the Toronto Stock Venture Exchange ("TSX-V") under the symbol PRY. Additional information related to the Company, including the Company's Annual Information Form ("AIF") may be found on the Canadian Securities Administrators' System for Electronic Distribution and Retrieval ("SEDAR") website at www.sedar.com.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

On January 1, 2011, Pinecrest adopted International Financial Reporting Standards ("IFRS") for financial reporting purposes. The unaudited interim condensed financial statements for the six months ended June 30, 2011 have been prepared under IFRS, with a transition date of August 1, 2009. Securities regulations require that if a change in year-end occurs, and the new year-end is less than nine months, the Company must choose the beginning of the "old reporting year" which is the twelve months ended July 31, 2010, for its transition to IFRS.

The unaudited condensed interim financial statements and the financial data contained in the MD&A have been prepared in accordance with International Accounting Standard ("IAS") 34 *Interim Financial Reporting* and are in accordance with IFRS 1 *First-time Adoption of International Financial Reporting Standards*, as issued by the International Accounting Standards Board ("IASB") and are in Canadian currency.

For all prior accounting periods prior to 2011, the Company prepared its financial statements under Canadian generally accepted accounting principles ("GAAP"). The adoption of IFRS has not had an impact on the Company's strategic decisions, operations, or cash flow. Further information on the impacts of IFRS is provided in the Accounting Changes and Pronouncements section of this MD&A as well as in Note 22 to the unaudited condensed interim financial statements.

NON-IFRS MEASURES

The Company uses the following terms for measurement within the MD&A that do not have a standardized prescribed meaning under IFRS and these measurements may differ from other companies and accordingly may not be comparable to measures used by other companies. The terms "funds flow from operations", "funds flow from operations per share", "operating netback per boe" and "cash flow netback per boe" in this MD&A are not recognized measures under IFRS. Management of the Company believes that these terms are useful, in addition to profit and loss and cash flow from operating activities as defined by IFRS, for evaluating the Company's operating performance and leverage. Funds flow from operations is expressed as cash flow from operating activities before changes in non-cash working capital and asset retirement expenditures. Funds flow from operations per share is calculated using the weighted-average basic and diluted shares used in calculating earnings per share (see "Calculation of Cash Flow from Operations" below).

Operating netback is a measure of operating margin used in capital allocation decisions. Pinecrest defines operating netback as average realized price per boe, less royalties per boe, less operating and transportation expenses per boe, plus any realized gain or loss per boe on financial instruments.

Cash flow netback is a measure of operating netback, plus other operating income less net cash general and administrative and cash interest expenses. **Readers are cautioned that these measures should not be construed as an alternative to profit or loss, or cash flow from operating activities as calculated under IFRS, as an indication of the Company's performance.**

BOE Conversion (51-101 Advisory)

In accordance with National Instrument 51-101, Standards for Disclosure of Oil and Gas Activities ("NI 51-101"), petroleum and natural gas reserves and volumes are converted to an equivalent measurement basis referred to as a "barrel of oil equivalent" ("boe") on the basis of 6 thousand cubic feet of natural gas equal to 1 barrel of oil. This conversion is based on an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. Readers are cautioned that boe may be misleading, particularly if used in isolation.

Frequently Used Terms:

The following terms are frequently used in this MD&A:

Barrel	Bbl
Barrel(s) of oil equivalent	Boe
Barrel(s) of oil equivalent per day	boe/d
Thousand cubic feet	Mcf
Thousand cubic feet per day	mcf/d
Natural gas liquids	NGL

FORWARD LOOKING STATEMENTS

Certain statements in this document constitute forward-looking statements under applicable securities laws. Such statements are based on assumptions of future events and actual results could vary from these assumptions. Events or circumstances may cause actual results to differ materially from those predicted as a result of numerous known and unknown risks, uncertainties and other factors, many of which are beyond the control of the Company. These include, but are not limited to, risks associated with petroleum and natural gas exploration, production, marketing and transportation, such as loss of market, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, imprecision of accounting estimates, environmental risk, competition from other producers and ability to access sufficient capital from internal and external sources. Although Management believes that the expectations reflected in such forward-looking statements and information are reasonable, it can give no assurance that such expectations will prove to be accurate, as results and future events could differ materially from those expected or estimated in such statements. As such, readers are cautioned not to place undue reliance on these forward-looking statements. The forward-looking statements and information contained in this document are made as of the date hereof for the purposes of providing the readers with the Company's expectations for the coming year. The forward-looking statements and information may not be appropriate for other purposes. Furthermore, the Company undertakes no obligation to update or revise these forward-looking statements or information as a result of new information, future events or otherwise.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

	Three months ended			Six months ended		
	June 30 2011	July 31 2010	% Change	June 30 2011	July 31 2010	% Change
FINANCIAL (\$ except per share amounts)						
Petroleum and natural gas sales	7,747,513	561,351	1,280	13,847,449	755,815	1,732
Funds flow from (used in) operations ⁽¹⁾	4,579,331	(263,623)	1,837	8,172,305	(217,056)	3,865
Per share - basic	\$0.03	(\$0.00)	100	\$0.05	(\$0.01)	600
Per share - diluted	\$0.02	(\$0.00)	100	\$0.04	(\$0.01)	500
Net income (loss)	1,129,484	(2,188,915)	152	802,863	(2,279,393)	135
Per share - basic	\$0.01	\$(0.04)	125	\$0.00	\$(0.08)	100
Per share - diluted	\$0.01	\$(0.04)	125	\$0.00	\$(0.08)	100
Capital expenditures	21,269,804	27,656,662	(23)	68,757,481	27,936,998	146
Debt and working capital	(10,501,868)	17,531,301	(160)	(10,501,868)	17,531,301	(160)
Common Shares Outstanding						
Weighted average – basic	170,337,311	55,822,737	205	170,131,401	30,359,064	460
Weighted average – diluted	199,998,889	75,748,837	164	199,481,192	38,166,773	423
OPERATING						
Number of producing days	91	92		181	181	
Production						
Crude oil (bbls/d)	810	71	1,041	779	49	1,490
Natural gas (mcf/d)	63	20	215	32	15	113
Natural gas liquids (bbls/d)	9	4	125	7	3	133
Barrels of oil equivalent (boe/d– 6:1)	830	78	964	792	54	1,367
Average realized price						
Crude oil (\$/bbl)	104.00	82.12	27	97.47	81.49	20
Natural gas (\$/mcf)	4.17	4.62	(10)	3.73	4.71	(21)
Natural gas liquids (\$/ bbl)	63.16	49.59	27	61.54	50.72	21
Barrels of oil equivalent (6:1)	102.55	78.24	31	96.63	77.75	24
Netback per boe (\$)						
Petroleum and natural gas sales	102.55	78.24	31	96.63	77.75	24
Royalties	(11.35)	(8.56)	33	(11.50)	(9.51)	21
Operating & transportation expenses	(21.76)	(18.54)	17	(20.00)	(19.31)	4
Operating netback	69.44	51.14	36	65.13	48.93	33
Wells drilled						
Gross	-	-		10	-	100
Net	-	-		7.0	-	100
Success rate (%)	-	-		100%	-	100

⁽¹⁾Funds flow from operations is a NON-IFRS measure

RESULTS OF OPERATIONS

The following are the highlights of Pinecrest's operations for the three months ended June 30, 2011:

- Increased the Company's low risk development drilling inventory by approximately 35% to 242 locations, based on 4 wells per section;
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- Completed and tied-in a total of 4 gross (3.5 net) horizontal oil wells in the Greater Red Earth area, for a total of 20 gross (11.1 net) horizontal wells equipped to produce as at June 30, 2011;
- Established production of over 2,300 bbls/d of light oil (prior to the suspension of the Rainbow pipeline); current production is approximately 1,900 bbls/d with approximately 200 shut in due to adverse weather/access conditions;
- Completed a major pipeline and regional gathering system, installing over 29 kilometers of pipelines;
- Completed the expansion of the Evi oil processing facility, increasing throughput to over 10,000 bbls/d of oil (~4,000 bbls/d net);
- Commenced injection on the Company's first waterflood;
- Completed and tied-in a total of 4 gross (3.5 net) horizontal oil wells in the Greater Red Earth area, for a total of 20 gross (11.1 net) horizontal wells equipped to produce as at June 30, 2011;
- Increased average daily production by 10% to 830 boe/d compared to 753 boe/d for the three months ended March 31, 2011; and by 1,367% or 792 boe/d compared to 54 boe/d for the six months ended July 31, 2010;
- Amended the \$30.0 million credit facility with a Canadian chartered bank to provide supplemental funding for the Company's general operations and capital program; and
- On August 3, 2011, Pinecrest announced a \$60 million bought-deal offering of 25,000,000 shares, plus an over-allotment option of 3,750,000 shares, at a price of \$2.40 per share. Closing is anticipated to occur on August 24, 2011.

PINECREST 2011 OUTLOOK

During the second quarter, the Company was presented with a series of unique and unrelated challenges in its core operating area of Red Earth, Alberta. Wildfires, the suspension of the Rainbow pipeline and subsequent wet conditions impacted the Company's ability to maintain continuous production from its assets. Despite these challenges, the Company's capital program has not been affected, and exit guidance has remained unchanged at 3,000 - 3,200 bbls/d of light sweet crude oil.

Additionally, the Company has made strategic investments in undeveloped land acquisition and key infrastructure projects. In the last three months, Pinecrest has successfully grown its low risk development drilling inventory by approximately 35% to 242 locations (based on 4 wells per section), and has grown its land base prospective for the Slave Point to 97 net sections, which is an increase of approximately 50%.

At Red Earth, the Company has installed over 29 km of pipelines and participated in an expansion of the Evi oil battery, allowing for increased oil production from the Company's active capital program. This investment in facility infrastructure will ensure Pinecrest has the ability to get its oil to market throughout the year, reducing reliance on the availability of trucks, road or lease conditions. Production certainty, low

processing and water disposal costs, lower overall operating costs and under normal circumstances, no trucking costs, are the immediate benefits resulting from the investment in this key producing infrastructure (current incremental trucking charges attributable to the Rainbow pipeline disruption are approximately \$8/bbl).

Due to the challenges previously discussed, Pinecrest is in the process of optimizing production from its final three wells in its winter drilling season. All three wells are producing at a restricted rate while still recovering load water from their fracture stimulation treatments. The Company is confident that the wells will meet or exceed the Company's type curve. The average initial production from the three wells is as follows:

Average Days on Production	24
Average Oil rate	262 bbls/d
Average Current rate	308 bbls/d

Pinecrest has been successful in assembling a significant land position in the Greater Red Earth Slave Point play, and is now focused on the execution of an aggressive capital program to organically grow its reserves, production and cash flow per share. Pinecrest's management team and its Board of Directors has been focused on the identification; evaluation and acquisition of high working interest, operated lands in the emerging Slave Point resource play. The successful execution of this plan has resulted in the Company assembling a significant land position, a significant drilling inventory and strategic producing infrastructure in the heart of the Slave Point light oil resource play.

PRODUCTION

Pinecrest increased daily production by 964% for the three months ended June 30, 2011 to 830 boe/d compared to 78 boe/d for the three months ended July 31, 2010. Production for the six months ended June 30, 2011 increased by 1,374% over the six month period ended July 31, 2010. This large increase in production reflects production from the successful drilling program in the Greater Red Earth area of Alberta, which commenced in early October 2010, and property acquisitions which closed between mid-July 2010 and late December 31, 2010.

Production for the three months ended June 30, 2011 increased by 10% to 830 boe/d over the quarter ended March 31, 2011 (753 boe/d) due to wells drilled late in the first quarter of 2011. Even though production increased for the three months ended June 30, 2010, it was lower than expected due to forest fires in the Slave Lake area, a third-party sales-oil pipeline break and heavy rain fall in the Evi area resulting in a significant portion of Pinecrest's Alberta production being shut-in. During the quarter ended June 30, 2011, a limited amount of sales oil was by-passing the third-party pipeline system and was trucked from the Company's newly expanded treating facility to various clean-oil sales terminals in the surrounding area. Currently, production has resumed in the Greater Red Earth area, and is being trucked from the Company's treating facility in the Evi field.

Production in the Viewfield area of southeast Saskatchewan was also negatively affected due to flooding. Currently six of the Company's twelve horizontal wells are producing in Saskatchewan.

	Three months ended			Six months ended		
	June 30 2011	July 31 2010	%Change	June 30 2011	July 31 2010	%Change
Number of days	91	92	-	181	181	-
Crude oil (bbls/d)	810	71	1,041	779	49	1,489
Natural gas (mcf/d)	63	20	215	32	15	113
Natural gas liquids (bbls/d)	9	4	125	7	3	133
Total (boe/d - 6:1)	830	78	964	792	54	1,367
Crude oil (%)	98	91	7	98	91	7
Natural gas (%)	1	4	(3)	1	3	(2)
Natural gas liquids (%)	1	5	(4)	1	6	(5)
Total (%)	100	100	-	100	100	-

Pinecrest's commodity mix for the three and six months ended June 30, 2011 was comprised of 99% oil and NGL's and 1% natural gas, which is consistent with the quarter ended March 31, 2011. The change in commodity mix from the three and six months ended July 31, 2010 reflects production in Alberta, which is primarily oil, with minimal associated gas and liquids production.

Production from the Company's main operating regions is as follows:

	Three months ended			Six months ended		
	June 30 2011	July 31 2010	%Change	June 30 2011	July 31 2010	%Change
boe/d						
Greater Red Earth	695	15	4,533	626	8	7,725
Southeast Saskatchewan	135	63	114	165	46	259
Total	830	78	964	791	54	1,365

PETROLEUM AND NATURAL GAS REVENUE

(\$)	Three months ended			Six months ended		
	June 30 2011	July 31 2010	%Change	June 30 2011	July 31 2010	%Change
Petroleum and Natural Gas Sales	7,747,513	561,351	1,280	13,847,449	755,815	1,732
Royalties	(857,434)	(61,386)	1,297	(1,648,407)	(92,458)	1,683
Petroleum and Natural Gas Revenue	6,890,079	499,965	1,278	12,199,042	663,357	1,739

PETROLEUM AND NATURAL GAS SALES

Petroleum and natural gas sales (before royalties) increased 1,280% to \$7,747,513 for the three months ended June 30, 2011 up from \$561,351 for the three months ended July 31, 2010 and increased 1,732% to \$13,847,449 for the six months ended June 30, 2011 compared to the six months ended July 31, 2010. The increase in sales is primarily the result of increased production and higher realized average prices for the three and six months ended June 30, 2011 reflecting the Company's sales from new horizontal drilling and property acquisitions as compared to the prior year.

Petroleum and natural gas sales (before royalties), increased 27% to \$7,747,513 for the three months ended June 30, 2011 up from \$6,099,936 for the three months ended March 31, 2011. The increase over the prior quarter is due mainly to volume increases resulting from the Company's first quarter drilling program.

(\$)	Three months ended			Six months ended		
	June 30	July 31	%Change	June 30	July 31	%Change
	2011	2010		2011	2010	
Crude oil sales	7,670,228	536,266	1,330	13,745,487	722,133	1,803
Natural gas sales	23,959	8,662	1,766	21,836	12,412	76
Natural gas liquids sales	53,326	16,423	2,247	80,126	21,270	277
Total sales	7,747,513	561,351	1,280	13,847,449	755,815	1,732

REALIZED PRICES

Pinecrest realized an average price of \$102.55 per boe for the three months ended June 30, 2011, a 31% increase over the three month period ended July 31, 2010. An average price of \$96.63 per boe was realized for the six months ended June 30, 2011, an increase of 24% compared to \$77.75 per boe for the six months ended July 31, 2010. The current year increase is due to light crude oil price increases over the prior year.

Pinecrest realized an average price of \$102.55 per boe for the three months ended June 30, 2011; a 14% increase compared to \$90.03 per boe for the three months ended March 31, 2011.

(\$)	Three months ended			Six months ended		
	June 30	July 31	%Change	June 30	July 31	%Change
	2011	2010		2011	2010	
Average Realized Prices						
Crude oil (\$/bbl)	104.00	82.12	27	97.47	81.49	20
Natural gas (\$/mcf)	4.17	4.62	(10)	3.73	4.71	(21)
Natural gas liquids (\$/bbl)	63.16	49.59	27	61.54	50.72	21
Total (\$/boe – 6:1)	102.55	78.24	31	96.63	77.75	24
Benchmark Prices						
Edmonton light crude (\$/bbl)	102.63	72.81	41	95.57	77.19	24
AECO natural gas (\$/Mmbtu)	3.84	3.91	(2)	3.82	4.43	(14)

Oil Prices

The Company realized an average oil price of \$104.00/bbl for the three months ended June 30, 2011, an increase of 27% over the three months ended July 31, 2010. In addition, the average realized oil price increased by 20% to \$97.47/bbl for the six months ended June 30, 2011 compared to \$81.49/bbl for the six months ended July 31, 2010. Pinecrest does not have any commodity price swaps or hedges in place, therefore the Company's crude oil prices are based on Alberta's Edmonton light stream, adjusted for quality differentials. The Company realizes a small pricing premium over the benchmark price due to the overall high quality of the Slave Point and Granite Wash light sweet oil production in Red Earth and the Bakken light sweet oil production in southeast Saskatchewan.

Oil prices for the three months ended June 30, 2011 increased by 15% to \$104.00/bbl over the three months ended March 31, 2011. This increase reflects the change in crude oil spot prices for the period.

Natural Gas Prices

The Company realized an average gas price of \$4.17/mcf for the three months ended June 30, 2011 a 10% decrease compared to \$4.62/mcf for the three months ended July 31, 2010. The average realized gas price for the six months ended June 30, 2010 was \$3.73/mcf, a 21% decrease from the six months ended July 31, 2010. The Company's natural gas prices are based on the Alberta AECO reference price. Due to the high heating content of the Company's sweet solution gas conserved from its Bakken oil production in Saskatchewan, Pinecrest receives premium pricing as compared to the AECO benchmark. Natural gas prices remain relatively low, mainly due to a supply/demand imbalance.

Liquids Prices

The Company's natural gas liquids prices are based on market prices and vary depending on the specific proportion of liquids products in the Company's production mix. Pinecrest recorded an increase of 27% in natural gas liquids price to \$63.16/bbl in the three months ended June 30, 2011 compared to the three months ended July 31, 2010. The realized natural gas liquids price for the six months ended June 30, 2010 was \$61.54/bbl a 21% increase over the six months ended July 31, 2010. Natural gas liquids prices were \$63.16/bbl compared to \$58.56/bbl in the three months ended March 31, 2011.

Risk Management

The risk exposure inherent in fluctuations in the price of crude oil and natural gas, the US/Cdn dollar exchange rate and interest rates are monitored by the Company's management and its board of directors. A hedging policy has been established to mitigate these risks. Currently, the Company has not undertaken any risk management contracts or commodity price contracts, and therefore has no realized or unrealized gains or losses in the three months and six months ended June 30, 2011 nor were there any for the three months and six months ended July 31, 2010.

ROYALTY EXPENSE

The following table provides a summary of royalty expenses for the three months ended June 30, 2011 and July 31, 2010, and the six months ended June 30, 2011 and July 31, 2010:

	Three months ended			Six months ended		
	June 30	July 31	%Change	June 30	July 31	%Change
	2011	2010		2011	2010	
Royalty \$						
Crown	548,697	9,046	5,966	927,311	9,046	10,151
Freehold and freehold production tax	285,283	46,463	514	667,285	73,388	809
Gross overriding and other	23,454	5,877	299	53,811	10,024	437
Total royalties	857,434	61,386	1,297	1,648,407	92,458	1,683
Average Royalty Rate (% of sales)						
Crown	7	2	250	7	1	600
Freehold and freehold production tax	4	8	(50)	5	10	(50)
Gross overriding and other	-	1	(100)	-	1	(100)
Total	11	11	-	12	12	-
\$ Per boe	11.35	8.56	33	11.50	9.51	21

Royalties were \$857,434 (11% of sales, before royalties) for the three months ended June 30, 2011 compared to \$61,386 (11% of sales, before royalties) for the three months ended July 31, 2010. Royalties were \$1,648,407 (12% of sales, before royalties) for the six months ended June 30, 2011 compared to \$92,458 (12% of sales, before royalties) for the six months ended July 31, 2010.

Total royalty expense increased to \$857,434 for the three months ended June 30, 2011 by 8% compared to \$790,973 for the three months ended March 31, 2011 but decreased to an average of 11% of sales, before royalties compared to 13% of sales, before royalties for the three months ended March 31, 2011. The average royalty rate for the three months ended June 30, 2011 was lower than the prior three months as a result of the newly drilled wells qualifying for the Alberta Horizontal Oil New Well Royalty Rates. New horizontal drilling in the Greater Red Earth area qualifies for lower royalty rates which were introduced by the Alberta Government in 2009. A total of four (3.5 net) new wells were placed on production in the three months ended June 30, 2011, all of which were in the Red Earth area. Pinecrest placed a total of 20 wells on production during the six months ended June 30, 2011, of which 16 wells were in Alberta and will attract the Horizontal Oil New Well Royalty Rates ("HONWRR", which provide for a maximum royalty rate of 5% on production between 24 to 30 months or on the first 60,000 to 70,000 barrels, whichever comes first ("HONWRR" is a function of the total measured depth of each horizontal well)).

Pinecrest's production in Saskatchewan is from horizontal Bakken wells which are on freehold lands and attract an overall royalty rate of approximately 6% of sales. Corporate freehold royalty rates as a percentage of sales are lower for the three and six months ended June 30, 2011 compared to the three and six months ended July 31, 2010 due to an increase in the production mix from the Alberta wells.

OPERATING AND TRANSPORTATION EXPENSE

Operating and transportation expense was \$1,643,983 an increase of 1,136% in the three months ended June 30, 2011 compared to \$133,038 for the three months ended July 31, 2010. Operating and transportation expenses increased by 1,427% to \$2,866,572 for the six months ended June 30, 2011 from \$187,672 for the six months ended July 31, 2010. These increased costs are primarily the result of increased production in the Greater Red Earth area for the current year.

Per unit operating and transportation expense increased to \$21.76/boe for the three months ended June 30, 2011 compared to \$18.54/boe for the three months ended July 31, 2010 and increased marginally from \$19.31/boe for the six months ended July 31, 2010 to \$20.00 per boe for the six months ended June 30, 2011. By comparison, operating and transportation costs for the three months ended June 30, 2011 were \$21.76/boe compared to \$18.04/boe for the three months ended March 31, 2011. Increased operating and transportation costs per boe for the three months ended June 30, 2011 are primarily due to increased trucking costs which were incurred as a result of the Rainbow Pipeline disruption. The incremental increase in trucking costs was approximately \$8.00 per barrel for the quarter. Pinecrest anticipates that with the resumption of the Rainbow pipeline, continued exploitation of its assets and increased production in its core operating area that operating and transportation expenses per boe will decrease significantly.

	Three months ended			Six months ended		
	June 30 2011	July 31 2010	%Change	June 30 2011	July 31 2010	%Change
(\$) Transportation and operating expense	1,643,983	133,038	1,136	2,866,572	187,672	1,427
\$ Per boe	21.76	18.54	17	20.00	19.31	4

OTHER OPERATING INCOME

Other operating income is comprised primarily of third party-processing and road-use fees. Pinecrest acquired an interest in an oil treating facility at the end of December 31, 2010 and has subsequently earned third-party fees associated with the properties in the Evi field, located in the Red Earth area of Alberta. Prior to December 31, 2010, Pinecrest did not own any interests in facilities where third-party fees could be earned.

Other operating income for the three months ended June 30, 2011 increased to \$.065 per boe as compared to \$0.17 per boe for the three months ended March 31, 2011, mostly due to increased road use income.

(\$)	Three months ended			Six months ended		
	June 30 2011	July 31 2010	%Change	June 30 2011	July 31 2010	%Change
Other operating income	49,863	-	100	61,359	-	100
Interest income	-	(882)	100	160	(882)	118
Total other operating income	49,863	(882)	5,753	61,519	(882)	7,075
\$ Per boe	\$0.65	\$(0.12)	642	\$0.42	\$(0.09)	567

EXPLORATION EXPENSE

Under IFRS, costs such as undeveloped land acquisition and lease costs, geological and geophysical costs and exploratory drilling costs associated with determining the technical feasibility and commercial viability of the land are capitalized and classified as exploration and evaluation assets. Costs associated with undeveloped lands that expire in the period are expensed in the statement of comprehensive loss. Under the full cost method of accounting for oil and gas properties under Canadian GAAP, these costs would be moved into the cost pool to be depleted.

(\$)	Three months ended			Six months ended		
	June 30 2011	July 31 2010	%Change	June 30 2011	July 31 2010	%Change
Exploration expense	246,680	-	100	2,126,108	-	100
\$ Per boe	\$3.27	\$0.00	100	\$14.84	\$0.00	100

Exploration expense associated with expired undeveloped land of \$246,680 (\$3.27/boe) was recorded for the three months ended June 30, 2011 (three months ended March 31, 2011 – \$1,879,428, \$27.74/boe; three months ended July 31, 2010 – nil). Exploration expense of \$2,126,108 (\$14.84/boe) was recorded for the six months ended June 30, 2011 (six months ended July 31, 2010 – nil). These expired leases were acquired by the Company through the seven property acquisitions that closed between July and November 2010. Pinecrest's strategy is to only permit lands that are not key to our exploitation plans to expire.

GENERAL AND ADMINISTRATIVE EXPENSE

General and administrative expenses decreased by 61% to \$1,005,208 (\$13.30/boe) for the three months ended June 30, 2011 compared to \$2,568,564 (\$357.98/boe) for the three months ended July 31, 2010 and decreased by 31% for the six months ended June 30, 2011 compared to \$2,627,072 (\$270.26/boe) for the six months ended July 31, 2010. The current year decrease in general and administrative expense primarily reflects a decrease in share based payments from the three and six months ended July 31, 2010. General and administrative costs have decreased on a per boe basis for the three and six months ended June 30, 2011 due to decreased share-based payments, increased overhead recoveries, increased capitalized expenses and increased production for the same periods.

Overhead recoveries increased for the three and six months ended June 30, 2011 to \$342,668 and \$858,369 respectively and are directly related to the increase in the Company's operated capital expenditures for the three and six months ended June 30, 2011. These recoveries are charged to capital projects as part of the permitted expenditures under the joint operating agreements with joint venture partners. As such, the Company's partners have been billed for their share of these costs incurred during

the three and six months ended June 30, 2011. In addition, Pinecrest capitalizes personnel expenses directly attributable to new capital projects. During the three months ended June 30, 2011 a total of \$226,320 (\$368,048 for the six months ended June 30, 2011) was capitalized to projects, which is approximately 15% of the year to date gross personnel expense.

(\$)	Three months ended			Six months ended		
	June 30	July 31	%Change	June 30	July 31	%Change
	2011	2010		2011	2010	
General and administrative	1,250,545	725,598	72	2,413,029	784,106	208
Overhead recoveries	(342,668)	(1,190)	28,696	(858,369)	(1,190)	72,032
Capitalized	(226,320)	(113,842)	99	(368,048)	(113,842)	223
Net cash general & administrative	681,557	610,566	12	1,186,612	669,074	77
Share based payments (net) ¹	323,651	1,957,998	(84)	624,724	1,957,998	(68)
General and administrative	1,005,208	2,568,564	(61)	1,811,336	2,627,072	(31)
\$ Per boe net cash G&A	9.02	85.06	(89)	8.28	68.83	(88)
\$ Per boe share based payments	4.28	272.92	(98)	4.36	201.43	(98)
\$ Per boe	13.30	357.98	(96)	12.64	270.26	(95)

¹Share-based payments (net) is a non-cash charge to the statement of comprehensive income (loss)

Share-based Payments

The Company has an incentive stock option plan whereby options may be granted from time to time to directors, officers, employees and consultants of the Company with shares to be reserved for issuance as options not to exceed 10% of the issued and outstanding common shares. One third of the options vest immediately, with one third vesting in 12 months and the remainder vesting in 24 months from date of grant. Stock awards granted are measured at fair value at the grant date, with graded vesting, and expensed over the vesting period, based on the Company's estimate of stock awards that will vest. When stock awards vest in installments each installment is accounted for as a separate arrangement. A total of 50,000 stock options were issued in the three months ended June 30, 2011. See note 15 in the unaudited condensed interim financial statements for further disclosures about the fair values used to estimate the current quarter share-based payments.

Net share-based payment expense was \$323,651 (\$4.28 per boe) for the three months ended June 30, 2011 compared to \$1,957,998 (\$272.92/boe) for the three months ended July 31, 2010. The decrease is due mainly because during the three and six months ended July 31, 2010 a total of 4,830,000 performance shares were issued to various service providers of Pinecrest all of which immediately vested and resulted in a non-cash charge to the statement of comprehensive loss of \$1,103,424. In addition, stock-based compensation for the three and six months ended July 31, 2010 included a deemed fair value charge of \$1,152,702 that was related to the issue of flow-through shares to various service providers to Pinecrest. A total of \$298,128 of share-based payments was capitalized to property, plant and equipment in the three and six month period ending July 31, 2010. None of these charges occurred during the three and six months ended June 30, 2011.

(\$)	Three months ended			Six months ended		
	June 30 2011	July 31 2010	%Change	June 30 2011	July 31 2010	%Change
Total share-based payments	427,491	2,256,126	(81)	831,267	2,256,126	(63)
Share-based payments capitalized	(103,840)	(298,128)	(65)	(206,543)	(298,128)	(31)
Share-based payments expense	323,651	1,957,998	(83)	624,724	1,957,998	(68)
\$ per boe	4.28	272.92	(84)	4.36	201.43	(68)
Number of stock awards granted ⁽¹⁾	50,000	4,830,000	(99)	50,000	4,830,000	(99)
Number of stock awards exercisable	6,505,003	4,830,000	35	6,505,003	4,830,000	35

⁽¹⁾ Stock awards include stock options and performance warrants

FINANCE EXPENSE

Accretion expense

Pinecrest records its decommissioning liability as the present value of the estimated abandonment and reclamation costs for its well sites, pipelines and facilities using a credit adjusted risk-free interest rate. Management reviews and updates, when necessary, the costs and discount rate at each reporting period to reflect current market assessments of the risks specific to the obligation. Changes in these estimates are added or deducted to the liability with an offset to the asset. In addition, the liability is increased when properties are acquired, new wells are drilled and due to the passage of time.

Accretion expense for the three months ended June 30, 2011 increased by 2,769% compared to \$930 for the three months ended July 31, 2010. Accretion expense for the six months ended June 30, 2011 increased 1,543% to \$44,643 compared to \$2,717 for the six months ended July 31, 2010. The increase is due mainly to increased overall fair value of the obligations relating to an increased number of wells and facilities for the three and six months ended June 30, 2011.

Accretion expense for the three months ended June 30, 2011 increased 49% to \$26,685 compared to \$17,958 for the three months ended March 31, 2011. The increase is due mainly to the passage of time resulting in an increase in the expense. There were no changes in the discount or inflation rate used during the three months ended June 30, 2011.

Interest expense

Interest expense for the three months ended June 30, 2011 increased 100% to \$41,219 compared to the three months March 31, 2011 which was nil. Interest expense for the three months ended June 30, 2011 increased by 278% compared to \$10,894 for the three months ended July 30, 2010. For the six months ended June 30, 2011 interest expense increased to \$41,219 (189%) compared to \$14,277 for the six months ended July 31, 2011. Interest recorded for the three and six months ended June 30, 2011 relates to the amended and restated \$30.0 million credit facility with a Canadian chartered bank. (See "Liquidity and Capital Resources").

Interest recorded for the three months and six months ended July 31, 2010 was due to an outstanding related party loan, with an interest rate of 4% per annum. The related party loan balance was paid in full in May 2010 with proceeds from the Company's recapitalization transaction.

(\$)	Three months ended			Six months ended		
	June 30 2011	July 31 2010	%Change	June 30 2011	July 31 2010	%Change
Accretion ⁽¹⁾	26,685	930	2,769	44,643	2,717	1,543
Interest	41,219	10,894	278	41,219	14,277	189
Total finance expense	67,904	11,824	474	85,862	16,994	405
\$ Per boe	0.90	1.65	(45)	0.60	1.74	(66)

⁽¹⁾ Accretion expense is a non-cash charge to the statement of comprehensive income (loss)

DEPLETION AND DEPRECIATION EXPENSE

Under IFRS, the Company has chosen to deplete its oil and gas assets using proved plus probable reserves as the depletion base. Costs relating to the development of petroleum and natural gas reserves are capitalized. These costs, along with estimated future development capital expenditures to be incurred in order to develop proved and probable reserves, and estimated costs relating to asset retirement obligations, are depleted on a unit of production basis, using estimated proved plus probable petroleum and natural gas reserves. Corporate assets are depreciated using the declining balance method, at rates ranging from 20% - 30%.

Depletion and depreciation increased to \$2,459,413 (\$32.55/boe) for the three months ended June 30, 2011 compared to \$1,725,189 (\$25.46/boe) for the three months ended March 31, 2011. The increase in depletion and depreciation is primarily due to the addition of costs associated with the Company's oil transportation pipeline and related facilities which was commissioned in early April 2011. No new reserves were added during the second quarter as there was no drilling activity.

Depletion and depreciation increased for the three months ended June 30, 2011 to \$2,459,413 (\$32.55/boe) compared to \$125,223 (\$17.45/boe) for the three months ended July 31, 2010 and increased for the six months ended June 30, 2011 to \$4,184,602 (\$29.20/boe) compared to \$253,011 (\$25.89/boe) for the six months ended July 31, 2010. The per unit increase in depletion and depreciation is the result of significant additions to the capital base for facilities and pipelines and increased production for the three and six months ended June 30, 2011

(\$)	Three months ended			Six months ended		
	June 30 2011	July 31 2010	%Change	June 30 2011	July 31 2010	%Change
Depletion and depreciation expense⁽¹⁾	2,459,413	125,223	1,864	4,184,602	253,011	1,554
\$ Per boe	32.55	17.45	87	29.20	26.03	12

⁽¹⁾ Depletion and depreciation is a non-cash charge to the statement of comprehensive loss.

NET EARNINGS AND CASH FLOW

Net Earnings

Pinecrest recorded net income of \$1,129,484 (\$0.01 per basic and diluted share) in the three months ended June 30, 2011; an increase of 152% compared to a net loss of \$2,188,915 (loss of \$0.04 per basic and diluted share) in the three months ended July 31, 2010. Net income for the six months ended June 30, 2011 was \$802,863 (\$0.00 per basic and diluted share) compared to a net loss of \$2,279,393 (loss of \$0.08 per basic and diluted share) for the six months ended July 31, 2010. The increase in net income for the three and six months ended June 30, 2011 reflects an increase in operating netbacks (increased net revenues and reduced operating and transportation expenses) offset by non-cash charges for exploration expense and depletion and depreciation and a decrease in general and administrative expenses (mainly share-based payments).

Cash Flow

During the three months ended June 30, 2011, Pinecrest increased cash flow from operations by 1,058% to \$9,028,260 (\$0.05 per basic and diluted share), compared to cash flow used in operations of \$942,473 (cash flow use of \$0.02 per basic and diluted share). The Company recorded a 1,382% increase in cash flow from operations of \$11,375,610 (\$0.07 per basic and \$0.06 per diluted share) for the six months ended June 30, 2011 compared to a cash flow deficit from operations of \$887,226 (loss of \$0.03 per basic and diluted share) for the six months ended July 31, 2010. Increased cash flow from operations was primarily the result of an increase in petroleum and natural gas revenue, offset, in part by increased operating expenses, a decrease in general and administrative expenses and an increase in the change in non-cash working capital for the six months ended June 30, 2011.

Funds Flow from Operations (Non-IFRS Measure)

The Company recorded funds flow from operations for the three months ended June 30, 2011 of \$4,579,331 (\$0.03 per basic and \$0.02 per diluted share) compared to funds flow use of \$263,623 (\$0.00 per basic and diluted share) for the three months ended July 31, 2010. Funds flow from operations increased by 3,865% to \$8,172,305 (\$0.05 per basic and \$0.04 per diluted share) for the six months ended June 30, 2011, compared to a funds flow use from operations of \$217,056 (\$0.01 per basic and diluted share) for the six months ended July 31, 2010.

Calculation of Funds Flow from Operations⁽¹⁾

\$	Three months ended			Six months ended		
	June 30 2011	July 31 2010	%Change	June 30 2011	July 31 2010	%Change
Cash flow from (used in) operations (IFRS)	9,028,260	(942,473)	1,058	11,375,610	(887,226)	1,382
Deduct:						
Change in non-cash working capital	4,448,929	(678,850)	755	3,203,305	(670,170)	578
Funds flow from (used in) operations (Non-IFRS)	4,579,331	(263,623)	1,837	8,172,305	(217,056)	3,865
Per Share – Basic	\$0.03	\$(0.00)	300	\$0.05	\$(0.01)	600
Per Share - Diluted	\$0.02	\$(0.00)	200	\$0.04	\$(0.01)	500

⁽¹⁾ Funds flow from Operations is a Non-IFRS measure and is defined by the Company as cash flow from operations, less the change in non-cash working capital and expenditures on decommissioning

Netbacks

Pinecrest realized a 36% increase in operating netback to \$69.44/boe for the three months ended June 30, 2011, compared to the three months ended July 31, 2010 and an increase of 33% (\$65.13/boe) compared to \$48.93/boe for the six months ended July 31, 2010. Increased operating netbacks are due primarily to increased production and commodity prices, offset by increased per unit operating and transportation expenses (due to higher costs associated with fluid trucking) for the three months ended June 30, 2011. Operating netbacks for the three months ended June 30, 2011 increased by 15% to \$69.44/boe compared to \$60.31/boe for the three months ended March 31, 2011. The quarter over quarter growth was due mostly to increased production and commodity prices for the three month period.

The follow table summarizes the net income (loss) on a barrel of oil equivalent for the periods indicated:

\$ Per boe	Three months ended			Six months ended		
	June 30 2011	July 31 2010	%Change	June 30 2011	July 31 2010	%Change
Average realized price	102.55	78.24	31	96.63	77.75	24
Royalty expenses	(11.35)	(8.56)	33	(11.50)	(9.51)	21
Operating & transportation expenses	(21.76)	(18.54)	17	(20.00)	(19.31)	4
Operating netback	69.44	51.14	36	65.13	48.93	33
Other income (loss)	0.65	(0.12)	642	0.43	(0.09)	578
Cash general & administrative expenses	(9.02)	(85.06)	(89)	(8.28)	(68.83)	(88)
Cash financing	(0.55)	(1.52)	(64)	(0.29)	(1.47)	(80)
Cash flow netback	60.52	(35.56)	270	56.99	(21.46)	366
Exploration expense ⁽¹⁾	(3.27)	-	100	(14.84)	-	100
Depletion and depreciation	(32.55)	(17.45)	87	(29.20)	(26.03)	12
Accretion	(0.35)	(0.13)	169	(0.31)	(0.28)	11
Share-based payments (net)	(4.28)	(272.92)	(98)	(4.36)	(201.43)	(98)
Income tax expense	(5.13)	20.96	125	(2.67)	14.70	118
Net income (loss)	14.94	(305.10)	105	5.61	(234.50)	102

⁽¹⁾Exploration expense represents the cost of expired lands acquired in previous property acquisitions

CAPITAL EXPENDITURES, ACQUISITIONS AND CAPITAL RESOURCES

Capital Expenditures

During the three months ended June 30, 2011, Pinecrest spent a total of approximately \$21.3 million compared to approximately \$27.7 million in the three months ended July 31, 2010. Expenditures for the three months ended June 30, 2011 were primarily on crown land acquisitions in Alberta and well equipping, facilities and pipeline costs. Total capital expenditures for the six months ended June 30, 2011 were \$68.8 million compared to \$27.9 million for the six months ended July 31, 2010. The current year expenditures reflect the costs associated with the drilling program, including completion and well equipping and tie-in costs and major facilities upgrade expenditures in the Greater Red Earth area of Alberta. To the end of June 30, 2011, a total of approximately \$4.7 million of costs were incurred for projects under construction.

\$	Three months ended			Six months ended		
	June 30	July 31	%Change	June 30	July 31	%Change
	2011	2010		2011	2010	
Evaluation and exploration(E&E) expenditures						
Undeveloped land	13,256,883	9,369,476	41	13,288,603	9,369,476	42
Geological and geophysical	3,316	-	100	3,316	-	100
Drilling	(4,114)	-	(100)	706,687	-	100
E&E acquisitions	2,405,590	15,768,034	(85)	2,425,590	15,768,034	(85)
	15,661,675	25,137,510	(38)	16,424,196	25,137,510	(35)
Property, plant and equipment expenditures						
Geological and geophysical	16,142	-	100	21,312	-	100
Drilling and completions	461,285	36,965	1,148	31,222,008	150,920	20,588
Equipment and facilities	4,774,303	26,299	18,054	20,108,500	77,680	25,786
Property acquisitions	115,540	2,196,807	(95)	577,070	2,311,807	(75)
Capitalized administrative	226,300	113,842	99	368,028	113,842	223
Corporate assets	14,558	145,239	(90)	36,367	145,239	(75)
	5,608,128	2,519,152	123	52,333,285	2,799,488	17,694
Total capital expenditures	21,269,803	27,656,662	(23)	68,757,481	27,936,998	146

Drilling Results

Pinecrest did not drill any wells in the three months ended June 30, 2011. A total of 9 gross (6.0 net) horizontal wells were drilled and completed, and 1 gross (1 net) vertical test well was drilled in the first six months ended June 30, 2011. In addition, Pinecrest equipped a total of 12 gross (8.8 net) operated oil wells during the first six months ended June 30, 2011.

From May 2010 to July 2011, Pinecrest has drilled a total of 16 gross (8.8 net) horizontal wells into the Slave Point formation, and 1 gross (1 net) vertical well into the Banff formation in the Greater Red Earth area of Alberta. In addition, Pinecrest has drilled 4 gross (2.3 net) horizontal wells in the Bakken formation in southeast Saskatchewan. Of the total 21 gross (12.1 net) wells drilled, Pinecrest operated 16 gross (11.1 net) wells. Subsequent to June 30, 2011, Pinecrest has rig released 1 gross (0.95 net) Slave Point horizontal well and spudded an additional 1 gross (1 net) Slave Point horizontal oil well in the Red Earth area.

Number	Recapitalization to Date (from May 2010)		Three months ended June 30 2011		Three months ended March 31 2011		Five months ended December 31 2010	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Crude Oil	20	11.1	-	-	9	6.0	11	5.1
Standing	1	1.0	-	-	1	1.0	-	-
Total	21	12.1	-	-	10	7.0	11	5.1
Success rate (%)	100	100	100	100	100	100	100	100

Land Holdings

At June 30, 2011, Pinecrest owned a total of 58,590 net acres of undeveloped land, representing a 54% increase compared to the first quarter ended March 31, 2011, and a 45% increase in undeveloped land as at December 31, 2010. Pinecrest's land acquisition strategy has been to acquire highly prospective mineral rights at 100% working interest, where possible. As such, Pinecrest's average working interest in its land holding has increased to 85% at June 30, 2011, compared to 78% at March 31, 2011. During the quarter a total of 144 net undeveloped acres of land in non-core fields expired resulting in an exploration expense charge of \$246,680 to the statement of comprehensive income.

Pinecrest's land acquisition is concentrated on the emerging Slave Point light oil play in the Greater Red Earth area of Alberta. The majority of the Slave Point rights are encompassed by the same land tenure documents that overlay productive petroleum and natural gas rights, and as such are not technically defined as undeveloped lands.

(Acres)	As at June 30, 2011		As at March 31, 2011		% Change		As at December 31, 2010	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Developed	13,163	6,575	12,949	6,257	2	5	12,189	5,681
Undeveloped	63,249	58,590	43,561	37,951	45	54	48,451	40,309
Total	76,412	65,165	56,510	44,208	35	47	60,640	45,990
Average working interest		85%		78%				76%

Pinecrest's ongoing land acquisition strategy is focused on building the land base with a high working interest, through Crown land sales and strategic property acquisitions to facilitate internally generated prospects.

LIQUIDITY AND CAPITAL RESOURCES

Total Debt and Working Capital

\$	As at June 30, 2011	As at March 31, 2011	As at December 31, 2010
Total current assets	12,376,629	47,317,237	62,897,107
Total current liabilities	(14,096,127)	(41,422,725)	(13,430,826)
Working capital surplus (deficiency)	(1,719,498)	5,894,512	49,466,281
Credit facility	(8,782,370)	-	-
Total debt and working capital	(10,501,868)	5,894,512	49,466,281

Working Capital

Pinecrest funded its capital expenditures program during the first six months of 2011 with a combination of cash flow from operations and bank debt. At June 30, 2011, Pinecrest had a working capital deficiency (current assets minus current liabilities) of \$1.7 million as compared to a working capital surplus of \$5.9 million at March 31, 2011 and a working capital surplus of \$49.5 million at December 31, 2010. The deficit at the end of June 30, 2011 results from expenditures associated with completion activities, and facilities and pipeline projects which were completed near the end of April 2011.

At June 30, 2011 the major components of working capital included: accounts receivable from joint interest partners for operations and capital programs (64 %); accounts receivable from marketers for June sales (20%) which was substantially received in July 2011; accounts receivable from government and other parties (16%), which was offset by trade payables (65%) and accrued capital and operating expenses (35%).

Pinecrest manages its working capital deficit using its cash flow from operations and advances under its credit facility (see below). A working capital deficit does not reduce the amount available under the credit facility. Pinecrest did not have any liquidity concerns during the six months ended June 30, 2011.

Credit Facility

On May 18, 2011, Pinecrest amended and restated its \$30.0 million credit facility with a Canadian chartered bank to provide supplemental funding for the Company's general operations and capital program. At June 30, 2011, the amount outstanding under Pinecrest's credit facility was \$8,782,370, net of unamortized fees and interest of \$67,600.

The following table shows the amount of maximum credit available under the Company's credit facility as at June 30, 2011 and December 31, 2010:

	As at June 30, 2011	As at December 31, 2010
Maximum borrowing base limit ⁽¹⁾	\$30,000,000	\$30,000,000
Amount drawn on credit facility	(8,850,000)	-
Total available credit facility	\$21,150,000	\$30,000,000

⁽¹⁾The next review of the borrowing base is schedule for November 30, 2011.

The credit facility is secured by a \$100,000,000 general debenture and a general security interest on all of the present and future acquired assets of the Company. The credit facility constitutes a revolving facility for a 364 day term which is extendable annually for a further 364 day revolving period if requested by the Company and accepted by the lender. If the revolving period is not extended, the undrawn portion of the facility will be cancelled and the amount outstanding will convert to a 366 day non-revolving term facility. The amounts outstanding under the non-revolving facility are required to be repaid at the end of the non-revolving term being May 18, 2013. The current term conversion date for the credit facility is May 18, 2012.

Management anticipates that the Company will continue to have adequate liquidity to fund future working capital requirements and capital expenditures through combination of operating cash flow, the availability of the credit facility, and the issuance of common shares, if required. On August 3, 2011, Pinecrest announced it had entered into a \$60 million bought deal financing with a group of underwriters to issue a total of 25,000,000 Common shares at a price of \$2.40 per share. (See Subsequent Events).

Share Capital

The Company had the following outstanding common shares and equity instruments:

	Six months ended June 30, 2011	Year ended July 31, 2010
Weighted Average Outstanding Common Shares		
Basic	170,131,401	17,071,207
Diluted	199,481,192	17,071,207
Outstanding securities:		
Common Shares	170,501,364	85,315,774
Common Share Purchase Warrants ⁽¹⁾	33,896,483	34,758,930
Stock Options	5,025,000	-

⁽¹⁾ Includes a total of 4,830,000 performance warrants

Total Market Capitalization

The Company's market capitalization at June 30, 2011 was as follows:

	At June 30, 2011	At March 31, 2011	% Change
Common shares – fully diluted	209,422,847	209,372,847	-
Share price ⁽¹⁾	\$2.43	\$2.26	8
Market Capitalization	\$508,897,518	\$473,182,634	8

⁽¹⁾ Represent the close price on the TSX Venture Exchange

During the period from July 1, 2011 to August 11, 2011, 125,000 warrants were exercised for \$0.50 per share. At August 11, 2011 Pinecrest had the following equity instruments outstanding: 170,626,364 common shares, 33,771,483 common share purchase warrants, and 5,025,000 stock options.

BUSINESS RISKS

Statements in this document may contain forward-looking information including expectations of future production, components of cash flow and earnings, expected future events and/or financial results that are forward-looking in nature and subject to substantial risks and uncertainties. The reader is cautioned that assumptions used in the preparation of such information may prove to be incorrect. The Company cautions the readers that actual performance will be affected by a number of factors, many of which may respond to changes in economic and political circumstances throughout the world. Events or circumstances may cause actual results to differ materially from those predicted, a result of numerous known and unknown risks, uncertainties, and other factors, many of which are beyond the control of the Company. These risks include, but are not limited to:

Development and Production Risk

Pinecrest's production and exploration activities are concentrated in the Western Canadian Sedimentary Basin, where activity is highly competitive and includes a variety of different sized companies ranging from smaller junior producers to much larger integrated petroleum companies. Pinecrest is exposed to the following development and production risk factors:

- Finding and developing petroleum and natural gas reserves at economic costs;
- Production of petroleum and natural gas in commercial quantities; and
- Marketability of petroleum and natural gas produced.

In order to reduce exploration risk, the Company strives to employ highly qualified and motivated professional employees with demonstrated ability to generate quality proprietary geological and geophysical prospects. To help maximize drilling success, Pinecrest combines exploration in areas that afford multi-zone prospect potential, targeting a range of low to moderate risk prospects. Pinecrest also explores in areas where the Company's officers and employees have significant drilling and completions experience. The Company mitigates its risk related to producing hydrocarbons through the utilization of the most appropriate technology and information systems. In addition, Pinecrest seeks operational control of its projects, where feasible.

Environmental and Climate Change Risk: Petroleum and natural gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. In order to mitigate such risks, Pinecrest conducts its operations at high standards and follows safety procedures intended to reduce the potential for personal injury to employees, contractors and the public at large. The Company maintains current insurance coverage for general and comprehensive liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect changing corporate requirements, as well as industry standards and government regulations.

Commodity Price Risk: Crude oil prices are affected by worldwide factors such as supply and demand fundamentals, and geopolitical events. Natural gas prices are influenced by the price of alternative fuel sources such as oil or coal, and by North American natural gas supply and demand fundamentals. In accordance with policies approved by our Board of Directors, Pinecrest may, from time to time, manage these risks through the use of physical delivery contracts, swaps, collars or other financial instruments not to exceed 50% of net commodity production (after royalties).

Credit Risk: Credit risk is the risk of loss if purchasers or counterparties default on their financial obligations. The maximum exposure of the Company to credit risk at June 30, 2011 and December 31, 2010 is limited to the cash and accounts receivable balances as reported on the balance sheets. Cash is comprised of bank balances. Currently, the Company does not intend to carry short-term investments. Should this change in the future, counterparties will be selected based on credit ratings and management will monitor all investments to ensure a stable return, and all complex investment vehicles with high risk will be avoided.

The Company's accounts receivable are subject to concentration of credit risk as all of the Company's customers are in the oil and gas sector. Management is of the opinion that any risk of loss is reduced due to the financial strength of its operators, and therefore concentration of credit risk is mitigated by having concentrations with credit worthy operators.

Liquidity Risk: Liquidity risk is the risk that the Company will not be able to meet its financial liabilities as they come due. Liquidity risk also includes the risk of the Company not being able to liquidate assets in a timely manner at a reasonable price. The Company meets its liquidity requirements by anticipating operating, investing and financing activities and ensuring there are enough funds to cover these activities. Liquidity risks may necessitate the need for the Company to conduct equity issues or obtain debt financing. The Company prepares annual and quarterly capital expenditure budgets, which are regularly monitored and updated when necessary to include a review of debt forecasts and working capital requirements. In addition, Pinecrest uses authorizations for expenditures for operated and non-operated capital projects to facilitate monitoring capital programs.

Foreign Currency Risk: World oil prices are quoted in United States (US) dollars and the price received is therefore affected by the Canadian/US dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased in value against the US dollar, which negatively impacts commodity prices valued in Canadian dollars, thereby indirectly reducing Pinecrest's oil revenues and future value of reserves, as determined by independent evaluators.

Interest Rate Risk: Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The interest charged on Pinecrest's credit facility fluctuates with the interest rates posted by lenders, plus a margin. The Company has not entered into any mitigating interest rate swaps or hedges as at June 30, 2011. Had the borrowing rate been 100 basis points higher (or lower) for the six months ended June 30, 2011, net income would have been affected by \$2,850 based on the average outstanding bank debt balance outstanding for the period.

CRITICAL ACCOUNTING ESTIMATES

Certain accounting policies require management to make decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. A summary of Pinecrest's critical accounting estimates and judgments can be found in Note 3 and a summary of significant accounting policies can be found in Note 4 to the unaudited condensed interim financial statements for the period ended June 30, 2011.

Pinecrest's management reviews its estimates frequently; however, the emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. Pinecrest attempts to mitigate this risk by employing individuals with the appropriate skill set and knowledge to make reasonable estimates, developing internal control systems and comparing past estimates to actual results.

The Company's financial and operating results include estimates of the following:

- Depletion, depreciation and accretion and tests for impairment are based on estimates of crude oil and natural gas reserves;
- Revenues, operating expenses and royalties for which accruals have been recorded for actual revenues and costs which have been earned or incurred but have not yet been received;
- Capital expenditures on projects that are in progress;
- Decommissioning liability including estimates of future costs and the timing of the costs;
- Deferred income taxes and the recoverability of deferred income tax assets have been recorded based on temporary differences between the carrying value and tax basis of the Company's assets and liabilities. These provisions require estimating the timing of these temporary differences and estimating whether tax assets will be realized before expiry.

ACCOUNTING CHANGES AND PRONOUNCEMENTS

International Financial Reporting Standards ("IFRS")

In February 2008, the AcSB confirmed that IFRS will be required for interim and annual financial Statements effective for fiscal years beginning on or after January 1, 2011, including comparatives for 2010 and an opening balance sheet showing the changes from Canadian GAAP (`GAAP`) to IFRS. For Pinecrest, the date of transition is August 1, 2009 due to the change in fiscal year ends from July 31 to December 31. Securities regulations require that if a change in year-end occurs, and the new year-end stub period is less than nine months, the Company must choose the beginning of the "old reporting year" which is the twelve months ended July 31, 2010, for its transition to IFRS.

Pinecrest has prepared its June 30, 2011 unaudited condensed interim financial statements in accordance with International Accounting Standard ("IAS") 34 *Interim Financial Reporting* and are in accordance with International Financial Reporting Standard ("IFRS") 1 *First-time Adoption of International Financial Reporting Standards*. The Company's IFRS accounting policies are provided in Note 4 to the unaudited condensed interim financial statements. In addition, Note 22 to the unaudited condensed interim financial statements presents reconciliations to show how the transition from GAAP to IFRS has affected the Company's balance sheet, financial performance and cash flows.

Accounting Policy Impacts of IFRS Adoption

Pinecrest's IFRS unaudited interim financial statements have been prepared using IFRS standards that were in effect on June 30, 2011. These unaudited interim financial statements have been prepared in accordance with the accounting policies the Company expects to adopt in its December 31, 2011 financial statements. Those accounting policies are based on the IFRS standards and International Financial Reporting Interpretations Committee ("IFRIC") interpretations that the Company expects to be applicable at that time.

The Company's unaudited condensed interim financial statements for the three and six months ended June 30, 2011 provide the following reconciliations from GAAP to IFRS:

- Equity as at August 1, 2009; July 31, 2010 and December 31, 2010;
- Comprehensive loss for:
 - the five months ended December 31, 2010;
 - the twelve months ended July 31, 2010;
 - the six months ended July 31, 2010 and;
 - the three months ended July 31, 2010.

The following provides a summary reconciliation of net comprehensive loss between the Company's previous GAAP and IFRS, along with a discussion of the significant accounting policy changes:

	Three months ended July 31, 2010	Six months ended July 31, 2010	Five months ended December 31, 2010	Twelve months ended July 31, 2010
GAAP - Net loss and comprehensive loss	\$ (919,414)	\$ (1,065,091)	\$ (2,040,648)	\$ (1,221,192)
<i>Decrease (increase) in net loss:</i>				
Depletion and depreciation	(163,786)	(87,222)	251,705	43,209
Share-based payments	(1,152,702)	(1,152,702)	286,908	(1,152,702)
Deferred income tax recovery	46,987	25,622	(147,828)	(11,234)
	(1,269,501)	(1,214,302)	390,785	(1,120,727)
IFRS – Net loss and comprehensive loss	\$ (2,188,915)	\$ (2,279,393)	\$ (1,649,863)	\$ (2,341,919)

- a) **Property Plant and Equipment ("PP&E"):** Under GAAP, Pinecrest followed the full cost method of accounting whereby all costs directly associated with the exploration, acquisition and development of petroleum and natural gas reserves are capitalized on a country-by country cost center basis. Costs are depleted using the unit-of-production method based on proved reserves determined using estimated future prices and costs. Upon transition to IFRS, Pinecrest was required to adopt new accounting policies for its property, plant and equipment.

Pre-exploration costs, costs incurred before the legal right to explore must be expensed under IFRS. Previously, these costs were capitalized under GAAP and were depleted on a unit of production basis. At August 1, 2009 these costs are not material. Evaluation and exploration costs are those expenditures incurred to assess the technical feasibility and commercial viability of various land holdings. Pinecrest capitalized and reported these costs as evaluation and exploration costs on the balance sheet under IFRS. When an area or project is determined to be technically feasible and commercially viable, these costs will be tested for impairment and transferred to property, plant and equipment. Any unrecoverable exploration and evaluation costs will be expensed.

IFRS permits the option to measure PP&E using either the cost model or the revaluation model for each class of PP&E. Pinecrest uses the cost model to account for all PP&E. Development costs include those expenditures that are incurred to bring reserves to commercial production and include

drilling, completion and equipping costs. These costs are capitalized under IFRS within property, plant and equipment on the balance sheet. Pinecrest depletes these costs over proved plus probable reserves using the unit-of-production method, by unit of account (specific areas) instead of the country cost center level currently utilized under GAAP.

Under IFRS, divestitures of PP&E will generally result in a gain or loss recognized in net earnings. Under GAAP, proceeds from divestitures are deducted from the full cost pool unless the deduction would result in a change in the depletion rate by more than 20%, in which case the gain or loss would be recorded in net earnings. In addition, Pinecrest is required to perform an impairment test on exploration and evaluation expenditures when there is a determination that the expenditures have resulted in a technically feasible and commercially viable project. At that time, the expenditures would be tested for impairment, and then transferred to the developed and producing assets category.

Pinecrest adopted the IFRS 1 exemption, which allows the Company to deem its August 1, 2009 IFRS petroleum and gas properties costs to be equal to its GAAP historical net book value. On August 1, 2009 the IFRS exploration and evaluation assets were \$154,589, which is equal to the GAAP unproved properties balance. The IFRS development costs are equal to the full cost pool balances under GAAP. These costs have been allocated over the proved plus probable reserves to establish the area level depletion units of account.

As at December 31, 2010 the Company's exploration and evaluation assets were \$84,733,613 (July 31, 2010 - \$25,297,075). For the five months ended December 31, 2010, the application of IFRS resulted in a decrease of \$251,705 of depletion (for the twelve months ended July 31, 2010 – a decrease of \$43,209; for the six months ended July 31, 2010 – an increase of \$87,222; and for the three months ended July 31, 2010 – an increase of \$163,786).

- b) **Impairment of Assets:** Under GAAP, Pinecrest is required to perform an impairment test on its property, plant and equipment at each reporting date, using the undiscounted cash flow from proved reserves for a country level cost center. If the carrying amount of the assets is less than the cash flows, the impairment is measured using the sum of the fair values of the proved and probable reserves, plus the costs of unproved properties. Impairments recognized under GAAP are not reversed.

Under IFRS, Pinecrest is not permitted to test for asset impairment at the cost center level (country level) as permitted under the GAAP full cost guideline. IFRS requires impairment testing to be performed at the cash generating unit level, which is at a lower level than the current cost center level. IFRS uses a one-step approach for testing and measuring asset impairments, with asset carrying values being compared to the higher of value-in-use and fair value less costs to sell. Value in use is defined as the amount equal to the present value of future cash flows expected to be derived from the asset. In the absence of an active market, fair value less costs to sell may also be determined using discounted cash flows. The use of discounted cash flows under IFRS to test and measure asset impairment differs from GAAP, which uses undiscounted cash flows. This may result in more frequent write-downs in the carrying amounts of assets under IFRS because the asset carrying amounts previously supported under GAAP were based on undiscounted cash flows. However under IFRS, impairment losses that were previously recognized may be reversed where circumstances change such that the impairment is reduced. Pinecrest did not recognize asset impairment on the IFRS opening balance sheet at August 1, 2009.

- c) **Asset Retirement Costs:** Pinecrest is required to recognize asset retirement obligations under GAAP and IFRS. However, under IFRS, the recognition criteria for contingent liabilities are much more explicit than Canadian GAAP and may potentially require the booking of additional liabilities associated with the asset retirement obligations of Pinecrest's petroleum and natural gas assets. Liabilities for decommissioning and restoration are recognized for both legal and constructive

obligations. Under IFRS, the estimated liability is re-measured at each reporting period using estimates of credit adjusted risk-free rates to adjust future cash outflows, whereas under GAAP the estimated liability is not re-measured using current discount rates. Pinecrest continues to use its credit adjusted risk-free discount rate to determine its decommissioning liabilities under IFRS, and has performed its preliminary calculation for decommissioning costs at August 1, 2009.

Pinecrest did not have any change to the liability on transition date. There was also no change to the liability at December 31, 2010 or July 31, 2010.

- d) **Stock-based Compensation:** Similar to GAAP, share-based payments under IFRS require that the expense be measured at fair value. However, IFRS requires the expense related to share-based payments to be recognized as the options or warrants vest, each tranche of options must be recognized separately and requires that forfeitures are estimated at time of grant. Because Pinecrest recognized the expense associated with stock-based compensation using the graded-vesting method under GAAP, the adjustment from GAAP to IFRS was the result of the change in calculation from determining the expense on a single grant basis to multiple tranches.

Pinecrest has taken the IFRS 1 exemption for share-based payments, and consequently there was no impact to its opening balance sheet at August 1, 2009. For the three months ended December 31, 2010, the application of IFRS resulted in a decrease of \$286,908 of share-based compensation expense, and a reduction of \$98,120 of capitalized share-based payments to property, plant and equipment. There was no impact for the twelve, six or three months ended July 31, 2010.

- e) **Flow-through Shares:** Under IFRS, proceeds from a flow-through share offering are allocated between the sale of the shares and the sale of the tax benefit. The allocation is made based on the difference between the quoted market price of the existing shares and the amount the investor pays for the flow through shares. A liability is established for the difference that is reversed upon renunciation of the tax benefit and the difference between the liability and the deferred tax liability is recorded as an income tax expense or recovery, if applicable.

Prior to August 1, 2009 the Company issued flow-through shares for proceeds of \$271,650. The provision for the tax benefit of \$67,912 was established at date of transition, with an increase to provisions for liabilities and other charges and a reduction to share capital. The expenditures were renounced to investors for the year ended July 31, 2010 and the full amount of the provision was reversed against the deferred tax asset.

During the year ended July 31, 2010, Pinecrest issued flow-through units to various officers, directors and employees of the company at a cost of \$0.375 per unit. Under IFRS 2 – Share-based payments, the Company is required to record a share-based payment expense for an amount that is the deemed fair value benefit from the sale of the shares. Accordingly, the Company recorded a \$1.2 million share-based payment expense associated with the sale of the flow-through units in the twelve months ended July 31, 2010 (six months ended July 31, 2010 - \$1.2 million; three months ended July 31, 2010 - \$1.2 million) with a provision for the sale of the tax benefit.

Recent Pronouncements Issued

All accounting standards effective for periods beginning on or after June 30, 2011 have been adopted as part of the transition to IFRS. The following new IFRS pronouncements have been issued but are not yet effective. Management is currently assessing the impact of these new standards on the Company's accounting policies and financial statement presentation:

- **IFRS 7 Financial Instruments: Disclosures-Transfers of Financial Assets** - was amended in October 2010 to require additional disclosure on the transfer of financial assets to: (i) understand the relationship between transferred financial assets that are not derecognized in their entirety and the associated liabilities, and (ii) to evaluate the nature of, and risks associated with, the entity's continuing involvement in derecognized financial assets. IFRS 7 is effective for annual periods beginning on or after July 1, 2011.
- **IFRS 9 Financial Instruments:** is effective for annual periods beginning on or after January 1, 2013 with early adoption permitted. IFRS 9 was issued by the IASB in November 2009 and amended in October 2010 and is the first step to replace IAS 39, "Financial Instruments: Recognition and Measurement". IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets.
- **IAS 12 Income Taxes:** IAS 12 was amended in December 2010 to remove subjectivity in determining on which basis an entity measures the deferred tax relating to an asset. The amendment introduces a presumption that an entity will assess whether the carrying value of an asset will be recovered through the sale of the asset. The amendment to IAS 12 is effective for annual periods beginning on or after January 12, 2012 with early adoption permitted.
- **IFRS 10 Consolidated Financial Statements:** IFRS 10 was issued in May 2011 and will replace portions of IAS 27 "Consolidation and Separate Financial Statements" and interpretation SIC-12 "Consolidation - Special Purpose Entities." The key features of IFRS 10 include consolidation using a single control model, definition of control, considerations on power and continuous reassessment. IFRS 10 is effective for annual periods beginning on or after January 1, 2013 with early adoption permitted.
- **IFRS 11 Joint Arrangements:** IFRS 11 was issued in May 2011 and will replace the guidance in IAS 31 "Interests in Joint Ventures." Under IFRS 11, joint arrangements are classified as either joint operations or joint ventures. The legal form of the arrangement will no longer be the most significant factor when classifying the joint arrangement as either a joint operation or joint venture, but rather the rights and obligations of the arrangements will be focused on. In addition, IFRS 11 removes the option to account for jointly controlled entities ("JCEs") using proportionate consolidation; instead, JCEs that meet the definition of a joint venture must be accounted for using the equity method. IFRS 11 is effective for annual periods beginning on or after January 1, 2013 with early adoption permitted. Management has determined that early adoption of this standard will have no impact on its financial statements.
- **IFRS 12 Disclosure of Interests in Other Entities:** IFRS 12 was issued in May 2011 and contains the disclosure requirements for entities that have interests in subsidiaries, joint arrangements (i.e. joint operations or joint ventures), associates and/or unconsolidated structured entities. The disclosures are intended to provide information in order to evaluate the nature of, and the risks associated with, an entity's interest in other entities, and the effects of those interests on the entity's financial position, financial performance and cash flows. IFRS 12 is effective for annual periods beginning on or after January 1, 2013 with early adoption permitted.
- **IFRS 13 Fair Value Measurement:** IFRS 13 was issued in May 2011 and replaces the fair value measurement guidance contained in individual IFRSs with a single source of fair value measurement guidance. It defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, i.e. an exit price. IFRS 13 is effective for annual periods beginning on or after January 13, 2013 and is to be applied prospectively.

- **IAS 27 Separate Financial Statements:** IAS 27 was reissued in May 2011 as a result of the new consolidation suite of standards, as the consolidation guidance will now be included in IFRS 10. IAS 27 will now only prescribe the accounting and disclosure requirements for investments in subsidiaries, joint ventures and associates when an entity prepares separate financial statements. These amendments are effective for annual periods beginning on or after January 1, 2013 with early adoption permitted.
- **IAS 28 Investments in Associates and Joint Ventures:** IAS 28 was amended in May 2011 as a consequence of the issuance of IFRS 10, IFRS 11 and IFRS 12 and will provide the accounting guidance for investments in associates and will set out the requirements for the application of the equity method when accounting for investments in associates and joint ventures. The amended IAS 28 will be applied by all entities that are investors with joint control of, or significant influence over, an investee. These amendments are effective for annual periods beginning on or after January 1, 2013 with early adoption permitted.

INTERNAL CONTROLS

During the three months ended June 30, 2011, Pinecrest has hired additional staff, which will enhance the Company's segregation of duties and internal controls. There have been no other changes to the Company's internal controls since year end December 31, 2010.

OFF BALANCE SHEET ARRANGEMENTS

No off balance sheet arrangements existed at June 30, 2011.

RELATED PARTY TRANSACTIONS

The Company has retained the law firm of Burnet Duckworth and Palmer to provide legal services. The current Chairman of the Board and Corporate Secretary are partners at the law firm. During the six months ended June 30, 2011, the Company incurred legal fees and disbursements of \$55,522 related to general matters and equity financings, of which \$37,158 was outstanding at July 31, 2011. The related party transactions were conducted in the normal course of business and have been measured at the fair value amount.

COMMITMENTS

The Company has the following commitments as at June 30, 2011:

- Office lease:** The Company has an obligation under its existing sub-lease to pay \$65,910 to September 2011. During the six months ended June 30, 2011 the Company entered into a new lease agreement, effective October 1, 2011 which expires September 30, 2014 which commits Pinecrest to make lease payments over the next 3 years of \$230,160 plus operating costs.
- Equipment purchases:** During the six months ended June 30, 2011, the Company has entered into commitments to purchase well equipment, which will be delivered over the next 12 months, totaling \$2,866,690. The equipment purchase commitments all have cancellation clauses, which require the Company to give 30 days notice should the equipment not be required.
- Farm-in agreement:** During the six months ended June 30, 2011, the Company has a drilling commitment pursuant to a farm-in agreement to drill and complete one horizontal well in the Slave Point formation in the Greater Red Earth Area, by September 1, 2011. Capital costs of approximately \$2.2 million are expected which will earn Pinecrest a 100% working interest in the well.

SUBSEQUENT EVENTS

- a) **Property Swap:** On July 27, 2011, the Company completed an exchange agreement with a partner, effective June 30, 2011 in which undeveloped land and certain developed and producing properties were exchanged for undeveloped land and certain developed and producing properties in the Greater Red Earth area of Alberta. The exchange consolidated Pinecrest's interests in certain fields in the Red Earth area.
- b) **Bought Deal Financing \$60,000,000:** On August 3, 2011, the Company announced that it had entered into an agreement with a syndicate of underwriters to issue on a bought deal basis 25,000,000 Common Shares at an issue price of \$2.40 per share for gross proceeds of approximately \$60,000,000. In addition, the Company has granted the underwriters an option (the "Over-Allotment Option") to purchase up to an additional 3,750,000 Common Shares at an issue price of \$2.40 per Common Share for additional gross proceeds of \$9,000,000. The Over-Allotment Option is exercisable in whole or in part for a period of 30 days following the closing of the offering. The Preliminary Prospectus was filed on August 9, 2011 and the Offering is expected to close on or about August 24, 2011.

SUPPLEMENTAL QUARTERLY INFORMATION

The following summarizes key financial and operating information by quarter, IFRS basis:

	Q2 Jun. 30 2011 Three months	Q1 Mar. 31 2011 Three months	Q4 Dec. 31 2010 ⁽¹⁾ Three months	Q3 Sep. 30 2010 ⁽¹⁾ Two months	Q4 Jul. 31 2010 ⁽¹⁾ Three months	Q3 Apr. 30 2010 ⁽¹⁾ Three months
FINANCIAL (\$ except per share amounts)						
Petroleum and natural gas sales ⁽²⁾	7,747,513	6,099,936	1,386,045	520,308	561,351	194,464
Cash flow from (used in) operating activities	9,028,260	2,347,350	(557,001)	(308,012)	(942,474)	55,248
Per share - basic	\$0.05	\$0.01	(\$0.00)	(\$0.00)	(\$0.01)	\$0.01
Per share - diluted	\$0.05	\$0.01	(\$0.00)	(\$0.00)	(\$0.01)	\$0.01
Net income (loss)	1,129,484	(326,621)	(1,156,225)	(133,608)	(2,188,915)	(90,478)
Per share - basic	\$0.01	(\$0.00)	(\$0.01)	(\$0.00)	(\$0.04)	(\$0.02)
Per share - diluted	\$0.01	(\$0.00)	(\$0.01)	(\$0.00)	(\$0.04)	(\$0.02)
Capital expenditures	21,269,803	47,487,678	78,232,897	8,944,956	27,641,369	296,583
Total assets	195,335,939	211,968,939	184,693,215	87,520,307	51,086,261	3,330,740
Working capital (deficit)	(1,719,498)	5,894,512	49,466,279	41,617,140	17,531,301	(729,287)
Debt	8,782,370	-	-	-	-	-
OPERATING						
Number of producing days	91	90	92	61	92	89
Average Daily Production ⁽²⁾						
Crude oil (bbls/d)	810	748	183	111	71	26
Natural gas (mcf/d)	63	1	32	23	20	9
Natural gas liquids (bbls/d)	9	5	2	4	4	1
Total (boe/d – 6:1)	830	753	190	119	78	28
Average Price Received						
Crude oil (bbls/d)	104.00	90.30	80.88	74.01	82.12	79.73
Natural gas (mcf/d)	4.17	(18.99)	4.19	3.75	4.62	4.93
Natural gas liquids (bbls/d)	63.16	58.56	46.21	50.93	49.59	54.98
Combined (\$/boe)	102.55	90.03	78.54	71.57	78.24	76.37
Royalties (\$/boe)	11.35	11.67	13.64	5.88	8.56	12.20
Operating and transportation expenses (\$/boe)	21.76	18.04	16.32	22.86	18.54	21.46
Operating netback (\$/boe)	69.44	60.32	48.58	42.83	51.14	42.71

⁽¹⁾ Quarters are restated to reflect the transition to IFRS.

⁽²⁾ Amounts are before royalties.

ADDITIONAL INFORMATION

Additional information about Pinecrest is available on at www.sedar.com; at the Company's website at www.pinecrestenergy.com; or by contacting the Company at Pinecrest Energy Inc. Suite 500, 255 5th Avenue SW, Calgary, Alberta, T2P 3G6.