**TRAVERSE ENERGY LTD.**
**MANAGEMENT'S DISCUSSION AND ANALYSIS**
**FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2015**

This management's discussion and analysis ("MD&A") of Traverse Energy Ltd. ("Traverse" or "the Company") dated November 16, 2015 should be read in conjunction with the Company's unaudited interim financial statements as at and for the nine months ended September 30, 2015 and the audited financial statements as at and for the year ended December 31, 2014. This MD&A should also be read in conjunction with the Company's MD&A for the year ended December 31, 2014 ("2014 MD&A"), as disclosure which is unchanged from December 31, 2014 may not be duplicated herein. Additional information relating to the Company, including Traverse's Annual Information Form, is available on SEDAR at www.sedar.com.

## Description of the Company

Traverse Energy Ltd. is an oil and gas exploration, development and production company based in Calgary, Alberta, Canada. Traverse conducts its operations in the province of Alberta. The common shares of Traverse trade on the TSX Venture Exchange under the symbol "TVL".

## Non-IFRS measures

In this MD&A references are made to terms commonly used in the oil and gas industry. Funds from operations, funds from operations per share, operating netback, operating netback per BOE and adjusted working capital are not defined by IFRS and therefore may not be comparable to performance measures presented by others. Funds from operations represents cash flow from operating activities prior to changes in non-cash working capital and settlement of decommissioning obligations as detailed under the heading "Funds from operations and net income (loss)". Funds from operations per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of net income (loss) per share. Adjusted working capital is calculated as current assets (excluding financial derivative assets) less current liabilities (excluding financial derivative liabilities). Operating netback represents revenue and realized gain or loss on financial derivatives, less royalties, operating and transportation expenses and is calculated on a per unit basis. The calculation of Traverse's operating netback is detailed under the heading "Operating netback". Management believes that in addition to net income (loss), the aforementioned non-IFRS measures are useful supplemental measures as they assist in the determination of the Company's operating performance, leverage and liquidity. Investors should be cautioned however, that these measures should not be construed as an alternative to both net income (loss) and net cash from operating activities, which are determined in accordance with IFRS, as indicators of the Company's performance.

## BOE presentation

Where amounts are expressed on a barrel of oil equivalent basis (BOE), natural gas volumes have been converted to BOE using a ratio of 6,000 cubic feet of natural gas to one barrel of oil equivalent. This conversion ratio is based upon an energy equivalent conversion method primarily applicable at the burner tip and does not represent value equivalence at the wellhead. BOE figures may be misleading, particularly if used in isolation.

## Oil and Gas Advisory

Any references in this MD&A to production tests are useful in confirming the presence of hydrocarbons; however, such tests are not necessarily determinative of the production rates at which such wells will commence production and decline thereafter. While encouraging, readers are cautioned not to place reliance on such rates in calculating aggregate production for the Company. In all cases in this MD&A, production test rates are not necessarily indicative of long-term performance of the relevant well or of the ultimate recovery of hydrocarbons.

### Forward-looking information

This MD&A contains forward-looking information. Forward-looking information is based upon the opinions, expectations and estimates of management as at the date the information is provided and, in some cases, information received from or disseminated by third parties. In particular, the Company's statements with respect to the intention to place on production a well in the Coyote area through existing facilities and for funding capital expenditures during 2016 contain forward-looking information. This forward-looking information is subject to a variety of substantial known and unknown risks and uncertainties and other factors that could cause actual events or outcomes to differ materially from those anticipated or implied by such forward-looking information. The Company's Annual Information Form filed with securities regulatory authorities (accessible through the SEDAR website  www.sedar.com) describes the risks, material assumptions and other factors that could influence actual results and which are incorporated herein by reference.

The forward-looking information contained in this MD&A is made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

| | Three months ended Sept. 30, | | Nine months ended Sept. 30, | |
|---|---|---|---|---|
| **HIGHLIGHTS *(Unaudited)*** | **2015** | 2014 | **2015** | 2014 |
| Financial *($ thousands, except per share amounts)* | | | | |
| Petroleum and natural gas revenue | **2,924** | 5,336 | **9,710** | 14,209 |
| Cash flow from operating activities | **1,767** | 3,160 | **5,956** | 6,709 |
| Per share - basic and diluted | **0.02** | 0.05 | **0.08** | 0.10 |
| Funds from operations (1) | **1,760** | 3,131 | **5,238** | 8,136 |
| Per share - basic and diluted | **0.02** | 0.05 | **0.07** | 0.12 |
| Net income (loss) | **(4,011)** | 635 | **959** | 1,788 |
| Per share - basic and diluted | **(0.06)** | 0.01 | **0.01** | 0.03 |
| Capital expenditures | **4,119** | 10,658 | **7,531** | 23,096 |
| Total assets | **42,790** | 49,007 | **42,790** | 49,007 |
| Adjusted working capital (2) | **2,063** | (1,695) | **2,063** | (1,695) |
| Common shares | | | | |
| Outstanding *(millions)* | **70.8** | 69.2 | **70.8** | 69.2 |
| Weighted average *(millions)* | **70.8** | 68.8 | **70.7** | 64.6 |
| Operations *(units as noted)* | | | | |
| Average production | | | | |
| Natural gas *(mcf/day)* | **2,917** | 3,710 | **2,836** | 2,560 |
| Oil and NGL *(bbls/day)* | **465** | 497 | **524** | 457 |
| Total (BOE/day) | **951** | 1,115 | **997** | 883 |
| Average sales price | | | | |
| Natural gas *($/mcf)* | **3.01** | 4.04 | **3.22** | 4.35 |
| Oil and NGL *($/bbl)* | **49.49** | 86.63 | **50.45** | 89.65 |
| Operating netback *($/BOE)* (3) | | | | |
| Petroleum and natural gas revenue | **33.42** | 52.02 | **35.69** | 58.93 |
| Realized gain (loss) on financial derivatives | **-** | (0.30) | **-** | (0.91) |
| Royalties | **(0.77)** | (8.22) | **(1.31)** | (9.40) |
| Operating and transportation costs | **(13.24)** | (10.35) | **(12.79)** | (11.19) |
| Operating netback | **19.41** | 33.15 | **21.59** | 37.43 |

*(1) Funds from operations represents cash flow from operating activities prior to changes in non-cash working capital and settlement of decommissioning obligations. Funds from operations does not have a standardized measure prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other companies.*

*(2) Adjusted working capital is calculated as current assets (excluding financial derivative assets) less current liabilities (excluding financial derivative liabilities). Adjusted working capital does not have a standardized measure prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other companies.*

*(3) Operating netback represents revenue and realized gain or loss on financial derivatives, less royalties, operating and transportation expenses and is calculated on a per unit basis. Operating netback does not have a standardized measure prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other companies.*

### Operations review

In the third quarter Traverse drilled one vertical and one horizontal well. The horizontal well was the first horizontal well drilled into an upper Mannville zone, previously delineated by wells drilled into the Coyote Ellerslie pool. The well was drilled to a total depth of 2,510 metres, including a 1,140 metre horizontal section and was fracture treated in 22 stages. The well was placed on production in mid August as a flowing oil well and in the first 90 days has produced an average of 168 bbls of oil/day and 900 mcf/day (339 BOE/day). The vertical exploration well was drilled in the Coyote area approximately 5 miles west of the existing Coyote production. The well was completed and placed on production in October and is producing oil and gas at low rates. Additional drilling in this area will be dependent on improved economics.

In October Traverse drilled a second horizontal well into the upper Mannville zone at Coyote. The well was drilled to a total depth of 2,565 metres, including a 1,200 metre horizontal section and was fracture treated in 24 stages. The well was initially swabbed and flowed for cleanup and production testing. During the test a total of 1,300 barrels of oil and 3.4 mmcf of raw natural gas were produced over a 4 day period. Final flow rates for the last 24 hours of the test were 290 barrels of oil per day and 1.25 mmcf of raw natural gas per day. The well is currently shut-in for a pressure survey and will be placed on production through existing facilities. These early test results, although preliminary, are encouraging based on analogous similar pools in East Central Alberta. These results are not necessarily indicative of long-term performance or of ultimate recovery.

In the fourth quarter, Traverse completed a two mile gas pipeline from its Coyote battery to a nearby gas plant to accommodate additional solution gas volumes from recent drilling and future development. The AER has granted GPP (good production practice) and issued a holding for increased well density in the Coyote Ellerslie pool which allows for future development with horizontal wells. In October, downhole gas separators were installed in the two Ellerslie horizontal wells drilled in the prior year resulting in increased production and pumping efficiency.

In June, Traverse sold its royalty interest in the Brazeau area of Alberta for cash proceeds of approximately $8.9 million. The royalty interest in 10 sections (6,400 acres) contained 22 producing horizontal Cardium oil wells and one Notikewin gas well at March 31, 2015. The royalty property contributed a total of 29 BOE/day during the nine months ended September 30, 2015.

Undeveloped land holdings in Alberta at September 30, 2015 were 185,100 gross (184,400 net) acres. At September 30, 2015 the Company had adjusted working capital of approximately $2.1 million and an approved credit facility of $10 million. Traverse anticipates total capital expenditures for 2015 to be approximately $11.5 million. The Board of Directors has approved an initial exploration and development program for 2016 of $12 million to be financed by cash flow, working capital and new equity issues or debt as appropriate.

| | Three months ended Sept. 30, | | Nine months ended Sept. 30, | |
|---|---|---|---|---|
| **Production** | **2015** | 2014 | **2015** | 2014 |
| Average working interest production | | | | |
| Natural gas *(mcf/day)* | **2,878** | 3,360 | **2,697** | 2,177 |
| Crude oil *(bbls/day)* | **465** | 454 | **508** | 403 |
| Total *(BOE/day)* | **944** | 1,014 | **958** | 765 |
| Average royalty production | | | | |
| Natural gas *(mcf/day)* | **39** | 350 | **139** | 383 |
| Crude oil *(bbls/day)* | **-** | 43 | **16** | 54 |
| Total *(BOE/day)* | **7** | 101 | **39** | 118 |
| Total production | | | | |
| Natural gas *(mcf/day)* | **2,917** | 3,710 | **2,836** | 2,560 |
| Crude oil *(bbls/day)* | **465** | 497 | **524** | 457 |
| Total *(BOE/day)* | **951** | 1,115 | **997** | 883 |
| % Oil and NGL | **49%** | 45% | **53%** | 52% |

Production in the three and nine months ended September 30, 2015 decreased 15% and increased 13%, respectively, compared to the three and nine months ended September 30, 2014 (the "Corresponding Periods"). Production in the third quarter of 2015 declined compared to the third quarter of 2014 due to flush production from 2 horizontals at Coyote in the 2014 period. Production for the nine months ended September 30, 2015 increased compared to the nine months ended September 30, 2014 due to the addition of the prior year horizontals and a new horizontal well in 2015. Production during the third quarter of 2015 increased 3% from the second quarter of 2015 as new production from a Mannville horizontal at Coyote commenced in the third quarter.

| | Three months ended Sept. 30, | | Nine months ended Sept. 30, | |
|---|---|---|---|---|
| **Production by area (BOE/day)** | **2015** | 2014 | **2015** | 2014 |
| Coyote | **578** | 438 | **572** | 294 |
| Turin | **345** | 558 | **365** | 448 |
| Minor | **28** | 119 | **60** | 141 |
| **Total BOE per day** | **951** | 1,115 | **997** | 883 |
| % of BOE/day | | | | |
| Royalty | **1%** | 9% | **4%** | 13% |
| Working interest | **99%** | 91% | **96%** | 87% |

Production from the Coyote area increased 32% and 95%, respectively, in the three and nine months ended September 30, 2015 compared to the Corresponding Periods mainly as a result of the horizontal drilling program at Coyote. Production from minor areas, which includes royalty income, decreased 76% and 58%, respectively, over the Corresponding Periods. In June 2015 the Company sold its royalty interest in the Brazeau area of Alberta for proceeds of approximately $8.9 million resulting in a gain on sale of approximately $8.8 million.

| | Three months ended Sept. 30, | | Nine months ended Sept. 30, | |
|---|---|---|---|---|
| **Pricing** | **2015** | 2014 | **2015** | 2014 |
| Average sales price | | | | |
| Oil *($/bbl)* | **52.13** | 79.75 | **52.79** | 84.42 |
| NGL *($/bbl)* | **14.22** | 58.97 | **21.25** | 60.76 |
| Natural gas *($/mcf)* | **3.01** | 4.04 | **3.22** | 4.35 |
| Realized gain (loss) on financial derivatives | **-** | (0.30) | **-** | (0.91) |
| BOE *($/BOE)* | **33.42** | 52.02 | **35.69** | 58.93 |

Traverse realized oil prices of $52.13 per bbl and $52.79 per bbl during the three and nine months ended September 30, 2015, respectively (Corresponding Periods: $79.75 per bbl and $84.42 per bbl, respectively). The realized oil price also incorporates the result of any fixed physical delivery contracts. During the three and nine months ended September 30, 2015 the impact on oil sales of these contracts was $145,473 (Corresponding Periods: $0). During the three and nine months ended September 30, 2015, Traverse's discount to CAL (Central Alberta) at Edmonton approximated $7 per bbl (Corresponding Periods; $7 and $8 per bbl, respectively). These pricing differentials are a function of North American refinery supply/demand fundamentals as well as crude quality.

In the three and nine months ended September 30, 2015, Traverse realized natural gas prices of $3.01 per mcf and $3.22 per mcf, respectively (Corresponding Periods: $4.04 per mcf and $4.35 per mcf, respectively). The Company's natural gas generally receives a premium of 5 to 10% above the AECO daily benchmark due to the higher heat content of its natural gas. The realized natural gas price also incorporates the result of any fixed physical delivery contracts. During the three and nine months ended September 30, 2015 the impact on natural gas sales of these contracts was $13,267 and $235,676, respectively (Corresponding Periods: $(57,751) and $(313,181), respectively).

The average BOE sales price received in the three and nine months ended September 30, 2015 decreased 36% and 39%, respectively, from the Corresponding Periods due to declining commodity prices. The proportion of oil and NGL in the Company's sales mix for the three and nine months ended September 30, 2015 has increased to 49% and 53%, respectively (Corresponding Periods: 45% and 52%, respectively).

Volatility in the commodity markets will continue to impact realized prices in 2015. At September 30, 2015 Traverse had natural gas physical delivery contracts for the remainder of 2015 outstanding for an average of 750 GJ per day at $2.91 per GJ. Traverse also has an oil physical delivery contract for 150 barrels per day to December 2015 at $74.50 Cdn $/bbl WTI with a fixed differential to CAL at Edmonton of $8.16 per barrel.

There were no derivative commodity contracts outstanding during the first nine months of 2015 or as at September 30, 2015. The realized loss on financial derivatives in the comparable periods of 2014 was $(0.30) per BOE and $(0.91) per BOE, respectively.

| | Three months ended Sept. 30, | | Nine months ended Sept. 30, | |
|---|---|---|---|---|
| **Petroleum and natural gas revenue ($)** | **2015** | 2014 | **2015** | 2014 |
| Revenue by source | | | | |
| Working interest production | **2,915,308** | 4,838,809 | **9,378,686** | 12,307,206 |
| Royalty interest production | **8,860** | 497,160 | **331,563** | 1,901,960 |
| Total | **2,924,168** | 5,335,969 | **9,710,249** | 14,209,166 |
| Revenue by commodity | | | | |
| Oil and NGL | **2,116,408** | 3,956,898 | **7,216,263** | 11,172,670 |
| Natural gas | **807,760** | 1,379,071 | **2,493,986** | 3,036,496 |
| Total | **2,924,168** | 5,335,969 | **9,710,249** | 14,209,166 |

Revenue during the three and nine months ended September 30, 2015 decreased 45% and 32%, respectively, compared to the Corresponding Periods. Revenue in the third quarter of 2015 decreased 11% from the second quarter of 2015 despite increased production due to decreased commodity prices.

**Royalties**

| | Three months ended Sept. 30, | | Nine months ended Sept. 30, | |
|---|---|---|---|---|
| ***($)*** | **2015** | 2014 | **2015** | 2014 |
| Royalties | **67,590** | 842,882 | **356,797** | 2,265,699 |
| $ per BOE | **0.77** | 8.22 | **1.31** | 9.40 |
| Percentage of revenue | **2.3%** | 15.8% | **3.7%** | 15.9% |

The Company's corporate royalty rate (as a percentage of revenue) decreased in the three and nine months ended September 30, 2015 compared to the Corresponding Periods. Royalties decreased as a result of crown incentives on new production, reduced crown royalty rates due to commodity price declines and increased crown gas deductions resulting from 2014 capital expenditures.

**Operating and transportation expenses**

| | Three months ended Sept. 30, | | Nine months ended Sept. 30, | |
|---|---|---|---|---|
| ***($)*** | **2015** | 2014 | **2015** | 2014 |
| Operating | **1,011,638** | 951,729 | **3,001,075** | 2,443,716 |
| Transportation | **146,599** | 110,203 | **479,186** | 253,038 |
| | **1,158,237** | 1,061,932 | **3,480,261** | 2,696,754 |
| ***$/BOE*** | | | | |
| Operating | **11.56** | 9.28 | **11.03** | 10.14 |
| Transportation | **1.68** | 1.07 | **1.76** | 1.05 |
| | **13.24** | 10.35 | **12.79** | 11.19 |

Transportation expenses increased during the three and nine months ended September 30, 2015 as compared to the Corresponding Period due to the Coyote battery expansion which was completed in the third quarter of 2014. Prior to the battery expansion, oil from the Coyote area was shipped as emulsion and the related costs were classified as operating. After the battery expansion clean oil hauling costs have been classified as transportation costs. Operating costs increased on a BOE basis for the three and nine months ended September 30, 2015 compared to the Corresponding Period, despite the clean oil hauling, mainly due to additional costs associated with higher gas production and the sale of royalty income volumes which did not have associated operating costs.

### Operating netback

| | Three months ended Sept. 30, | | Nine months ended Sept. 30, | |
|---|---|---|---|---|
| ***$ per BOE*** | **2015** | 2014 | **2015** | 2014 |
| Petroleum and natural gas revenue | **33.42** | 52.02 | **35.69** | 58.93 |
| Realized gain (loss) on financial derivatives | **-** | (0.30) | **-** | (0.91) |
| Royalties | **(0.77)** | (8.22) | **(1.31)** | (9.40) |
| Operating and transportation costs | **(13.24)** | (10.35) | **(12.79)** | (11.19) |
| Operating netback | **19.41** | 33.15 | **21.59** | 37.43 |

The operating netback decreased in the three and nine months ended September 30, 2015 compared to the Corresponding Periods due to the decline in commodity prices.

### General and administrative

| | Three months ended Sept. 30, | | Nine months ended Sept. 30, | |
|---|---|---|---|---|
| ***($)*** | **2015** | 2014 | **2015** | 2014 |
| General and administrative costs - gross | **295,564** | 342,878 | **983,916** | 1,101,366 |
| Operator recoveries | **68,200** | 137,471 | **128,162** | 330,272 |
| General and administrative costs - net | **227,364** | 205,407 | **855,754** | 771,094 |
| Per BOE | **2.60** | 2.00 | **3.15** | 3.20 |

Gross general and administrative costs decreased 14% and 11%, respectively, in the three and nine months ended September 30, 2015 compared to the Corresponding Periods due mainly to reductions in office staff associated with the reduced capital program. Operator recoveries declined in both the three and nine months ended September 30, 2015 due to the reduction in capital expenditures in 2015. Net general and administrative costs remained consistent during the 2015 periods compared to the Corresponding Periods.

### Share based compensation

| | Three months ended Sept. 30, | | Nine months ended Sept. 30, | |
|---|---|---|---|---|
| ***($)*** | **2015** | 2014 | **2015** | 2014 |
| Share based compensation | **31,856** | 82,377 | **629,049** | 740,019 |
| Per BOE | **0.36** | 0.80 | **2.31** | 3.07 |

Share based compensation expense decreased for both the three and nine months ended September 30, 2015 compared to the Corresponding Periods due to the decrease in the weighted average fair value of stock options granted. The weighted average fair value of options granted in 2015 decreased to $0.28 compared to $0.46 in 2014 due to the decreased exercise price of the stock options granted ($0.62 compared to $0.96).

### Net finance expense

| | Three months ended Sept. 30, | | Nine months ended Sept. 30, | |
|---|---|---|---|---|
| ***($)*** | **2015** | 2014 | **2015** | 2014 |
| Interest income | **(4,576)** | (10,428) | **(5,764)** | (37,197) |
| Interest expense and financing charges | **15,068** | 28,604 | **125,214** | 38,462 |
| Accretion on decommissioning obligations | **18,750** | 22,000 | **58,250** | 57,000 |
| Net finance expense | **29,242** | 40,176 | **177,700** | 58,265 |

Interest income decreased for the three and nine months ended September 30, 2015 compared to the Corresponding Periods due to lower interest earning cash balances. Interest expense and financing charges increased in the three and nine months ended September 30, 2015 as compared to the Corresponding Periods due to a larger credit facility as well as utilization of the credit facility.

The accretion on decommissioning obligations increased for the three and nine months ended September 30, 2015 as compared to the Corresponding Periods due to the additional decommissioning obligations incurred by the Company.

### Exploration and evaluation expense

| | Three months ended Sept. 30, | | Nine months ended Sept. 30, | |
|---|---|---|---|---|
| ***($)*** | **2015** | 2014 | **2015** | 2014 |
| Land expiries | **438,617** | 206,604 | **730,199** | 442,352 |
| Unsuccessful exploration | **18,679** | - | **271,035** | - |
| Exploration and evaluation expense | **457,296** | 206,604 | **1,001,234** | 442,352 |

Exploration and evaluation ("E&E") expenses result from impairment of E&E assets, unsuccessful E&E costs and the expiry of undeveloped lands. In 2015 E&E expenses were recorded relating to the unsuccessful re-entry of a well at Hanna, there were no unsuccessful exploration costs recorded in the Corresponding Periods.

### Depletion and depreciation

Traverse depletes its developed oil and natural gas properties, by area, based on proved and probable reserves. The calculation of depletion expense includes future development costs related to these reserves of $4,644,000 at September 30, 2015 (2014 - $964,000) and excluded $1,300,000 (2014 - $1,110,000) for estimated salvage values. Future development costs at September 30, 2015 relate mainly to two additional horizontal wells at Coyote.

| | Three months ended Sept. 30, | | Nine months ended Sept. 30, | |
|---|---|---|---|---|
| ***($)*** | **2015** | 2014 | **2015** | 2014 |
| Depletion and depreciation | **1,850,330** | 1,933,760 | **5,651,884** | 3,938,532 |
| Per BOE | **21.15** | 18.85 | **20.77** | 16.34 |

Depletion and depreciation expense on a total dollar basis decreased 4% and increased 44%, respectively, for the three and nine months ended September 30, 2015 over the Corresponding Periods. Depletion and depreciation for the three months ended September 30, 2015 declined compared to the third quarter of 2014 as production declines more than offset the increased depletion rate which resulted from negative technical reserve revisions at the end of 2014. Depletion and depreciation increased for the nine months ended September 30, 2015 as production increased combined with the increased depletion rate. On a per BOE basis, depletion and depreciation increased 12% and 27%, respectively, for the three and nine months ended September 30, 2015 compared to the Corresponding Periods due to the higher cost of reserve additions in 2014 as well as negative technical reserve revisions in the fourth quarter of 2014 resulting from production performance at Coyote.

### Impairment

At September 30, 2015 due to declining natural gas and oil prices, the Company determined that impairment triggers were present and tested all of its cash-generating units ("CGUs") for impairment. The recoverable amounts of the Company's CGUs were estimated as the fair value less costs to sell based on the net present value of the before income tax cash flows from proved plus probable reserves, originally estimated by the Company's external reserve evaluators and updated internally for production since December 31, 2014 and to reflect the September 30, 2015 external evaluators price deck, discounted at a rate of 10%. As a result, the Company recorded a total impairment charge of $4.5 million relating to the oil CGU. As the recoverable amount of the CGUs are sensitive to a decrease in commodity prices, further impairment could be recorded in future periods. Alternatively, an improvement of commodity prices could reverse any impairment charge recorded to date, less applicable depletion expense.

### Income taxes

The Company recorded an income tax recovery in the three months ended September 30, 2015 due to the impairment on property and equipment. A income tax provision was recorded for the nine months ended September 30, 2015 due to the gain on sale of the Brazeau royalty property and the recognition of the pending increase in the Alberta corporate income tax rate.

| | Three months ended Sept. 30, | | Nine months ended Sept. 30, | |
|---|---|---|---|---|
| ***($)*** | **2015** | 2014 | **2015** | 2014 |
| Current income tax (recovery) | **(300,000)** | 45,000 | **(340,000)** | 119,904 |
| Deferred income tax | **(1,085,200)** | 270,000 | **1,226,460** | 1,160,000 |
| Income taxes | **(1,385,200)** | 315,000 | **886,460** | 1,279,904 |

For the three and nine months ended September 30, 2015 the Company recorded a recovery of current income tax compared to a provision for current income tax in the comparable period due to the decrease in taxable income in 2015 resulting from the decline in commodity prices.

At September 30, 2015 the Company's tax pools available for deduction against future taxable income are estimated at $23 million. The approximate average rate of deduction from these tax pools is an annual rate of 25%. The current recovery of income taxes will depend on commodity prices, the level and type of capital expenditures during the remainder of 2015 as well as the results of such expenditures.

### Cash and funds from operations and net income (loss)

| | Three months ended Sept. 30, | | Nine months ended Sept. 30, | |
|---|---|---|---|---|
| ***($)*** | **2015** | 2014 | **2015** | 2014 |
| Cash provided by operating activities | **1,767,401** | 3,159,784 | **5,956,403** | 6,708,905 |
| Decommissioning expenditures | **40,192** | - | **69,146** | 38,158 |
| Change in non-cash working capital | **(47,108)** | (28,432) | **(787,562)** | 1,388,935 |
| Funds from operations | **1,760,485** | 3,131,352 | **5,237,987** | 8,135,998 |
| Per share basic and diluted | **0.02** | 0.05 | **0.07** | 0.12 |
| Net income (loss) | **(4,010,768)** | 634,911 | **958,871** | 1,788,015 |
| Per share basic and diluted | **(0.06)** | 0.01 | **0.01** | 0.03 |

Funds from operations decreased 44% and 36%, respectively in the three and nine months ended September 30, 2015 compared to the Corresponding Periods due mainly to the decline in commodity prices.

Net income decreased in both the three and nine months ended September 30, 2015 compared to the corresponding periods due to declining commodity prices and the impairment of property and equipment partially offset by the gain on the sale of the Brazeau royalty property in June 2015.

### Capital expenditures

The Company incurred $4.1 million in expenditures in the third quarter of 2015 relating mainly to the drilling, completion and tie in of a horizontal Mannville well at Coyote, the drilling of a vertical well at Coyote and recompletions and workovers.

| | Three months ended Sept. 30, | | Nine months ended Sept. 30, | |
|---|---|---|---|---|
| ***($)*** | **2015** | 2014 | **2015** | 2014 |
| Land acquisition and rentals | **98,192** | 221,012 | **381,995** | 752,335 |
| Geological and geophysical | **82,387** | 252,033 | **300,713** | 1,140,381 |
| Drilling and completions | **3,350,345** | 5,039,757 | **5,041,521** | 12,528,290 |
| Equipping and facilities | **588,132** | 5,021,173 | **1,802,620** | 8,507,018 |
| Exploration and development capital | **4,119,056** | 10,533,975 | **7,526,849** | 22,928,024 |
| Property and equipment dispositions | **(1,779)** | - | **(8,915,869)** | - |
| Corporate assets | **-** | 123,538 | **4,091** | 168,239 |
| Net capital expenditures | **4,117,277** | 10,657,513 | **(1,384,929)** | 23,096,263 |

### Liquidity and capital resources

At September 30, 2015 Traverse had adjusted working capital of approximately $2.1 million, no debt outstanding and an unutilized credit facility of $10 million. The Company anticipates total capital expenditures for 2015 to be approximately $11.5 million. The Company intends to fund capital expenditures and commitments during the remainder of 2015 with a combination of cash flow, working capital and the net proceeds from the private placement completed in October.

As at November 16, 2015 Traverse had 71,948,269 common shares outstanding and 5,545,000 common share options outstanding.

In October 2015 the Company completed a private placement of 1,168,000 flow-through common shares at a price of $0.60 per common share for gross proceeds of $700,800. Directors and officers of the Company subscribed for 454,667 common shares for consideration of $272,800. The qualifying expenditures must be incurred by December 31, 2015.

### Commitments

The Company has entered into a lease commitment for office space. The term of the lease is 10 years commencing November 1, 2011. The annual payments under this commitment are as disclosed in the notes to the audited financial statements.

### Summary of quarterly results

*($ thousands, except per share amounts)*
*(Unaudited)*

| Quarter ended | **Sept. 30 2015** | **June 30 2015** | March 31 2015 | December 31 2014 |
|---|---|---|---|---|
| Petroleum and natural gas revenue | **2,924** | **3,273** | 3,513 | 5,508 |
| Cash provided by operating activities | **1,767** | **2,189** | 2,000 | 3,473 |
| Funds from operations | **1,760** | **1,739** | 1,739 | 3,420 |
| Per share - basic and diluted | **0.02** | **0.02** | 0.02 | 0.05 |
| Net income (loss) | **(4,011)** | **5,525** | (555) | (6,358) |
| Per share - basic and diluted | **(0.06)** | **0.08** | (0.01) | (0.10) |
| Adjusted working capital (deficiency) | **2,063** | **4,460** | (5,240) | (4,641) |
| Production *(BOE/day)* | **951** | **924** | 1,116 | 1,249 |
| Capital expenditures, net of dispositions | **4,117** | **(7,824)** | 2,322 | 7,725 |

| Quarter ended | September 30 2014 | June 30 2014 | March 31 2014 | December 31 2013 |
|---|---|---|---|---|
| Petroleum and natural gas revenue | 5,336 | 4,338 | 4,535 | 4,055 |
| Cash provided by operating activities | 3,160 | 1,461 | 2,088 | 2,723 |
| Funds from operations | 3,131 | 2,409 | 2,596 | 1,958 |
| Per share - basic and diluted | 0.05 | 0.03 | 0.05 | 0.04 |
| Net income | 635 | 407 | 746 | 27 |
| Per share - basic and diluted | 0.01 | 0.01 | 0.01 | 0.00 |
| Adjusted working capital (deficiency) | (1,695) | 5,800 | 8,641 | 2,430 |
| Production *(BOE/day)* | 1,115 | 775 | 756 | 787 |
| Capital expenditures, net of dispositions | 10,658 | 5,475 | 6,964 | 5,482 |

In the fourth quarter of 2013 production volumes increased as a result of higher natural gas prices resulting in increased natural gas royalty volumes. No new working interest production was added. Commodity prices declined from the third quarter resulting in decreased revenue, funds from operations and net income. Two wells were drilled, completed and equipped during the quarter and a third well commenced drilling at year end. Capital expenditures were also incurred on facility expansion at Coyote and seismic acquisition. A well drilled at Turin in the first quarter was completed and expensed as a dry hole. In December 2013 the Company completed the acquisition of a private company owned by certain directors and officers of Traverse to consolidate its interest in Southern Alberta and for the tax pools of the acquired company. Traverse also completed a private placement of 4 million flow-through common shares for gross proceeds of $3.4 million.

In the first quarter of 2014 production volumes decreased as a result of a partial suspension of production in the Coyote area relating to the conservation of solution gas. Subsequent to quarter end, modifications were completed to allow conservation of solution gas and the battery returned to production May 1, 2014. Despite a decrease in production volumes, commodity price increases resulted in increased funds from operations and net income. Capital expenditures in the first quarter relating to the drilling of 5 wells and the re-entry of an existing wellbore. In March 2014 the Company completed a bought deal financing of 14,375,000 common shares for gross proceeds of $11.5 million.

In the second quarter of 2014 production volumes increased slightly as the partial suspension of production in the Coyote area ended May 1 and new production from 2014 drilling commenced late in June. Declines in the natural gas price resulted in decreased revenue during the second quarter. The expiration of the New Well Royalty Rate on certain wells resulted in increased royalties in the second quarter. These additional royalties combined with increased operating costs relating to start up of new wells and compression resulted in decreased funds from operations. Stock based compensation relating to option grants during the second quarter further reduced net income. Capital expenditures in the second quarter related to the drilling of 4 oil wells at Coyote, equipping and tie in activities and the installation of compression at the Turin facility.

In the third quarter of 2014 production volumes increased as new production from 2014 drilling commenced. Increased production and commodity prices resulted in increased revenue during the third quarter. New production resulted in a decline in royalties and new facilities helped to reduce operating costs on a unit basis. These decreased costs combined with increased revenue resulted in increased funds from operations and net income. Capital expenditures in the quarter related to the drilling and completion of 3 wells at Coyote, the drilling of a horizontal well at Coyote and the construction of the Coyote battery.

In the fourth quarter of 2014 production volumes increased as new production from two horizontal wells at Coyote commenced. Increased production resulted in increased revenue despite declining commodity prices. New production resulted in a decline in royalties and these decreased costs combined with increased revenue resulted in increased funds from operations. During the fourth quarter the Company recorded an impairment of property and equipment resulting in a net loss for the quarter. Capital expenditures in the quarter related mainly to the drilling of a second horizontal well at Coyote and the completion and tie in of both horizontals.

In the first quarter of 2015 production volumes declined as flush production from the Coyote horizontals declined. Commodity price declines resulted in decreased revenue and funds from operations. Increased depletion resulting from increased volumes and higher finding costs resulted in a net loss for the quarter. Capital expenditures in the quarter related mainly to the drilling and completion of one well at Coyote and the re-entry and abandonment of a well at Hanna.

In the second quarter of 2015 production volumes declined mainly due to the decrease in flush production from the Coyote horizontals. Commodity price declines resulted in decreased revenue. Funds from operations was unchanged as revenue declines were offset by decreases in operating and royalty expenses. The sale of the Brazeau royalty property resulted in a gain on sale which resulted in net income for the quarter. Capital expenditures for the quarter related mainly to the tie in of one well in the Coyote area and pre drill expenditures.

In the third quarter of 2015 production volumes increased due to the addition of a new production from the Coyote area. Commodity price declines resulted in decreased revenue. Funds from operations was consistent as revenue declines were offset by decreases in general and administrative expenses and increases in current tax recoveries. During the third quarter the Company recorded an impairment of property and equipment resulting in a net loss for the quarter. Capital expenditures for the quarter related mainly to the drilling, completion and tie in of a horizontal Mannville well at Coyote, the drilling of a vertical well at Coyote and recompletions and workovers.

## Critical accounting estimates

The preparation of financial statements in accordance with IFRS requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis.

*Reserves*

The assessment of reported recoverable quantities of proved and probable reserves include estimates regarding production profile, commodity prices, exchange rates, remediation costs, timing and amount of future development costs, and production, transportation and marketing costs for future cash flows. It also requires interpretation of geological and geophysical models in anticipated recoveries.

The economical, geological and technical factors used to estimate reserves may change from period to period. Changes in reported reserves can impact the carrying value of the Company's petroleum and natural gas properties and equipment, the calculation of depletion, the provision for decommissioning obligations, and the recognition of deferred tax assets due to changes in expected future cash flows. The recoverable quantities of reserves and estimated cash flows from the Company's petroleum and natural gas interests are independently evaluated by reserve engineers at least annually. Traverse's petroleum and natural gas reserves are determined pursuant to National Instrument 51-101, Standards of Disclosures for Oil and Gas Activities.

*Decommissioning obligations*

The Company estimates future decommissioning obligations of production facilities, wells and pipelines based on current legal and constructive requirements, technology, price levels and expected plans for remediation. In most instances, removal of assets occurs many years into the future. This requires assumptions regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability specific discount rates to determine the present value of these cash flows.

*Stock based compensation*

Compensation costs recognized for share based compensation plans are subject to the estimation of what the ultimate payout will be using pricing models such as the Black Scholes model which is based on significant assumptions such as share price, volatility, forfeiture rate, dividend yield and expected term.

*Financial derivatives*

The Company's estimate of the fair value of derivative financial instruments is dependent on estimated forward prices and volatility in those prices.

*Deferred income taxes*

Tax interpretations, regulations and legislation in the jurisdictions in which the Company operates are subject to change. As such, income taxes are subject to measurement uncertainty. Deferred income tax assets are assessed by management at the end of each reporting period to determine the likelihood that they will be realized from future taxable earnings.

*Business combinations*

In a business combination, management makes estimates of the fair value of assets acquired and liabilities assumed which includes assessing the value of oil and gas properties based upon the estimation of recoverable quantities of proven and probable reserves being acquired.

**Business environment and risk**

Additional risk factors can be found under "Risk Factors" in the Company's 2014 Annual Information Form ("AIF"), which can be found on www.sedar.com. Many risk factors are listed below and in the AIF, but these risk factors should not be construed as exhaustive. There are numerous factors, both known and unknown, that could cause actual results or events to differ materially from anticipated results.

The business risks the Company is exposed to are those inherent in the oil and gas industry as well as those governed by the individual nature of Traverse's operations. Geological and engineering risks, the uncertainty of discovering commercial quantities of new reserves, commodity prices, interest rate and foreign exchange risks, competition and government regulations – all of these govern the business and influence the controls and management at the Company.

Traverse manages these risks by attracting and retaining a team of highly qualified and motivated professionals who have a vested interest in the success of the Company, operating properties in order to maximize opportunities, maintaining a strong financial position and maintaining strict environmental, safety and health practices.