# MOUNTAINVIEW ENERGY LTD

## Management's Discussion and Analysis

## Six Months Ended June 30, 2013

## Expressed in US Dollars

Management's Discussion and Analysis ("MD&A"), dated August 29, 2013, is management's assessment of the financial position and operating results of Mountainview Energy Ltd. (the "Company" or "Mountainview") and should be read in conjunction with the interim consolidated financial statements and the accompanying notes for the period ended June 30, 2013 and 2012. Additional information relating to the Company, are available on SEDAR at www.sedar.com. Mountainview is listed for trading on the TSX Venture Exchange ("**TSX-V**") under the symbol "MVW". All amounts are in US dollars, unless otherwise stated.

## BASIS OF PRESENTATION

The condensed interim consolidated financial statements, including comparatives, have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of interim financial statements, including IAS 34, "Interim Financial Reporting". The condensed consolidated interim financial statements should be read in conjunction with the annual consolidated financial statements for the year ended December 31, 2012, which have been prepared in accordance with IFRS as issued by the IASB.

The reporting and the measurement currency is the US dollar. For the purpose of calculating unit costs, natural gas is converted to a barrel equivalent ("boe") using six thousand cubic feet of natural gas equal to one barrel of oil unless otherwise stated. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. The following MD&A compares the results of the three and six months ended June 30, 2013 ("2013") to the three and six months ended June 30, 2012 ("2012").

## MOUNTAINVIEW'S BUSINESS

Mountainview Energy Ltd. ("Mountainview" or "the Company") was incorporated under the laws of the Province of British Columbia, Canada and was continued into the Province of Alberta in May 2012. The Company is engaged in the exploration, development, acquisition and operation of petroleum and natural gas reserves properties through the drilling of horizontal Three Forks and Bakken wells on the Company's acreage located in the Williston Basin in Montana and North Dakota and the South Alberta Bakken Play in the State of Montana, USA.

## FORWARD-LOOKING INFORMATION

### Forward-Looking Statements

This MD&A contains certain forward-looking statements within the meaning of applicable securities laws. These statements relate to future events or future performance and are based on the Company's current expectations reflected in the forward-looking statements. Although management believes that such expectations are reasonable, there can be no assurance that such expectations will prove to be correct. Accordingly, undue reliance should not be placed on these forward-looking statements. The use of any of the words "expect", "anticipate", "continue", "estimate", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", and similar expressions are intended to identify forward-looking statements or information. In particular, but without limiting the foregoing, this MD&A contains forward-looking information concerning: the 2013 capital budget and allocation thereof; projected average production volumes for 2013; anticipated prices for oil and natural gas; anticipated 2013 average operating expenses and the Company's ability to reduce such expenses; tax horizon and available tax pools; the remaining amount and allocation of the 2013 capital program; ability to fund the remaining capital program and the timing of funding our financial obligations. In addition, information and statements relating to oil and/or natural gas reserves are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

These forward-looking statements are based on certain key expectations and assumptions made by Mountainview, including but not limited to expectations and assumptions concerning: prevailing and future market prices for oil, natural gas; prevailing and future foreign exchange rates, interest rates and inflation rates; applicable royalty rates, tax rates and related laws and regulations; future production rates; the performance of existing and future wells; the success obtained in drilling new wells; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour and services, including but not limited to drilling and completion equipment and services; adequate weather and environmental conditions for drilling and completion activities, including the transportation of associated equipment, the ability to obtain external sources of financing on acceptable terms; and the realization of the anticipated benefits of acquisitions.

Actual results achieved during the forecast periods will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties, the variances may be material. Such risks and uncertainties include: operational risks generally associated with oil and natural gas exploration, development, exploitation, production, transportation and marketing; volatility in market prices for oil and/or natural gas; access to capital markets and stock price volatility; increased debt levels or debt service requirements; unanticipated fluctuations or declines in the Company's oil, natural gas production levels; adverse changes in legislation, including but not limited to tax laws, royalty rates and environmental regulations; ability to attract and retained qualified personnel; changes in the demand for Mountainview's products; fluctuations in foreign exchange rates, interest rates and inflation rates, risks associated with adverse weather, the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production rates, costs and expenses; and competition for, among other things, capital resources, acquisitions of reserves, undeveloped land and services.

**Capital Expenditures, Acquisitions and Dispositions**

**Williston Basin**

During the six-month period ending June 30, 2013, the Company successfully drilled and completed three wells in the 12-Gage Project located in Divide County, ND. Following are the most recent results of the three-well drilling program:

- The Wigness 5-8-1H well, the first horizontal Three Forks well in the winter drilling program, has been on production since March 2013. To-Date the Wigness well has produced 24,772 boe and had an average daily production rate of 164 boe/day for the month of June 2013.

- The Leininger 3-10-1H well, the second horizontal Three Forks well in the winter drilling program, has been on production since April 2013. To-date the Leininger well has produced 24,723 boe and had an average daily production of 174 boe/day for the month of June 2013.

- The Olson 35-26-1H well, the third horizontal Three Forks well in the winter drilling program, has been on production since April 2013. To-date the Olson well has produced 17,739 boe and had an average daily production of 155 boe/d for the month of June 2013.

Through its wholly-owned subsidiary Mountain Divide, LLC ("Mountain Divide"), Mountainview holds: (a) a 93.75% working interest in the Wigness Well, 25% of which is subject to reversion to another working interest owner following payout of 100% of the cost of their proportionate working interest costs in the well plus a 200% penalty; (b) an 87.51% working interest in the Leininger Well, 3.12% of which is subject to reversion to another working interest owner following payout of 100% of the cost of their proportionate working interest costs in the well plus a 200% penalty; and (c) a 62.27% working interest in the Olson Well, 16.37% of which is subject to reversion to another working interest owner following payout of 100% of the cost of their proportionate working interest costs in the well plus a 200% penalty. Pursuant to Mountain Divide's credit facility (the "**Facility**"), all of Mountain Divide's oil and gas properties located in Divide County, North Dakota (including the lands on which the Wigness Well, the Leininger Well and the Olson Well are situated) are subject to a 39% after pay-out net profits interest held by Mountain Divide's lender under the Facility. These payments shall not commence until repayment in full of the outstanding Facility and will automatically reduce to 20% once the Lender achieves a 1.65 x return on investment.

(Reported in US Dollars, unless otherwise indicated)

The following table outlines the Company's first three drilled wells on the 12-Gage Project:

| Well Name | Operator | Working Interest | Net Revenue Interest | Spud Date | Current Status |
|---|---|---|---|---|---|
| Wigness 5-8-1H | Mountain Divide, LLC | 93.75% | 76.8067% | 14-Nov-12 | Producing |
| Leininger 3-10-1H | Mountain Divide, LLC | 87.51% | 69.9866% | 12-Dec-12 | Producing |
| Olson 35-26-1H | Mountain Divide, LLC | 61.27% | 49.2783% | 5-Jan-13 | Producing |

**Non-Operational Update – Williston Basin**

To-date the Company has participated in 14(gross) Bakken/Three Forks wells in the Williston Basin. The following table lists the wells and their current status:

| Well Name | Operator | Working Interest | Net Revenue Interest | Spud Date | Current Status |
|---|---|---|---|---|---|
| Olson | G3 Operating, LLC | 12.50% | 10.0000% | 4-Mar-11 | Producing |
| Wolter | SM Energy | 3.25% | 2.6000% | 12-Sep-11 | Producing |
| Strahan | Hess Corporation | 0.63% | 0.5000% | 1-Feb-11 | Producing |
| Miller | Petro-Hunt LLC | 0.79% | 0.6296% | 16-Nov-11 | Producing |
| Zuma | Samson Resources Company | 9.75% | 7.8000% | 14-Jan-12 | Producing |
| Riva Ridge | Samson Resources Company | 3.24% | 2.5920% | 11-Feb-12 | Producing |
| Anton | American Eagle Energy Corp | 3.38% | 2.7040% | 16-Jun-12 | Producing |
| Muzzy | American Eagle Energy Corp | 3.38% | 2.7040% | 26-Oct-12 | Completing |
| Orville Hendrickson | Marathon Oil Corporation | 12.50% | 9.7500% | 18-Jun-12 | Producing |
| Panther | Zavanna, LLC | 2.20% | 0.2751% | 11-Oct-11 | Producing |
| Jaguar | Zavanna, LLC | 1.02% | 0.1269% | 14-Aug-11 | Producing |
| Leopard | Zavanna, LLC | 1.02% | 0.1269% | 27-Feb-12 | Producing |
| Quale | Whiting Oil & Gas Corporation | 3.25% | 2.6000% | 14-Mar-12 | Producing |
| Albert | American Eagle Energy Corp | 3.38% | 2.6688% | 15-May-13 | Completing |

During the three and six-month period ending June 30, 2013 the Company acquired the following additional acreage in Montana and North Dakota:

Divide County, ND:

- 349.82 Acres for a total of $147,523.64

Sheridan County, MT:

- 1,498.56 Acres for a total of $224,784.00

(Reported in US Dollars, unless otherwise indicated)

**Results of operations**

| | Q2 2013 | Q1 2013 | Q4 2012 | Q3 2012 |
|---|---|---|---|---|
| South Alberta Bakken (Bbls per day) | 99 | 101 | 149 | 134 |
| Williston Basin (bbls per day) | 603 | 249 | - | - |
| Natural gas (Mcf per day) | 309 | 336 | 337 | 335 |

| | Q2 2012 | Q1 2012 | Q4 2011 | Q3 2011 |
|---|---|---|---|---|
| South Alberta Bakken (Bbls per day) | 117 | 136 | 143 | 109 |
| Williston Basin (bbls per day) | - | - | - | - |
| Natural gas (Mcf per day) | 241 | 29 | 29 | 29 |

Oil production increased to 702 bbl/d during Q2 2013 compared with 117 bbl/d in Q2 2012. The Company increased the oil production by the drilling and completing of the three wells in the 12-Gage property located in the Williston Basin. The Company increased revenues from its natural gas interests through the acquisition of the Pondera business acquisition. Production of natural gas in Q2 2013 was 309 Mcf/d compared with 241 Mcf/d in Q2 2012.

**Average Realized Prices**

| | Q2 2013 | Q1 2013 | Q4 2012 | Q3 2012 |
|---|---|---|---|---|
| Average benchmark prices | | | | |
| Oil - WTI crude oil USD ($/Bbl) | 94.22 | 94.37 | 87.96 | 90.83 |
| Oil - CHS crude oil USD ($/Bbl) | 78.21 | 77.17 | 73.31 | 74.83 |
| Natural gas - AECO-C Daily spot ($/mcf) | 3.53 | 3.07 | 3.08 | 2.19 |
| Mountainview Average Realized Prices | | | | |
| South Alberta Bakken ($/Bbl) | 76.30 | 79.72 | 73.94 | 74.21 |
| Williston Basin ($/Bbl) | 87.81 | 90.83 | - | - |
| Natural gas ($/Mcf) | 2.25 | 1.88 | 1.89 | 1.37 |

| | Q2 2012 | Q1 2012 | Q4 2011 | Q3 2011 |
|---|---|---|---|---|
| Average benchmark prices | | | | |
| Oil - WTI crude oil USD ($/Bbl) | 93.48 | 102.89 | 97.82 | 84.89 |
| Oil - CHS crude oil USD ($/Bbl) | 73.20 | 85.51 | 83.64 | 78.12 |
| Natural gas - AECO-C Daily spot ($/mcf) | 1.82 | 2.52 | 3.37 | 3.86 |
| Mountainview Average Realized Prices | | | | |
| South Alberta Bakken ($/Bbl) | 71.95 | 84.55 | 82.60 | 77.03 |
| Williston Basin ($/Bbl) | - | - | - | - |
| Natural gas ($/Mcf) | 0.97 | 1.52 | 1.78 | 2.14 |

The Company's crude oil production consists of 42 API sweet crude oil quality in the Stateline/Medicine Lake and 12-Gage acreage located in the Montana and North Dakota, Williston Basin properties and heavy oil which ranging in quality from 22 degree to 34 degree API, seen in the Montana, South Alberta

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Bakken. The Company's realized prices are reflected net of adjustments for gravity deviations from 40 degrees on the heavier crude. The Company saw an increase in sweet crude oil production due to the 12-Gage development project and other non-operated wells in the Williston Basin.

The Company realized an average oil price of $76.30/bbl in the South Alberta Bakken for the three-month period ending June 30, 2013 which is an increase from the $73.20/bbl realized for the three-month period ended June 30, 2012.

In the Williston Basin, the Company realized an average oil price of $87.81 for the three-months ended June 30, 2013. There was no production in the Williston Basin in the three months ended June 30, 2012.

The Company's natural gas is sold under marketing arrangements tied to the Alberta daily spot price at AECO, with a premium or discount received specific to the quality (based on heat-content) of the Company's natural gas production. The Company realized an average natural gas price of $2.25/mcf for the three-month period ended June 30, 2013 which is an increase from the $1.82/mcf from the three-month period ended June 30 2012.

**Revenue**

| | | Q2 2013 | | Q1 2013 | | Q4 2012 | | Q3 2012 |
|---|---|---|---|---|---|---|---|---|
| Oil sales | $ | 5,049,703 | $ | 1,924,319 | $ | 689,681 | $ | 920,215 |
| Natural gas | | 57,538 | | 84,680 | | 88,490 | | 41,224 |
| Gross oil and natural gas revenues | **$** | **5,107,241** | **$** | **2,008,999** | **$** | **778,171** | **$** | **961,439** |

| | | Q2 2012 | | Q1 2012 | | Q4 2011 | | Q3 2011 |
|---|---|---|---|---|---|---|---|---|
| Oil sales | $ | 716,916 | $ | 1,061,329 | $ | 928,840 | $ | 796,781 |
| Natural gas | | 21,813 | | 10,057 | | 9,562 | | 10,892 |
| Gross oil and natural gas revenues | **$** | **738,729** | **$** | **1,071,386** | **$** | **938,402** | **$** | **807,673** |

Total oil and gas revenue during the three months ended Q2 2013 increased to $5,107,241 from the $738,729 reported in Q2 2012. The increase relates to production from the three wells drilled and completed on the 12-Gage property in Divide County, ND during Q4 2012 and Q1 2013.

**Royalties**

Royalties are paid to mineral owners, which may include freehold landowners and other parties by way of contractual overriding royalties. Royalty rates are generally dependent on commodity prices and well productivity.

Total royalty expenses during the three months ended Q2 2013 were $807,103 from $68,970 in Q2 2012 due to increased sales volumes and revenues from the three wells on the 12-Gage property.

(Reported in US Dollars, unless otherwise indicated)

**Production and operating Expenses**

Significant components of the Company's operating expenses include well servicing, fuel and power, labour and production taxes. The total operating expenses for the three months ended Q2 2013 increased to $1,902,056 from $282,571 in Q2 2012. Operating expenses increased due to the Company completing the three wells that were drilled on the 12-Gage property.

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Production and operating expenditures | $ 1,902,056 | $ 282,571 | $ 2,655,391 | $ 716,110 |

The Company incurs significant production and operating costs for material, labour, production taxes, electrical and water disposal costs.

**General and Administrative Expense**

The Company recorded G&A expenses for the three months ended in Q2 2013 of $499,549 an increase of $376,312 from Q2 2012. The G&A expenses for the three and six months ended June 30, 2013 and 2012 are as follows:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Accounting and Auditing | $ 83,601 | $ 36,921 | $ 384,674 | $ 92,082 |
| Salaries and Wages | 161,319 | 130,452 | 277,835 | 233,953 |
| Travel and promotion | 77,818 | 74,816 | 136,209 | 126,424 |
| Legal Fees | 99,854 | - | 134,018 | - |
| Office expense | 28,269 | 29,203 | 65,371 | 60,094 |
| Insurance | 15,108 | 8,144 | 29,999 | 24,035 |
| Listing and filing fees | 10,476 | 3,026 | 20,391 | 6,178 |
| Shareholder relations | 4,402 | 63,767 | 16,406 | 84,350 |
| Director fees | 12,960 | 15,534 | 12,960 | 15,534 |
| Investor Relations | 4,396 | 10,628 | 8,858 | 26,095 |
| Transfer Agent Fees | 1,346 | 3,821 | 4,015 | 5,376 |
| | $ 499,549 | $ 376,312 | $ 1,090,736 | $ 674,121 |

The large increase in accounting and auditing, salaries and wages, legal fees and office expenses relates directly to the Company expanding its operations.

**Share-based Compensation Expense**

Share-based compensation expense is a non-cash item representing the estimated fair value of the stock options granted to employees and others, recognized when the options vest. The Company recorded in the three months ended Q2 2013 $138,452 and $Nil of share-based compensation.

**Depletion, accretion and Depreciation Expense**

Depletion, accretion and depreciation of property, plant and equipment is calculated on the unit-of-production basis using depletable capital costs, production and estimated proved plus probable reserves. Depletion, accretion and depreciation expense in the three months ended June 30, 2013 increased to $1,884,112 from the $267,023 reported for Q2 2012. Increase in depletion, accretion and depreciation expense relates to the increase in non-operator wells, purchase of additional vehicles and the new wells drilled during the period in the 12-Gage Project in Divide County, ND.

**Impairment of Oil and Natural Gas Properties**

At June 30, 2013, the Company reviewed the carrying value of the oil and gas properties by cash generating units for impairment. As a result of the review, it was determined that there was no impairment on the oil and gas properties. The recoverable amount is determined based on the fair value less cost to sell method using discounted future cash flows at a discount rate of 12%. The estimated future cash flows utilized in the calculation incorporated the Company's best estimates of future oil and gas production based on the current plans, estimates of future oil and gas prices, operating costs and residual values.

**Capitalized Interest and Interest Expense**

At June 30, 2013, the Company, had capitalized interest of $717,345 and $Nil for the same period in 2012 in addition to interest expense of $1,016,332 and $88,048, respectively. During the prior year, the Company capitalized interest related to the 12-Gage property development. Interest expense during the three months ended June 30, 2013 increased as a result of the Company obtaining additional financing to expand its operations and the interest relating to the 12-Gage property.

**Going Concern**

These interim consolidated financial statements have been prepared on a going concern basis, which assumes the realization of assets and liquidation of liabilities in the normal course of business. The Company has experienced losses in the periods ended June 30, 2013 and December 31, 2012. At June 30, 2013 and December 31, 2012, the Company had a deficit of $13,972,583 and $11,526,480 respectively and working capital (deficit) of ($17,572,215) and ($17,481,721), respectively. Continuing operations, as intended, are dependent on management's ability to raise required funding through future equity issuances, credit facilities, asset sales or a combination thereof, which is not assured, especially in today's volatile and uncertain financial markets. There can be no assurance that management's plans will be successful. These uncertainties cast substantial doubt on the Company's ability to continue as a going concern. These consolidated financial statements do not include any adjustments to the recoverability and classification of recorded asset amounts and classification of liabilities that might be necessary, should the Company be unable to continue as a going concern.

**Liquidity and Capital Resources**

As of June 30, 2013 the Company's current assets totaled $8,452,341 , which is comprised of , among other items, cash balances totaling $2,438,518, trade receivables totaling $1,652,087, and amounts due from the Company's working interest partners totaling $4,135,802. The Company's working capital deficit as of June 30, 2013 was ($17,572,215) compared to ($17,481,721) as of December 31, 2012.

As of June 30, 2013 and December 31, 2012, the Company recorded accounts payable of $12,842,199 and $8,576,036 in addition to outstanding bank debt of $8,660,000 and $8,494,000, a convertible debenture of $2,163,334, and $2,123,947, promissory notes payable of $8,666,133 and $8,061,005, a credit facility of $16,084,972 and $1,004,308 along with long-term debt of $193,249 and $120,257 comparatively.

The Company acquired a compressor plant and equipment for consideration of $2,660,000 from another company (the "**Vendor**") owned, in part (50%), by a director and officer of the Company. The Company paid $283,000 in cash for consideration and agreed to issue a Convertible Debenture (the "**Convertible Debenture**") in the amount of $2,377,000 convertible into common shares of the Company at a price of $2.50 per share. The Convertible Debenture was later reduced by $304,946 due to costs incurred by the Vendor and paid by the Company on the Vendor's behalf prior to the transaction closing. The original maturity date of the Convertible Debenture was on or before June 1, 2013. During the quarter ended June 30, 2013 the original Convertible Debenture was cancelled and a new Convertible Debenture was signed to extend the maturity date to June 1, 2015. At June 30, 2013 the balance of the Convertible Debenture was $2,072,053 plus accrued interest of $95,300. At June 30, 2013, if the Convertible Debenture had been converted the Company would have issued 828,821 additional common shares of the Company.

On April 17, 2012, the Company entered into a revolving line of credit with First Interstate Bank for $5,500,000 and on June 27, 2012, increased the line of credit to $8,700,000 (the "Credit Line"). The outstanding balance at March 31, 2013 was $8,660,000. The Credit Line is secured by the assets of the Company and guaranteed by its Chief Executive Officer and a significant shareholder of the Company. Interest is payable monthly at a variable rate of prime plus 1.25%. The minimum interest rate is 5.25%. The Line of Credit has an original due date of June 17, 2013 but the Company was granted a 6-month extension by First Interstate Bank.

On November 1, 2012, Mountain Divide, LLC ("**Mountain Divide**") entered into the Credit Facility. Mountain Divide received $3,883,071 under the Credit Facility at December 31, 2012, and recorded $2,622,912 relating to the sale of the 20% NPI. The Company has determined the fair value of the conveyance portion of the arrangement using a relative percentage of the conveyed property's fair value determined at its acquisition date and has recorded this amount of $2,622,912 as an adjustment to the property. The residual amount of the initial proceeds has been determined to be a borrowing and has been recorded as long-term debt based upon the expected terms of repayment. The discount to the face amount of the debt will be accreted over the term of the debt. The offsetting entry will be to the 12-Gage property until production commences and then will be expensed until maturity. At June 30, 2013, the Company had received $17,858,462 under the Credit Facility.

The Company has various vehicle loans outstanding at June 30, 2013 and December 31, 2012 of $246,654 and $179,032, respectively. The current portion of vehicle loans at June 30, 2013 and December 31, 2012 is $53,405 and $58,775. The loans vary from 0% interest to 4% and will be repaid after five years.

The Company entered into two promissory notes payable with major shareholders of the Company, each for $4,000,000 (total $8,000,000), bearing interest at 9% per annum and drawdown of the full principal balance. The principal was originally due and payable on or before May 30, 2014. During the period one of the major shareholders signed a new promissory note to extend the maturity date to May 30, 2015. The interest on the promissory notes is still payable quarterly. During 2012 the Company paid interest of $209,178 on two of the Notes in addition to $150,000 in principle on one of the promissory notes. Interest accrued during 2012 was $211,005. During the period ended June 30, 2013, the balance due on the promissory notes was $7,850,000 plus accrued interest of $562,401.

The Company entered into two promissory notes payable with one major shareholder and with a Company partially owned by an officer and director of the Company each for $125,000 (total $250,000), bearing interest at 5% per annum. The principal is due March 12, 2015. During the period ended June 30, 2013 the Company accrued interest of $3,732.

Historically, the Company has successfully raised additional operating capital through private equity funding sources and from the sale oil and gas generated revenues.

**Net Earnings (Loss)**

The Company reported a net loss in Q2 2013 of $1,065,276 or $0.01 per common share. The loss relates to a significant increase in depletion, accretion and deprecation and finance costs. The Company's net loss for the three months ended Q2 2012 was $362,013 or $0.01 per share.

**Equity**

The Company's equity structure consists of common shares outstanding and stock options outstanding to acquire additional common shares on a one-for-one basis. The Company's common shares are listed on the TSX-V under the trading symbol MVW.

**Related Party Transactions**

Please refer to Note 15 of our interim consolidated financial statements for related party transactions during the three months ended June 30, 2013.

**Segment Information**

Please refer to Note 19 of our interim consolidated financial statements for segment information for the three months ended June 30, 2013.

**Financial Instruments and Risk Management**

Mountainview is subject to a number of financial risks, including market risk, liquidity risk and credit risk. Market risk is the risk that the fair value of future cash flows will fluctuate due to movements in market prices, as comprised of commodity price risk, foreign exchange rate risk and interest rate risk. Market risk is managed by Mountainview through ongoing monitoring of the markets. Liquidity risk is the risk that the Company will encounter financial difficulty in meeting obligations associated with financial liabilities. Mountainview manages its liquidity risk through cash and debt management and review of financial ratios. Credit risk is the risk that a counterparty to a financial asset will default resulting in the Company incurring a loss. Mountainview manages credit risk by entering into sales contracts with creditworthy entities and reviewing its exposure to individual entities on a regular basis. Details of risk management contracts in place as at June 30, 2013 and the accounting treatment of the Company's financial instruments are disclosed in the notes to the interim consolidated financial statements as at and for the three months ended June 30, 2013.

**Off-Balance Sheet Arrangements**

The Company has no off-balance sheet arrangements.

**CRITICAL ACCOUNTING ESTIMATES**

Management is often required to make judgments, assumptions and estimates in the application of IFRS that may have a significant impact on the financial results of the Company. The preparation of financial information in accordance with IFRS requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. The following is a summary of key areas where critical accounting estimates are made:

Financial statement item and Critical accounting estimates

**Depletion and depreciation expense**

Accumulated costs are depleted using the unit-of-production method based on estimated proved reserves. Depletion is calculated based on individual components (i.e. fields or combinations thereof and other major components with different useful lives).

**Impairment of non-current assets**

The carrying amounts of the Company's property, plant and equipment are reviewed at each reporting date for indicators of impairment. If any such indication exists, the recoverable amount of the asset is estimated in order to determine the amount of the impairment, if any. The recoverable amount of an asset is evaluated at the Cash Generating Unit ("CGU") level, which is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The recoverable amount of a CGU is the greater of its fair value less costs to sell and its value in use. Fair value is determined as the amount that would be obtained from the sale of the asset in an arm's length transaction between knowledgeable and willing parties, less the costs of disposal. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. An impairment loss is recognized in earnings for the period to the extent that the carrying amount of the asset (or CGU) exceeds the recoverable amount.

Impairment losses recognized in prior periods are assessed at each reporting date for any indication that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimate used to determine the recoverable amount. An impairment loss is reversed only to the extent that the carrying amount of the asset (or CGU) does not exceed the carrying amount that would have been determined, net of depletion and depreciation, had no impairment loss been recognized for the asset (or CGU). A reversal of an impairment loss is recognized immediately in earnings.

E&E assets are assessed for impairment when they are reclassified to property, plant and equipment, or if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

**Exploration and evaluation (“E&E”) costs**

Once the legal right to explore has been acquired, costs directly associated with the exploration project are capitalized as either tangible or intangible exploration and evaluation assets according to the nature of the asset acquired. Such E&E costs may include undeveloped land acquisition, geological, geophysical and seismic, exploratory drilling and completion, testing, decommissioning and directly attributable internal costs. E&E costs are not depleted and are carried forward until technical feasibility and commercial viability of extracting a mineral resource is considered to be determined. The technical feasibility and commercial viability of an oil and gas resource is considered to be established when proved and/or probable reserves are determined to exist. All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the exploratory activity. When this is no longer the case, the impairment costs are charged to exploration and evaluation expense. Upon determination of proved and/or probable reserves, E&E assets attributed to those reserves are first tested for impairment and then reclassified to oil and gas development and production assets within property, plant and equipment, net of any impairment. Expired land costs are also expensed to exploration and evaluation expense as they occur.

E&E assets are assessed for impairment if facts and circumstances suggest that the carrying amount exceeds the recoverable amount, and upon transfer to property, plant and equipment whereby they are allocated to cash-generating units based on geographical proximity and other factors.

**Decommissioning liabilities**

Decommissioning liabilities are recognized for the future legal or constructive obligation to abandon and reclaim the Company's oil and natural gas properties. The amount of the decommissioning liabilities represents the net present value of the estimated future expenditures required to abandon and reclaim the Company's net ownership in wells and facilities determined in accordance with local conditions, current technology and current requirements. The liabilities are calculated using currently estimated abandonment and reclamation costs inflated to the estimated decommissioning date and then discounted using a risk free discount rate. A liability is recorded in the period in which an obligation arises with a corresponding decommissioning cost added to the carrying amount of the related asset. The liability is progressively accreted over time as the effect of discounting unwinds, creating an accretion expense which is recognized as part of finance expense. The related decommissioning cost capitalized in property, plant and equipment is depreciated in a manner consistent with the depletion and depreciation of the underlying asset.

Changes in the estimated liability resulting from revisions to estimated timing of decommissioning, expected amount of cash flows or changes in the discount rate are recognized as a change in the decommissioning liability and the related decommissioning cost.

Actual decommissioning expenditures incurred are charged against the accumulated liability to the extent recorded.

**Share-based payments**

The grant date fair value of options to employees and directors is recognized as share-based compensation expense, with a corresponding increase in contributed surplus, over the vesting period of the options. Share-based payments to non-employees are measured at the fair value of the goods or services received or the fair value of the equity instruments issued if it is determined the fair value of the goods or services cannot be reliably measured, and are recorded at the date the goods or services are received. Each tranche in an award is considered a separate grant with its own vesting period and grant date fair value. Fair value is determined using the Black-Scholes option pricing model. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest.

Upon the exercise of stock options, the consideration received by the Company plus the associated amount recorded in contributed surplus are transferred to common shares within equity.

**Deferred income taxes**

The tax expense for the period comprises current and deferred tax. Tax is recognized in the statement of loss, except to the extent that it relates to items recognized in other comprehensive loss or directly in equity. In this case, the tax is also recognized in other comprehensive loss or directly in equity, respectively. The current income tax charge is calculated on the basis of the tax laws enacted or substantively enacted at the balance sheet date in the countries where the Company and its subsidiaries operate and generate taxable income.

Management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulation is subject to interpretation. It establishes provisions where appropriate on the basis of amounts expected to be paid to the tax authorities.

Deferred income tax is recognized, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the consolidated financial statements. However, deferred tax liabilities are not recognized if they arise from the initial recognition of goodwill; deferred income tax is not accounted for if it arises from initial recognition of an asset or liability in a transaction other than a business combination that at the time of the transaction affects neither accounting nor taxable profit or loss. Deferred income tax is determined using tax rates (and laws) that have been enacted or substantially enacted by the date of the statement of financial position and are expected to apply when the related deferred income tax asset is realized or the deferred income tax liability is settled.

**Subsequent Events**

Subsequent to the three and six-month periods ending June 30, 2013, the Company commenced new operations on a drilling program in the 12-Gage Prospect, Divide County, ND. Please refer to Note 20 of our interim consolidated financial statements for segment information for the three months ended June 30, 2013.

Following are the results of that program to-date:

**<u>Heckman 7-6-1H, Section 7 & 6 T162N-101W, Divide County, North Dakota</u>**

Mountainview completed drilling operations on the Heckman 7-6-1H well (the "Heckman Well"), the first Three Forks well of Mountainview's planned three-well summer drilling program on its 12-Gage Project. The Heckman Well successfully reached a total depth of 18,165’ in 19 days. Good geologic oil and gas shows were encountered while drilling the lateral and the well was drilled under budget by Nabors Rig No 272.

(Reported in US Dollars, unless otherwise indicated)

**Olson 2-11S-1H, Section 2 & 11 T162-101W, Divide County, North Dakota**

The Company's second Three Forks well of its summer drilling program is the Olson 2-11S-1H well (the "Olson 2 Well"). The well was spudded at 11pm on August 7th and the Company successfully ran 1,435' of 7" surface casing. The Olson well is being drilled on a dual pad with the Olson 35-26-1H well, which will provide significant cost savings due to the use of the same location and road.

**Charlotte 1-12-1H, Section 1 & 12 T162-R101W, Divide County, North Dakota**

The third well planned for the summer drilling program is the Charlotte 1-12-1H (the "Charlotte Well"). The Charlotte well is permitted and we are currently constructing the location. This well is a direct eastern offset to the Olson 2-11S-1H well.

This three-well summer drilling program will result in increased capital expenditures in the aggregate amount of $14 million. Mountainview has contracted with Nabors Rig 272 for the three-well summer drilling program and projects well costs, including drilling, completion and tie-in to be approximately $7-7.5 million (gross) per well. The following table illustrates the projected location and working interests in the three-well program:

| Well Name | Location | Working Interest |
|---|---|---|
| Heckman 6-7-1H | Sec. 6 & 7, T162N-R101W, Divide County, ND | 90.26% |
| Olson 2-11-1H | Sec. 2 & 11, T162N-R101W, Divide County, ND | 70.26% |
| Charlotte 1-12-1H | Sec. 1 & 12, T162N-R101W, Divide County, ND | 30.23% |

To fund this increased capital program, Mountainview's wholly-owned subsidiary Mountain Divide, LLC ("**Mountain Divide**"), which holds the interest in the 12-Gage project, will draw an additional $14 million on its $75 million dollar senior secured credit facility (the "**Facility**"). Including this draw, the total amount drawn under this facility to date will be $32 million.

**Future Changes in Accounting Policies**

The following accounting standards have been issued or amended and are effective for future reporting periods. The Company is evaluating the impact of these new or amended standards and a more detailed description of these policies is disclosed in note 3 t) to the consolidated financial statements for the year ended December 31, 2012:

| | |
|---|---|
| IFRS 7 | Financial Instrument Disclosures |
| IFRS 10 | Consolidated Financial Statements |
| IFRS 11 | Joint Arrangements |
| IFRS 12 | Disclosure of Interest in Other Entities |
| IFRS 13 | Fair Value Measurement |
| IAS 32 | Financial Instruments Presentation |

**Controls and procedures**

In connection with Exemption Orders issued in November 2007 and revised in December 2008 by each of the securities commissions across Canada, the Chief Executive Officer and Chief Financial Officer of the Company will file a Venture Issuer Basic Certificate with respect to the financial information contained in the unaudited interim financial statements and the audited annual financial statements and respective accompanying Management's Discussion and Analysis.

In contrast to the certificate under National Instrument ("NI") 52-109 (Certification of disclosure in an Issuer's Annual and Interim Filings), the Venture Issuer Basic Certification does not include representations relating to the establishment and maintenance of disclosure controls and procedures and internal control over financial reporting, as defined in NI 52-109.

**Disclosure controls and procedures**

Disclosure controls and procedures ("DC&P") are intended to provide reasonable assurance that information required to be disclosed is recorded, processed, summarized and reported within the time periods specified by Canadian securities regulations and that information required to be disclosed is accumulated and communicated to management. Internal controls over financial reporting ("ICFR") are intended to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian generally accepted accounting principles.

TSX-V listed companies are not required to provide representations in the annual filings relating to the establishment and maintenance of DC&P and ICFR, as defined in Multinational Instrument 52-109. In particular, the CEO and CFO certifying officers do not make any representations relating to the establishment and maintenance of (a) controls and other procedures designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation, and (b) a process to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's generally accepted accounting principles.

The issuer's certifying officers are responsible for ensuring that processes are in place to provide them with sufficient knowledge to support the representations they are making in their certificates regarding the absence of misrepresentations and fair disclosure of financial information. Investors should be aware that inherent limitations on the ability of certifying officers of a TSX-V issuer to design and implement on a cost effective basis DC&P and ICFR as defined in Multinational Instrument 52-109 may result in additional risks to the quality, reliability, transparency and timeliness of interim and annual filings and other reports provided under securities legislation.

## Risk Factors

### Financial Risk

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions that could have a positive or negative impact on Mountainview's business. Financial risks the Company is exposed to include: marketing reserves at an acceptable price given market conditions; finding and producing reserves at a reasonable cost; volatility in market prices for oil and natural gas; fluctuations in foreign exchange and interest rates; stock market volatility; debt service which may limit timing or amount of dividends as well as market price of shares; the continued availability of adequate debt and equity financing and cash flow to fund planned expenditures; sufficient liquidity for future operations; lost revenue or increased expenditures as a result of delayed or denied environmental, safety or regulatory approvals; cost of capital risk to carry out the Company's operations; and uncertainties associated with credit facilities and counterparty credit risk.

### Operational Risk

Operational risk is the risk of loss or lost opportunity resulting from operating and capital activities that, by their nature, could have an impact on the Company's ability to achieve objectives. Operational risks Mountainview is exposed to include: uncertainties associated with estimating oil and natural gas reserves; incorrect assessments of the value of acquisitions and exploration and development programs; failure to realize the anticipated benefits of acquisitions; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; delays in business operations, pipeline restrictions, blowouts; unforeseen title defects; increased competition for, among other things, capital, acquisitions of reserves and undeveloped lands; competition for and availability of qualified personnel or management; loss of key personnel; unexpected geological, technical, drilling, construction and processing problems; availability of insurance; competitive action by other companies; the ability of suppliers to meet commitments and risks; and uncertainties related to oil and gas interests.

### Safety, Environmental and Regulatory Risks

Safety, environmental and regulatory risks are the risks of loss or lost opportunity resulting from changes to laws governing safety, the environment, royalties and taxation. Safety, environmental and regulatory risks Mountainview is exposed to include: uncertainties associated with regulatory approvals; uncertainty of government policy changes; the risk of carrying out operations with minimal environmental impact; changes in or adoption of new laws and regulations or changes in how they are interpreted or enforced; obtaining required approvals of regulatory authorities and stakeholder support for activities and growth plans. There are no new material environmental initiatives impacting Mountainview at this time.

(Reported in US Dollars, unless otherwise indicated)

**Risk Management**

Mountainview is committed to identifying and managing these risks in the near term, as well as on a strategic and longer term basis at all levels in the organization in accordance with the Company's board-approved Risk Management and Counterparty Credit Policy and risk management programs. Issues affecting, or with the potential to affect, the Company's assets, operations and/or reputation, are generally of a strategic nature or are emerging issues that can be identified early and then managed, but occasionally include unforeseen issues that arise unexpectedly and must be managed on an urgent basis. Mountainview takes a proactive approach to the identification and management of issues that can affect the Company's assets, operations and/or reputation and have established consistent and clear policies, procedures, guidelines and responsibilities for issue identification and management. Specific actions Mountainview takes to ensure effective risk management include: employing qualified professional and technical staff; concentrating in a limited number of areas with low cost exploitation and development objectives; utilizing the latest technology for finding and developing reserves; constructing quality, environmentally sensitive and safe production facilities; adopting and communicating sound policies governing all areas of our business; maximizing operational control of drilling and production operations; adhering to conservative borrowing guidelines; monitoring counterparty creditworthiness and obtaining counterparty credit insurance.

**Non-IFRS Measures**

EBITDA (Earnings before Interest Taxes Depreciation and Amortization) is calculated by adding finance costs, and depreciation to net earnings. Adding back non-operating expenses allows management to consistently compare periods by removing changes in tax rates, long-term assets and financing costs.

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Net loss | $ (1,065,276) | $ (362,013) | $ (2,446,103) | $ (624,318) |
| Finance costs | 1,016,332 | 88,048 | 1,894,383 | 89,324 |
| Depletion, accretion and depreciation | 1,884,112 | 267,023 | 2,731,777 | 521,302 |
| EBITDA | $ 1,835,168 | $ (6,942) | $ 2,180,057 | $ (13,692) |

**Summary of Quarterly Results**

| | Q2 2013 | Q1 2013 | Q4 2012 | Q3 2012 |
|---|---|---|---|---|
| Net Revenue | $ 4,307,186 | $ 1,746,674 | $ 732,602 | $ 959,243 |
| Net Income (Loss) | $ (1,065,275) | $ (1,475,284) | $ (7,339,991) | $ (428,315) |
| Income (Loss) per Share - Basic | $ (0.01) | $ (0.02) | $ (0.10) | $ (0.00) |
| Income (Loss) per Share - Diluted | $ (0.01) | $ (0.02) | $ (0.10) | $ (0.00) |
| Total Assets | $ 67,252,582 | $ 65,036,162 | $ 49,055,600 | $ 49,359,566 |
| Total Liabilities | $ 49,052,580 | $ 46,183,923 | $ 28,823,571 | $ 21,926,374 |

(Reported in US Dollars, unless otherwise indicated)

| | Q2 2012 | Q1 2012 | Q4 2011 | Q3 2011 |
|---|---|---|---|---|
| Net Revenue | $ 704,659 | $ 1,011,233 | $ 994,900 | $ 762,979 |
| Net Income (Loss) | $ (366,292) | $ (262,305) | $ (611,520) | $ (503,778) |
| Income (Loss) per Share - Basic | $ (0.01) | $ (0.00) | $ (0.01) | $ (0.01) |
| Income (Loss) per Share - Diluted | $ (0.01) | $ (0.00) | $ (0.01) | $ (0.01) |
| Total Assets | $ 47,945,130 | $ 21,248,818 | $ 19,151,591 | $ 23,840,827 |
| Total Liabilities | $ 20,083,623 | $ 4,879,397 | $ 2,519,865 | $ 1,764,716 |

**Selected Annual Information**

Set out below is selected annual information for Mountainview for the last three years:

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| Oil and natural gas sales | $ 3,559,782 | $ 3,439,500 | $ 2,900,253 |
| Royalties | 298,547 | 314,559 | 246,015 |
| Operating expense | 1,799,832 | 1,584,852 | 1,171,588 |
| Depletion, accretion and depreciation | 1,479,268 | 872,483 | 698,982 |
| | (17,865) | 667,606 | 783,668 |
| General and administrative expense | 1,726,042 | 1,940,116 | 878,964 |
| Impairment of oil and natural gas assets | 6,903,662 | - | - |
| Gain on sale of oil and natural gas assets | (576,269) | - | - |
| Interest expense | 295,652 | 5,260 | 1,416 |
| Interest income | (3,692) | (15,896) | (10,756) |
| Loss from operations | (8,363,260) | (1,261,874) | (85,956) |
| Per share - Basic and diluted | (0.11) | (0.03) | (0.01) |
| Net income (loss) | (8,396,903) | $ (4,736,238) | $ 371,470 |
| Per share - Basic and diluted | (0.11) | (0.10) | 0.04 |
| Exploration and evaluation assets | 14,737,242 | 6,397,705 | 512,927 |
| Property, plant and equipment | 92,168 | 255,389 | 54,453 |
| Oil and gas property | 6,294,679 | 1,250,378 | - |
| Dispositions | (3,622,913) | - | (174,149) |
| Net debt | 26,788,367 | 11,900 | - |
| Total assets | 49,055,600 | $ 19,151,591 | $ 6,634,616 |
| Weighted Average Shares outstanding | | | |
| Basic | 75,836,349 | 49,208,929 | 9,766,850 |
| Diluted | 75,836,349 | 49,208,929 | 9,766,850 |