International Frontier Resources Corporation
Management's Discussion and Analysis
2011 Annual and Fourth Quarter Results

International Frontier Resources Corporation is engaged in the exploration for and development of oil and gas reserves in north-west Montana USA, in the Central Mackenzie Valley ("CMV"), Northwest Territories, Canada and in south-east Alberta, Canada.

The following is management's discussion and analysis ("MD&A") of International Frontier Resources Corporation's ("International Frontier" or "IFR" or 'Frontier' or the "Corporation" or the "Company") operating and financial results for the year ended December 31, 2011, as well as information concerning the Company's future outlook based on currently available information. The MD&A has been prepared by management as at April 16, 2012 in accordance with IFRS and should be read in conjunction with the audited consolidated financial statements as at December 31, 2011 and 2010 together with accompanying notes, the Statement of Reserves Data and Other Oil and Gas Information contained in the Company's annual information form dated December 31, 2011. This MD&A contains forward looking statements, the definitions of which are defined herein.

The MD&A and the annual consolidated financial statements and accompanying notes have been prepared by management and approved by the Audit Committee and the Board of Directors.

The quarterly financial statements have not been reviewed or audited on behalf of the shareholders by the Company's independent external auditors. All financial measures presented in this MD&A Report are expressed in Canadian dollars unless otherwise indicated.

Operations Review

This report provides a review of operations for the period January 1, 2011 to March 31, 2012.

Southern Alberta Basin ~ NW Montana

In Q2 Frontier entered into Mineral Title Purchase and Sale Agreements ("PSA") with ten vendors to purchase title on the vendor's freehold mineral rights ("fee acreage" or "fee land") for US$186.33 per net mineral acre. In Q4, 2011 a title opinion was completed, the report confirmed that the vendor's own an interest in 17,083 gross ~ 14,412 net mineral acres. As a result of the vendors owning less net acres than originally thought the purchase price will be adjusted downward to US$2,609,388 (after estimated closing adjustments) from the $3,183,133 reported in a news release dated May 31, 2011.

In Q4 the Company entered into Mineral Title Purchase and Sale Agreements with three vendors to purchase up to 5,600 gross acres at US$186.33 per net acre. A review on the mineral titles is in progress, the title opinion should be completed in June 2012 after which closing will occur.

The majority (95%) of the fee acreage is located on the Blackfeet Reserve ("Reserve") in Glacier County, NW Montana. The Reserve covers an area of 1.5 million acres of which two-thirds is prospective for tight oil resource plays. The prospective formations include the Bakken, Three Forks, Nisku, Lodgepole and a series of Cretaceous plays in the thrust belt on the west side of the Reserve.

The previous owners of the fee acreage entered into leases with various oil companies and land brokers. For the most part the land brokers transferred the leases to their clients - Anschutz Exploration (private), Newfield Production Company (NYSE: NFX) and Rosetta Resources (NASDQ: ROSE). Anschutz, Newfield and Rosetta have each entered into lease agreements with the Blackfeet covering large land blocks, each in excess of 250,000 acres. Under the terms of the Blackfeet lease agreements the companies have annual drilling commitments to earn in lands which they select at the end of their lease term (2014/15).

Companies that hold leases on Frontiers' fee acreage are required to drill a well, or wells, before the term of their lease(s) expire. If a well is drilled Frontier is carried and receives a royalty on any

production obtained from the lease. If a well is not drilled the acreage reverts to IFR (100% net revenue). The leases expire at various times commencing in 2014 and running out to 2018. The leases reserve in favor of the lessor (Frontier) gross over-riding royalties ranging from 12.50% to 18.75%. As Frontier owns the mineral titles our fee acreage never expires.

As a mineral title owner Frontier is not entitled to confidential well data or the operators drilling plans. In future leases Frontier plans to increase the royalty, decrease the term of the lease, and include a clause whereby operators will provide confidential well data.

A summary of activity in the Southern Alberta Basin to March 31, 2012 is as follows,

- **Anschutz Exploration Corporation (private)** ~ Anschutz have permitted 14 wells on the Reserve. State records indicate that nine wells are drilled, one well is currently drilling, and four wells are permitted for drilling. The wells are all located in the thrust belt area on the west side of the Reserve. The target for 12 of the wells is Cretaceous age formations, primarily the Cone Member. The remaining two wells are testing up-hole objectives. The wells are at various stages in terms of drilling, completion, multi-fracing and production testing. To date all wells are classified as confidential.

  The exploration trend that Anschutz is drilling on is 36 miles long. Frontiers' fee land position on this promising trend is 9,480 acres. The Company's royalties on the west side of the Reserve range from 12.50% to 18.75%. To date there have been two wells drilled and one well permitted directly offsetting Frontiers' fee acreage. In addition four wells have been drilled and four wells are permitted for drilling within a three to four mile radius of the Company's fee land parcels.

- **Rosetta Resources (NASDQ: ROSE)** ~ Rosetta have been drilling wells to evaluate the prospectivity of the Bakken System plays on the east side of the Reserve. Rosetta reports that 11 delineation wells encountered oil; they estimate a hydrocarbon resource in place of 6 billion barrels oil equivalent and 1,500 potential well locations on their 300,000 net acres. As of Q4/11 Rosetta have drilled three horizontal multi-frac wells, initial production rates from the middle Bakken interval are; Simonson ~ 104 BOEPD, Riverbend 7- 4H ~154 BOEPD and Riverbend 12-13H ~ 403 BOEPD. Frontier has 1,710 fee acres located within a ½ to three-mile radius of the Riverbend 12-13H discovery well. In the Riverbend area Frontiers' royalties range from 15% to 18.75%.

  Rosetta's 2012 plans for the Southern Alberta Basin are, "completion of seven-well horizontal drilling program, test new frac stimulation methodology, maintain and high-grade acreage position. Rosetta has identified fracture stimulation design improvements to utilize in three of four remaining horizontal wells, improve isolation for more effective stimulations using a cement liner and perf & plug frac, we have advanced the well science work needed to "crack code" on a complex play".

  Of the remaining four horizontal wells to be drilled in 2012 Frontier has fee land directly offsetting two of the wells. The Company's fee land position on the east side of the Reserve is 2,890 acres, the majority of which is in close proximity to delineation and horizontal wells that have already been drilled.

- **Newfield Production Company (NYSE: NFX)** are exploring in the central and eastern region of the Reserve. To date Newfield have permitted 16 wells. State records indicate that ten wells have been drilled and six wells remain to be drilled. In Q3/11 Newfield reported, "we are nearing the end of the vertical well drilling program, all wells drilled to date have encountered oil and we remain encouraged on the play. To date Newfield has drilled two horizontal wells on the play, one well was not fracture-stimulated and in the other well a 4,000-foot horizontal section was drilled and completed but only one-third of the frac was placed in the prospective zone. This well had an initial production rate (IP) of

225 BOPD from the Nisku ~ had the zone been fully fracture-stimulated the IP rate could have been much better"

Newfield have permitted three horizontal multi-frac wells that are within a one to three mile radius of Frontiers' fee land parcels. Newfield has not provided guidance on their 2012 drilling plans on the Reserve.

- **FX Energy (NASDQ: FXEN)** have drilled three vertical wells through the Bakken group and they report "logs, cores and tests were as good as or better than expected". The wells are located in the southeast corner of the Reserve.

- P**rimary Petroleum (TSXV: PIE)** announced the sale of 94,757 net acres to an undisclosed major joint venture partner for $48.5 million ($512/acre). The sale proceeds will be used to acquire 3D seismic, drill six vertical pilot wells and six horizontal wells. The JV partner has an option to acquire an additional 17.50% interest in the play for $41 million. If the option were exercised the JV partners' cost per acre would be $945. Primary reported that the 3D seismic and six vertical pilot wells should be finished in Q2/12. Frontier has open fee acreage (100% net revenue) ½ mile east of the Rockport 16-19V vertical pilot well and two miles north of the Springhill 14-34V vertical pilot well.

- In SW Alberta, Townships 1 - 3 Ranges 17 - 25 W4M, immediately north of the Montana border operators have licensed or drilled 35 wells. The majority of the wells are on confidential status however there has been some encouraging results recently reported ~ Dee Three IP4: 550 bopd – IP30: 415 bopd and a second well IP3: 800 bopd, Legacy-Bowood IP14: 357 bopd and Murphy IP42: 400 bopd and on a second well IP30: 216 bopd. Further north on the play fairway Argosy announced an IP of 585 bopd and Torc IP4: 500 bopd ~ IP90: 280 bopd (source Macquarie report 29 March 2012). The report also mentioned 12 – 15 mmbbls in place per 640 acres, which compares to Rosetta's estimate of 13 – 15 mmbbls in place per 640 acres. Frontier has fee lands immediately adjacent to the Alberta border and on trend with wells recently drilled.

It should be noted there have also been a number of disappointing wells drilled on the play in both Montana and Alberta however industry continues to drill wells to see if they can un-lock the potential of the tight oil resource plays in the Southern Alberta Basin.

It is worthwhile advising shareholders on why the Company chose the Royalty model versus a working interest in a resource play. There is considerable risk associated in the early stages of developing a resource play. The challenges facing a junior company today are, enormous land prices for resource prospective land and limited access to drilling rigs and frac pumping equipment at competitive prices. Resource plays are capital intensive with horizontal drilling costs ranging from $2 million to $10 million and fracing costs of $1+ million. There is also capital required for pilot wells, testing lateral well lengths, various frac methods, all of which makes for a very expensive proposition. Having said the above horizontal drilling and multi-frac technology has revitalized the industry and opened the door to many new oil & gas resource plays that 3-5 years ago were not even on the radar screen. It is for the above reasons Frontier chose to purchase fee acreage in the tight oil plays in NW Montana. It would be impossible to duplicate this acquisition in Alberta.

We are encouraged by the fact that wells continue to be drilled on the Reserve and remain optimistic that wells will get drilled on Frontiers' fee acreage.

Central Mackenzie Valley, NWT

There was renewed interest in the CMV in 2011 as Exploration Licenses covering approximately 2,218,735 acres were awarded for work commitments of $534 million. Husky was the top bidder being awarded two licenses for combined work commitments of $376 million. The land sale also

saw three new entrants with Conoco Phillips acquiring one license for a work commitment of $66.7 million, Imperial Oil acquiring two licenses for work commitments of $43 million and Shell Canada acquiring three licenses for work commitments of $43 million. MGM Energy also acquired three licenses for work commitments of $5 million. It is worthy to note that the new entrants are also proponents for the Mackenzie Valley gas pipeline ("MGP").

In Q1/12 Husky drilled two vertical pilot wells to evaluate the resource potential in an emerging Canol shale oil play. Conoco Philips Canada and MGM Energy Corp. have indicated that they plan to drill exploration wells in 2013 to evaluate unconventional shale resource plays. If the shale oil plays are encouraging then it is likely that horizontal multi-frac wells will be drilled to appraise the plays. If commercial oil is discovered west of the Mackenzie River then a pipeline will need to be built to tie-into the Enbridge oil pipeline that delivers oil from Norman Wells to Zama Alberta. If such a development occurs the value of our SDL & freehold assets would significantly increase.

Frontier holds an interest in three Significant Discovery Licenses ("SDL") and three freehold parcels, one of which is included in the Stewart SDL. The SDL lands cover 21,362 gross acres (3,430 net) and the two freehold parcels cover 28,570 gross acres (5,700 net). Freehold parcel M-39 is located within Imperial's CMV parcel 11 that was acquired for a work commitment of $21.5 million. The SDL acreage does not expire and nor will the freehold acreage if annual freehold rentals are paid.

In Q2/12 two exploration licenses are due to expire; as the total amount of the work commitment was not fulfilled the Company will forfeit a cash deposit in the amount of $339,150. A provision was included in the December 31, 2011 audited financial statements for $339,150 as an impairment of exploration and evaluation assets.

In March 2011 the National Energy Board approved the application for the Mackenzie Valley Pipeline. The applicants are in discussions with the Federal Government on a financial deal that would make the MGP viable. The proponents have until 2013 to commit to construct the MGP however no timeline for construction has been established.

Husky Oil Operations, operator of the SDL and freehold acreage, has not proposed any exploration activity in 2012/13. Frontier believes that it is prudent to not spend any significant capital on its northern assets until results on new wells, in particular the shale oil plays, are known.

Alderson – south east Alberta

The Company operates five producing oil wells and an oil battery located in the Alderson area of south-east Alberta. In Q3 a production optimization plan was completed resulting in production increasing from 28 BOPD in June 2010 to 41 BOPD in the second half of 2011.

Mannyberries – south east Alberta

In 2011, the Company acquired an additional 480 acres on the Manyberries prospect. The Company now holds a 100% interest in 1,120 acres. The acreage is prospective for oil in the Sawtooth and Sunburst channel sands.

The Company's website has been updated; it provides more details on the Company`s assets please go to www.internationalfrontier.com

The Company's MD&A for the year ending December 31, 2011 is provided as follows.

Liquidity, capital resources and financing activities

Working Capital

At December 31, 2011 cash and cash equivalents were $4,037,930 (December 31, 2010 $6,813,190), and working capital was $3,065,520 (December 31, 2010 - $6,590,615). At December 31, 2011 the Company had restricted cash securing letters of credit in the amount of $374,305; the letters of credit secure work deposits on the Company's Northwest Territories Exploration Licenses. At December 31, 2011 the Company set up a provision for EL-443 in the amount $305,555, this license will expire in May 2012 and the deposit will be forfeited. At December 31, 2009 the Company set up a provision for EL-445 in the amount of $68,750 and wrote these costs off as impairment costs in that year. Subsequent to the year ended December 31, 2011 the Company received notification that $35,155 net of the total deposit has qualified as eligible expenditures, therefore the Company will be required to pay the remaining amount of the deposit of $33,595 when the license expires in May 2012.

The decrease in working capital at December 31, 2011 is the result of the purchase of mineral titles in Northwest Montana, USA of $3,193,370 mitigated by increased net oil revenues in 2011.

Future Capital Requirements

The Corporation regularly forecasts its capital needs on an annual, quarterly and monthly basis. The Corporation's current internally generated cash flows do not provide sufficient capital for the Corporation's current exploration plans. Historically, the Corporation has relied on proceeds from the sale of its Common Shares to fund its operations. In order to accelerate the Corporation's current exploration programs the Corporation may require additional capital. The timing, pace, scope and amount of the Corporation's capital expenditures is largely dependent on the operators capital expenditure program(s) and the availability of capital to the Corporation.

The Corporation may obtain funds for future capital investments from strategic alliances with other energy or financial partners, the issuance of additional Common Shares, preferred shares or debt securities, project financing, sale of property interests, or other arrangements, all of which may dilute the interest of the Corporation's existing shareholders or the Corporation's interest in the specific project financed. The Corporation may change the allocation of capital among the categories of anticipated expenditures depending upon future events that the Corporation cannot predict. For example, the Corporation may change the allocation of its expenditures based on the actual results and costs of future exploration, appraisal, development, production, property acquisition and other activities. In addition, the Corporation may have to change its anticipated expenditures if costs of placing any particular discovery into production are higher, if the field is smaller or if the commencement of production takes longer than expected.

In the management of capital, the Company includes shareholders' equity, cash and cash equivalents, marketable securities and restricted cash less accounts payable and current portion of decommissioning liabilities in the definition of capital. Management reviews its capital requirements on an ongoing basis and believes that its approach, given the relative size of the Company is reasonable. As at December 31, 2011, the Company's capital as defined above was approximately $2,925,055 (December 31, 2010 – $6,771,180).

The Corporation has a number of options available to it if existing working capital does not cover future capital expenditures including, but not limited to, i) revising its capital expenditure plans ii) selling or leasing mineral acreage in Montana iii) selling 100% interest in a property to a third party, iv) obtain joint venture financing from a third party, v) obtaining debt financing, or a combination of these possible steps.

Annual Results

The following table summarizes results for the years 2011 and 2010:

	2011	2010
Statement of operations		
Sales volumes - BOE/ day (Canada)	37	28
Production volumes - BOE/ day (Canada)	37	28
Oil revenues, net (Canada)	$ 770,850	$ 474,515
Interest income from continuing operations	$ 36,105	$ 18,150
Net loss and comprehensive loss		
Net loss from continuing operations	$ (673,340)	$ (4,483,885)
Net loss from discontinued operations	$ -	$ (113,250)
Net loss and comprehensive loss	$ (673,340)	$ (4,597,135)
Loss per share		
Net loss from continuing operations per share	$ (0.01)	$ (0.08)
Net loss from discontinued operations per share	$ (0.00)	$ (0.00)
Net loss per share	$ (0.01)	$ (0.08)
Cash flow		
Net cash provided (used in)		
Operating activities	$ (229,245)	$ (894,150)
Investing activities	$ (2,546,015)	$ 3,615,210
Financing activities	$ -	$ -
Balance sheet		
Assets of Continuing operations		
Exploration and evaluation assets	$ 9,814,875	$ 6,491,090
Property and equipment	$ 1,109,615	$ 1,158,145
Total assets	$ 15,727,840	$ 15,405,755
Working capital	$ 3,065,520	$ 6,590,615
Investing Activities		
Canada	$ 514,180	$ 470,115
United States	$ 3,193,370	$ -
Discontinued operations	$ -	$ 108,870
	$ 3,707,550	$ 578,985

Summary of Alderson Operations

Twelve months ended	December 31, 2011		December 31, 2010	
Sales volumes (Bbl/day)		37		28
Production volumes (Bbl/day)		37		28
Oil Revenues	$	1,017,325	$	712,525
Royalties		246,475		238,010
Net Revenues		770,850		474,515
Operating expenses		363,235		393,680
Net Income	$	407,615	$	80,835
Oil Sales ($/BBL)	$	75.93	$	68.83
Operating costs ($/BBL)	$	27.11	$	38.03
Depletion per BOE	$	11.77	$	18.66

- Oil sales and production volumes in 2011 were 37 Bbl/day a 32% increase as compared to 28 Bbl/day in 2010.
- Oil revenue in 2011 was $1,017,325, an increase of 42.78% as compared to $712,525 in 2010.
- Oil sales in 2011 were higher due to increased production volumes resulting from a field maintenance program in 2011 coupled with 10.32% increase in price received in 2011.
- During 2011 the Company paid royalties of $206,785, an increase of 49.75% as compared to $138,090 in 2010. The increase in royalties is consistent with the increase in production in the year.
- During the year the Company paid $39,690 (2010 - $99, 910) to employees and consultants pursuant to the Company`s Royalty Incentive Plan. In 2010 this amount included $75,795 paid pursuant to the sale of the Company's North Sea operations.
- Operating expenses in 2011 were $363,235 or $27.11 per Bbl a decrease of 28.71% per Bbl as compared to $393,680 or $38.03 per Bbl in 2010.
- The decrease in operating expenses per BBL in 2011 is due increased production coupled with a decrease in operating expenses in the year

Interest income

- In 2011 the Company earned interest income of $36,105 from short-term investments (2010 - $18,150).
- The increase in interest income in 2011 was due to an increase in funds invested during the year coupled with an increase in interest rates in 2011.

Depletion, depreciation and impairments

Depletion, depreciation and impairments at December 31, 2011 and 2010 consist of the following;

Depletion, depreciation and impairments	Dec. 31, 2011		Dec. 31, 2010	
Depletion of oil and gas properties	$	158,910	$	188,920
Impairment of oil and gas properties		39,810		927,130
Depreciation of equipment		2,330		2, 975
	$	201,050	$	1,119,025

- Depletion of oil and gas properties for the year ended December 31, 2011 was $158,910 or $11.77 per Bbl a decrease of $30,010 as compared to $188,920 or $18.66 per Bbl for the same period in 2010.
- The decrease in depletion in 2011 was due to a decrease in the depletable cost base at December 31, 2011.
- At December 31, 2011 an impairment test was performed which calculates the amount by which the carrying amount of capitalized costs related to producing properties exceeds the fair value of the reserves as estimated by the Company's reservoir engineers at December 31, 2011. As a result a $39,810 (2010 - $927,130) impairment charge of petroleum and natural gas assets has been recorded as part of depletion to reflect the excess carrying amount of assets over fair value of future reserves in Canada.

Exploration and evaluation costs

- The carrying value of exploration and evaluation properties of $9,814,875 at December 31, 2011 (December 31, 2010 - $6,491,090) have been evaluated as of December 31, 2011 and it was determined that no costs had met the requirements to be transferred to property and equipment.
- These costs were also evaluated for impairment and it was determined that an impairment of $307,155 existed with respect to expiration of licenses in the NWT for the period ended December 31, 2011 (December 31, 2010- $2,765,065)
- At December 31, 2011 the Company booked a recovery of exploration and evaluation assets in the amount of $35,155 which represents eligible expenditures with respect to EL-445. The total amount of the license of $68,750 was written off in 2009.

Accretion of asset retirement obligation

- Accretion of asset retirement obligations at December 31, 2011 were $20,840, an increase of $5,200 compared to $15,640 in 2010.
- Increase in accretion in 2011 is due to increase in decommissioning liability of $75,900 with respect to change in estimates at December 31, 2011.

General and administrative expenses

	2011	2010
Investor relations	$ 29,970	$ 18,650
Filing and transfer fees	28,675	23,255
Professional fees	92,270	100,700
Consulting fees and salaries	224,060	328,435
Consulting fees and salaries – capitalized	-	(49,250)
Rent and corporate costs	166,095	148,675
	$ 541,070	$ 570,465

- In 2011 general and administrative expenses were $541,070, a decrease of $29,395 or 5.15% as compared with $570,465 in 2010.

Stock based compensation

- Stock based compensation costs of $97,190 were calculated using the Black Scholes model for options granted in the second and fourth quarters of 2011.

Net loss

For the year ended December 31, 2011 the Company recorded a consolidated net loss of $673,340 ($0.01 loss per share).

Net earnings (loss):	2011	2010
Net loss from continuing operations	$ (673,340)	$ (4,483,885)
Net loss from discontinued operations	-	(113,250)
Consolidated net loss	$ (673,340)	$ (4,597,135)

Loss per share		2011		2010
Continuing operations	$	(0.01)	$	(0.08)
Discontinued operations	$	(0.00)	$	(0.00)
Loss per share	$	(0.01)	$	(0.08)

- Net loss from continuing operations decreased in 2011 as compared to 2010 due to an impairment of exploration and evaluation assets in NWT, Canada in 2010 of $2,765,065 and depletion, depreciation and impairments of properties and equipment in Canada of $1,119,025 booked at December 31, 2010 (December 31, 2011 - $307,155 and $201,050 respectively)
- The loss from discontinued operations in 2010 is represented by a net loss from U.K. operations at December 31, 2010 of $89,610 and loss booked on the impairment of assets of discontinued operations of $23,640.

Financial Instruments

As disclosed in Note 3 to the consolidated financial statements, the Company holds various forms of financial instruments. The nature of these instruments and the Company's operations expose the Company to interest rate risk, foreign exchange risk, fair value risk and industry credit risk. The Company manages its exposure to these risks by operating in a manner that minimizes its exposure to the extent practical.

a) Fair value of financial assets and liabilities: The Company's financial instruments as at December 31, 2011 and 2010 include cash and cash equivalents, trade accounts receivable, restricted cash and trade accounts payable. The fair values of trade accounts receivable and trade accounts payable approximate their carrying amounts due to their short terms to maturity. The cash and cash equivalents and the restricted cash balances are equal to their fair values.

	2011		2010	
	Carrying Value ($)	Fair Value ($)	Carrying Value ($)	Fair Value ($)
Financial assets:				
Receivables	118,830	118,830	111,010	111,010
Total financial assets	118,830	118,830	111,010	111,010
Financial liabilities				
Payables and accruals	1,473,195	1,473,195	607,600	607,600
Total financial liabilities	1,473,195	1,473,195	607,600	607,600

The Company classifies the fair value of financial instruments held for trading according to the following hierarchy based on the amount of observable inputs used to value the instrument.

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. 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 marketplace.

Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

At December 31, 2011 cash and cash equivalents and restricted cash have been classified as Level 1.

b) **Credit risk:** Substantially all of the accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Though, the Company markets its oil to only one marketer revenues are not significant so that the exposure to the Company is minimized. Management does not believe that there is significant credit risk arising from any of the Company's customers or partners, as substantially all amounts outstanding at December 31, 2011 have been received subsequent to period end. The maximum exposure to loss arising from accounts receivable at any given time is equal to their total carrying amounts on the balance sheet.

Total receivables:	0 to 30 days	31 to 60 days	61 to 90 days	Greater than 90 days
$ 118,830	$ 108,830	$ -	$ 10,000	$ -

c) **Interest rate risk:** The Company is exposed to interest rate cash flow risk to the extent the changes in market interest rates will impact the Company's interest rate price risk. In addition, the Company is also exposed to interest rate risk to the Canada Revenue Agency for interest on unexpended funds on the Company's flow through share obligations from February 1 to December 31 of each year. The Company does not use interest rate hedges or fixed interest rate contracts to manage the Company's exposure to interest rate fluctuations. A 1% increase or decrease in interest rates would have had no material impact on the cash flow of the Company during the period ended December 31, 2011.

d) **Liquidity risk:** Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's objective in managing liquidity risk is to ensure that it has sufficient resources available to meet its liabilities when due. At December 31, 2011, the Company's accounts payable and accrued liabilities were $1,473,195 all of which are due for payment within normal terms of trade which is generally between 30 and 60 days. The Company regularly reviews its accounts payable balances and follows up on amounts past due. The Company's financial liabilities are summarized below:

Total payables:	0 to 30 days	31 to 60 days	61 to 90 days	Greater than 90 days
$ 1,473,195	$ 467,100	$ 15,100	$ 952,320	$ 38,675

Investing Activities

Exploration and evaluation assets

	Twelve months ended December31,					
	2011			2010		
	Canada	United States	Total	Canada	Discontinued Operations	Total
Cash Expenditures	$ 132,245	$ 2,232,075	$ 2,364,320	$ 203,750	$ 108,870	$ 312,630
EL -443 Accrual	$ 305,555	-	305,555	266,365	-	266,365
Property accruals	-	961,065	961,065	-	-	-
	$ 437,800	$ 3,193,140	$ 3,630,940	$ 470,115	$ 108,870	$ 578,995

- Capital expenditures in 2011 were $2,364,320 (2010 - $312,630) of which $132,245 or 6% (2010 – 65%) is related to activities in Canada and $2,232,075 or 94% is related to the costs to acquire mineral titles in Northwest Montana, USA.
- At December 31, 2011 the Company accrued $961,065 with respect to costs to purchase mineral titles in Northwest Montana, USA.
- In 2010, capital expenditures of $108,870 relate to costs incurred for drilling costs incurred in the North Sea.

Property and equipment

- During 2011 the Company incurred $76,620 (2010 - $nil) with respect to Battery turnaround costs for the Company's oil battery at Alderson. Alberta.

Obligations

- The Company is party to an agreement to lease its premises until December 31, 2014. The annual rent of premises consists of a minimum rent payment of $43,120 plus occupancy cost per year for 2012 to 2014.
- The Company has established a Royalty Incentive Agreement for employees, consultants and senior executives that are also directors. Under the plan, the compensation committee issues units on an annual basis to employees, consultants and directors. The units entitle the holder to receive an annual payment based on 2% of the Company's annual production revenue, net of transportation and processing fees. Under the terms of the agreement, once the Company has recovered payout of 100% of its cumulative annual capital expenditures from licenses and lands owned by the Company, the payment to employees, consultants and directors is based on 4% of the Company's annual production revenue less transportation and processing fees. At December 31, 2011, payout of 100% of cumulative annual capital expenditures had been reached on the Alderson oil property.

Related Party Transactions

Certain officers who are directors and consultants provide professional, consulting and management services to the Company and are eligible to receive royalties pursuant to the Company's Royalty Incentive Plan. The amounts paid to officers (directors) and consultants during for the period ending December 31, 2011 are provided below, these costs are included in general and administrative expenses on the consolidated statements of earnings (loss), deficit and comprehensive earnings (loss) at December 31, 2011:

- Compensation paid to executive officers was $213,750 (2010 - $233,100) of which $Nil (2010 - $49,250) was capitalized to property and equipment for the year ended December 31, 2011.
- At December 31, 2011 royalties of $39,690 (2010 - $99,910) were paid to officers and consultants pursuant to the Company's Royalty Incentive Plan. Royalties paid in 2010 include an amount of $75,795 covering the sale of the Company's North Sea operation.

Summary of Fourth Quarter Results

Selected financial information:

	Three months ended, December 31,		Three months ended, September 30	
	2011	2010	2011	2010
Statement of operations				
Sales volumes - BOE/ day (Canada)	39	29	48	26
Production volumes - BOE/ day (Canada)	41	26	44	31
Oil revenues, net (Canada)	$ 223,440	$ 145,940	$ 242,630	$ 111,445
Interest income from continuing operations	$ 10,225	$ 15,355	$ 7,780	$ 1,055
Net loss and comprehensive loss				
Net loss from continuing operations	$ (297,685)	$ (3,483,475)	$ (29,550)	$ (76,380)
Net loss from discontinued operations	$ -	$ (1,185)	$ -	$ -
Net loss and comprehensive loss	$ (297,685)	$ (3,484,660)	$ (29,550)	$ (76,380)

	Three months ended, December 31,		Three months ended, September 30	
	2011	2010	2011	2010
Net loss per share				
Net loss from continuing operations per share	$ (0.00)	$ (0.06)	$ (0.00)	$ (0.00)
Net loss from discontinued operations per share	$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)
Net loss per share	$ (0.00)	$ (0.06)	$ (0.00)	$ (0.00)
Cash flow				
Net cash provided (used in)				
Operating activities	$ 139,525	$ (252,910)	$ (1,820)	$ (77,830)
Investing activities	$ (208,320)	$ 28,140	$ (1,877,595)	$ 24,500

Summary of Alderson Operations

Three months ended	December 31, 2011	September 30, 2011	December 31, 2010
Sales volumes (Bbl/day)	39	48	29
Production volumes (Bbl/day)	41	44	26
Oil Sales	$ 299,725	$ 310,790	$ 186,640
Royalties	76,285	68,160	40,700
Net Revenues	223,440	242,630	145,940
Operating expenses	54,715	82,545	146,715
Net Income	$ 168,725	$ 160,085	$ (775)
Oil Sales ($/BBL)	$ 83.96	$ 69.82	$ 70.09
Operating costs ($/BBL)	$ 15.33	$ 18.55	$ 55.09
Depletion per BOE	$ 15.24	$ 10.41	$ 22.17

- Sales volumes for the three months ended December 31, 2011 were 39 Bbl/day a 18.75% decrease as compared to 48 Bbl/day for the third quarter of 2011 (Q4,2010 – 29 Bbl/day)
- Increase in sales volumes in the third quarter of 2011 is due to increased production resulting from a field maintenance program in Q2, 2011 and related oil inventory sold in Q3, 2011.
- Oil revenue in Q4, 2011 was $299,725 which is consistent with $310,790 in Q3, 2011 (Q4, 2010 - $186,640)
- In Q4, 2011 the Company paid royalties of $76,285 and increase of 11.92% as compared to Q3, 2011 (Q4, 2010 - $40,700). The increase in royalties is consistent with the increase in production in the period.
- Operating expenses in the fourth quarter of 2011 were $54,715, a decrease of $27,830 or $3.22 per Bbl as compared to the third quarter of 2011 (Q4, 2010 - $146,715 or $55.09 per Bbl)
- The decrease in operating expenses per BBL in Q4, 2011 is due increased production coupled with a decrease in expenses in the quarter.

Interest income

- In Q4, 2011 interest income from short term investments was $10,225 (Q3, 2011 - $7,780, Q4, 2010 - $15,355) the increase is due to an increase in interest rates received in Q4, 2011.

Depletion, depreciation and impairments

For the three months ended	December 31, 2011	September 30, 2011	December 31, 2010
Depletion of oil and gas properties	$ 57,700	$ 41,675	$ 52,220
Impairment of oil and gas properties	39,810	-	927,130
Depreciation of equipment	520	560	680
	$ 98,030	$ 42,235	$ 980,030

- Depletion of oil and gas properties for the three months ended December 31, 2011 was $57,700 or $15.24 per Bbl as compared to $41,675 or $10.41 per Bbl Q3, 2011. (Q4, 2010 $52,220 or $22.17 per Bbl)
- Increase in depletion in Q4, 2011 is due to increased carrying value of properties and equipment in the period.

Accretion of asset retirement obligation

- Accretion of asset retirement obligations for the three months ended December 31, 2011 was $3,660 compared with $3,484 in Q3, 2011 (Q4, 2010 - $6,285).

General and administrative expenses

Three months ended:	31-Dec-11	30-Sep-11	31-Dec-10
Investor relations	$ 9,985	$ (2,290)	$ 155
Filing and transfer fees	2,120	10,440	270
Professional fees	54,705	9,540	69,165
Consulting fees and salaries	55,840	55,955	64,255
Consulting fees and salaries – capitalized	-	-	(6,245)
Rent and corporate costs	57,590	34,740	41,510
	$ 180,240	$ 108,385	$ 169,110

- In Q4 general and administrative expenses were $180,240 an increase of $71,855 or 66.30% as compared with $108,385 in Q3, 2011 (Q4, 2010 - $169,110)
- The increase in G&A is due to year end accruals for accounting fees at December 31, 2011.

Net loss

Three months ended:	Q-4 2011	Q-3 2011	Q-4 2010
Net loss from continuing operations	$ (297,685)	$ (29,550)	$ (3,483,475)
Net loss from discontinued operations	-	-	(1,185)
Net loss	$ (297,685)	$ (29,550)	$ (3,484,660)
Loss per share			
Continuing operations	$ (0.00)	$ (0.00)	$ (0.06)
Discontinued operations	$ (0.00)	$ (0.00)	$ (0.00)
Loss per share	$ (0.00)	$ (0.00)	$ (0.06)

The increased loss in Q4 as compared with Q3 is a result of the following adjustments.

- An impairment charge on properties and equipment of $39,810 in Q4, 2011
- An impairment charge of exploration and evaluation assets of $305,155 in Q4, 2011
- Accrual for year-end audit fees and 51-101 reserve report costs of $55,000.
- Stock based compensation expense of $24,090 in Q4 for options issued in that period

Summary of Quarterly Results

The following table summarized the Company's financial and operating highlights for the past eight quarters:

Quarter ended:	Mar 31, 2010	June 30, 2010	Sept 30, 2010	Dec 31, 2010
Statement of operations				
Sales volumes - BOE/ day (Canada)	29	30	26	29
Production volumes - BOE/ day (Canada)	29	25	31	26
Oil revenues, net (Canada)	$ 148,225	$ 68,905	$ 111,445	$ 145,940
Net loss and comprehensive loss				
Net loss from continuing operations	$ (149,450)	$ (774,580)	$ (76,380)	$ (3,483,475)
Net loss for discontinued operations	$ (104,255)	$ (7,810)	$ -	$ (1,185)
Net loss and comprehensive loss	$ (253,705)	$ (782,390)	$ (76,380)	$ (3,484,660)
Net loss per share				
Net loss from continuing operations per share	$ (0.00)	$ (0.01)	$ (0.00)	$ (0.06)
Net loss from discontinued operations per share	$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)
Net loss per share	$ (0.00)	$ (0.01)	$ (0.00)	$ (0.06)
Balance Sheet				
Total assets	$ 19,253,585	$18,109,400	$ 17,945,340	$ 15,405,755
Working capital	$ 7,630,215	$ 7,294,650	$ 7,170,570	$ 6,590,615
Refundable Deposits	$ 640,670	$ 640,670	$ 640,670	$ 640,670
Funds flow from operations	$ (134,130)	$ (436,890)	$ (77,830)	$ (245,300)

Quarter ended:	March 31, 2011	June 30, 2011	Sept 30, 2011	Dec. 31, 2011
Statement of operations				
Sales volumes - BOE/ day (Canada)	26	34	48	39
Production volumes - BOE/ day (Canada)	28	35	44	41
Oil revenues, net (Canada)	$ 122,665	$ 182,115	$ 242,630	$ 223,440
Net loss and comprehensive loss				
Net earnings (loss) from continuing operations	$ (132,955)	$ (213,150)	$ (29,550)	$ (297,685)
Net loss for discontinued operations	$ -	$ -	$ -	$ -
Net loss and comprehensive loss	$ (132,955)	$ (213,150)	$ (29,550)	$ (297,685)
Net loss per share				
Net loss from continuing operations per share	$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)
Net loss from discontinued operations per share	$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)
Net loss per share	$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)
Balance Sheet				
Total assets	$ 14,985,285	$14,543,495	$ 14,462,870	$ 15,727,840
Working capital	$ 6,124,775	$ 5,901,525	$ 4,375,000	$ 3,065,520
Refundable Deposits	$ 640,670	$ 374,305	$ 374,305	$ 374,305
Funds flow from operations	$ (187,010)	$ (179,725)	$ (1,820)	$ 139,310

Other Items

Outstanding shares, options and warrants

The Company's share capital structure is as follows:

As of:	December 31, 2011	April 16, 2012
Common shares outstanding	59,578,965	59,578,965
Options outstanding	5,531,500	5,531,500
Fully diluted	65,110,465	65,110,465

Additional details on the shares and stock options outstanding at December 31, 2011 are available in the notes to the December 31, 2011 audited consolidated financial statements.

Accounting Policies and Estimates

The Company is assessing the new and revised accounting pronouncements that have been issued that are not yet effective:

Adoption of IFRS

The Company has prepared its consolidated financial statements for year ended December 31, 2011 in accordance with IFRS 1 – *First-time Adoption of IFRS*. Previously, the Company prepared its financial statements in accordance with Canadian GAAP. The adoption of IFRS has not changed the Company's business activities or actual cash flow; however, it has resulted in adjustments to the Company's financial statements.

The areas that were most impacted by the transition to IFRS are accounting for exploration and evaluation assets, accounting for property, plant and equipment, asset impairment testing, and accounting for income taxes. Refer to Note 3 of the Company's consolidated financial statements for the Company's detailed IFRS accounting policies.

In order to allow the users of the financial statements to better understand the impact of the change to IFRS, the Company's Canadian GAAP balance sheets at January 1, 2010 and December 31, 2010, and the Company's consolidated statements of operations and comprehensive loss for the year ended December 31, 2010 have been reconciled to IFRS.

The following provides a summary reconciliation of the Company's 2010 Canadian GAAP and IFRS results. Further discussion of the significant IFRS accounting policy changes can be found in Note 18 of the Company's Consolidated Financial Statements.

	2010				
Summary of Net Earnings Reconciliation	**Q-1**	**Q-2**	**Q-3**	**Q-4**	**2010**
Net loss - GAAP	$ (270,115)	$ (658,925)	$ (100,335)	$ (5,194,000)	$ (6,223,375)
Additions (deductions):					
Exploration and evaluation costs	24,450	167,080	2,000	(1,624,750)	(1,431,220)
Depletion	(31,345)	(33,500)	(14,950)	(73,605)	(153,400)
Adjust investment in subsidiary to equity method of consolidation	(105)	(105)	(105)	(95)	(410)
Decommissioning liabilities - accretion	(9,410)	(10,010)	(10,900)	(10,895)	(41,215)
	(16,410)	123,465	(23,955)	(1,709,345)	(1,626,245)
Net loss - IFRS	$ (253,705)	$ (782,390)	$ (76,380)	$ (3,484,655)	$ (4,597,130)

Changes in accounting policies and new pronouncements

The Company is assessing the new and revised accounting pronouncements that have been issued that are not yet effective:

(a) Presentation of Financial Statements

In June 2011, the International Accounting Standards Board ("IASB") issued IAS 1, "Presentation of Items of OCI: Amendments to IAS 1 Presentation of Financial Statements." The amendments stipulate the presentation of net earnings and OCI and also require the Company to group items within OCI based on whether the items may be subsequently reclassified to profit or loss. Amendments to IAS 1 were effective for the Company on January 1, 2012 with required retrospective application and early adoption permitted.
The Company retrospectively adopted the amendments on January 1, 2012. The adoption of the amendments to this standard did not have a material impact on the Company's financial statements.

(b) Financial Instruments: Recognition and Measurement

In November 2009, as part of the International Accounting Standards Board's (IASB) project to replace International Accounting Standard (IAS) 39 Financial Instruments: Recognition and Measurement, the IASB issued the first phase of IFRS 9 Financial Instruments. It contained requirements for the classification and measurement of financial assets, and was updated in October 2010 to incorporate financial liabilities. The standard is applicable for annual periods starting on or after January 1, 2015.

(c) Fair Value Measurements

In May 2011, the IASB issued IFRS 13 Fair Value Measurement, which establishes a single source of guidance for all fair value measurements, clarifies the definition of fair value, and enhances the disclosures on fair value measurement. Prospective application of this standard is effective for fiscal years beginning on or after January 1, 2013, with early application permitted. The company does not anticipate significant changes to its fair value measurements and related disclosures as a result of this standard.

(d) Reporting Entity

In May 2011, the IASB issued IFRS 10 Consolidated Financial Statement, IFRS 11 Joint Arrangements, IFRS 12 Disclosures of Interests in Other Entities, and amendments to IAS 27 Separate Financial Statements and IAS 28 Investments in Associates and Joint Ventures. IFRS 10 creates a single consolidation model by revising the definition of control in order to apply the same control criteria to all types of entities, including joint arrangements, associates and special purpose vehicles. IFRS 11 establishes a principle-based approach to the accounting for joint arrangements by focusing on the rights and obligations of the arrangement and limits the application of proportionate consolidation accounting to arrangements that meet the definition of a joint operation. IFRS 12 is a comprehensive disclosure standard for all forms of interests in other entities, including joint arrangements, associates and special purpose vehicles. Retrospective application of these standards with relief for certain transactions is effective for fiscal years beginning on or after January 1, 2013, with earlier application permitted if all five standards are collectively adopted. The company is currently assessing the impact of these standards.

(e) Employee Benefits

In June 2011, the IASB issued amendments to IAS 19 Employee Benefits, which revises the recognition, presentation and disclosure requirements for defined benefit plans. The revised standard requires immediate recognition of actuarial gains and losses in other comprehensive income, eliminating the previous options that were available, and enhances the disclosure requirements for defined benefit plans. Retrospective application of this standard is effective for fiscal years beginning on or after January 1, 2013, with early application permitted. The company does not anticipate significant impacts as a result of these amendments.

Critical Accounting Estimates

Management is required to make judgments, assumptions and estimates in the application of International Financial Reporting Standards that have a significant impact on the financial results of the Company. Reserve estimates are a key component in the calculation of depletion, depreciation and accretion costs. A change in reserve quantity estimates will result in a corresponding change in DD&A costs. In addition, if capitalized costs are determined to be in excess of the calculated ceiling, which is based on reserve quantities and values, the excess must be written off as an expense. Decommissioning liabilities are estimated, discounted and carried on the balance sheet as a liability. A change in estimated future asset restoration costs will change the liability on the balance sheet and the amortization of the decommissioning liabilities included in property and equipment.

Operational and other business risks

Current Economic Conditions

The volatility in the price of oil and natural gas has created a substantially more volatile business environment. These conditions may limit certain of the Company's business activities and it will continue to provide risk for International Frontier's exploration projects.

Need to Replace and Grow Reserves

The future oil and natural gas production of International Frontier, and therefore future cash flows, are highly dependent upon ongoing success in exploring its current and future undeveloped land base, exploiting the current producing properties, and acquiring or discovering additional reserves. Without reserve additions through exploration, acquisition or development activities, reserves and production will decline over time as reserves are depleted.

The business of discovering, developing, or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited or unavailable, the ability of International Frontier to make the necessary capital investments to maintain and expand its oil and natural gas reserves may be impaired.
There can be no assurance that International Frontier will be able to find and develop or acquire additional reserves to replace and grow production at acceptable costs.

Exploration, Development and Production Risks

Oil and natural gas exploration in the Central Mackenzie Valley, NWT and in NW Montana involves a high degree of risk, which even with a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that expenditures made on future exploration by International Frontier will result in new discoveries of oil and natural gas in commercial quantities. 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 or additional seismic data and interpretations thereof.

The long-term commercial success of International Frontier depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that International Frontier will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participation are identified, International Frontier may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

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 recover of drilling, completion and operating cost. 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 rate 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.

In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blowouts, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

Reserve Estimates

The production forecast and recoverable estimates contained in International Frontier's engineering report are only estimates and the actual production and ultimate recoverable reserves from the properties may be greater or less than the independent estimates of McDaniel & Associates Consultants Ltd. There is no certainty that it will be commercially viable to produce any portion of the contingent resources identified in the May 2010 McDaniel & Associates report.

There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived thereof, including many factors that are beyond the control of International Frontier. The reserve and cash flow information set forth herein represent estimates only. The reserves and estimated future net cash flow from the assets of International Frontier have been independently evaluated effective December 31, 2011 by McDaniel & Associates Consultants Ltd. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditure, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of International Frontier. Actual production and cash flows derived thereof will vary from these evaluations, and such variations could be material. The foregoing evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived thereof contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations.

Contingent Resources

The resources assigned to the Company's properties have been classified as contingent. The Canadian Oil and Gas Evaluation Handbook (COGEH) Volume 1 defines contingent resources as quantities of oil and gas estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be sub classified based on project maturity and/or characterized by their economic status.

- Low Estimate: This is considered to be a conservative estimate of the quantity that will actually be recovered from the accumulations. If probabilistic methods are used this term reflects a P90 confidence level.
- Best Estimate: This is considered to be the best estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used this term is a measure of the central tendency of the uncertainty distribution (most likely/mode, P50/median, or arithmetic average/mean).
- High Estimate: This is considered to be an optimistic estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term reflects a P10 confidence level.

There is no certainty that a gas pipeline will be constructed to tie-in the Company's contingent resources, nor is there certainty that it will be commercially viable to produce any portion of the contingent resources identified in the McDaniel & Associates NWT contingent resource report date May 2010.

Volatility of Oil and Natural Gas Prices

The operational results and financial condition of International Frontier will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect of the operations, proved reserves, and financial conditions of International Frontier and could result in a reduction of the net production revenue of the Company causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings which might be made available to the Company are typically determined in part by the borrowing base of the reserves of International Frontier. A sustained material decline in prices from historical average prices could reduce the borrowing base of International Frontier, therefore reducing the bank credit available to International Frontier and could require that a portion of such bank debt be repaid.

Operational Hazards and Other Uncertainties

Oil and natural gas exploration operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, and oil spills, each of which could result in substantial damage to oil and natural gas wells, production faculties, other property and the environment or in personal injury. In accordance with industry practice, International Frontier is not fully insured against all of these risks, nor is all such risks insurable. Although International Frontier will maintain liability insurance, where available, in an amount which it considers adequate and consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event International Frontier could incur significant costs that could have a material adverse affect upon its financial condition. Business interruption insurance may also be purchased for selected facilities, to the extent that such insurance is available. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such equipment or access restrictions may affect the availability and/or cost of such equipment to International Frontier and may delay exploration and development activities. To the extent International Frontier is not the operator of its oil and gas properties, the Company will be dependent on other operators for timing of activities related to non-operating properties and will be largely unable to direct or control the activities of the operators.

Although property title reviews will be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such

reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of International Frontier which could result in reduction of the revenue received by the Company.

Competition

There is strong competition relating to all aspects of the oil and natural gas industry. International Frontier will actively compete for capital, skilled personnel, undeveloped land, reserve acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than does International Frontier.

Key Personnel

The success of International Frontier will depend in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse affect on International Frontier. International Frontier does not have key person insurance in effect for management. The contributions of these individuals to the immediate operations of International Frontier are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that International Frontier will be able to continue to attract and retain all personnel necessary for the development and operation of its business.

Environmental Risks

The oil and natural gas industry is subject to environmental regulation pursuant to a variety of international conventions and Canadian federal, provincial and municipal laws, regulations, and guidelines and Montana state laws and regulations. A breach of such regulations may result in the imposition of fines or issuances of clean up orders in respect of International Frontier or its assets. Such regulation may be changed to impose higher standards and potentially more costly obligations on International Frontier. There can be no assurance that future environmental costs will not have a material adverse affect on International Frontier.

Forward Looking Statements

Certain statements contained in this MD&A constitute forward-looking statements. The use of any of the words “anticipate”, “continue”, “estimate”, “expect”, “may”, “will”, “project”, “should”, “believe”, “strategy” and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements are based on reasonable assumptions but no assurance can be given that these expectations will prove to be correct and the forward-looking statements included in this MD&A should not be unduly relied upon. These statements are made only as of the date of this MD&A.

In particular, this MD&A may contain forward-looking statements including, but not limited to, the following:

- oil and natural gas production rates;
- commodity prices for crude oil or natural gas;
- supply and demand for oil and natural gas;
- the estimated quantity of oil and natural gas reserves, including reserve life;
- capital expenditure programs;
- future exploration, development and production costs;
- timing of drilling plans;
- plans for and results of exploration and development activities;
- expectations regarding the Corporation's ability to raise capital and to continually add to oil and natural gas reserves through acquisitions, exploration and development; and

- treatment under governmental regulatory regimes and tax laws.

With respect to forward-looking statements contained in this MD&A and other documents of public record, the Corporation has made assumptions regarding, among other things:

- future oil and natural gas production levels from IFR's properties and the prices obtained from the sales of such production;
- the level of future capital expenditure required to exploit and develop reserves; and
- the Company's ability to obtain financing on acceptable terms, as required.

The Corporation's actual results could differ materially from those anticipated in these forward-looking statements and information as a result of assumptions proving inaccurate and of both known and unknown risks as set forth below:

- general economic, political, market and business conditions;
- risks inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, capital, acquisitions of reserves, undeveloped lands, drilling equipment and skilled personnel;
- geological, technical, drilling and processing problems;
- incorrect assessments of the value of acquisitions;
- the availability of capital on acceptable terms;
- volatility in market prices for oil and natural gas;
- actions by governmental authorities, including regulatory, environmental and taxation policies; and
- fluctuations in foreign exchange or interest rates and stock market volatility
- ability to raise project finance capital from chartered banks

Other information

Additional information regarding International Frontier Corporation's reserves and other data are available on SEDAR at www.sedar.com