



TRAFINA
ENERGY LTD.

**2010 MANAGEMENT'S
DISCUSSION & ANALYSIS**

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") is a review of the financial results of Trafina Energy Ltd. (the "Company" or "Trafina") for the three months and year ended December 31, 2010 and should be read in conjunction with the audited financial statements and accompanying notes as at and for the year ended December 31, 2010. This MD&A is dated April 8, 2011.

All references to dollar values refer to Canadian dollars, unless otherwise stated.

In this MD&A, reserves and production are commonly stated in barrels of oil equivalent (boe) on the basis that six thousand cubic feet (Mcf) of natural gas is equivalent to one barrel of oil (Bbl). Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent an equivalency of value at the wellhead.

FORWARD-LOOKING STATEMENTS

Certain information set forth in this MD&A contains forward-looking information. Such information is frequently characterized by words such as "plan," "expect," "project," "intend," "believe," "anticipate," "estimate" or other similar words, or statements that certain events or conditions "may" or "will" occur. Forward-looking information is based on management's expectations regarding the Company's future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof) and anticipated financial condition and liquidity. Readers are cautioned that assumptions used in the preparation of forward looking statements may prove to be incorrect. Events or circumstances may cause actual results to differ materially from those predicted, as a result of numerous known and unknown risks, uncertainties, and other factors, many of which are beyond the control of the Company. These risks include, but are not limited to, credit risks associated with collection of outstanding accounts receivable and access to capital, changes to the Company's lending line of credit and including the ability to raise funds by issuing equity or disposing of assets. Operations risks include commodity price and exchange rate fluctuations, which ultimately affect the Company's realized oil and natural gas revenue, and future production mix and operating expenses, which have an effect on funds flow from operating activities. Industry related risks include, but are not limited to: operational risks in exploration, development and production of oil and natural gas, and production risks associated with sour hydrocarbons, dependence on third-party owned and operated production facilities, availability of skilled personnel and services, failure to obtain industry partners, regulatory and other third-party consents and approvals, delays or changes in plans, risks associated with the uncertainty of reserve and resource estimates, health, safety and environmental risks and the uncertainty of estimates and projections of current production, operating costs, capital expenses and abandonment estimates. Reference is made to Trafina's annual information form (the "AIF") for a description of additional risks that could affect the Company's future results and could cause results to differ materially from those expressed in the Company's forward looking statements. The risks outlined above and in the AIF should not be construed as exhaustive and readers are cautioned not to place undue reliance on these forward-looking statements. Except as required by applicable securities laws the Company has no obligation to update or revise this forward-looking information.

NON-GAAP MEASURES

The MD&A uses the term "funds flow from (used in) operations", which is not defined under Canadian generally accepted accounting principles ("GAAP") and should not be considered an alternative to, or more meaningful than, cash flow from (used in) operating activities as determined in accordance with GAAP as an indicator of the Company's performance. Trafina's determination of funds flow from (used in) operations may not be comparable to that reported by other companies. The Company also presents funds flow from operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per share. Management believes that, in addition to cash flow from operating activities, funds flow from (used in) operations is a useful supplemental measure as it demonstrates Trafina's ability to generate cash necessary to repay debt or fund future growth through capital investment before changes in non-cash working capital balances. Investors are cautioned, however, that the measure should not be construed as an alternative to cash flow from (used-in) operating activities determined in accordance with GAAP as an indication of Trafina's performance.

The following table reconciles cash flow from (used in) operating activities to funds flow from operations:

	Three Months Ended December 31		Year Ended December 31	
	2010	2009	2010	2009
Cash flow from (used in) operating activities	\$ (843,673)	\$ 443,237	\$ (2,268,252)	\$ (144,677)
Change in non-cash operating working capital	387,977	(433,736)	1,377,925	261,699
Funds flow from (used in) operations	\$ (455,696)	\$ 9,501	\$ (890,327)	\$ 117,022

The Company also considers field netback a key performance measure. However, field netback is not defined under GAAP and therefore may not be comparable with the calculation of similar measures by other companies. Field netback and field net loss is comprised of the Company's revenue from petroleum and natural gas sales, a liability settlement, unrealized and realized gains and losses on commodity contracts and other income, less royalties and operating expenses. A reconciliation of field netback and field net loss (each being non-GAAP) to net loss (GAAP) is presented under the Netback Analysis section of this MD&A. In addition, the Company presents "net debt and working capital deficiency" which consists of current liabilities, less current assets and excludes the effect of commodity contracts.

2010 OVERVIEW

- Maintained average production levels of 400 barrels of oil equivalent per day ("boe/day") despite disposing of 40 boe/day of non-core producing assets.
- Increased year over year oil and liquids production 104 percent.
- Raised gross proceeds of approximately \$3.9 million through non-brokered private placements and issued approximately 11.2 million Class A common Shares and approximately 6.3 million warrants to purchase Class A common shares.
- Acquired a relatively large undeveloped land position in northeastern Alberta with the potential of Wabiskaw heavy oil production, subsequently doubling the land position in February 2011.
- Tied-in and placed on production a Pembina Cardium oil well that has averaged approximately 168 (42 net) boe/day since January 1, 2011.
- Drilled, completed and tied-in an Upper Shaunavon horizontal oil well in southwest Saskatchewan which has produced approximately 44 (35 net) boe/day since January 1, 2011.

It was a very busy year for Trifina as the Company began its transformation from primarily gas focused non-operated producing properties to oil focused operated producing properties. This transformation process has not been without challenges, such as maintaining production levels while disposing of non-core producing properties, initial start-up expenses and unexpected costs from acquiring properties out of receivership that had been previously shut in for over a year, and most significantly weather related delays in drilling key oil wells. As oil prices started to recover, the Company sold non-core producing assets and focused on oil production in southwest Saskatchewan. Net oil production in the area increased from 32 bbls/day in the first three months of 2010 to 68 bbls/day in the last three months of 2010, with the Company's newly drilled horizontal well only commencing production in late December. The Company expects to drill up to two (1.6 net) Upper Shaunavon wells in 2011. In addition to operations in southwest Saskatchewan, the Company commenced the drilling of its much anticipated Cardium oil well. After numerous weather-related delays the well was placed on production in December 2010 and is still producing at a steady rate of approximately 42 boe/day net to the Company. Up to three wells (0.73 net) may be drilled in 2011 targeting the Cardium zone.

Continuing the paradigm shift to oil, in November 2010 and February 2011 the Company purchased 33 sections of undeveloped property in northeastern Alberta with the potential of Wabiskaw heavy oil production. To fund this purchase and further execute on its plan (including the drilling of oil wells), the Company raised gross proceeds of approximately \$3.9 million on a non-brokered private placement basis by issuing approximately 11.2 million Class A common Shares of the Company and approximately 6.3 million warrants to purchase Class A common shares. As at April 8, 2011 the Company is in the process of a short form prospectus offering of units to raise up to \$9 million (*see Subsequent Events*) and expects to be well capitalized to take advantage of stronger oil prices should the offering be completed.

SELECTED FINANCIAL INFORMATION

	For the three months ended December 31		% Change
	2010	2009	
Total gross petroleum and gas revenue (\$)	1,285,780	1,225,710	5
Royalties (\$)	158,633	167,164	(5)
Operating expenses (\$)	1,111,554	680,376	63
Funds flow from (used-in) operations ⁽¹⁾ (\$)	(455,696)	9,501	---
per basic common share (\$)	(0.02)	---	---
Weighted average basic shares outstanding	23,388,001	13,514,502	73
Loss before income taxes (\$)	(1,928,403)	(1,254,165)	54
Net loss (\$)	(1,538,118)	(870,969)	77
per basic and diluted common share (\$)	(0.07)	(0.06)	(17)
Net capital expenditures (\$)	4,445,515	2,484,314	79
Total assets (\$)	21,043,591	19,011,188	11
Net debt and working capital deficiency ⁽²⁾ (\$)	(6,228,982)	(3,887,476)	60

(1) Funds flow from operations is a Non-GAAP Measure. See *NON-GAAP MEASURES* in this MD&A.

(2) Net debt and working capital deficiency excludes commodity contract liability.

	For the years ended December 31		
	2010	2009	2008
Total gross petroleum and gas revenue (\$)	5,166,961	4,122,704	5,854,915
Liability settlement (\$)	---	533,716	---
Royalties (\$)	611,567	486,740	951,908
Operating expenses (\$)	3,956,057	2,291,717	1,800,601
Funds flow from (used-in) operations ⁽¹⁾ (\$)	(890,327)	117,022	791,300
per basic common share (\$)	(0.05)	0.01	0.13
Weighted average basic shares outstanding	19,694,604	11,845,631	6,257,758
Loss before income taxes (\$)	(5,392,939)	(3,590,850)	(1,913,880)
Net loss (\$)	(4,167,758)	(2,659,572)	(1,342,575)
per basic and diluted common share (\$)	(0.21)	(0.22)	(0.21)
Net capital expenditures (\$)	5,421,767	3,355,059	5,259,351
Total assets (\$)	21,043,591	19,011,188	17,987,380
Net debt and working capital deficiency ⁽²⁾ (\$)	(6,228,982)	(3,887,476)	(3,631,929)

(1) Funds flow from operations is a Non-GAAP Measure. See *NON-GAAP MEASURES* in this MD&A.

(2) Net debt and working capital deficiency excludes commodity contract liability.

PRODUCTION

	Three Months Ended December 31			Year Ended December 31		
	2010	2009	% Change	2010	2009	% Change
Natural gas	1,660 mcf/day	1,951 mcf/day	(15)	1,785 mcf/day	2,111 mcf/day	(15)
Oil and natural gas liquids	116 bbls/day	64 bbls/day	81	102 bbls/day	50 bbls/day	104
Total production	393 boe/day	389 boe/day	1	400 boe/day	402 boe/day	---

Although production rates remained relatively flat for the three months and year ended December 31, 2010 when compared to the three months and year ended December 31, 2009, the Company's production mix changed dramatically. In the three months ending December 31, 2010 oil and natural gas liquids production rates increased 81 percent over the same period in 2009 and in the year ended December 31, 2010 oil and natural gas liquids production rates increased 104 percent compared to the year ended December 31, 2009. Trafina's transformation project started in early 2010 with the Company disposing of various non-core gas weighted properties in the first three months of 2010, resulting in natural gas production in 2010 dropping 15 percent from the same period in 2009. Disposing of non-core gas properties and focusing on oil properties resulted in the Company's production mix in 2010 increasing to 26 percent oil production from 12 percent oil production in 2009. Currently the Company's production mix is 35 percent oil and 65 percent gas.

BENCHMARK PRICES

	Three Months Ended December 31		Year Ended December 31	
	2010	2009	2010	2009
AECO daily spot natural gas price	\$3.63/mcf	\$4.56/mcf	\$4.01/mcf	\$3.99/mcf
West Texas Intermediate oil price (WTI)	US\$85.08/bbl	US\$75.96/bbl	US\$79.43/bbl	US\$61.63/bbl
Edmonton Par oil price	\$80.71/bbl	\$76.75/bbl	\$77.80/bbl	\$66.20/bbl
US/CDN \$ average exchange rate	0.99	0.95	0.97	0.88

An improving world economy in the first three months of 2010 helped push commodity prices higher than the last three months of 2009. However, volatility in the market continued in the summer months of 2010 as both commodities declined in price due to continued high natural gas storage levels and continued slow economic recovery. In the last three months of 2010, moderate North American temperatures and high storage levels pushed natural gas prices downward. Oil prices in the last three months of 2010 started to increase as the world economy showed encouraging signs of recovery. Year over year comparisons resulted in gas prices remaining relatively flat while oil prices increased. In the three months ended December 31, 2010 gas prices were lower than the same period in 2009; oil prices were higher in the three months ended December 2010 when compared to the same period in 2009.

COMPANY REALIZED PRICES

	Three Months Ended December 31		Year Ended December 31	
	2010	2009	2010	2009
Natural gas	\$3.60/mcf	\$4.58/mcf	\$4.01/mcf	\$3.99/mcf
Oil and natural gas liquids	\$68.82/bbl	\$68.38/bbl	\$68.38/bbl	\$57.14/bbl
Total	\$35.56/boe	\$34.24/boe	\$35.39/boe	\$28.09/boe

The Company's realized natural gas prices in the three months and year ended December 31, 2010 and 2009 followed the benchmark AECO daily spot prices. The Company's realized oil and natural gas liquids prices in the years ended December 31, 2009 and 2010 and the three months ended December 31, 2009 followed the trend set by the benchmark Edmonton par oil prices; however, in the last three months of 2010 the spread between the Edmonton par and the Company's realized oil and natural gas liquids price widened mainly as a result of the Company's southwest Saskatchewan oil being of a heavier nature and thereby subject to seasonal demand variations.

PETROLEUM AND NATURAL GAS REVENUE

	Three Months Ended December 31		Year Ended December 31	
	2010	2009	2010	2009
Natural gas	\$ 549,142	\$ 822,736	\$ 2,609,378	\$ 3,076,141
Oil and natural gas liquids	736,637	402,974	2,557,583	1,046,563
Total petroleum and natural gas revenue	\$ 1,285,780	\$ 1,225,710	\$ 5,166,961	\$ 4,122,704

Lower natural gas revenues for the three months and year ended December 31, 2010 when compared to the same periods in 2009 were due to the Company disposing of natural gas non-core producing assets and a falling natural gas price in 2010. Oil and natural gas liquids revenue in the three months and year ended December 31, 2010 were higher than the three months and year ended December 31, 2009 as a result of an increase in oil production.

REALIZED GAIN ON COMMODITY CONTRACTS

	Three Months Ended December 31		Year Ended December 31	
	2010	2009	2010	2009
Realized gain on commodity contracts	\$ 48,318	\$ ---	\$ 299,244	\$ ---

A realized gain was recorded in the three months and year ended December 31, 2010 as a result of the Company entering into favourable gas commodity price contracts.

UNREALIZED LOSS ON COMMODITY CONTRACTS

	Three Months Ended December 31		Year Ended December 31	
	2010	2009	2010	2009
Unrealized loss on commodity contracts	\$ (161,589)	\$ (24,000)	\$ (95,589)	\$ (24,000)

In an attempt to mitigate volatile commodity price fluctuations, management entered into two financial commodity price contracts prior to year-end 2010 as follows:

Type	Daily Volume	Duration	Price
Fixed-Gas	300 GJ/day	January 1, 2011 to December 31, 2011	\$3.85/GJ
Collar-Oil	50 bbl/day	January 1, 2011 to December 31, 2011	Floor \$75.00 WTI Cdn Ceiling \$90.00 WTI Cdn

For the three months and year ended December 31, 2010, the Company recorded an unrealized loss of \$161,589 and \$95,589, respectively, primarily as a result of the difference between future oil price projections at December 31, 2010 compared to the Company's contracted rates. The unrealized loss for the three months and year ended December 31, 2010 was partially offset by the completion of two previous natural gas financial sales contracts.

LIABILITY SETTLEMENT

	Three Months Ended December 31		Year Ended December 31	
	2010	2009	2010	2009
Liability settlement	\$ ---	\$ ---	\$ ---	\$ 533,716

On July 29, 2009, the Company signed an agreement with an industry partner to settle an amount owed to that industry partner. This debt was a result of an over-allocation of revenue in prior periods. The Company had provided for this obligation in its financial statements. As a result of the settlement, the Company reduced its working capital deficit by approximately \$534,000 and recorded an increase in revenue.

OTHER REVENUE

	Three Months Ended December 31		Year Ended December 31	
	2010	2009	2010	2009
Other revenue	\$ 14,377	\$ 49,197	\$ 61,334	\$ 109,625

Other revenue relates to miscellaneous processing and water disposal income from the Company's Kinsella area, which was acquired in September 2009.

ROYALTIES

	Three Months Ended December 31				Year Ended December 31			
	2010	Royalty as percent of Petroleum & natural gas revenue	2009	Royalty as percent of Petroleum & natural gas revenue	2010	Royalty as percent of Petroleum & natural gas revenue	2009	Royalty as percent of Petroleum & natural gas revenue
Total royalties	\$158,633	12	\$167,164	14	\$611,567	12	\$486,740	12

Royalty payments as a percentage of petroleum and natural gas revenue were flat in the year ended December 31, 2010 compared to the royalty percentage in the year ended December 31, 2009. Royalty payments as a percentage of petroleum and natural gas revenue for the three months ended December 31, 2009 were slightly higher than in the same period in 2010 as a result of a prior period adjustment.

OPERATING EXPENSES

	Three Months Ended December 31				Year Ended December 31			
	2010	\$/boe	2009	\$/boe	2010	\$/boe	2009	\$/boe
Operating expenses	\$1,111,554	\$30.74	\$680,376	\$19.01	\$3,956,057	\$27.09	\$2,291,717	\$15.62

Operating expenses, including processing and transportation costs, for the three months ended December 31, 2010 were \$1,111,554 (\$30.74/boe), an increase of 62 percent on a \$/boe basis over the same period in 2009. The increase is primarily attributable to higher operating costs at southwest Saskatchewan associated with handling large water volumes that are produced in conjunction with oil production. Additionally, for the three months ended December 31, 2010 the Company's southwest Saskatchewan area incurred expenses to repair a pipeline, repair and replace down-hole equipment and excessive snow removal costs. The Company also incurred extensive start-up expenses (including numerous start-up related charges which were not capitalized). Battery site repairs, miscellaneous parts replacements, lease repairs and lease clean-ups also contributed to an increase in operating expenses.

FIELD NETBACK (NETLOSS) ⁽¹⁾

	Three Months Ended December 31				Year Ended December 31			
	2010	\$/boe	2009	\$/boe	2010	\$/boe	2009	\$/boe
Petroleum and natural gas revenue	\$1,285,780	\$35.56	\$1,225,710	\$34.25	\$5,166,961	\$35.39	\$4,122,704	\$28.10
Liability settlement	---	---	---	---	---	---	533,716	3.64
Realized gain on commodity contract	48,318	1.34	---	---	299,244	2.05	---	---
Unrealized loss on commodity contract	(161,589)	4.47	(24,000)	0.67	(95,589)	0.65	(24,000)	0.16
Other revenue	14,377	0.40	49,197	1.37	61,334	0.42	109,625	0.75
Royalties	(158,633)	4.39	(167,164)	4.67	(611,567)	4.19	(486,740)	3.32
Operating expenses	(1,111,554)	30.74	(680,376)	19.01	(3,956,057)	27.09	(2,291,717)	15.62

Field netback (net loss) ⁽¹⁾	\$(83,301)	\$2.30	\$403,367	\$11.27	\$864,326	\$5.92	\$1,963,588	\$13.38
Sales volumes (boe)	36,156		35,788		146,000		146,730	

(1) See *NON-GAAP MEASURES* in this MD&A.

Field netback for the year ended December 31, 2010 was \$864,326 compared to a field netback at December 31, 2009 of \$1,963,588. Higher petroleum and natural gas revenue and the realization of a commodity contract gain in 2010 were offset by higher royalties, operating costs, and a greater unrealized loss on commodity contracts. In addition, the year ended December 31, 2009 included the recording of a liability settlement, which increased the 2009 field netback by \$533,716. In the three months ended December 31, 2010 the Company recorded a field net loss of \$83,301, compared to a field netback of \$403,367 for the same period in 2009. Although petroleum and natural gas revenue in both periods was similar, the three months ended December 31, 2010 had a greater unrealized loss, less other revenue and higher operating expenses, offset slightly by a realized gain on a commodity contract. Removing the non-cash effect of the unrealized loss in the three months ended December 31, 2010, results in a field netback of \$78,288.

GENERAL AND ADMINISTRATIVE (“G&A”) EXPENSE

	Three Months Ended December 31		Year Ended December 31	
	2010	2009	2010	2009
G&A	\$ 492,319	\$ 421,242	\$ 1,703,375	\$ 1,338,220
G&A per boe	\$ 13.62	\$ 11.77	\$ 11.67	\$ 9.12

General and administrative expenses for the three months ended December 31, 2010 were relatively flat when compared to general and administrative expenses for the same period in 2009. General and administrative expenses increased by \$365,155 in the year ended December 31, 2010 compared to the year ended December 31, 2009. The increase is mainly attributable to an increase in banking charges, salaries and consulting, third party engineering services and legal fees resulting from the Company’s active asset acquisition and divestiture program and equity raising activities.

DEPLETION, DEPRECIATION, AND ACCRETION

For the three months and year ended December 31, 2010, depletion, depreciation and accretion expense was \$1,245,091 (\$34.44/boe) and \$4,180,584 (\$28.63/boe), respectively. For the three months and year ended December 31, 2009, depletion, depreciation and accretion expense was \$1,092,708 (\$30.53/boe) and \$3,901,794 (\$26.59/boe), respectively. The Company’s depletion calculation uses the unit-of-production method in its computation.

STOCK BASED COMPENSATION EXPENSE

Stock based compensation expense totaled \$226,439 for the year ended December 31, 2010 versus \$222,974 for the year ended December 31, 2009. Although only 575,000 stock options were granted in 2010 compared to 1,300,000 stock options granted in 2009 the stock based compensation expense was similar in both periods. This is primarily due to recording a full year of stock based compensation expense in 2010 based on the grants made in 2009 in addition to recording stock based compensation expense on the grants made in 2010. For the three months ended December 31, 2010, stock based compensation expense totaled \$66,027 compared to \$120,605 for the three months ended December 31, 2009. The difference is mainly due to the Company granting 405,000 stock options in the three months ended December 31, 2010 versus the Company granting 560,000 stock options in the three months ended December 31, 2009.

INTEREST EXPENSE

Interest expense for the three months and year ended December 31, 2010 was \$41,665 and \$146,867, respectively, and interest expense for the three months and year ended December 31, 2009 was \$22,977 and \$91,450, respectively. Higher interest charges in 2010 when compared to 2009 are a result of an increased reliance by the Company on debt to fund operations, a greater amount of interest charged relating to the Company’s liability settlement, partially offset by a lesser amount of interest accrued to the Canada Revenue Agency (“CRA”) for outstanding flow-through share obligations after February 2010 compared to interest accrued to the CRA for outstanding flow-through share obligations after February 2009.

INCOME TAXES

For the three months ended December 31, 2010, the Company recorded a future income tax reduction of \$390,285. For the year ended December 31, 2010, the Company recorded a future income tax reduction of \$1,225,181. For the three months and year ended December 31, 2009, the Company recorded a future income tax reduction of \$356,843 and \$774,651, respectively. Trafina's tax horizon depends on factors such as production, commodity prices, the tax classification of wells drilled as well as the diversified nature of other capital expenditures incurred throughout the year.

The estimated tax pools available for deduction into future years are as follows:

Tax Pools	Rate %	2010	2009
Canadian exploration expenses	100	2,384,893	777,708
Successor Canadian exploration expenses	100	815,525	---
Canadian development expenses	30	3,031,102	2,200,873
Successor Canadian development expenses	30	5,426,357	---
Canadian oil and gas property expenses	10	1,709,629	---
Undepreciated capital costs	10-30	6,267,815	4,519,736
Financing costs	Straight line	284,447	294,738
Non-capital losses	100	2,582,229	1,604,320
Non-capital losses	100 (Alberta)	402,650	402,650
Total tax pools		22,904,647	9,800,025

NET LOSS

	Three Months Ended December 31		Year Ended December 31	
	2010	2009	2010	2009
Net loss	\$ (1,538,118)	\$ (870,969)	\$ (4,167,758)	\$ (2,659,572)

The Company recorded a net loss of \$1,538,118 in the three months ended December 31, 2010 compared to a net loss of \$870,969 in the three months ended December 31, 2009. A larger net loss in the three months ended December 31, 2010 compared to December 31, 2009 was mainly a result of higher revenues in 2010, offset by higher operating, G&A and depletion, depreciation and accretion expense. For the years ended December 31, 2009 and December 31, 2010, the Company recorded net losses of \$2,659,572 and \$4,167,758, respectively. The larger net loss in the year ended December 31, 2010 compared to the same period in 2009 was due to higher net revenue in 2010, offset by higher operating, G&A and depletion, depreciation and accretion expense. The net loss before income taxes was offset slightly by a future tax reduction. Comprehensive loss consists of net loss and other comprehensive loss ("OCL"). Because the Company does not have any OCL, the Company's net loss and comprehensive loss are the same.

FUNDS FLOW FROM (USED-IN) OPERATIONS⁽¹⁾

	Three Months Ended December 31		Year Ended December 31	
	2010	2009	2010	2009
Cash flow from (used in) operating activities	\$ (843,673)	\$ 443,237	\$ (2,268,252)	\$ (144,677)
Change in non-cash operating working capital	387,977	(433,736)	1,377,925	261,699
Funds flow from (used-in) operations ⁽¹⁾	\$ (455,696)	\$ 9,501	\$ (890,327)	\$ 117,022
Funds flow from (used-in) operations per share – basic	\$ (0.02)	---	\$ (0.05)	\$ 0.01

(1) See *NON-GAAP MEASURES* in this MD&A.

For the three months ended December 31, 2010 the Company used funds of \$455,696 in its operations compared to generating funds of \$9,501 in its operations for the three months ended December 31, 2009. The use of funds in the three months ended December 31, 2010 was primarily due to low revenues as a result of lower commodity prices, offset by high operating costs as a result of repairs and snow removal and G&A expenditures. For the three months ended December 31, 2009 funds flow from operations was \$9,501 as a result of revenues being slightly offset by lower operating costs and lower G&A costs. For the year ended December 31, 2010 funds were used in operations as a result of high operating costs attributable to start-up costs in southwest Saskatchewan and high G&A costs associated with banking fees, increased overhead, third party engineering costs and legal fees. For the year ended December 31, 2009 funds were generated from operations as a result of revenues only slightly being offset by operating and G&A costs. In 2009 the Company's producing areas were primarily comprised of natural gas wells with characteristically low operating costs.

NETBACK ANALYSIS

The following table reconciles field netback and field net loss (each non-GAAP) to funds flow from (used in) operations (non-GAAP) to net loss (GAAP) for the three months and years ended December 31, 2010 and December 31, 2009:

	Three Months Ended December 31		Year Ended December 31	
	2010	2009	2010	2009
Petroleum and natural gas revenue	\$1,285,780	\$1,225,710	\$5,166,961	\$4,122,704
Liability settlement	---	---	---	533,716
Realized gain on commodity contract	48,318	---	299,244	---
Unrealized loss on commodity contract	(161,589)	(24,000)	(95,589)	(24,000)
Other revenue	14,377	49,197	61,334	109,625
Royalties	(158,633)	(167,164)	(611,567)	(486,740)
Operating expenses	(1,111,554)	(680,376)	(3,956,057)	(2,291,717)
Field netback (net loss) ⁽¹⁾	(83,301)	403,367	864,326	1,963,588
General and Administrative	(492,319)	(421,242)	(1,703,375)	(1,338,220)
Interest	(41,665)	(22,977)	(146,867)	(91,450)
Current tax	---	26,353	---	156,627
Unrealized loss on commodity contract	161,589	24,000	95,589	24,000
Abandonment expenditures	---	---	---	(63,807)
Liability settlement revenue	---	---	---	(533,716)
Funds flow from (used-in) operations ⁽¹⁾	(455,696)	9,501	(890,327)	117,022
Depletion, depreciation and accretion	(1,245,091)	(1,092,708)	(4,180,584)	(3,901,794)
Future income tax reduction	390,285	356,843	1,225,181	774,651
Stock-based compensation	(66,027)	(120,605)	(226,439)	(222,974)
Liability settlement	---	---	---	533,716
Unrealized loss on commodity contract	(161,589)	(24,000)	(95,589)	(24,000)
Abandonment expenditures	---	---	---	63,807
Net loss	\$(1,538,118)	\$(870,969)	\$(4,167,758)	\$(2,659,572)

(1) See *NON-GAAP MEASURES* in this MD&A.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2010, the Company had net debt and working capital deficiency of \$6,228,982, which excludes the fair value of commodity contracts. At December 31, 2009 the Company had a net debt and working capital deficiency of \$3,887,476, which excludes the fair value of commodity contracts. The primary reason for the additional debt and working capital deficit is the increase in capital expenditures in 2010 relating to the Company's shift from gas focused non-operated producing properties to oil focused producing properties.

In the year ended December 31, 2010, the Company attempted to prudently manage its debt levels, including by disposing of non-core properties for net proceeds of \$2.6 million. The Company is taking further steps to reduce its net debt and working capital deficiency by undertaking a short form prospectus financing of units (see *Subsequent Events*). Assuming the offering is completed, a portion of the net proceeds (along with other sources of funding available to the Company) will be used by the Company for its 2011 capital program (which includes drilling up to three Cardium wells at Pembina, Alberta, drilling up to two horizontal wells at southwest Saskatchewan and drilling up to four vertical evaluation wells in northeastern Alberta).

BANK DEBT

At December 31, 2010 the Company had credit facilities consisting of a \$4,000,000 revolving operating demand facility, with interest charged on advances under the facility at the bank's prime rate plus 1.50 percent and a \$1,250,000 acquisition and development demand facility, with interest charged on advances at the bank's prime rate plus 2.00 percent. The facilities are secured by a \$50,000,000 fixed and floating charge debenture on all assets. The revolving operating demand facility requires maintenance of a 1:1 working capital ratio covenant. The Company has an outstanding letter of guarantee for approximately \$139,000.

At December 31, 2010, the Company had drawn a total of \$3,673,466 on its available facilities with \$2,693,466 drawn on its revolving operating demand credit facility and \$980,000 drawn on its acquisition and development facility. Principal repayments relating to the acquisition and demand facility amount to \$30,000 per month and commenced September 1, 2010. At December 31, 2010, the Company was in violation of its working capital covenant. However, in light of the proposed financing (see *Subsequent Events*) the Company asked for and received an unconditional waiver from the bank.

In January 2011 the bank completed a scheduled review of the Company's assets and revised the revolving operating demand facility lending value to \$4,600,000. The Company's acquisition and development demand facility lending value was reduced to \$650,000, with principal repayments of \$30,000 per month commencing February 1, 2011. The next review date is scheduled for May 2011.

EQUITY

Changes to equity of the Company for the year ended December 31, 2010 were as follows:

Shares Issues

- i. Shares issued on exercise of stock options:

January 2010

A director of the Company exercised 30,000 stock options at a price of \$0.30 per share and was issued 30,000 Class A common shares for gross proceeds of \$9,000.

- ii. Shares issued as partial consideration for property purchase:

February 2010

As part of the consideration for acquiring certain assets in February 2010, the Company issued 324,000 special warrants convertible into Class A common shares of the Company. The conversion of these special warrants was subject to the Company obtaining approval of the transfer of certain well licenses by the Alberta Energy Resources Conservation Board ("ERCB"). In May 2010 the Company received the necessary ERCB approvals and converted the special warrants to 324,000 Class A common shares.

- iii. Shares issued for cash upon private placements:

November 2010

The Company completed a non-brokered private placement to an employee of Trafina and issued 150,000 Class A common shares at a price of \$0.30 per share for gross proceeds of \$45,000. The Class A common shares issued pursuant to the private placement were subject to a hold period that expired March 6, 2011.

The Company completed a non-brokered private placement of Class A common shares issued on a flow-through basis pursuant to the *Income Tax Act* (Canada) for gross proceeds of \$1.5 million and issued 3,750,000 flow-through shares at a price of \$0.40 per share. Directors and senior officers of the Company indirectly purchased an aggregate of 550,000 flow-through shares pursuant to the private placement. The Company paid a finder's fee of \$24,000 to an arm's-length party in connection with the subscriptions of certain subscribers who participated in the private placement. The Class A common shares issued pursuant to the private placement were subject to a hold period that expired March 6, 2011.

December 2010

The Company completed a non-brokered private placement of units for proceeds of \$1.9 million. The Company issued 6,334,000 units (comprised of 6,334,000 Class A common shares and 6,334,000 share purchase warrants) at a price of \$0.30 per unit (the "December Private Placement"). The Common Shares and Warrants issued pursuant to the completed portion of the private placement were subject to a hold period that expired April 1, 2011 and April 3, 2011 respectively.

The Company completed a non-brokered private placement of Class A common shares issued on a flow-through basis pursuant to the *Income Tax Act* (Canada) resulting in gross proceeds of \$0.5 million and issued 1,000,000 flow-through shares at a price of \$0.50 per share (the . The common shares issued pursuant to the private placement are subject to a hold period that expires April 19, 2011.

Set forth below is the use of the proceeds of the private placements.

	<u>Disclosed Use of Proceeds</u>	<u>How Net Proceeds Were Used</u>
November, 2010 and December, 2010 flow-through share private placements.	Gross proceeds will be used to incur eligible exploration expenditures that will be renounced to subscribers as Canadian exploration expenses effective on or before December 31, 2010.	The gross proceeds were renounced to subscribers as Canadian exploration expenses effective on or before December 31, 2010. The Company incurred \$1.1 million in qualified expenditures by the end of December, 2010, resulting in a remaining obligation of \$0.9 million of qualified expenditures to be incurred prior to December 31, 2011
December, 2010 private placement of units.	Net proceeds from the sale of the units were anticipated to be used to drill up to three additional Cardium wells in 2011.	The net proceeds were used to purchase the land in northeastern Alberta.

Share Purchase Warrants

As a result of the non-brokered private placement of units described above 6,334,000 share purchase warrants ("Warrants") were issued and outstanding at December 31, 2010. Each Warrant entitles the holder thereof to acquire one Class A common share at a price of \$0.45 per share on or before November 30, 2012 (the "Expiry Date"). If at any time after November 30, 2010 and the Expiry Date, the 20 day VWAP of the common shares is greater than \$0.50 per share, the Company is entitled, upon 30 days prior written notice to all holders of the Warrants, to require all then outstanding Warrants to be exercised to acquire Class A common shares at a price of \$0.45 per share by a date to be specified by the Company in such notice (the "VWAP Conversion Date"). All Warrants that remain unexercised following the VWAP Conversion Date shall immediately expire and all rights of holders of such Warrants terminated without any compensation to any such holder. "VWAP" means the volume weighted average trading price of the Class A common shares on the TSX Venture Exchange Inc. (or such other stock exchange upon which the Class A common shares may be then listed), calculated by dividing the total value by the total volume of Class A common shares traded for the relevant period. On March 7, 2011 the Company announced the acceleration of the expiry of the Warrants (*See Subsequent Events*).

Flow-through Shares

In February 2010, the Company renounced \$0.74 million of flow-through obligations as a result of the issuance of approximately 1.9 million Class A common shares issued on a flow-through basis in December 2009 pursuant to the *Income Tax Act* (Canada). As a result, a future income tax liability and corresponding reduction of share capital of \$190,277 was recorded for the year ended December 31, 2010. As at December 31, 2010 the Company had fulfilled its flow-through spending obligation relating to the December 2009 flow-through issue.

Share issue costs

Share issue costs relating to the above transactions totaled \$88,759.

Stock Options

The Company has an employee stock option plan under which employees, consultants and directors are eligible to receive options to purchase Class A common shares of the Company. For stock options granted, one third of the options vest on the day following the date of grant, one third on the day following the first anniversary date of the grant and the remaining options vest on the day following the second anniversary date of the grant. For the year ended December 31, 2010, the Company issued 575,000 stock options to employees and consultants of the Company with a weighted average exercise price of \$0.40 per common share.

Outstanding share, warrants and stock options data

At April 8, 2011 the Company had outstanding equity issues as follows:

Common shares and preferred shares:

Trafina is authorized to issue an unlimited number of Class A voting common shares, an unlimited number of Class B non-voting common shares and an unlimited number of preferred shares. At April 8, 2011, 29,961,262 Class A common shares were issued and outstanding (*see Subsequent Events*). There are nil Class B common shares and nil preferred shares outstanding.

Warrants:

As a result of two separate non-brokered private placements the Company has the following share purchase warrants outstanding:

6,334,000 warrants with an exercise price of \$0.45, subject to expire on April 15, 2011 (*see Subsequent Events*).

2,513,335 warrants with an exercise price of \$0.45, subject to expire on June 3, 2011.

Stock Options:

At April 8, 2011, the Company had 2,095,000 stock options outstanding.

CAPITAL EXPENDITURES

The following table summarizes capital expenditures for the three months and year ended December 31, 2010 and 2009.

	Three months ended December 31		Year ended December 31	
	2010	2009	2010	2009
Acquisition	\$2,223,489	\$8,899	\$2,826,052	\$125,896
Disposition	(47,470)	(604,152)	(2,653,258)	(604,152)
Land and Seismic	269,386	---	321,216	22,111
Drilling, completions and recompletions	1,616,582	1,716,034	2,870,339	1,990,242
Equipping and facilities	353,986	84,448	1,861,850	752,181
Non-operated joint interest partner 2008 accrual adjustment	---	---	---	(246,469)
Office equipment and capital G&A	42,132	52,003	195,568	88,168
Other	---	1,227,082	---	1,227,082
Total capital expenditures	\$4,458,105	\$2,484,314	\$5,421,767	\$3,355,059

During the three months ended December 31, 2010 the Company acquired a relatively large undeveloped land position in northeast Alberta from a private oil and gas company. The Company acquired 24.5 sections of undeveloped land with the potential for Wabiskaw heavy oil production for approximately \$2.2 million, with a right to earn an additional 25% working interest in 13 gross sections (3.25 net sections) by drilling two wells, with the Company paying 50% to earn its 25% working interest. If the Company earns such interest, the Company will have interests in 37.5 gross sections (27.75 net sections). Additionally, as part of the agreement, a third party vendor has the right but not the obligation to back in for a 20% working interest in two sections of land by paying its 20% share of the gross costs in any additional wells drilled. If the third party elects not to participate then its right to participate in further drilling shall terminate. The Company also purchased 6 sections of lands in the same area at a Crown land sale for approximately \$0.25 million. Also in the three months ended December 31, 2010 the Company spent \$1.6 million to complete, tie-in and place on production a Cardium oil well in Pembina, Alberta and also to drill, complete, equip and place on production 1 (0.8 net) well at southwest Saskatchewan. Office equipment and capital G&A for the three months ended December 31, 2010 totaled approximately \$30,000. For the year ended December 31, 2010 the Company acquired the aforementioned undeveloped land in northeastern Alberta for approximately \$2.2 million and acquired a central Alberta property which was paid for using cash and the issuance of Class A common shares of the Company. Total consideration for the property was approximately \$0.265 million. Additional acquisition costs were associated with the acquisition of assets in southwest Saskatchewan from a private oil and gas corporation that were exchanged for amounts owing to the Company on January 15, 2010. Costs incurred during the year to realize on the acquisition were approximately \$0.3 million. As part of the Company's oil focused transition project the Company disposed of several non-core properties for net proceeds of \$2.6 million. The remaining expenditures in the year ended December 31, 2010 consisted of drilling, completing and tie-in of one well at Pembina and completing an additional well awaiting tie-in at Pembina; drilling, completing and equipping one well and equipping various wells and facilities in southwest Saskatchewan; equipping two wells in central Alberta and constructing a pipeline in southern Alberta.

In the year ended December 31, 2009 the Company incurred expenditures to drill 2 (2 net) wells in southwest Alberta and drill 1 (0.5 net) Cardium well in Pembina. The Company also completed and placed on production several Wetaskiwin area coal bed methane wells, which were drilled in 2008. In November 2009, Trafina completed the purchase from a Canadian chartered bank of the outstanding indebtedness and liabilities to the bank of a private oil and gas corporation with assets in southwest Saskatchewan. In December 2009, Trafina appointed a receiver and acquired the corporation's assets on January 15, 2010 in exchange for the debt and liabilities owing to the Company. From November 2009 to the final transfer of assets in January 2010, Trafina made certain payments, among other things, to acquire the debt, pay secured creditors, governmental agencies and pay service providers to maintain the properties throughout the receivership process. The payments in 2009 amounted to \$1,227,082 and are included under "Other" in the above table.

COMMODITY CONTRACTS

The following table summarizes the Company's commodity contracts:

Commodity price financial contracts:

Type	Daily Volume	Duration	Price
Fixed-Gas	300 GJ/day	January 1, 2011 to December 31, 2011	\$3.85/GJ
Collar-Oil	50 bbl/day	January 1, 2011 to December 31, 2011	Floor \$75.00 WTI Cdn Ceiling \$90.00 WTI Cdn

Subsequent to year end the Company has also entered into the following commodity price financial contracts:

Type	Daily Volume	Duration	Price
Fixed-Gas	300 GJ/day	May 1, 2011 to December 31, 2011	\$4.41/GJ
Collar-Oil	50 bbl/day	May 1, 2011 to December 31, 2011	Floor \$90.00 WTI US Ceiling \$108.90 WTI US

CONTRACTUAL OBLIGATIONS

At December 31, 2010, the Company had the following contractual obligations:

Flow-through

As a result of completing a private placement financing in November and December, 2010, the Company is required to incur \$2.0 million on eligible flow-through expenditures prior to December 31, 2011. The Company incurred \$1.1 million in qualified expenditures by the end of December, 2010, resulting in a remaining obligation of \$0.9 million of qualified expenditures to be incurred prior to December 31, 2011.

Office rent

Trafina has an office lease arrangement terminating August 30, 2014. The Company's total remaining rent obligation is as follows:

2011	\$134,000
2012	\$146,000
2013	\$158,000
2014	\$112,000

The Company expects to fulfill these obligations from funds flow and bank debt.

OFF BALANCE SHEET TRANSACTIONS

There were no off balance sheet transactions entered into during the period, and none are outstanding as of April 8, 2011.

RELATED PARTY TRANSACTIONS

A law firm of which the Company's corporate secretary is a partner provides general and corporate legal services to the Company. For the year ended December 31, 2010, fees for legal services billed from this related party were approximately \$199,000 (December 31, 2009, \$108,000), of which \$50,000 is included in accounts payable and accrued liabilities at December 31, 2010 (December 31, 2009, \$24,000). These services are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

SUBSEQUENT EVENTS

On March 7, 2011 the Company announced that it has elected to accelerate the expiry of the Warrants originally issued on November 30, 2010 and December 2, 2010 as part of its private placement unit offering. Each Warrant entitles the holder thereof to acquire one common share ("Common Share") of Trafina at a price of \$0.45 per share. The Warrants were originally set to expire on November 30, 2012 and will now expire on April 15, 2011.

On April 5, 2011 the Company announced that it has agreed to a marketed public offering of units on a reasonable best efforts agency basis to issue a minimum of 14,286,000 units and a maximum of 22,858,000 units, at a price of \$0.35 per unit, for gross proceeds of a minimum amount of approximately \$5,000,000 and up to a maximum amount of approximately \$8,000,000. Each Unit will consist of one Class A common share ("Common Share") and one transferable Common Share purchase warrant ("Warrant") to acquire an additional Common Share at an exercise price of \$0.45 for a period of eighteen months from the date of closing. On April 8, 2011 the board of directors of the Company approved an increased maximum under the offering to \$9 million. Assuming the minimum offering is received, a minimum of 14,286,000 units and up to a maximum of 25,715,000 units will be issued.

HISTORICAL QUARTERLY FINANCIAL INFORMATION

Outlined below is a table of historical quarterly financial information over the last eight quarters:

	2010				2009			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production (boe/day)	393	369	413	424	398	392	403	423
Revenue (\$)	1,285,780	1,110,876	1,125,671	1,515,528	1,225,710	803,263	913,483	1,187,571
Revenue (\$/boe)	35.56	32.74	33.99	39.21	34.25	22.24	24.91	31.19
G&A (\$)	492,319	359,122	398,980	452,954	421,242	257,667	279,805	379,506
Funds flow from (used-in) operations (\$) ⁽¹⁾	(455,696)	(18,580)	(73,035)	(343,013)	9,501	(28,572)	60,826	75,266
Funds flow per basic and diluted common share (\$)	(0.02)	---	---	(0.02)	---	---	0.01	0.01
Net loss (\$)	(1,538,118)	(789,592)	(935,108)	(904,940)	(870,969)	(763,808)	(341,010)	(683,782)
Net loss per basic and diluted common share (\$)	(0.07)	(0.04)	(0.05)	(0.05)	(0.06)	(0.07)	(0.03)	(0.06)
Capital expenditures (\$)	4,458,105	1,509,568	(401,894)	(144,011)	2,484,314	309,572	333,882	227,289
Net debt and working capital deficiency (\$) ⁽¹⁾	(6,228,982)	(5,195,863)	(3,667,818)	(4,158,567)	(3,911,476)	(3,444,260)	(2,896,332)	(3,712,758)

(1) See *NON-GAAP MEASURES* in this MD&A.

In the year ended December 31, 2009, the Company generated funds flow from operations in all quarters except Q3 when the Company used funds flow, primarily as a result of low natural gas prices. In the year ended December 31, 2010 all quarters used funds from operations. In Q1 2010 the Company used funds flow in its operations, primarily as a result of start-up and repair charges at its southwest Saskatchewan properties. In Q2 2010 repair costs at southwest Saskatchewan somewhat diminished and reduced funds flow used in operations to \$73,035. In Q3 2010 funds were used as a result of shut in production due to repairs on a non-operated gas transmission line at Wetaskiwin in the month of September. In Q4 2010 funds flow was used in operations due to high operating expenses and high G&A costs. In the first quarter of 2009, the Company had a net loss of \$683,782 primarily as a result of lower commodity prices and higher depletion expense. The Company's net loss for the second quarter of 2009 decreased to a net loss of \$341,010, primarily a result of recording a \$533,000 liability settlement gain. A continual decline in natural gas prices resulted in a net loss for the third quarter of \$763,808. In the fourth quarter of 2009, the Company's net loss increased to \$870,969 mainly as a result of higher depletion, depreciation and accretion expenses. Q1 2010 saw a net loss of \$904,940, primarily due to the aforementioned start-up operating expenses at southwest Saskatchewan. The Q2 2010 net loss was mainly due to lower commodity prices and higher expenses. In Q3 2010 a net loss of \$789,592 was recorded, primarily as a result of low revenues and a net gain on commodity

contracts, offset by high depletion, depreciation and accretion, operating and G&A expenses. A net loss in Q4 2010 was a result of higher revenues offset by high operating, G&A and depletion, depreciation and accretion expenses.

FINANCIAL INSTRUMENTS

The Company has certain financial instruments, including accounts receivable, commodity contracts, accounts payable and accrued liabilities, liability settlement and bank debt, and is exposed to risks such as credit risk, liquidity risk and market risk. The Company manages its exposure to these risks by operating in a manner that minimizes its exposure to the extent practical.

The carrying amount of the Company's accounts receivable, accounts payable and accrued liabilities and liability settlement approximate their fair values due to short terms to maturity. Bank debts bear interest at a floating market rate and accordingly the fair value approximates the carrying value. The carrying value of the Company's liability settlement is calculated using an interest rate agreed upon between two non-related parties dealing at arm's length, thus the carrying value approximates the fair value.

As at December 31, 2010, the only financial instrument that required disclosure of fair value according to the new three-level hierarchy was the Company's commodity contracts (derivative financial instruments), which are recorded at fair value and are considered level 2. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the market place.

BUSINESS RISKS

There are a number of risk factors facing Canadian oil and gas exploration corporations. Certain risks are summarized below; however, a more extensive discussion of risks is available in the Company's AIF filed on SEDAR at www.sedar.com.

Reserves and Resources Replacement

The future oil and natural gas production of the Company, and its cash flows, are highly dependent upon ongoing success in exploring its current and future undeveloped land base, exploiting the current producing properties, further developing its current reserve and resource base to production and acquiring or discovering additional reserves and resources. Without reserves additions through exploration, acquisition or development activities, reserves and production will decline over time as reserves are depleted. There can be no assurance that the Company will be able to find and develop or acquire additional reserves to replace production at commercially feasible costs.

Exploration, Development and Production Risks

Oil and natural gas exploration involves a high degree of risk, with a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that new exploration wells will find commercial quantities of oil and gas and or further commercial quantities of oil and natural gas will be discovered by drilling new wells in developed areas. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over-pressured zones, tools lost in the hole and changes in drilling plans and locations as a result of prior exploratory wells.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Volatility of Oil and Natural Gas Prices and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Company will be affected by numerous factors beyond its control.

The Company's revenues, profitability, future growth of its oil and gas properties are substantially dependent on prevailing prices of oil and gas. Prices for oil and gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include economic conditions in the United States and Canada, the actions of the Organization of the Petroleum Exploration Countries, governmental regulation, and political stability in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil or gas would have an adverse effect on the Company's revenues, profitability and cash flows from operations, which may have a negative effect on the Company's borrowing capacity. The exchange rate between the Canadian and U.S. dollar also affects profitability of the Company. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

The Company attempts to mitigate commodity price risk through the use of financial contracts. On November 1, 2010 management entered into two financial commodity price contracts with the first contract based on selling 300 GJ/ day of natural gas at \$3.85/ GJ commencing January 1, 2011 and ending December 31, 2011 and the second contract based on selling 50 bbls/day of oil with a floor price of \$75.00 WTI Cdn and a ceiling price of \$90 WTI Cdn. Subsequent to the year ended December 31, 2010 management has entered into two additional commodity price contracts whereby the Company has agreed to a costless collar based on selling 50 bbls/day with a floor price of \$90.00 WTI US and a ceiling price of \$108.90 WTI US and agreed to a commodity swap based on selling 300 GJ/day of natural gas at \$4.41/GJ.

The Company's ability to market its natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Company may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities, and related to operational problems with such pipelines and facilities as well as extensive government regulation relating to allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

Royalties

Each of the provinces in which the Company operates has legislation and regulations governing royalties, land tenure, production rates and taxes, environmental protection, and other matters under their respective jurisdictions. The royalty regime applicable in the provinces in which the Company operates is a factor in the profitability of the Company's production. Crown royalties are determined by government regulation and are typically calculated as a percentage of the value of production. The value of the production and the rate of royalties payable depend on prescribed reference prices, well productivity, geographical location, and the type of product produced. Crown royalty payments are subject to change and any changes may have an adverse impact on the profitability of a project. For further details on each province's royalty regulations and how the regulations may affect the Company's operations, refer to the Company's AIF.

Royalties payable on production of privately owned minerals are determined by negotiations between the Company and the mineral rights owners. Other royalty-like interests may also be carved out of a working interest through non-public transactions and are often referred to as overriding royalties, gross overriding royalties, net profit interests or net carried interests.

Capital Requirements, Additional Financing and Issuance of Debt

Depending on future exploration, development, production, acquisition and divestiture plans, the Company expects that it will require additional financing in the future. The ability of the Company to arrange such financing in the future will depend in part upon the prevailing capital market conditions as well as the business performance of the Company. There can be no assurance that the Company will be successful in its efforts to arrange additional financing on terms satisfactory to the Company or at all. If additional financing is raised by the issuance of shares from treasury of the Company, control of the Company may change and shareholders may suffer additional dilution.

Credit Risk

Credit risk is generally related to the collection of the Company's accounts receivable from petroleum and natural gas purchasers and joint interest partners. At December 31, 2010, approximately 42 percent of the Company's accounts receivable trade balance was from various petroleum and natural gas purchasers and has subsequently been received. A further 34 percent of the Company's accounts receivables as at December 31, 2010 have been received to date. The remaining 24% of the account receivable trade balance is due from joint interest partners. At December 31, 2010, approximately \$193,000 (year end December 31, 2009 - \$217,500) of receivables were outstanding for more than 90 days.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during winter months because the ground surrounding the sites in these areas consists of swampy terrain. At present, all of the Company's properties are accessible year round, except the Company's northeastern Alberta lands in respect of which an all weather access road is presently under construction. Year round accessibility doesn't guarantee 100 percent access especially during spring break-up. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Company. Major facilities through which the Company's production is processed may temporarily be shut down for a short period of time during the year to conduct repair and maintenance operations.

Environmental Regulations

The oil and gas industry is currently subject to environmental regulations pursuant to a variety of Provincial and Federal legislation. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of the applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operation costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur significant costs to remedy such discharge. The Company maintains an insurance program consistent with industry practice to protect against losses due to accidental destruction of assets, well blowouts, pollution and other operating accidents or disruptions and has implemented an Emergency Response Plan. Although the Company believes that it is in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Company's financial condition, results of operation or prospects. For further details of risks relating to environmental matters see the Company's AIF.

CRITICAL ACCOUNTING ESTIMATES

The Company's management prepared the financial statements in accordance with Canadian GAAP. GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes and these estimates and assumptions are developed based on best available information and are believed by management to be reasonable under the existing circumstances. Over time newly acquired information may result in the revision of estimates and assumptions. The information below describes what management believes involve the most use of estimates and assumptions. Additional estimates are available under note 2 in the Company's annual financial statements as at and for the years ended December 31, 2010 and 2009.

Reserves

Reserve estimates may have a significant effect on net earnings as a result of their impact on depletion, amortization and ceiling tests, which are discussed below. Independent reserve engineers perform evaluations on the Company's oil and reserves on an annual basis (and more frequently as may be requested by the Company from time to time). Evaluations are based on available geological, geophysical and historical economic data. Changes may occur as a result of actual reservoir performance, changes in commodity prices and changes to the Company's future plans. Changes to reserve estimates may impact the Company's depletion calculation and ceiling test.

Depletion and amortization

The Company follows the full cost method of accounting for its petroleum and natural gas properties. All costs relating to the acquisition, exploration and development of petroleum and natural gas reserves, including asset retirement costs, are capitalized and costs associated with production are expensed. Capitalized costs, excluding costs relating to unproved properties, are depleted and amortized using the unit-of-production method, based on estimated proved petroleum and natural gas reserves, before royalties, as determined by independent engineers. A change in estimated reserves would have an impact on the Company's depletion rate.

Ceiling test

Oil and gas assets are evaluated in each reporting period to determine that their net book value is recoverable and does not exceed their fair value. The net book value is assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves and the lower of cost and market of unproved properties exceeds the net book value of the oil and gas assets. If the net book value of the oil and gas assets is assessed not to be recoverable, an impairment loss is recognized. The impairment loss is estimated as the amount by which the net book value of assets exceeds the sum of the fair value of proved and probable reserves and the cost (less any impairment) of unproved properties that have been subject to a separate test for impairment and contain no probable reserves. Fair value of proved and probable reserves is based on expected future net revenues (based on future product prices and costs) discounted at risk-free rates, without giving effect to abandonment, taxes or financing costs. The estimates identified in calculating the Company's ceiling test, by their very nature are subject to measurement uncertainty and any changes to these estimates may impact the financial statements materially.

Asset retirement obligations

Asset retirement obligations ("ARO") associated with site restoration and abandonment of tangible long-lived assets are initially measured at fair value by estimating the cost a third party would incur in performing the tasks necessary to retire such assets. The fair value of the ARO is recorded in the financial statements as a liability, equal to the present value of expected future cash outflows, with a corresponding increase in the carrying amount of the related asset. Subsequent to initial measurement, the effect of the passage of time on the ARO, or accretion expense, and the amortization of the asset retirement cost are charged to earnings in the period. Changes to the above estimates would impact the ARO liability recorded on the Company's balance sheet and impact the accretion expense recorded on the Company's statement of operations and comprehensive loss.

Income taxes

The Company uses the asset and liability method of accounting for income taxes. Under this method, the Company records future income taxes for the effect of any difference between the accounting and income tax basis of an asset or liability. A future income tax asset or liability is recorded based on when temporary differences are expected to reverse and the related tax rate in those periods. All tax filings are subject to audit and potential reassessment after the fact. As a result of the above, actual income taxes and future income tax assets or liabilities may differ from estimates.

Stock-based compensation

The Company has a stock based compensation plan and stock based payments relating to stock options are measured using the fair value method of accounting. For stock options granted, fair value is measured at the grant date and compensation expense is recognized in the financial statements over the vesting period of the awards with a corresponding increase in contributed surplus. Fair values are determined using the Black – Scholes option pricing model. Once the value of the options is determined as of the grant date, no adjustments are recorded thereafter. It is likely that the actual value of options will differ from what has been recorded in the financial statements.

Accrual accounting

The accrual method of accounting requires management to estimate certain amounts that haven't been received at a certain date; however, in the case of royalty, operating, G&A and capital costs, obligations have been created or in the case of revenues, products have been delivered. In its estimates management uses project information and third party documentation in order to record its accruals.

INTERNATIONAL FINANCIAL REPORTING STANDARDS ("IFRS")

The CICA Accounting Standards Board adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public companies will converge with International Financial Reporting Standards for financial periods beginning on January 1, 2011. The objective of the change-over is to improve financial reporting by having a set of accounting standards that are comparable with other international corporations. As a result of this transition in 2011, Trafina will be required to disclose comparative 2010 results in accordance with IFRS. This will require Trafina to restate its opening balance sheet as at January 1, 2010, all interim quarterly reports in 2010 and for its year-end ended December 31, 2010 using IFRS standards.

The Company's first step toward IFRS change-over was to complete a high level analysis of its financial records in order to determine the areas that will be materially impacted by the transition. The Company's analysis began by focusing on its balance sheet at December 31, 2009, in particular property and equipment, asset retirement obligations and contributed surplus.

The Company's second step toward IFRS change-over was to complete in-depth reviews with a particular focus on cash generating units, elections available for full-cost accounting companies, impairment testing, decommissioning liabilities and share-based compensation.

The Company is still assessing the impact on IFRS and has not finalized any opening balance sheet elections or accounting policy choices. The following is a description of the IFRS analysis to date that includes exemptions, policies and standards that the Company anticipates in adopting. The following also is not exhaustive as to all actual or potential differences which remain subject to determination and change.

IFRS-1 is a standard under IFRS that includes mandatory and optional exemptions that a Corporation may elect to help in its transition to IFRS. The elections are only available to corporations that are transitioning to IFRS for the first time and is only applicable to the opening balance sheet of the Company. The Company is still assessing its election choices; however, the following are IFRS-1 exemptions that the Company anticipates to elect and anticipated changes to its opening balance sheet at January 1, 2010. The following choices and anticipated changes are not exhaustive and remain subject to further analysis and change.

Property and equipment (“P&E”)

The Company has elected to use the deemed cost exemption under IFRS-1. This election enables the Company to use the balance sheet carrying amount of its P&E at December 31, 2009 prepared under Canadian GAAP. P&E amounts will be segregated into three categories; pre exploration expenditures, exploration and evaluation expenditures (“E&E”) and development and production expenditures (“D&P”). The Company expects to have no pre exploration expenditures at January 1, 2010. The Company does expect to have certain expenditures classified as E&E expenditures. The remaining expenditures will be classified as D&P expenditures. The P&E amounts that have been segregated to D&P expenditures will then be allocated to various cash generating units (“CGU”) based on the Company’s reserve volumes or reserve values. The Company anticipates that it will use proved plus probable reserve values to allocate these amounts and expects to have approximately 10 CGU’s. Once certain P&E assets are allocated to CGU’s the Company is required to perform an impairment test on each CGU.

Impairment of P&E assets

Upon the initial adoption of IFRS the Company is required to perform an impairment test in accordance with IAS 36 – “Impairment of Assets” on its E&E assets and D&P assets. The Company doesn’t expect any impairment write-down to occur on its E&E assets. An impairment test of D&P assets is performed at a CGU level and if impairment has occurred then a CGU is written down to the recoverable amount. Recoverable amount is defined under IFRS as the higher of “value in use” or “fair value less costs to sell”. The Company is expected to use fair value less costs to sell when testing for impairment. The Company anticipates impairments on some of its CGU’s on transition to IFRS.

Asset retirement obligations (“ARO”)

ARO under IFRS is referred to as Decommissioning Liabilities and is referenced under IAS-37 – “Provisions, Contingent Liabilities and Contingent Assets”. Under IFRS-1 the Company has elected to use an exemption that allows the Company to measure decommissioning liabilities as at the date of transition to IFRS in accordance with IAS-37 and recognize any transitional differences to Canadian GAAP in Retained Earnings. The decommissioning liability should reflect risks specific to the liability and will be based on management’s best assumptions and estimates. The discount rate used for the decommissioning liability will be a risk free rate as the estimated provision is adjusted to reflect risks specific to the liability. Under Canadian GAAP the Company currently uses a credit-adjusted risk free rate in its ARO calculation. As a result of using a risk free rate in its decommissioning estimate it is expected that the ARO /Decommissioning amount on the Company’s balance sheet will increase.

Contributed surplus (“share-based payments”)

The Company has chosen an election under IFRS-1, which allows the Company to apply IFRS-2 – “Share-based payments” to any unvested options outstanding as at December 31, 2009. At December 31, 2009 the Company has 983,000 unvested options outstanding. Under IFRS each award is treated as a separate award and a graded vesting method is used in the calculation instead of each award treated as a single award under Canadian GAAP and calculated using a straight-line method. As a result the Company expects its opening contributed surplus amount to increase over the Canadian GAAP amount on the transition to IFRS.

The last step in the transition to IFRS is to prepare 2010 quarterly financial statements and financial statements for the year ended December 31, 2010. The Company has begun the initial preparation process.

The Company is continually evaluating the impact on the change-over to IFRS reporting and remains in consultation with its auditors.

ADDITIONAL INFORMATION

Additional information relating to the Company, including the Company’s AIF, is filed on SEDAR at www.sedar.com and on the Company’s website at www.trafinaenergy.com. Information can also be obtained by contacting the Company at Trafina Energy Ltd., 2210, 530-8th Avenue S.W., Calgary, Alberta T2P 3S8.